

Q3

State of the Market Report for PJM

January through September

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

11.12.2020

2020

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 *2020 Quarterly State of the Market Report for PJM: January through September*.³

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

² OATT Attachment M.

³ All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2020 Quarterly State of the Market Report for PJM: January through September*.

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Introduction

2020 Q3 in Review

The goal of competition in PJM is to provide customers wholesale power at the lowest possible price, but no lower. The PJM markets have done that. The PJM markets work, even if not perfectly. The results of the energy market were competitive in the first nine months of 2020. The results of the last base capacity auction, run in 2018 for 2021/2022, were not competitive and the underlying issues need to be addressed, including the overstated offer cap in the capacity market. The PJM markets bring customers the benefits of competition. But the PJM markets, and wholesale power markets in the U.S., continue to face challenges that potentially threaten the viability of competitive markets. The value of markets is under attack, from those who assert that energy prices are too low and from those who assert that markets are incompatible with decarbonization of the power sector. Organized, competitive wholesale power markets are the best way to facilitate the least cost path to decarbonization. Markets provide incentives for innovation and efficiency. Renewables can compete. Innovation will occur in renewable technologies in unpredictable and beneficial ways.

Some have suggested that, in response to FERC's MOPR order, states should opt out of the PJM capacity market using the Fixed Resource Requirement (FRR) option, as a preferred path to decarbonization, despite the lack of any evidence that the MOPR order would affect the competitiveness of renewables. The FRR approach is a nonmarket approach that would replace market incentives with judgments about preferred technologies and about appropriate pricing. As made clear in recent MMU analyses of FRR options in Illinois, Maryland, New Jersey and Ohio, the FRR approach is likely to lead to significant increases in payments by customers. More detailed FRR proposals in Illinois for the ComEd Zone and in New Jersey are primarily nuclear subsidy programs that would maintain or increase nuclear subsidies compared to the current Zero Emission Credits (ZECs) rules currently in place in both states while also providing for payments to some renewable resources at above market prices. The capacity market is a market. The discipline of markets

means that inefficient and high cost resources do not clear. The FRR construct is at best a weak form of cost of service regulation and centralized Integrated Resource Planning. Markets provide incentives to reduce costs and improve technology while the FRR approach would simply accept uneconomic offers as unavoidable and provide no incentives to reduce costs. The cost of service approach provides guaranteed profits based on the level of investment. The cost of service approach was rejected in favor of markets based on the fact that markets, among other things, shift risks to investors from customers and provide stronger performance incentives.

If the PJM states decide that carbon is a pollutant with a negative value, a market approach to carbon is preferred to an inefficient technology or unit specific subsidy approach or inconsistent RPS rules that in some cases subsidize carbon emitting resources. 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. Implementation of a carbon price using RGGI or a similar market mechanism by the states would mean that the states control the carbon price and that no FERC approval would be required and no PJM rule changes would be required. The carbon price would become part of the marginal costs of power plants and the impacts on production and consumption decisions would be market based. States would control the resulting revenues. This is the case regardless of the number of PJM states that join RGGI or a similar market.

The MMU continues to recommend that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to states in order to permit states to consider the development of a multistate framework: for RECs markets; for potential agreement on carbon pricing including the distribution of carbon pricing revenues; and for coordination with PJM wholesale markets.

PJM should proceed to run its overdue capacity market auctions as soon as practicable after receiving an appropriate order from FERC. Revenues for more than 160,000 MW of PJM capacity are at issue. PJM ran its last base

residual capacity auction in 2018 and missed the auctions in 2019 and 2020. No capacity market price has been established for June 1, 2021, or beyond.

PJM should not rush to overhaul its capacity market again. The current PJM capacity market design has not been given the opportunity to succeed. There are clear issues with the capacity market rules that prevent the intent of the design from being realized. These include the overstated offer cap, the shape and location of the capacity market demand curve, the application of penalties for nonperformance, the accuracy of load forecasting, and the role of demand side and energy efficiency resources. There is no evidence that the MOPR order will make the PJM capacity market less competitive or that nuclear and renewable resources will not clear. The MOPR rule could be modified to use the SMR approach to offer floors without a market overhaul.¹

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. Energy prices were lower in the first nine months of 2020 than in the first nine months of any year since the creation of PJM markets in 1999. Energy prices in PJM were already among the lowest in PJM's history in the first nine months of 2019. The load-weighted average real-time LMP was 23.1 percent lower in the first nine months of 2020 than in the first nine months of 2019, \$21.22 per MWh versus \$27.60 per MWh. Of the \$6.38 per MWh decrease, 57.7 percent was a direct result of lower fuel costs. The other major contributor to the decline in energy prices was the significant drop in demand as a result of both the mild winter weather and COVID-19. On a cumulative basis, PJM load was down 4.4 percent compared to the first nine months of 2019, and load was down 3.9 percent compared to weather normalized load.

As input prices change, markets react immediately. In the first nine months of 2020, coal-fired generation was markedly less competitive with gas-fired generation. In the first nine months of 2020, the short run marginal cost of combined cycle generation was substantially lower than the short run

marginal cost of even a new efficient coal plant as the combined result of lower gas prices and the high efficiency of gas-fired combined cycle plants. The capacity factor of coal units fell from 31.6 percent to 25.4 percent and the share of total PJM energy produced from coal fell from 24.5 percent in the first nine months of 2019 to 19.0 percent in the first nine months of 2020 while the share of gas increased from 36.2 to 40.9 percent. The increased role of gas-fired generation highlights the importance of ensuring that PJM has current, detailed and complete information on the gas supply arrangements of all generators. It is also essential that FERC consider and address the implications of the inconsistencies between the gas pipeline business model and the power producer business model.

Net revenue 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 are significantly affected by fuel prices, energy prices and capacity prices. Net revenues decreased for all unit types in the first nine months of 2020 compared to the first nine months of 2019 as a result of lower energy prices, although average energy market net revenues were higher in the third quarter than in either of the first two quarters of 2020 for all unit types. For example, theoretical net revenues decreased by 17 percent for a new combustion turbine, 23 percent for a new combined cycle, and 25 percent for a new nuclear plant. Theoretical net revenues decreased by 67 percent for a new coal unit, meaning that the theoretical capacity factor of a new entrant coal plant was 26 percent.

The PJM market design has brought significant benefits to participants and the fundamental current design of PJM markets is sustainable. There is no reason to overturn the key components of the PJM capacity and energy markets. The focus should be on the continued refinement of the market rules in order to ensure that the rules correctly incorporate the fundamentals of the markets, e.g. improved combined cycle modeling, accurate scarcity pricing, and matching dispatch and pricing intervals. Markets are preferred to the integrated resource planning approach, that some would reimpose, because markets provide technology neutral incentives to all market participants, including those who will introduce technologies not yet in existence. Markets

¹ Summary of the Sustainable Market Rule Proposal of the Independent Market Monitor for PJM, Docket Nos. ER18-1314-000, EL16-49-000, EL18-178-000 (Oct. 31, 2018) <http://www.monitoringanalytics.com/Filings/2018/IMM_Summary_of_Position_Docket_No_EL18-178_ER18-1314_EL16-49.pdf>.

continue to provide the most efficient way to organize the production of power at the lowest possible cost. Markets are also the most efficient way to integrate state supported renewable technologies.

The most important unresolved price formation issue is the real time process for defining prices and the underlying process for dispatching the system using PJM's SCED and LPC software.² PJM's current process creates an inconsistency between dispatch and pricing. The result of this dispatch and pricing misalignment is that prices do not reflect the actual marginal cost for the market interval. The existence of this core issue undermines the effectiveness of the existing market design and means that approaches like fast start pricing and the extended sloping ORDC would not produce the intended price formation results. The Commission directed PJM to address this issue prior to the implementation of fast start pricing. FERC approved PJM's short term proposal to resolve one part of the consistency issue in the near term, but there are significant consistency issues not addressed and new issues created in PJM's proposed short term approach. The short term changes will align real-time LMP with the target time of the SCED dispatch case, but the SCED dispatch case will continue to rely on a 10 minute ramp calculation. This means that prices will lag the corresponding dispatch signal by approximately five minutes, and by the time prices become active, resources will already be following a new dispatch signal. A 10 minute ramp time is not consistent with a five minute market, and misaligned dispatch, pricing, and uplift payments will persist until the long term change to a five minute ramp time is implemented. PJM has agreed to make the appropriate long term changes to dispatch and pricing and should not implement fast start pricing until the changes are in place.

The competitiveness of energy market prices cannot be taken for granted. Despite low marginal unit markups in the first nine months of 2020, 6.0 percent of marginal units set price with positive markups despite failing the Three Pivotal Supplier (TPS) test in the real-time energy market. This was the result of documented flaws in the application of offer capping when units fail the TPS test. PJM also schedules and pays uplift to units that fail the TPS test

without requiring that units use flexible operating parameters despite a tariff obligation to do so. During the cold and hot weather alerts in the first nine months of 2020, PJM scheduled and paid uplift to units without requiring the use of flexible operating parameter limits. In addition to the existing issues with market power mitigation, the definition of a competitive energy offer is now overstated through the inclusion of major maintenance costs which do not vary in the short run with energy output and are not short run marginal costs. Further, the use of and applicability of fuel cost policies are under attack. Fuel cost policies ensure that the costs in generator offers are clearly defined and are verifiable and systematic. Fuel cost policies are essential to effective and accurate market power mitigation. Some generation owners prefer to not have clearly defined costs in order to exercise market power and in order to avoid taking responsibility for the accuracy of their offers.

The details of PJM markets matter. It is essential that PJM focus on getting the details right even when market participants do not agree. For example, PJM continues to pay uplift to units that do not meet uplift eligibility requirements, including not following dispatch. PJM has left incorrect capital recovery factors (CRF) in the tariff resulting in overpayments to black start units and potential issues in the capacity market. PJM does not enforce the must offer rule requiring capacity resources to offer their full ICAP in the day-ahead energy market. PJM has not addressed generators' use of real time values to avoid using their start and notification time parameters required as part of the capacity performance incentives in the capacity market.

The evolution of wholesale power markets is far from complete. The market design can be improved and made more efficient and more competitive. PJM and its market participants will need to continue to work constructively to refine the competitive market design and to ensure the continued effectiveness of PJM markets in providing customers wholesale power at the lowest possible price, but no lower.

² SCED is security constrained economic dispatch. LPC is the locational price calculator.

PJM Market Summary Statistics

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

Table 1-1 PJM Market Summary Statistics: January through September, 2019 and 2020³

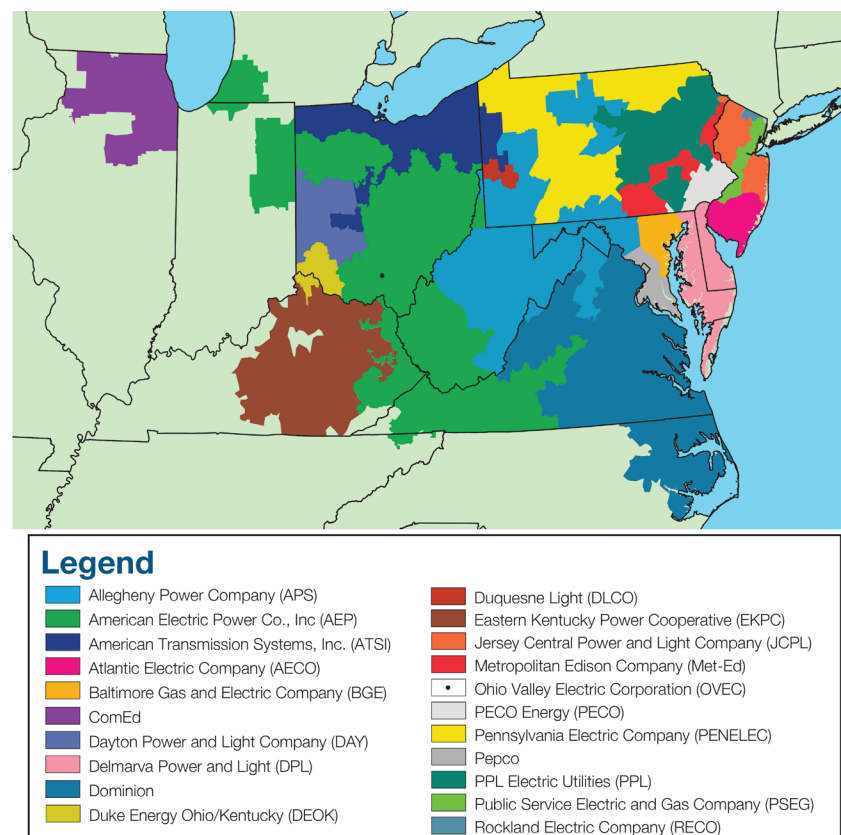
	Jan - Sep, 2019	Jan - Sep, 2020	Percent Change
Average Hourly Load Plus Exports (MW)	94,918	91,356	(3.8%)
Average Hourly Generation Plus Imports (MW)	96,659	92,983	(3.8%)
Peak Load (MW)	148,228	141,449	(4.6%)
Installed Capacity at September 30 (MW)	186,503	183,934	(1.4%)
Load Weighted Average Real Time LMP (\$/MWh)	\$27.60	\$21.22	(23.1%)
Total Congestion Costs (\$ Million)	\$419.1	\$396.1	(5.5%)
Total Uplift Credits (\$ Million)	\$70.5	\$58.6	(16.8%)
Total PJM Billing (\$ Billion)	\$29.97	\$25.01	(16.5%)

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2020, had installed generating capacity of 183,934 megawatts (MW) and 1,033 members including market buyers, sellers and traders of electricity in a region including more than 65 million people in all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia) and the District of Columbia (Figure 1-1).^{4 5 6}

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 the first nine months of 2020, PJM had total billings of \$25.01 billion, a decrease of 16.5 percent from \$29.97 billion in the first nine months of 2019 (Figure 1-2).⁷ The total of \$25.01 billion in the first nine months of 2020 was the lowest first nine month billing since 2012. The decline in weather normalized load, generation, prices and billings were all in significant part a result of the economic impact of COVID-19.

³ In Table 1-1, Average Hourly Load includes load and exports, and Average Hourly Generation includes generation and imports. Versions of this table prior to the 2020 Quarterly State of the Market Report for PJM, January through June did not include exports or imports in these calculations.

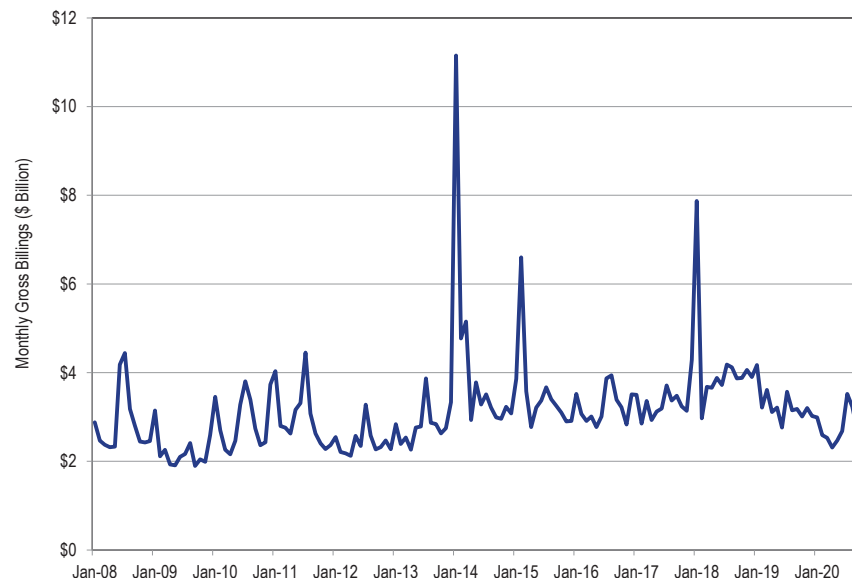
⁴ See PJM, "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.

⁵ See PJM, "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.

⁶ See the 2019 State of the Market Report for PJM, Volume II, Appendix A: "PJM Overview" for maps showing the PJM footprint and its evolution prior to 2020.

⁷ Monthly and year to date billing values are provided by PJM.

Figure 1–2 PJM reported monthly billings (\$ Billion): 2008 through September 2020



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.^{8,9}

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine months of 2020, 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.

⁸ See also the 2019 State of the Market Report for PJM, Volume 2, Appendix A: "PJM Overview."

⁹ Analysis of 2020 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 2020, see 2019 State of the Market Report for PJM, Volume 2, Appendix A: "PJM Overview."

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

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

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

Energy Market Conclusion

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2020.

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 aggregate energy market in the first nine months of 2020 was unconcentrated by FERC HHI standards. Average HHI was 723 with a minimum of 520 and a maximum of 1083 in the first nine months of 2020. The peaking segment of supply was highly concentrated. The fact that the average HHI and the maximum hourly HHI are in the unconcentrated range does not mean that the aggregate market was competitive in all hours. 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 definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during

periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.

- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's core functions is to identify actual or potential market design flaws.¹⁰ The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs

¹⁰ OATT Attachment M (PJM Market Monitoring Plan).

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.¹¹ 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. Units with market power have positive markups, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of \$1,000 per MWh.

Capacity Market Conclusion

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.¹² The conclusions are a result of the MMU's evaluation of the last Base Residual Auction, for the 2021/2022 Delivery Year.

¹¹ 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.

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

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.¹³ Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.¹⁴
- Participant behavior was evaluated as not competitive in the 2021/2022 RPM Base Residual Auction. 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 30 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 nonperformance 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.

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

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

- Market performance was evaluated as not competitive based on the 2021/2022 RPM Base Residual Auction. 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.
- PJM did not run the 2022/2023 Base Residual Auction in May 2019, the 2023/2024 Base Residual Auction in May 2020, or the 2022/2023 First Incremental Auction in September 2020 because the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved.

Tier 2 Synchronized Reserve Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for the first nine months of 2020.

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 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

The MMU analyzed measures of market structure, conduct and performance for the PJM DASR Market for the first nine months of 2020.

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 DASR market would have failed a three pivotal supplier test in zero hours in the first nine months of 2020. The day-ahead scheduling reserve market structure remains evaluated as not competitive based on persistent structural issues.
- 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. The day-ahead scheduling reserve market clearing price was above \$0 in 855 hours in the first nine months of 2020. In those hours, 60.1 percent of the clearing price was the offer

price of the marginal unit and the remaining 39.9 percent was based on lost opportunity cost.

- 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

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market for the first nine months of 2020.

Table 1-6 The regulation market results were not competitive

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

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 94.8 percent of the hours in the first nine months of 2020.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first nine months of 2020 because market power mitigation requires competitive offers when the three pivotal supplier test is failed, although the inclusion of a positive margin raises questions.
- Market performance was evaluated as not competitive, because all units are not paid the same price on an equivalent MW basis.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

FTR Auction Market Conclusion

The *2020 Quarterly State of the Market Report for PJM: January through September* focuses on the 2020/2021 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2020, through September 30, 2020. The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, offer behavior, and price. The MMU concludes that the PJM FTR auction market results were competitive in the first nine months of 2020.

Table 1-7 The FTR auction markets results were competitive

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

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 20/23 Long Term FTR Auction and the 20/21 Annual FTR Auction. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and moderately concentrated for the 20/21 Annual FTR Auction. Ownership of FTRs is disproportionately (73.6 percent) by financial participants.
- Participant behavior was evaluated as partially competitive as a result of the behavior of GreenHat Energy, LLC.
- Market performance was evaluated as competitive because it reflected the interaction between buyer behavior and the FTRs that PJM made available for sale. 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 and fundamental flaws with the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. ARR holders' rights to congestion revenues are not correctly defined. The

path based assignment of congestion rights is inadequate and incorrect. 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.

- The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs and the fact that auction surplus, despite resulting from FTR buyers' actual offer prices, is returned to buyers as needed rather than the sellers, means that the FTR design does not actually function as a market and raises questions about the market structure, the market performance and the market design.

Role of MMU

FERC assigns three core functions to MMUs: reporting, monitoring and market design.¹⁵ 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.¹⁶

Reporting

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

¹⁵ 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).

¹⁶ OATT Attachment M § IV; 18 CFR § 1c.2.

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.¹⁷ The MMU has direct, confidential access to FERC.¹⁸ The MMU may also refer matters to the attention of state commissions.¹⁹

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.²⁰ 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..."^{21 22 23} The

¹⁷ OATT Attachment M § IV.

¹⁸ OATT Attachment M § IV.K.3.

¹⁹ OATT Attachment M § IV.H.

²⁰ 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.")

²¹ 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.

²² OATT § I.1.

²³ The MMU has no prosecutorial or enforcement authority. The MMU notifies FERC when it identifies a significant market problem or market violation. OATT Attachment M § IV.I.1. If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff. *Id.* If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to FERC, state regulators, stakeholders or other authorities. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

MMU also monitors PJM for compliance with the rules, in addition to market participants.²⁴

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.²⁵

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the day-ahead and real-time energy markets.^{26 27 28 29}

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

²⁴ OATT Attachment M § IV.C.

²⁵ OATT Attachment M-Appendix § I.I.E.

²⁶ OATT Attachment M-Appendix § I.I.B.

²⁷ OATT Attachment M-Appendix § I.I.C.

²⁸ OATT Attachment M-Appendix § IV.

²⁹ OATT Attachment M-Appendix § VII.

that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with FERC or other regulatory authorities. FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals. PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

The PJM Markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.^{30 31}

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.³²

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.³³ The MMU initiates and proposes changes to the design of such markets or the PJM market rules in stakeholder or regulatory proceedings.³⁴ In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design, market rules and market rule implementation issues, including complaints or petitions.³⁵ 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

³⁰ OATT Attachment M–Appendix 5 II(p).

³¹ OATT Attachment M–Appendix 5 III.

³² OA Schedule 6 § 1.5.

³³ OATT Attachment M § IV.D.

³⁴ *Id.*

³⁵ *Id.*; see also, e.g., 171 FERC ¶ 61,039; 167 FERC ¶ 61,084 at PP 70–76, *reh'g denied*, 168 FERC ¶ 61,141.

the PJM Board.³⁶ The MMU may provide in its annual, quarterly and other reports “recommendations regarding any matter within its purview.”³⁷

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,”³⁸ 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 *2020 Quarterly State of the Market Report for PJM: January through September*, the MMU includes ten new recommendations.

New Recommendations from Section 3, Energy Market

- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved Fuel Cost Policy. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to have an approved Fuel Cost Policy. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include

³⁶ *Id.*

³⁷ OATT Attachment M § VI.A.

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

only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 4, Energy Uplift

- The MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 12, Generation and Transmission Planning

- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. New recommendation. Status: Not adopted.)

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

- The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately. (Priority: High. New recommendation. Status: PJM planning to implement.)

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of wholesale electricity in PJM markets. The total price is an average price. Prices vary by location and time period. 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 the first nine months of 2019 and 2020.

The total billing values shown in Table 1-8 are the total price per MWh, by category, multiplied by the total load. This total is different from the total billing that PJM reports as shown in Figure 1-2. PJM's reported total billing represents the total dollars that pass through the PJM settlement process. There are issues with the PJM total billing calculations. The PJM total billing calculation includes all billing line item charges including monthly billing adjustments for the month in which PJM makes the adjustment rather than the month to which the adjustment applies. Rather than adding positive and negative spot market and congestion charges, PJM calculates the average of the absolute value of the positive and negative charges. PJM also makes adjustments to eliminate certain transmission owners' network charges and monthly bilateral corrections.

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

Components of Total Price

- The Energy component is the real-time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and nonfirm point to point transmission service.³⁹
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.⁴⁰
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.⁴¹
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.⁴²
- 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 (ACC) 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.⁴³
- 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.⁴⁴
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.⁴⁵

39 OATT §§ 13.7, 14.5, 27A & 34.

40 OATT Schedules 1 §§ 3.2.3 & 3.3.3.

41 OATT Schedule 2 and OATT Schedule 1 § 3.2.3B. The line item in Table 1-8 includes all reactive services charges.

42 OATT Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.

43 OATT Schedule 12.

44 RAA Schedule 8.1.

45 OATT PJM Emergency Load Response Program.

- 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.⁴⁶
- 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.⁴⁷
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.⁴⁸
- The Black Start component is the average cost per MWh of black start service.⁴⁹
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.⁵⁰
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.⁵¹
- The Economic Load Response component is the average cost per MWh of day-ahead and real-time economic load response program charges to LSEs.⁵²
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.⁵³
- The nonsynchronized reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.⁵⁴
- The Emergency Energy component is the average cost per MWh of emergency energy.⁵⁵

46 OATT Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.

47 OATT Schedule 1A.

48 OATT Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.

49 OATT Schedule 6A. The line item in Table 1-8 includes all Energy Uplift (Operating Reserves) charges for Black Start.

50 OATT Attachments H-13, H-14 and H-15 and Schedule 13.

51 OATT Schedule 10-NEEC and OATT Schedule 10-RFC.

52 OATT Schedule 1 § 3.6.

53 OATT Schedule 1 § 5.3b.

54 OATT Schedule 1 § 3.2.3A.001.

55 OATT Schedule 1 § 3.2.6.

Table 1-8 shows that energy, capacity and transmission charges are the three largest components of the total price per MWh of wholesale power, comprising 96.9 percent of the total price per MWh in the first nine months of 2020. Transmission charges exceed capacity charges in the first nine months of 2020.

Table 1-8 Total price per MWh by category: January through September, 2019 and 2020^{56 57 58 59}

Category	Jan-Sep 2019 \$/MWh	Jan-Sep 2019 (\$ Millions)	Jan-Sep 2019 Percent of Total	Jan-Sep 2020 \$/MWh	Jan-Sep 2020 (\$ Millions)	Jan-Sep 2020 Percent of Total	Percent Change
Load Weighted Energy	\$27.60	\$16,243	54.2%	\$21.22	\$11,984	48.6%	(23.1%)
Capacity	\$11.79	\$6,939	23.2%	\$9.31	\$5,255	21.3%	(21.1%)
Capacity	\$11.77	\$6,925	23.1%	\$9.31	\$5,255	21.3%	(20.9%)
Capacity (FRR)	\$0.00	\$0	0.0%	\$0.00	\$0	0.0%	0.0%
Capacity (RMR)	\$0.02	\$14	0.0%	\$0.00	\$0	0.0%	(100.0%)
Transmission	\$10.18	\$5,989	20.0%	\$11.82	\$6,673	27.0%	16.1%
Transmission Service Charges	\$9.55	\$5,622	18.8%	\$11.14	\$6,292	25.5%	16.6%
Transmission Enhancement Cost Recovery	\$0.54	\$315	1.1%	\$0.58	\$329	1.3%	8.7%
Transmission Owner (Schedule 1A)	\$0.09	\$52	0.2%	\$0.09	\$52	0.2%	3.8%
Transmission Seams Elimination Cost Assignment (SECA)	\$0.00	\$0	0.0%	\$0.00	\$0	0.0%	0.0%
Transmission Facility Charges	\$0.00	\$0	0.0%	\$0.00	\$0	0.0%	0.0%
Ancillary	\$0.69	\$409	1.4%	\$0.71	\$400	1.6%	2.0%
Reactive	\$0.43	\$251	0.8%	\$0.47	\$266	1.1%	10.6%
Regulation	\$0.11	\$64	0.2%	\$0.10	\$54	0.2%	(12.3%)
Black Start	\$0.08	\$48	0.2%	\$0.09	\$49	0.2%	6.1%
Synchronized Reserves	\$0.04	\$25	0.1%	\$0.02	\$13	0.1%	(45.2%)
Non-Synchronized Reserves	\$0.01	\$8	0.0%	\$0.01	\$5	0.0%	(36.5%)
Day Ahead Scheduling Reserve (DASR)	\$0.02	\$13	0.0%	\$0.02	\$13	0.1%	5.1%
Administration	\$0.52	\$307	1.0%	\$0.53	\$301	1.2%	2.4%
PJM Administrative Fees	\$0.49	\$286	1.0%	\$0.50	\$281	1.1%	2.3%
NERC/RFC	\$0.03	\$19	0.1%	\$0.03	\$19	0.1%	7.5%
RTO Startup and Expansion	\$0.00	\$2	0.0%	\$0.00	\$1	0.0%	(43.3%)
Energy Uplift (Operating Reserves)	\$0.12	\$70	0.2%	\$0.10	\$58	0.2%	(13.4%)
Demand Response	\$0.00	\$1	0.0%	\$0.00	\$1	0.0%	(28.0%)
Load Response	\$0.00	\$1	0.0%	\$0.00	\$1	0.0%	(28.0%)
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	\$50.90	\$29,958	100.0%	\$43.69	\$24,672	100.0%	(14.2%)
Total Load (GWh)	588,506			564,700			(4.0%)
Total Billing (\$ Billions)	\$29.96			\$24.67			(17.6%)

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

57 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.

58 The total prices in this table are load weighted average system prices per MWh by category, even if each category is not charged on a per MWh basis.

59 The MMU publishes monthly detail of these components of PJM price. See <http://www.monitoringanalytics.com/data/pjm_price.shtml>.

Table 1-9 shows the inflation adjusted average price, by component, for the first nine months of 2019 and 2020. 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).⁶⁰

Table 1-9 Inflation adjusted total price per MWh by category: January through September, 2019 and 2020⁶¹

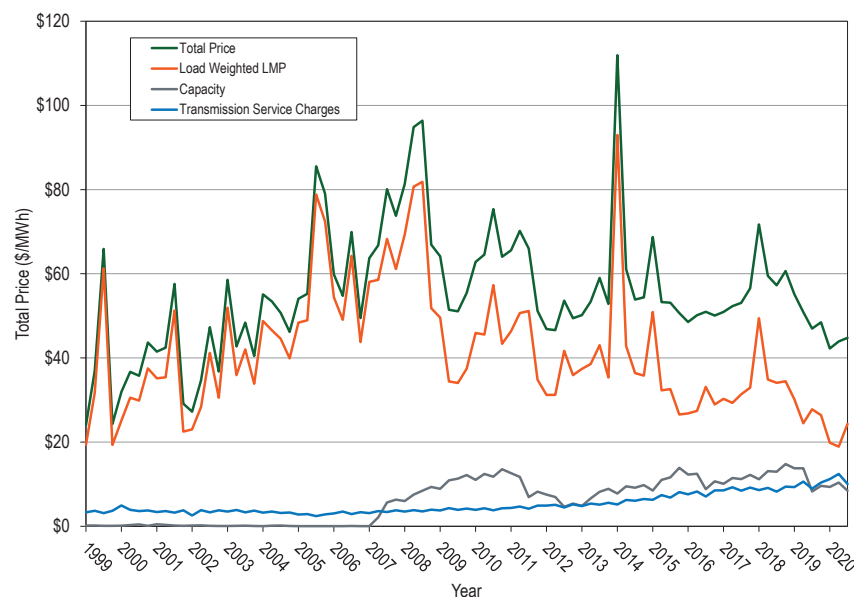
Category	Jan-Sep 2019 \$/MWh	Jan-Sep 2019 (\$ Millions)	Jan-Sep 2019 Percent of Total	Jan-Sep 2020 \$/MWh	Jan-Sep 2020 (\$ Millions)	Jan-Sep 2020 Percent of Total	Percent Change
Load Weighted Energy	\$17.49	\$10,293	54.2%	\$13.27	\$7,492	48.6%	(24.1%)
Capacity	\$7.48	\$4,399	23.2%	\$5.82	\$3,288	21.3%	(22.1%)
Capacity	\$7.46	\$4,390	23.1%	\$5.82	\$3,288	21.3%	(22.0%)
Capacity (FRR)	\$0.00	\$0	0.0%	\$0.00	\$0	0.0%	0.0%
Capacity (RMR)	\$0.01	\$9	0.0%	\$0.00	\$0	0.0%	(100.0%)
Transmission	\$6.45	\$3,793	20.0%	\$7.39	\$4,175	27.1%	14.7%
Transmission Service Charges	\$6.05	\$3,561	18.8%	\$6.97	\$3,937	25.5%	15.2%
Transmission Enhancement Cost Recovery	\$0.34	\$200	1.1%	\$0.36	\$206	1.3%	7.4%
Transmission Owner (Schedule 1A)	\$0.06	\$33	0.2%	\$0.06	\$33	0.2%	2.5%
Transmission Seams Elimination Cost Assignment (SECA)	\$0.00	\$0	0.0%	\$0.00	\$0	0.0%	0.0%
Transmission Facility Charges	\$0.00	\$0	0.0%	\$0.00	\$0	0.0%	0.0%
Ancillary	\$0.44	\$259	1.4%	\$0.44	\$250	1.6%	0.7%
Reactive	\$0.27	\$159	0.8%	\$0.29	\$166	1.1%	9.3%
Regulation	\$0.07	\$40	0.2%	\$0.06	\$34	0.2%	(13.4%)
Black Start	\$0.05	\$31	0.2%	\$0.05	\$31	0.2%	4.8%
Synchronized Reserves	\$0.03	\$16	0.1%	\$0.01	\$8	0.1%	(46.2%)
Non-Synchronized Reserves	\$0.01	\$5	0.0%	\$0.01	\$3	0.0%	(37.9%)
Day Ahead Scheduling Reserve (DASR)	\$0.01	\$8	0.0%	\$0.01	\$8	0.1%	3.7%
Administration	\$0.33	\$194	1.0%	\$0.33	\$188	1.2%	1.1%
PJM Administrative Fees	\$0.31	\$181	1.0%	\$0.31	\$176	1.1%	1.1%
NERC/RFC	\$0.02	\$12	0.1%	\$0.02	\$12	0.1%	5.9%
RTO Startup and Expansion	\$0.00	\$1	0.0%	\$0.00	\$1	0.0%	(42.1%)
Energy Uplift (Operating Reserves)	\$0.08	\$44	0.2%	\$0.06	\$36	0.2%	(14.5%)
Demand Response	\$0.00	\$1	0.0%	\$0.00	\$1	0.0%	(25.0%)
Load Response	\$0.00	\$1	0.0%	\$0.00	\$1	0.0%	(25.0%)
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	\$32.26	\$18,983	100.0%	\$27.32	\$15,430	100.0%	(15.3%)
Total Load (GWh)	588,506			564,700			(4.0%)
Total Billing (\$ Billions)	\$18.98			\$15.43			(18.7%)

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>> (October 13, 2020).

⁶¹ 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.

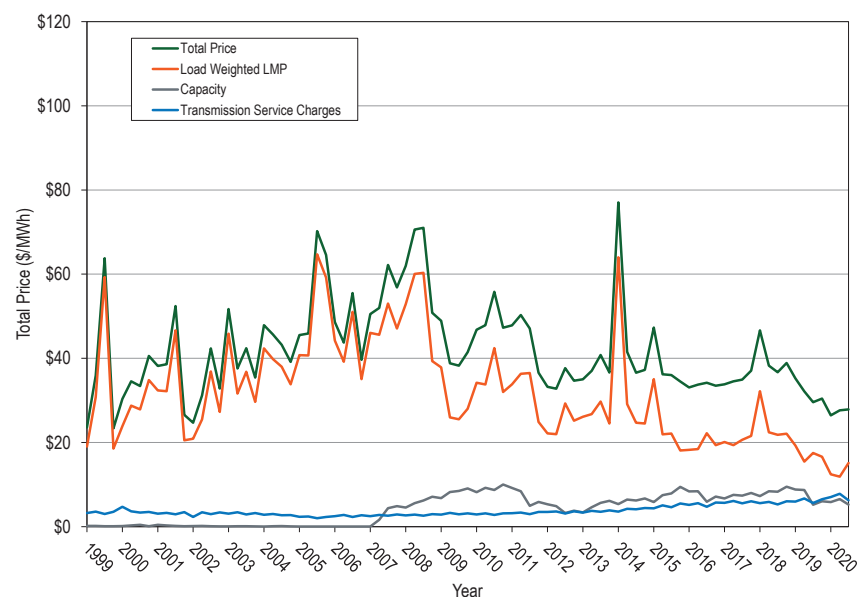
Figure 1-3 Top three components of quarterly total price (\$/MWh): January 1999 through September 2020⁶²



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

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 1999.⁶³

Figure 1-4 Inflation adjusted top three components of quarterly total price (\$/MWh): January 1999 through September 2020⁶⁴

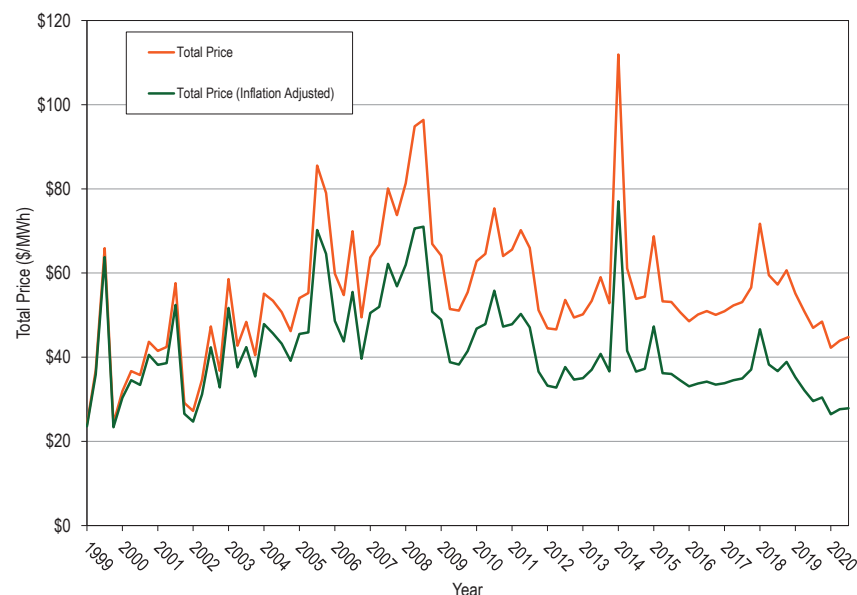


63 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by Bureau of Labor Statistics. <http://download.bls.gov/pub/time-series/cu/cu.data.1.AllItems> (October 13, 2020).

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

Figure 1-5 shows the total price of wholesale power and the inflation adjusted total price of wholesale power for each quarter since 1999.⁶⁵

Figure 1-5 Quarterly total price and quarterly inflation adjusted total price (\$/MWh): January 1999 through September 2020⁶⁶



⁶⁵ US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by Bureau of Labor Statistics. <https://download.bls.gov/pub/time-series/cu/cu.data.1.AllItems> (October 13, 2020).

⁶⁶ Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

Section Overviews

Overview: Section 3, Energy Market

Supply and Demand

Market Structure

- **Supply.** Supply includes physical generation, imports and virtual transactions. The maximum average on-peak hourly offered real-time supply was 152,122 MW for the 2020 summer, and 152,553 MW for the 2019 summer. In the first nine months of 2020, 1,248.4 MW of new resources were added in the energy market, and 2,469.0 MW of internal resources and 457 MW of pseudo tied resources retired.

PJM average hourly real-time cleared generation in the first nine months of 2020 decreased by 3.5 percent from the first nine months of 2019, from 95,531 MWh to 92,226 MWh.

PJM average hourly day-ahead cleared supply in the first nine months of 2020, including INCs and up to congestion transactions, decreased by 3.1 percent from the first nine months of 2019, from 118,913 MWh to 115,205 MWh.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load in the first nine months of 2020 was 141,449 MWh in the HE 1700 on July 20, 2020, which was 6,778 MWh, 4.6 percent, lower than the PJM peak load in the first nine months of 2019, which was 148,228 MWh in the HE 1800 on July 19, 2019.

PJM average hourly real-time demand in the first nine months of 2020 decreased by 4.4 percent from the first nine months of 2019, from 89,834 MWh to 85,886 MWh. PJM average hourly day-ahead demand in the first nine months of 2020, including DECs and up to congestion transactions, decreased by 3.8 percent from the first nine months of 2019, from 114,133 MWh to 109,850 MWh.

Market Behavior

- **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. In the first nine months of 2020, 16.4 percent of real-time load was supplied by bilateral contracts, 24.0 percent by spot market purchases and 59.7 percent by self supply. Compared to the first nine months of 2019, reliance on bilateral contracts increased by 1.0 percentage points, reliance on spot market purchases decreased by 0.8 percentage points and reliance on self supply decreased by 0.2 percentage points.
- **Generator Offers.** Generator offers are categorized as pool scheduled and self scheduled. Units which are available for economic commitment are pool scheduled. 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 offered MW, up to economic maximum output, in the first nine months of 2020, 63.7 percent were offered to be pool scheduled, 32.4 percent above economic minimum and 31.3 percent at the economic minimum. For self scheduled units, 14.2 percent were offered as self scheduled at a fixed output, and 22.1 percent were offered as self scheduled and dispatchable.
- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW increased by 8.1 percent and cleared MW decreased by 14.4 percent in the first nine months of 2020. The hourly average submitted decrement offer MW increased by 18.5 percent and cleared MW decreased by 5.5 percent in the first nine months of 2020. The hourly average submitted up to congestion bid MW decreased by 21.1 percent and cleared MW decreased by 0.1 percent in the first nine months of 2020.

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2020, coal units provided 19.0 percent, nuclear units 33.7 percent and natural gas units 40.6 percent of total generation. Compared to the first nine months of 2019, generation from coal units decreased 24.9 percent, generation from natural gas units increased 9.5 percent and generation from nuclear units decreased 1.5 percent. The trend toward more energy from natural gas and less from coal accelerated in the first nine months of 2020.
 - **Fuel Diversity.** The fuel diversity of energy generation in the first nine months of 2020, measured by the fuel diversity index for energy (FDI_e), decreased 2.2 percent compared to the first nine months of 2019.
 - **Marginal Resources.** In the PJM Real-Time Energy Market, in the first nine months of 2020, coal units were 17.3 percent and natural gas units were 73.6 percent of marginal resources. In the first nine months of 2019, coal units were 26.3 percent and natural gas units were 68.4 percent of marginal resources.
- In the PJM Day-Ahead Energy Market, in the first nine months of 2020, up to congestion transactions were 53.8 percent, INCs were 12.4 percent, DECc were 17.6 percent, and generation resources were 16.1 percent of marginal resources. In the first nine months of 2019, up to congestion transactions were 57.7 percent, INCs were 12.9 percent, DECc were 18.4 percent, and generation resources were 10.9 percent of marginal resources.
- **Prices.** PJM real-time and day-ahead energy market prices were at the lowest level in the history of PJM markets during the first nine months of 2020. Both the weather and COVID-19 played a role in this significant drop in prices.

PJM real-time energy market prices decreased in the first nine months of 2020. The load-weighted, average real-time LMP was 23.1 percent lower in the first nine months of 2020 than in the first nine months of 2019, \$21.22 per MWh versus \$27.60 per MWh.

PJM day-ahead energy market prices decreased in the first nine months of 2020. The load-weighted, average day-ahead LMP was 24.4 percent

lower in the first nine months of 2020 than in the first nine months of 2019, \$20.95 per MWh versus \$27.70 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in the first nine months of 2020, 24.6 percent of the load-weighted LMP was the result of coal costs, 39.8 percent was the result of gas costs and 1.80 percent was the result of the cost of emission allowances.

In the PJM Day-Ahead Energy Market, in the first nine months of 2020, 25.3 percent of the load-weighted LMP was the result of coal costs, 17.9 percent was the result of gas costs, 15.4 percent was the result of INC offers, 23.0 percent was the result of DEC bids, and 3.4 percent was the result of up to congestion transaction offers.

- **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 \$0.23 per MWh in the first nine months of 2020, and -\$0.11 per MWh in the first nine months of 2019. 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 two intervals with five minute shortage pricing in the first nine months of 2020. There were no emergency actions that resulted in Performance Assessment Intervals in the first nine months of 2020.
- There were 1,143 five minute intervals, or 1.4 percent of all five minute intervals in the first nine months of 2020 for which at least one solved RT SCED case showed a shortage of reserves, and 416 five minute intervals, or 0.5 percent of all five minute intervals in the first nine months of 2020 for which more than one solved RT SCED case showed a shortage of reserves. PJM triggered shortage pricing for two five minute intervals.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated.
- **Local Market Power.** For six out of the top 10 congested facilities (by real-time binding hours) in the first nine months of 2020, the number of suppliers providing constraint relief is three or less. There is a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure is not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.2 percent in the first nine months of 2019 to 1.6 percent in the first nine months of 2020. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.6 percent in the first nine months of 2019 to 1.0 percent in the first nine months of 2020. 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 the first nine months of 2020, nine control zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping

when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours remained at 0.0 percent in the first nine months of 2019 and 2020. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours remained at 0.0 percent in the first nine months of 2019 and 2020.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** One unit qualified for an FMU adder for the months of September and October, 2019. In the first nine months of 2020, five units qualified for an FMU adder in at least one month.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first nine months of 2020, in the PJM Real-Time Energy Market, 98.4 percent of marginal units had offer prices less than \$50 per MWh. While markups in the real-time market were generally low, some marginal units did have substantial markups. The highest markup for any marginal unit in the first nine months of 2020 was more than \$200 per MWh when using unadjusted cost-based offers.

In the first nine months of 2020, in the PJM Day-Ahead Energy Market, 99.3 percent of marginal generating units had offer prices less than \$50 per MWh. Markups in the day-ahead market were generally low. The highest markup for any marginal unit in the day-ahead market in the first nine months of 2020 was more than \$70 per MWh when using unadjusted cost-based offers.

- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that

PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power. Markup for coal and gas fired units decreased in the first nine months of 2020.

Market Performance

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

In the PJM Real-Time Energy Market in the first nine months of 2020, the unadjusted markup component of LMP was \$0.61 per MWh or 2.9 percent of the PJM load-weighted, average LMP. August had the highest unadjusted peak markup component, \$2.88 per MWh, or 9.7 percent of the real-time, peak hour load-weighted, average LMP. There were 28 hours in the first nine months of 2020 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded the 99th percentile of the hourly markup contribution or \$30.83 per MWh.

In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first nine months of 2020, the unadjusted markup component of LMP resulting from generation resources was -\$0.15 per MWh or -0.7 percent of the PJM day-ahead load-weighted average LMP. August had the highest unadjusted peak markup component, \$0.70 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.

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 6.0 percent of marginal unit intervals in the first nine months of 2020 the marginal unit had local

market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.

- **Markup and Aggregate Market Power.** In the summer of 2020, pivotal suppliers in the aggregate market set prices with high markups for some real-time market intervals.

Section 3 Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when 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.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the 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 2018. Status: Adopted 2020.)
- 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 2018. Status: Adopted 2020.)

- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved Fuel Cost Policy. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to have an approved Fuel Cost Policy. (Priority: Medium. New recommendation. Status: Not adopted.)

Cost-Based Offers

- 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 the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity

used and the unit characteristics. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in Cost Development Guidelines. (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 2020.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-

ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)

- 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, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, and during high load conditions such as cold and hot weather alerts or more severe emergencies, that 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, in order to ensure effective market power mitigation, that PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. First reported 2019. 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.⁶⁷ (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially 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 at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)

⁶⁷ This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. 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. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Not adopted.)
- 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: Adopted 2020.)

- 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 not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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: 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.^{68 69} (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the 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.)
- The MMU recommends that PJM model generators' operating transitions, including modeling soak time for units with a steam turbine and configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is

⁶⁸ 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.

⁶⁹ 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>>.

less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported Q1, 2020. 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: Adopted, 2019.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- 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, scheduled approach. (Priority: High. First reported 2018. Status: Not adopted.)

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. New recommendation. Status: Not adopted.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2020, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

PJM average hourly real-time cleared generation decreased by 3,305 MWh, 3.5 percent, and peak load decreased by 6,778 MWh, 4.6 percent, in the first nine months of 2020 compared to the first nine months of 2019. Both the weather and COVID-19 played a role in this significant drop in demand. 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. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The

existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.⁷⁰ 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. Many of 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, under the PJM Market Rules, is not currently correct. The definition, that energy costs must be related to electric production, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs.

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 at a given time. 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 the first nine months of 2020 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

⁷⁰ The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

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. Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices have been a primary cause of low PJM energy market prices. There is no evidence to support the need for a significant change to the calculation of LMP, such as fast start pricing or the extended ORDC. 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, because PJM is not implementing scarcity pricing when there is scarcity. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address the design of RT SCED/LPC, scarcity pricing, operator actions and the design of reserve markets. Implementing scarcity pricing when there is scarcity is a basic first step. 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 indicates a shortage of reserves, it should be used in calculating real-time prices and those prices should be applied to the market interval for which RT SCED calculated the shortage and during which resources followed associated dispatch instructions. 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 RT SCED cases used for resource dispatch and the RT SCED cases used to calculate real-time prices. Alignment of resource dispatch with pricing

and settlements requires reducing the RT SCED ramp time to five minutes to match the five minute settlement interval. PJM should fix its current operating practices and ensure consistency and transparency regarding approval of RT 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 PJM defined inputs to the dispatch tools, particularly the RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create price spikes through transmission line limit violations or restrictions on the resources available to resolve constraints. The automated adjustment of ramp rates by PJM, called Degree of Generator Performance (DGP), modifies the values offered by generators and limits the MW available to the RT SCED. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

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 prioritizes minimizing uplift over minimizing production costs. The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff will be created by PJM's fast start pricing proposal as approved by FERC and would be created in a much more extensive form by PJM's convex hull pricing proposal and reserve pricing proposal.

Units that start in one hour are not fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants

to behave competitively and to follow PJM's dispatch instructions. PJM will pay new forms of uplift in an attempt to counter the distorted incentives. But without reducing the dispatch period from 10 to five minutes, the new uplift payments will not correspond to following dispatch. The magnitude of the new payments and their effects on behavior are not well understood.

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 the 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, as in PJM's ORDC proposal, is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity

pricing only occurs when scarcity exists, 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. Administrative scarcity pricing that establishes scarcity pricing in about 85 percent of hours, as PJM's ORDC proposal would, is not scarcity pricing but simply a revenue enhancement mechanism. When combined with PJM's failure to address the energy and ancillary services offset in the capacity market, PJM's ORDC filing is not consistent with efficient market design and is even more clearly just a revenue enhancement mechanism.

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 the first nine months of 2020 or prior years. In the first nine months of 2020, marginal units were predominantly combined cycle gas generators with low fuel costs. The frequency of combined cycle gas units as the marginal unit type has risen rapidly, from 29.3 percent in 2016 to 66.0 percent in the first nine months of 2020. Overdue improvements in generator modeling in the energy market would allow PJM to more efficiently commit and dispatch combined cycle plants and to fully reflect the flexibility of these units. New combined

cycle units placed competitive pressure on less efficient generators, and the market reliably served load with less congestion, less uplift, and less markup in marginal offers than in the first nine months of 2019. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Given the structure of the energy market which can permit the exercise of aggregate and local market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2020.

Overview: Section 4, Energy Uplift

Energy Uplift Credits

- **Types of credits.** In the first nine months of 2020, energy uplift credits were \$58.6 million, including \$7.0 million in day-ahead generator credits, \$31.8 million in balancing generator credits, \$17.1 million in lost opportunity cost credits, and \$2.2 million in local constraint control credits.
- **Types of units.** In the first nine months of 2020, coal units received 89.5 percent of all day-ahead generator credits. During the same time period, combustion turbines received 88.0 percent of all balancing generator credits and 95.8 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In the first nine months of 2020, 86.9 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.2 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first nine months of 2020, less than 0.1 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 76.6 percent received energy uplift payments.

- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 18.0 percent of all credits. The top 10 organizations received 73.3 percent of all credits. The HHI for day-ahead operating reserves was 8481, the HHI for balancing operating reserves was 3859 and the HHI for lost opportunity cost was 5325, all of which are classified as highly concentrated.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by \$4.6 million or 36.6 percent, in the first nine months of 2020 compared to the first nine months of 2019, from \$12.5 million to \$17.1 million. Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive lost opportunity cost credits as a result. The amount of day-ahead generation paid LOC credits for this reason increased by 637.1 GWh or 131.4 percent during the first nine months of 2020, compared to the first nine months of 2019, from 484.8 GWh to 1,121.9 GWh.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges decreased by \$11.8 million, or 16.8 percent, in the first nine months of 2020 compared to the first nine months of 2019, from \$70.5 million to \$58.6 million.
- **Energy Uplift Charges Categories.** The decrease of \$11.8 million in the first nine months of 2020 was comprised of a \$6.9 million decrease in day-ahead operating reserve charges, a \$4.9 million decrease in balancing operating reserve charges, and a \$0.1 million decrease in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid \$0.012 per MWh, real-time load paid \$0.024 per MWh, a DEC paid \$0.345 per MWh and an INC and any load, generation or interchange transaction deviation paid \$0.333 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid \$0.012 per MWh, real-time load paid \$0.017 per MWh, a DEC paid \$0.314 per MWh and an INC and any load, generation or

interchange transaction deviation paid \$0.302 per MWh in the first nine months of 2020.

- **Reactive Services Rates.** JCPL, PPL, and EKPC control zones were the three zones with the highest local voltage support rates, excluding reactive capability payments. JCPL had a rate of \$0.010 per MWh, PPL had a rate of \$0.006 per MWh, and EKPC had a rate of \$0.005.

Geography of Charges and Credits

- In the first nine months of 2020, 88.8 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 3.9 percent by transactions at hubs and aggregates, and 7.3 percent by transactions at interchange interfaces.
- In the first nine months of 2020, generators in the Eastern Region received 35.8 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2020, generators in the Western Region received 61.3 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2020, external generators received 2.9 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 2018. 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: Partially adopted, 2019.)

- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead 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.)
- 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 2018.⁷¹)
- 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

⁷¹ 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*, Volume 2, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

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 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.⁷²)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends 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 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. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units

that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation. (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 start up and no load 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 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.

⁷² On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. PJM began posting unit specific uplift reports on May 1, 2019.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules.

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 will create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff will exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff will be created by PJM's fast start pricing proposal (limited convex hull pricing). This tradeoff would be created in more 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. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.⁷³ However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability in the day-ahead market.

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 continued to pay no energy uplift charges in the first nine months of 2020, which means that all others who pay these charges paid too much.⁷⁴ On July 16, 2020, following its investigation of the issue, the Commission ordered PJM to revise its rules so that UTCs are required to pay uplift on the withdrawal side (DEC) only.⁷⁵ 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

⁷³ On March 21, 2019 FERC accepted PJM's Order No. 844 compliance filing. The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates.

⁷⁴ 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.

⁷⁵ See 172 FERC ¶ 61,046.

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.⁷⁶

Under RPM, capacity obligations are annual.⁷⁷ Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.⁷⁸ First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.⁷⁹ 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.⁸⁰

The 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted in the first nine months of 2020.

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.⁸¹ 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.** In the first nine months of 2020, RPM installed capacity decreased 788.7 MW or 0.4 percent, from 184,722.8 MW on January 1 to 183,934.17 MW on September 30. 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 September 30, 2020, 45.7 percent was gas; 27.0 percent was coal; 17.6 percent was nuclear; 4.8 percent was hydroelectric; 3.4 percent was oil; 0.7 percent was wind; 0.4 percent was solid waste; and 0.5 percent was solar.
- **Market Concentration.** In the 2021/2022 RPM Second Incremental Auction, two participants in the EMAAC LDA market passed the TPS test.⁸² 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,

⁷⁶ The terms *PJM Region*, *RTD Region* and *RTD* are synonymous in this report and include all capacity within the PJM footprint.

⁷⁷ Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either with commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.

⁷⁸ See 126 FERC ¶ 61,275 at P 86 (2009).

⁷⁹ See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).

⁸⁰ See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.

⁸¹ 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.

⁸² 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).

the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.^{83 84 85}

- **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 10,586.0 MW for June 1, 2020, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2020/2021 delivery year (13,015.2 MW) less purchases of replacement capacity (2,429.2 MW).

Market Conduct

- **2021/2022 RPM Second Incremental Auction.** Of the 276 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for zero generation resources (0.0 percent).

Market Performance

- The 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted in the first nine months of 2020.⁸⁶ The weighted average capacity price for the 2019/2020 Delivery Year is \$109.82 per MW-day, including all RPM auctions for the 2019/2020 Delivery Year. The weighted average capacity price for the 2020/2021 Delivery Year is \$111.05 per MW-day, including all RPM auctions for the 2020/2021 Delivery Year.
- For the 2020/2021 Delivery Year, RPM annual charges to load are \$7.0 billion.

⁸³ See OATT Attachment DD § 6.5.

⁸⁴ 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).

⁸⁵ 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).

⁸⁶ FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

- In the 2021/2022 RPM Base Residual Auction, the 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 in the first nine months of 2020 was 6.3 percent, an increase from 6.0 percent in the first nine months of 2019.⁸⁷
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first nine months of 2020 was 86.8 percent, an increase from 85.2 percent in the first nine months of 2019.

Section 5 Recommendations⁸⁸

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

⁸⁷ The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on October 23, 2020. 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.

⁸⁸ 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.

types, including planned generation, demand resources and imports.^{89 90} (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.^{91 92} 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.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be reviewed. (Priority: Medium. First reported 2019. Status: Not adopted.)

⁸⁹ See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

⁹⁰ See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

⁹¹ See PJM Interconnection, LLC, Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

⁹² See the 2019 State of the Market Report for PJM, Volume 2, Section 7: Net Revenue.

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.⁹³ (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.⁹⁴ (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 the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate be left at its current level. The MMU recommends that PJM develop a

⁹³ Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000, -001; EL18-178 (October 2, 2018).

⁹⁴ 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).

forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the MSOC. 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 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 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit which is not capable of supplying energy consistent with its day-ahead offer which should equal its ICAP, reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement

that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

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: Not 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 nonperformance 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 filed a complaint with the Commission asserting that the market seller offer cap is overstated.⁹⁵ The result of an overstated market seller offer cap is to permit the exercise of market power, as occurred in the 2021/2022 BRA. That complaint remains pending. The outcome of the complaint could have a significant and standalone impact on clearing prices in the 2022/2023 BRA.

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 the last BRA and in the first nine months of 2020. 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.^{96 97 98 99 100 101} In 2019 and 2020, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

95 In 2019, the MMU filed a complaint seeking an order directing PJM to update the assumptions regarding the expected number of performance assessment intervals (PAI) in calculating the default capacity market seller offer cap (MSOC). Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47-000 (February 21, 2019).

96 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).

97 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).

98 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).

99 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).

100 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).

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

The capacity performance modifications to the RPM construct significantly improved the capacity market and addressed a number of issues that had been identified by the MMU. But significant issues remain in the PJM capacity market design.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 11,911.9 ICAP MW on June 1, 2020, and will have excess reserves of 18,401.8 ICAP MW on June 1, 2021, based on current positions.¹⁰² A majority of capacity investments in PJM were financed by market sources.¹⁰³ Of the 41,979.4 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2019/2020 delivery years, 32,333.9 MW (77.0 percent) were based on market funding. Of the 2,640.4 MW of additional capacity that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years, 2,553.6 MW (96.7 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

The issue of external subsidies, particularly for economic nuclear power plants, continued to evolve. 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 legislation to subsidize both nuclear and coal plants and to eliminate the RPS, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant and the requests for additional subsidies, the request in Pennsylvania to subsidize nuclear power plants, 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, the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal and the specific FRR proposals for ComEd and for New Jersey, all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the

102 The calculated reserve margin for June 1, 2021, does not account for cleared buy bids that have not been used in replacement capacity transactions.

103 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

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 and is now being 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. Competition to receive subsidies is now a reality and is accelerating in PJM.

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).¹⁰⁴ The SMR is fully consistent with the renewables targets of many states in the PJM footprint. The SMR is also consistent with incorporating economic nuclear power plants in the capacity market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a

¹⁰⁴ The MMU filed several comments as well as a proposal summary in the Capacity Market Investigation focused on the Sustainable Market Rule (SMR) in Docket Nos. ER18-1314-000, -001, EL16-49-000, and EL18-178-000 (October 2, 2018; October 31, 2018; November 6, 2018). MMU filings are located at the Monitoring Analytics website at <http://www.monitoringanalytics.com/Filings/2018.shtml>.

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 states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. As made clear in recent analyses of FRR options in Illinois, Maryland, New Jersey and Ohio, the FRR approach is likely to lead to significant increases in payments by customers.¹⁰⁵ The existing FRR rules were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The FRR rules should be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market.

Recent FRR proposals in Illinois for the ComEd Zone and in New Jersey are primarily nuclear subsidy programs that would increase nuclear subsidies well beyond the ZECs rules currently in place in both states while also providing

¹⁰⁵ The MMU has posted several reports regarding the creation of FRRs. "Potential Impacts of the Creation of a ComEd FRR," (December 18, 2019). http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf. "Potential Impacts of the Creation of Maryland FRRs," (April 16, 2020). http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf. "Potential Impacts of the Creation of New Jersey FRRs," (May 13, 2020). http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRs_20200513.pdf. "Potential Impacts of the Creation of Ohio FRRs," (July 17, 2020). http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Ohio_FRRs_20200717.pdf.

for payments to some renewable resources at above market prices.¹⁰⁶ The MMU has prepared reports with analysis on the potential impacts of states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey and Ohio, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.^{107 108 109 110} Additionally, the impact on the remaining PJM capacity market footprint is computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM capacity market would be significantly lower.

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. PJM is considering the application of the Effective Load Carrying Capability (ELCC) approach to defining a dynamic and market based method for determining the capacity contribution of intermittent resources. ELCC would be an advance over the current approach to discounting the reliability contribution of intermittent resources, if done correctly. But implementing ELCC incorrectly, based on average rather than marginal values and locking in values regardless of market realities, would be a significant

mistake and create new issues for the PJM capacity markets. The results could be degraded reliability, favoring old technologies over new technologies, and the inefficient displacement of thermal resources. It is essential to not build in a bad market design from the beginning as such designs gain momentum and gain entrenched supporters among the beneficiaries.

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.

¹⁰⁶ *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. E020030203.

Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_E020030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_E020030203_20200624.pdf> (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_E020030203_20200715.pdf> (July 15, 2020).

¹⁰⁷ See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).

¹⁰⁸ See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).

¹⁰⁹ See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRs_20200513.pdf> (May 13, 2020).

¹¹⁰ See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Ohio_FRRs_20200717.pdf> (July 17, 2020).

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/ISO to help ensure reliability.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.¹¹¹

The Commission issued its MOPR order on December 19, 2019 (“December 19th Order”).¹¹² The December 19th Order defines a clear path for defending competitive wholesale power markets in PJM. The Order defines a clear, consistent and comprehensive approach to the PJM markets and to the role of subsidized resources in the markets. The 2022/2023 BRA is expected to be run by mid 2021.¹¹³

In another proceeding, the Commission has ordered PJM on compliance to propose revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues

rather than historical.¹¹⁴ The MMU has recommended such an approach. The change in the offset will affect MOPR floor prices and the results of unit specific reviews under MOPR. PJM submitted its compliance filing on August 5, 2020, and the matter is now pending.

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.¹¹⁵ Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

Total demand response revenue decreased by \$122.0 million, 31.0 percent, from \$393.7 million in the first nine months of 2019 to \$271.8 million in the first nine months of 2020. Emergency demand response revenue accounted for 99.1 percent of all demand response revenue, economic demand response for 0.1 percent, demand response in the synchronized reserve market for 0.4 percent and demand response in the regulation market for 0.4 percent.

Total emergency demand response revenue decreased by \$119.5 million, 30.7 percent, from \$389.0 million in the first nine months of 2019 to \$269.4 million in the first nine months of 2020. This decrease consisted entirely of capacity market revenue.¹¹⁶

Economic demand response revenue decreased by \$0.6 million, 69.8 percent, from \$0.9 million in the first nine months of 2019 to \$0.3 million in the first nine months of 2020.¹¹⁷ Demand response revenue in the synchronized reserve market decreased by \$1.0 million, 46.4 percent, from \$2.1 million in the first nine months of 2019 to \$1.1 million in the

¹¹¹ See Monitoring Analytics, LLC, “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, 2008).

¹¹² 169 FERC ¶ 61,239.

¹¹³ Docket Nos. ER18-1314-000, -001, EL16-49-000, and EL18-178-000 (March 18, 2020 and June 1, 2020).

¹¹⁴ 171 FERC ¶ 61,153 at PP 320–321 (2020).

¹¹⁵ 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.

¹¹⁶ The total credits and MWh numbers for demand resources were calculated as of October 16, 2020 and may change as a result of continued PJM billing updates.

¹¹⁷ Economic credits are synonymous with revenue received for reductions under the economic load response program.

first nine months of 2020. Demand response revenue in the regulation market decreased by \$0.9 million, 47.2 percent, from \$1.8 million in the first nine months of 2019 to \$1.0 million in the first nine months of 2020.

- **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.¹¹⁸
- **Demand Response Market Concentration.** The ownership of economic load response resources was highly concentrated in the first nine months of 2019 and 2020. The HHI for economic resource reductions increased by 669 points from 8261 in the first nine months of 2019 to 8930 in the first nine months of 2020. The ownership of emergency load response resources was highly concentrated in the first nine months of 2020. The HHI for emergency load response committed MW was 1840 for the 2019/2020 Delivery Year. In the 2019/2020 Delivery Year, the four largest CSPs owned 79.1 percent of all committed demand response UCAP MW. The HHI for emergency demand response committed MW was 2171 for the 2020/2021 Delivery Year. In the 2020/2021 Delivery Year, the four largest CSPs owned 85.6 percent of all committed demand response UCAP MW.
- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. But PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small

end use customers to span an entire zone, which is inconsistent with nodal dispatch.

Section 6 Recommendations

- 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

¹¹⁸ "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 83 (Dec. 3, 2019).

resources, comparable to the rule applicable to generation capacity resources.¹¹⁹ (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 operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.¹²⁰ (Priority: Medium. First reported 2013. Status: Not adopted.)

¹¹⁹ See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

¹²⁰ 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 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.¹²¹)
- 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.)

¹²¹ PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

- The MMU recommends 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. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency 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. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported Q1 2020. 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 on how customers value the power and on the actual cost of that power.

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

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

demand resources are dispatched and demand resources do not have telemetry requirements similar to other Capacity Performance resources.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day-ahead energy market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that 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 (DR) 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 to being a substitute for generation in the capacity and energy markets, demand response resources should be on the demand side of the capacity market rather than on the supply side. Rather than detailed demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol.

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.¹²² The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.^{123 124} Under the MMU proposal,

¹²² 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>>.

¹²³ 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).

¹²⁴ 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).

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.¹²⁵ PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

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

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. 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 measurement and verification estimates are required. No promises of future reductions which can only be verified by inaccurate and biased measurement and verification methods are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, measurement and verification can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE.

125 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).

But the system would be paid for actual, metered usage, regardless of which contractual party takes that obligation.

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

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

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side. 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.

Overview: Section 7, Net Revenue

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and gas prices were lower in the first nine months of 2020 than in the first nine months of 2019.
- In the first nine months of 2020, average energy market net revenues decreased by 17 percent for a new combustion turbine (CT), 23 percent for a new combined cycle (CC), 67 percent for a new coal plant (CP),

25 percent for a new nuclear plant, 33 percent for a new diesel (DS), 33 percent for a new onshore wind installation, 27 percent for a new offshore wind installation and 27 percent for a new solar installation compared to the first nine months of 2019. Average energy market net revenues were higher in the third quarter than in either of the first two quarters of 2020 for all unit types.

- The prices of natural gas and oil fell in the first nine months of 2020. The marginal costs of a new CC and a new CT were less than the marginal cost of a new CP in the first nine months of 2020.
- Based on Western Hub prices, the spark spread in the first nine months of 2020 decreased by 4 percent while the spark spread standard deviation decreased by 51 percent. The dark spread decreased by 21 percent while the dark spread standard deviation decreased by 50 percent, and the quark spread decreased by 30 percent while the quark spread standard deviation decreased by 50 percent.
- The impact of lower energy prices on the net revenues of a new coal plant in the first nine months of 2020 was significant. New coal plant run hours were down 54 percent. New coal plant net revenues were reduced by a zonal average of 67 percent.
- Negative prices do not have a significant impact on total nuclear unit market revenue. Since 2014, negative prices have affected nuclear plants' annual gross revenues by an average of 0.1 percent.¹²⁶

Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Adopted 2020.)

¹²⁶ Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for the comparison.

Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have not covered 100 percent of their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE and PSEG Zones, but have not covered 100 percent of total costs in the ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

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 not covered 100 percent of their total costs, including the return on and of capital, on a cumulative basis. CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE and PSEG Zones, but have not covered 100 percent of their total costs in the ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

Overview: Section 8, Environmental and Renewables

Federal Environmental Regulation

- **MATS.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.¹²⁷ On May 22, 2020, the EPA published its determination that MATS is not appropriate and necessary based on a cost-benefit analysis.¹²⁸ The list of coal steam units subject to MATS, however, remains in place.¹²⁹ All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.
- **Air Quality Standards (NO_x and SO₂ 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.¹³⁰
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.¹³¹ NSR requires new projects and

existing projects receiving major overhauls that significantly increase emissions to obtain permits. Recent EPA proposals would reduce the number of projects that require permits.

- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.¹³² RICE do not have to meet the same emissions standards if they are emergency stationary RICE. Environmental regulations allow emergency stationary RICE participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.
- PJM does not prevent emergency stationary RICE that cannot meet its capacity market obligations as a result of EPA emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that cannot meet its capacity market obligations as a result of emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.
- **Greenhouse Gas Emissions.** On June 19, 2019, the EPA repealed the Clean Power Plan¹³³ and replaced it with the Affordable Clean Energy (ACE) rule, which establishes guidelines for states to develop plans to address greenhouse gas emissions from existing coal fired power plants.¹³⁴ Under the ACE Rule states may permit more CO₂ emissions than under the Clean Power Plan.
- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect

¹²⁷ 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).

¹²⁸ See National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review, Docket No. EPA-HQ-OAR-2018-0794, 85 Fed. Reg. 31286.

¹²⁹ *Id.* at 31291.

¹³⁰ CAA § 110(a)(2)(D)(i)(I).

¹³¹ Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).

¹³² See 40 CFR § 63.6640(f).

¹³³ Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (Aug. 3, 2015) (Clean Power Plan). The Clean Power Plan never took effect because it was subject to a stay issued by the U.S. Supreme Court.

¹³⁴ See *Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*, EPA Docket No. EPA-HQ-OAR-2017-0355, et al., 84 Fed. Reg. 32520 (July 8, 2019).

the best technology available for minimizing adverse environmental impacts.¹³⁵

- **Waters of the United States.** The EPA finalized a rule that significantly narrows the definition of the Waters of the United States. In contrast, the Supreme Court expanded the scope of the CWA when it held that discharge of pollutants from a point source into non jurisdictional groundwater “is the functional equivalent of a direct discharge” when pollutants are conveyed by groundwater into jurisdictional waters.¹³⁶
- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.¹³⁷ The EPA has proposed significant changes to the implementing regulations.

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO₂ 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 rejoined on January 1, 2020.¹³⁸ Virginia and Pennsylvania are preparing to join.¹³⁹ 140 The auction price in the September 2, 2020, auction for the 2018/2020 compliance period was \$6.82 per ton, or \$7.52 per metric tonne.
- **Carbon Price.** If the price of carbon were \$50.00 per metric tonne, short run marginal costs would increase by \$24.52 per MWh or 132.5 percent for a new combustion turbine (CT) unit, \$16.71 per MWh or 130.3 percent for a new combined cycle (CC) unit and \$43.15 per MWh or 158.6 percent for a new coal plant (CP) in 2020.

¹³⁵ 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).

¹³⁶ *County of Maui v. Hawaii Wildlife Fund*, Slip. Op. No. 18–260 (April 23, 2020).

¹³⁷ 42 U.S.C. §§ 6901 et seq.

¹³⁸ “Statement on New Jersey Greenhouse Gas Rule,” RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.

¹³⁹ See Regulation for Emissions Trading, 9 VAC 5-140. The Virginia Air Pollution Control Board is developing the regulation and considering public comments.

¹⁴⁰ Executive Order – 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <<https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>>.

State Renewable Portfolio Standards

- **RPS.** In PJM, nine of 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers’ load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of September 30, 2020, 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, Tennessee and West Virginia did not have renewable portfolio standards.
- **RPS Cost.** The cost of complying with RPS, as reported by the states, is \$4.5 billion over the five year period from 2014 through 2018, an average annual RPS compliance cost of \$893.1 million. The compliance cost for 2018, the most recent year with complete data, was \$986.9 million.

Emissions Controls in PJM Markets

- **Regulations.** Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology.
- **Emissions Controls.** In PJM, as of September 30, 2020, 93.9 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO₂ emissions, while 99.9 percent of coal steam MW had some type of particulate control, and 94.8 percent of fossil fuel fired capacity had NO_x emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 4.3 percent of total generation in PJM in the first nine months of 2020. RPS Tier I generation was 5.0 percent of total generation in PJM and RPS Tier II generation was 1.9 percent of total generation in PJM in the first nine months of 2020.

Only Tier I generation is defined to be renewable but Tier 1 includes some carbon emitting generation.

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. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. 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.¹⁴¹ 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. FERC's recent MOPR order addressed these impacts.

RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO on behalf of the states that would meet the standards and requirements of all states in the PJM footprint 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

¹⁴¹ 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.").

lack of transparent market data. The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to states in order to permit states to consider the development of a multistate framework: for REC markets; for potential agreement on carbon pricing including the distribution of carbon revenues; 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 \$6.33 per tonne in Washington, DC to \$18.22 per tonne in New Jersey. The price of carbon implied by SREC prices ranges from \$62.89 per tonne in Pennsylvania to \$878.57 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in September 2020 of \$7.52 per tonne and to the social cost of carbon which is estimated in the range of \$50 per tonne.¹⁴² The impact on the cost of generation from a new combined cycle unit of a \$50 per tonne carbon price would be \$16.71 per MWh.¹⁴³ The impact of an \$800 per tonne carbon price would be \$267.30 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

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

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost

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

PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. A mechanism like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide modeling information to the states adequate to inform such a decision making process. Such modeling information would include the impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state. This would permit states to make critical decisions about carbon pricing. For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by

¹⁴² "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>.

¹⁴³ The cost impact calculation assumes a heat rate of 6,296 MMBtu per MWh and a carbon emissions rate of 0.053070 tonne per MMBtu. The \$800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2019 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-18.

state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

The annual average cost of complying with RPS over the five year period from 2014 through 2018 for the nine jurisdictions that had RPS was \$893.1 million, or a total of \$4.5 billion over five years. The RPS compliance cost for 2018, the most recent year for which there is complete data, was \$986.9 million. RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately \$2.5 billion per year if the carbon price were \$6.82 per short ton and emissions levels were five percent below 2019 emission levels. If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately \$18.0 billion if the carbon price were \$50 per short ton and emission levels were five percent below 2019 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at \$6.82 per short ton would be about \$1.4 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Overview: Section 9, Interchange Transactions

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2020, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.¹⁴⁴ In the first nine months of 2020, the real-time net interchange was -30,988.1 GWh. The real-time net interchange in the first nine months of 2019 was -25,916.9 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2020, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months. In the first nine months of

¹⁴⁴ 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.

2020, the total day-ahead net interchange was -8,139.8 GWh. The day-ahead net interchange in the first nine months of 2019 was -4,540.7 GWh.

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2020, gross imports in the day-ahead energy market were 640.5 percent of gross imports in the real-time energy market (527.0 percent in the first nine months of 2019). In the first nine months of 2020, gross exports in the day-ahead energy market were 111.3 percent of the gross exports in the real-time energy market (130.5 percent in the first nine months of 2019).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2020, there were net scheduled exports at 14 of PJM's 19 interfaces in the real-time energy market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2020, there were net scheduled exports at 10 of PJM's 17 interface pricing points eligible for real-time transactions in the real-time energy market.^{145 146}
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2020, there were net scheduled exports at 14 of PJM's 19 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2020, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for day-ahead transactions in the day-ahead energy market.¹⁴⁷
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2020, up to congestion transactions were net exports at three of PJM's 18 interface pricing points eligible for day-ahead transactions in the day-ahead energy market.¹⁴⁸
- **Inadvertent Interchange.** In the first nine months of 2020, net scheduled interchange was -30,988 GWh and net actual interchange was -31,044

¹⁴⁵ In the first five months of 2020, there was one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

¹⁴⁶ On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP, DUKEXP and NIPSCO interface pricing points, reducing the number of real-time interfaces to 13.

¹⁴⁷ On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points, reducing the number of day-ahead interfaces to 13.

¹⁴⁸ On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points, reducing the number of day-ahead interfaces to 13.

GWh, a difference of 56 GWh. In the first nine months of 2019, the difference was 47 GWh. This difference is inadvertent interchange.

- **Loop Flows.** In the first nine months of 2020, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -1,623 GWh of net scheduled interchange and -8,670 GWh of net actual interchange, a difference of 7,047 GWh. In the first nine months of 2020, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 2,649 GWh of net scheduled interchange and 18,703 GWh of net actual interchange, a difference of 16,054 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2020, 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 67.3 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first nine months of 2020, 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 49.5 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2020, 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 66.8 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2020, 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 58.3 percent of the hours.
- **Hudson DC Line.** In the first nine months of 2020, 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 47.5 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued one TLR of level 3a or higher in the first nine months of 2020, compared to two such TLRs issued in the first nine months of 2019.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market increased by 5.2 percent, from 51,594 bids per day in the first nine months of 2019 to 54,299 bids per day in the first nine months of 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 0.1 percent, from 490,421 MWh per day in the first nine months of 2019, to 489,871 MWh per day in the first nine months of 2020.

Section 9 Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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: High. First reported 2013. Status: Partially adopted, Q2 2020.)

- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SouthIMP/EXP interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends changing the assignment of the Saskatchewan Power Company and Manitoba Hydro balancing authorities from the Northwest interface pricing point to the MISO interface pricing point and eliminating the Northwest interface pricing point from the day-ahead and real-time energy markets. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the NCMPAIMP and NCMPAEXP interface pricing points. It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. (Priority: High. First reported Q2, 2020. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made

available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)

- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 9 Conclusion

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

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

Prior to the integration of NIPSCO with MISO, transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. Starting May 1, 2004, when NIPSCO integrated with MISO, 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 pricing point in the real-time energy market after the integration of NIPSCO into MISO. The MMU has recommended that PJM terminate the NIPSCO interface pricing point since 2013. The NIPSCO pricing point is a pricing point that could no longer be used to price actual transactions and did not reflect actual price formation. On June 1, 2020, PJM terminated the NIPSCO interface pricing point.

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

On June 1, 2020, PJM terminated the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP interface pricing points. It is not clear why PJM did not also terminate the NCMPAIMP and NCMPAEXP interface pricing points at that time. The MMU continues to recommend the termination of these interface pricing points.¹⁴⁹ In addition to the NCMPAIMP and NCMPAEXP interface prices, the MMU recommends the termination of the Southeast and Southwest interface pricing points, the Northwest interface pricing point and the Ontario interface pricing point.¹⁵⁰ These pricing points can no longer be used to price actual transactions, are inappropriately used to support special agreements, or are pricing points that are noncontiguous to the PJM footprint that create opportunities for market participants to engage in sham scheduling activities.

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.¹⁵¹

PJM determines the primary reserve requirement based on the most severe single contingency in every approved RT SCED case. Every real-time market solution calculates the available tier 1 synchronized reserve. The required synchronized reserve and nonsynchronized reserve are calculated and dispatched in every real-time market solution, and there are associated clearing prices (SRMCP and NSRMCP) assigned every five minutes. Scheduled

¹⁴⁹ At the September 2, 2020, Market Implementation Committee (MIC) meeting, PJM reported that the NCMPAIMP and NCMPAEXP interface pricing points would be retired effective November 3, 2020.

¹⁵⁰ At the September 2, 2020, Market Implementation Committee (MIC) meeting, PJM reported that the Northwest interface pricing point would be retired effective October 1, 2020.

¹⁵¹ See PJM, "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 38 (Aug. 22, 2019)).

resources are credited based on a dispatched assignment and a five minute 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 the first nine months of 2020, the average primary reserve requirement was 2,460.0 MW in the RTO Zone and 2,422.2 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 in response to a PJM declared synchronized reserve event. 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 the first nine months of 2020, there was an average hourly supply of 2,067.7 MW of tier 1 available in the RTO Zone and an average hourly supply of 956.6 MW of tier 1 synchronized reserve available within the MAD Subzone.
- **Demand.** The synchronized reserve requirement is calculated for each real-time dispatch solution as the most severe single contingency within both the RTO Zone and the MAD Subzone. The requirement is reduced

by the amount of estimated tier 1. The remaining unfilled requirement (if any) is met with 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 for increasing its output (or reducing load for demand response) at the rate of \$50 per MWh in addition to LMP.¹⁵² This is the Synchronized Energy Premium Price.
- **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 synchronized energy premium price of \$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, \$4,732,025 in 2018, and \$3,217,178 in 2019. The hourly nonsynchronized reserve market clearing price was above \$0 in 682 intervals in the first nine months of 2020 resulting in a payment to tier 1 resources of \$986,042.

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, and that have an obligation to respond to PJM declared synchronized reserve events. Tier 2 synchronized reserve is penalized for failure to respond to a PJM declared synchronized reserve event. PJM has established a required amount of synchronized reserve as no less than the largest single contingency, and a 10 minute primary reserve at no less than 150 percent of the largest single contingency. This is stricter than the NERC

¹⁵² See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 109 (Oct. 15, 2020).

standard of the greater of 80 percent of the largest single contingency or 900 MW.¹⁵³

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 the first nine months of 2020, the supply of daily offered and eligible tier 2 synchronized reserve was 30,240.0 MW in the RTO Zone of which 4,996.2 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,699.0 MW in the RTO Reserve Zone and 1,683.8 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 178.1 MW in the MAD Subzone and 329.9 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 2020.

The average HHI for tier 2 synchronized reserve in the RTO Zone was 6043 which is classified as highly concentrated. The MMU calculates that the three pivotal supplier test would have been failed in 14 percent of intervals in the first nine months of 2020.

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 intervals in the Mid-Atlantic Dominion (MAD) Subzone was \$2.62 per MW in the first nine months of 2020, a decrease of \$0.45 from the \$3.07 in the first nine months of 2019.

The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the RTO Synchronized Reserve Zone was \$3.58 per MW in the first nine months of 2020, an increase of \$0.39 from \$3.19 in the first nine months of 2019.

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 the first nine months of 2020, the average five minute interval supply of eligible and available nonsynchronized reserve was 1,405.0 MW in the RTO Zone.
- **Demand.** Demand for nonsynchronized reserve equals the primary reserve requirement minus the tier 1 synchronized reserve estimate and

¹⁵³ NERC (June 2, 2020) <NERC Reliability Standard BAL-002-2 Glossary_of_Terms.pdf>.

minus the scheduled tier 2 synchronized reserve.¹⁵⁴ The actual amount of nonsynchronized reserve scheduled often exceeds the demand and the corresponding price is \$0.00. In the RTO Zone, the market scheduled an hourly average of 1,247.7 MW of nonsynchronized reserve in the first nine months of 2020.

- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 99.7 percent of intervals where the price was above \$0.01 in the first nine months of 2020.

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 intervals in the RTO Reserve Zone was \$0.10 in the first nine months of 2020.

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 is not required to maintain this level of secondary reserve in real time.

PJM maintains a day-ahead, offer-based market for 30 minute day-ahead secondary reserve. The PJM 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.¹⁵⁵ 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 the first nine months of 2020, the average available hourly DASR was 44,991.3 MW.
- **Demand.** The DASR requirement for November 2019 through October 2020 is 5.07 percent of peak load forecast, which is a 0.22 percentage point decrease from the previous twelve month period. The average hourly DASR MW purchased in the first nine months of 2020 was 4,987.2 MW. This is a reduction from the 5,460.3 hourly MW in 2019.
- **Concentration.** The three pivotal supplier test would have failed in zero hours in the first nine months of 2020.

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 the first nine months of 2020, 39.6 percent of daily unit offers were above \$0.00 and 16.4 percent of daily unit offers were 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 the first nine months of 2020.

¹⁵⁴ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 5b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 109 (Oct. 15, 2020). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

¹⁵⁵ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 109 (Oct. 15, 2020).

Market Performance

- **Price.** In the first nine months of 2020 the weighted average DASR price for all hours when the DASRMCP was above \$0.00 was \$2.17.

Regulation Market

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

Market Structure

- **Supply.** In the first nine months of 2020, the average hourly offered supply of regulation for nonramp hours was 704.1 performance adjusted MW (709.1 effective MW). This was a decrease of 92.6 performance adjusted MW (a decrease of 88.5 effective MW) from the first nine months of 2019. In the first nine months of 2020, the average hourly offered supply of regulation for ramp hours was 1,008.9 performance adjusted MW (1,053.1 effective MW). This was a decrease of 113.1 performance adjusted MW (a decrease of 74.4 effective MW) from the first nine months of 2019, when the average hourly offered supply of regulation was 1,122.0 performance adjusted MW (1,127.4 effective MW).

- **Demand.** The hourly regulation demand is 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 490.0 hourly average performance adjusted actual MW in the first nine months of 2020. This is an increase of 22.2 performance adjusted actual MW from the first nine months of 2019, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 467.9 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 703.0 hourly average performance adjusted actual MW in the first nine months of 2020. This is a decrease of 19.8 performance adjusted actual MW from the first nine months of 2019, where the average hourly regulation cleared MW for ramp hours were 722.8 performance adjusted actual MW.

The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.43 in the first nine months of 2020 (1.55 in the first nine months of 2019). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.44 in the first nine months of 2020 (1.70 in the first nine months of 2019).

- **Market Concentration.** In the first nine months of 2020, the three pivotal supplier test was failed in 04.8 percent of hours. In the first nine months of 2020, the actual MW weighted average HHI of RegA resources was 2519 which is highly concentrated and the weighted average HHI of RegD resources was 1850 which is moderately concentrated. The weighted average HHI of all resources was 1443, which is moderately concentrated.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be

following, RegA or RegD.¹⁵⁶ In the first nine months of 2020, there were 217 resources following the RegA signal and 52 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was \$12.59 per MW of regulation in the first nine months of 2020. This is a decrease of \$2.38 per MW, or 15.9 percent, from the weighted average clearing price of \$14.97 per MW in the first nine months of 2019. The weighted average cost of regulation in the first nine months of 2020 was \$15.59 per MW of regulation. This is a decrease of 18.6 percent, from the weighted average cost of \$19.15 per MW in the first nine months of 2019.
- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the regulation market were functioning efficiently and competitively, RegD and RegA resources would be paid the same price per effective MW. 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.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF 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 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.¹⁵⁷ The MMU and PJM filed requests for rehearing.¹⁵⁸ On March 26, 2020, the Commission issued an order denying the MMU and PJM's requests for rehearing.¹⁵⁹

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).¹⁶⁰

In the first nine months of 2020, total black start charges were \$49.3 million, including \$49.1 million in revenue requirement charges and \$0.160 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 the first nine months of 2020 ranged from \$0.04 per MW-day in the DLCO Zone (total charges were \$32,721) to \$3.95 per MW-day in the PENELEC Zone (total charges were \$3,260,274).

¹⁵⁷ 162 FERC ¶ 61,295.

¹⁵⁸ FERC Docket No. ER18-87-002.

¹⁵⁹ 170 FERC ¶ 61,259.

¹⁶⁰ OATT Schedule 1 § 1.3BB.

¹⁵⁶ See the 2019 State of the Market Report for PJM, Vol. 2, Appendix F "Ancillary Services Markets."

The capital recovery factor (CRF) defines the revenue requirement of black start units. The CRF is a rate, which when multiplied by the investment, provides for a return on and of capital over a defined time period. The PJM CRF table was created in 2007 as part of the new RPM capacity market design and incorporated in Attachment DD to the PJM OATT (Table 1-020). The CRF values were later added to the black start rules. The CRF table includes assumptions about tax rates that are no longer correct. The new depreciation rules allow for a more accelerated depreciation and therefore lower taxes. The tax code also reduced the corporate tax rate to 21 percent which also reduces taxes. The CRF values are significantly too high as a result. The PJM tariff tables including CRF values should have been changed for both black start and the capacity market when the tax laws changed in 2017. As a result, CRF values have overcompensated black start units since the changes to the tax code.

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

For the future, the CRF rates should be updated at least annually to reflect changes in federal or state taxes, including depreciation treatment and tax rates.

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVar). Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW). The same equipment provides both MVar and MW. The current rules permit double recovery of some fixed costs.

Reactive capability charges are based on FERC approved filings that permit recovery based on a cost of service approach.¹⁶¹ Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Total reactive charges increased 6.16 percent from \$250.6 million in the first nine months of 2019 to \$266.0 million in the first nine months of 2020. Reactive capability charges increased 6.2 percent from \$250.1 million in the first nine months of 2019 to \$265.6 million in the first nine months of 2020. Total reactive service charges in the first nine months of 2020 ranged from \$0 in the RECO and OVEC Zones, to \$36.5 million in the AEP 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 nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.¹⁶² PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.¹⁶³

The PJM Tariff requires that all new generator interconnection customers (Nuclear Regulatory Commission regulated facilities are exempt from this provision) have hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust real power output in a direction to correct for frequency deviations. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 0.036 deadband.¹⁶⁴ In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

¹⁶¹ OATT Schedule 2.

¹⁶² See 157 FERC ¶ 61,122 (2016).

¹⁶³ See 164 FERC ¶ 61,224 (2018).

¹⁶⁴ OATT Attachment O § 4.7.2 (Primary Frequency Response).

The response of generators within PJM to NERC identified frequency events in 2019 remains under evaluation. NERC uses a threshold value (L_{10}) equal to 262 MW/0.1 Hz and has selected 23 events in 2019 to evaluate. Evaluation will continue until later in 2020 when further recommendations will be discussed within PJM and the NERC Operating Committee.

Section 10 Recommendations

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.¹⁶⁵)
- 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.¹⁶⁶ FERC rejected.¹⁶⁷)
- 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.¹⁶⁸)
- 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.¹⁶⁹)
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.¹⁷⁰)
- 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 PJM replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: 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 2018. Status: Not adopted.)
- The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)

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

¹⁶⁶ 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.

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

¹⁶⁸ *Id.*

¹⁶⁹ *Id.*

¹⁷⁰ *Id.*

- 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: Adopted April 2019.)
- 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 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: 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 mitigate market power. (Priority: Low. First reported 2009. Modified, 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. The PJM capacity and energy markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. The CRF rates for units going into service since the change in the tax code should incorporate applicable changes to depreciation treatment and tax rates. The CRF rates for units constructed prior to the new tax law and to which the new tax law depreciation rules did not apply should incorporate only the applicable changes to the tax rate. The black start units should be required to commit to providing black start service for the life of the unit. (Priority: High. First reported Q2, 2020. 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 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 2018. Status: Not adopted.)
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019.¹⁷¹ Status: Partially 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.¹⁷²

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, 2017.¹⁷³ 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. 755.¹⁷⁴ The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.¹⁷⁵

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 economic withholding and is therefore not consistent with a competitive outcome. The \$7.50 margin should be eliminated. The variable operating and maintenance component of the synchronized reserve offer should also be eliminated. All variable operating and maintenance costs are incurred to provide energy and to make units available to provide energy. There are no variable operating and maintenance costs associated with providing synchronized reserve.

Participant performance has not been adequate for tier 2 synchronized reserve. Compliance with calls to respond to actual synchronized reserve events remains significantly less than 100 percent. Actual participant performance means that the penalty structure is not an adequate incentive for 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 to a synchronized reserve event. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the

¹⁷¹ The MMU has discussed this recommendation in state of the market reports since 2016 but Q3, 2019 was the first time it was reported as a formal MMU recommendation.

¹⁷² Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

¹⁷³ 18 CFR § 385.211 (2017)

¹⁷⁴ 162 FERC ¶ 61,295.

¹⁷⁵ 170 FERC ¶ 61,259.

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 has added more than \$100 million to the cost of primary reserve since 2014.

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

The MMU concludes that the regulation market results were not competitive, and the market design is significantly flawed. The MMU concludes that the synchronized reserve market results were competitive, 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 decreased by \$23.0 million or 5.5 percent, from \$419.1 million in the first nine months of 2019 to \$396.1 million in the first nine months of 2020.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by \$8.9 million or 1.7 percent, from \$511.4 million in the first nine months of 2019 to \$502.5 million in the first nine months of 2020.
- **Balancing Congestion.** Negative balancing congestion costs increased by \$14.0 million or 15.1 percent, from -\$92.3 million in the first nine months of 2019 to -\$106.3 million in the first nine months of 2020. Negative balancing explicit charges increased by \$6.9 million, from -\$59.4 million

in the first nine months of 2019 to -\$66.3 million in the first nine months of 2020.

- **Real-Time Congestion.** Real-time congestion costs increased by \$44.6 million or 8.6 percent, from \$517.3 million in the first nine months of 2019 to \$561.9 million in the first nine months of 2020.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2020 ranged from \$16.0 million in April to \$81.7 million in July.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Bagley – Graceton Line, the Conastone – Graceton Line, the Conastone – Peach Bottom Line, the Harwood – Susquehanna Line, and the Three Mile Island Transformer.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first nine months of 2020. The number of congestion event hours in the day-ahead energy market was about four times the number of congestion event hours in the real-time energy market.

Day-ahead congestion frequency decreased by 20.7 percent from 78,155 congestion event hours in the first nine months of 2019 to 61,957 congestion event hours in the first nine months of 2020.

Real-time congestion frequency increased by 23.5 percent from 13,495 congestion event hours in the first nine months of 2019 to 16,662 congestion event hours in the first nine months of 2020.

- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities except interfaces. The congestion event hours on the PA Central Interface increased from 43 hours in the first nine months of 2019 to 1,402 hours in the first nine months of 2020.

The Bagley – Graceton Line was the largest contributor to congestion costs in the first nine months of 2020. With \$56.2 million in total congestion costs, it accounted for 14.2 percent of the total PJM congestion costs in the first nine months of 2020.

- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** CT Price Setting Logic caused -\$0.4 million of day-ahead congestion in the first nine months of 2020 and -\$1.6 million of balancing congestion in the first nine months of 2020. None of the closed loop interfaces was binding in the first nine months of 2020 or 2019.
- **Zonal Congestion.** AEP had the largest zonal congestion costs among all control zones in the first nine months of 2020. AEP had \$72.0 million in zonal congestion costs, comprised of \$89.2 million in zonal day-ahead congestion costs and -\$17.2 million in zonal balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by \$153.5 million or 30.5 percent, from \$502.7 million in the first nine months of 2019 to \$349.2 million in the first nine months of 2020. The loss MWh in PJM decreased by 789.9 GWh or 6.8 percent, from 11,600.8 GWh in the first nine months of 2019 to 10,810.9 GWh in the first nine months of 2020. The loss component of real-time LMP in the first nine months of 2020 was \$0.01, compared to \$0.02 in the first nine months of 2019.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first nine months of 2020 ranged from \$22.5 million in April to \$67.0 million in July.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by \$151.1 million or 27.8 percent, from \$542.6 million in the first nine months of 2019 to \$391.5 million in the first nine months of 2020.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by \$2.4 million or 5.9 percent, from -\$39.9 million in the first nine months of 2019 to -\$42.3 million in the first nine months of 2020.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in the first nine months of 2020 by \$47.9 million or 29.6 percent, from \$162.1 million in the first nine months of 2019, to \$114.2 million in the first nine months of 2020.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs increased by \$105.3 million or 31.0 percent, from -\$339.3 million in the first nine months of 2019 to -\$234.0 million in the first nine months of 2020.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs increased by \$104.0 million or 25.5 percent, from -\$407.6 million in the first nine months of 2019 to -\$303.6 million in the first nine months of 2020.
- **Balancing System Energy Costs.** Balancing system energy costs decreased by \$0.3 million or 0.5 percent, from \$68.0 million in the first nine months of 2019 to \$67.7 million in the first nine months of 2020.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first nine months of 2020 ranged from -\$42.5 million in July to -\$15.9 million in April.

Section 11 Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and 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 the first nine months of 2020 was lower than congestion in the first nine months of any year from 2008 through 2019. This was the combined result of weather conditions and demand reductions due to COVID-19.

The monthly total congestion costs ranged from \$16.0 million in April to \$81.7 million in July in the first nine months of 2020.

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.¹⁷⁶

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all congestion revenues. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first four months of the 2020/2021 planning period, using the rules effective for each planning period, was 75.0 percent. Load has been underpaid by \$2.2 billion from the 2011/2012 planning period through the first four months of the 2020/2021 planning period.

Overview: Section 12, Planning

Generation Interconnection Planning

Existing Generation Mix

- As of September 30, 2020, PJM had a total installed capacity of 196,832.0 MW, of which 50,230.8 MW (25.5 percent) are coal fired steam units, 50,563.6 MW (25.7 percent) are combined cycle units and 33,452.6 MW (17.0 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 196,832.0 MW of installed capacity, 71,577.4 MW (36.4 percent) are from units older than 40 years, of which 36,939.4 MW (51.6 percent) are coal fired steam units, 532.0 MW (0.7 percent) are combined cycle units and 16,184.6 MW (22.6 percent) are nuclear units.

Generation Retirements¹⁷⁷

- There are 43,787.4 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 31,846.2 MW (72.7 percent) are coal fired steam units. Coal unit retirements are primarily a result of

the inability of coal units to compete with efficient combined cycle units burning low cost natural gas.

- In the first nine months of 2020, 2,469.0 MW of generation retired. The largest generator that retired in the first nine months of 2020 was the 337.0 MW Conesville 4 coal fired steam unit located in the AEP Zone. Of the 2,469.0 MW of generation that retired, 776.8 MW (31.5 percent) were located in the AEP Zone.
- As of September 30, 2020, there are 4,556.0 MW of generation that have requested retirement after September 30, 2020, of which 1,907.5 MW (41.9 percent) are located in the Dominion Zone. Of the Dominion generation requesting retirement, 1,121.5 MW (58.8 percent) are coal fired steam units.

Generation Queue¹⁷⁸

- There were 126,818.9 MW in generation queues, in the status of active, under construction or suspended, at the end of 2019. In the first nine months of 2020, the AF2 and AG1 queue windows closed. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On September 30, 2020, there were 148,361.6 MW in generation queues, in the status of active, under construction or suspended, an increase of 21,542.7 MW (17.0 percent) from the end of 2019.¹⁷⁹
- As of September 30, 2020, 5,367 projects, representing 624,142.5 MW, have entered the queue process since its inception in 1998. Of those, 932 projects, representing 71,856.6 MW, went into service. Of the projects that entered the queue process, 2,916 projects, representing 403,924.3 MW (64.7 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.

¹⁷⁶ 162 FERC ¶ 61,139 (2018).

¹⁷⁷ See PJM. Planning. "Generator Deactivations," (Accessed on September 30, 2020) <<http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>>.

¹⁷⁸ See PJM. Planning. "New Services Queue," (Accessed on September 30, 2020) <<https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>>.

¹⁷⁹ The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

- As of September 30, 2020, 148,361.6 MW were in generation request queues in the status of active, under construction or suspended. Based on historical completion rates, 38,864.3 MW of new generation in the queue are expected to go into service.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. PJM's benefit/cost analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through September 30, 2020, PJM has completed four market efficiency cycles under Order No. 1000.¹⁸⁰

PJM MISO Interregional Market Efficiency Process (IMEP)

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

PJM MISO Targeted Market Efficiency Process (TMEP)

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

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not

required for reliability, economic efficiency or operational performance criteria, as determined by PJM."¹⁸¹ Supplemental projects are exempt from the competitive planning process.

- The average number of supplemental projects in each expected in service year increased by 735.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 167 for years 2008 through 2020 (post Order 890).
- The process for designating projects as supplemental projects should be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build the project, or used to effectively replace the RTEP process.

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. Some Transmission Owners include end of life transmission projects in their Transmission Owner Form 715 Planning Criteria. These projects were exempt from the competitive planning process.¹⁸² On August 30, 2019, the Commission issued an Order Instituting Section 206 Proceeding that removed the proposal window exemption for Form No. 715 Planning Criteria.¹⁸³
- End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project.

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, as well as scope changes and project cancellations, but exclude supplemental and end of

¹⁸⁰ See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) [Order No. 1000], order on reh'g, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

¹⁸¹ See PJM, "Transmission Construction Status," (Accessed on September 30, 2020) <<http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>>.

¹⁸² See PJM, Operating Agreement, Schedule 6 § 1.5.8(o).

¹⁸³ 168 FERC ¶ 61,132 at P 13 (2019).

life projects, are periodically presented to the PJM Board of Managers for authorization.¹⁸⁴ In the first nine months of 2020, the PJM Board approved a net change of \$770.4 million in upgrades. As of September 30, 2020, the PJM Board has approved \$38.4 billion in system enhancements since 1999.

Transmission Competition

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

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of September 30, 2020, no QTUs have cleared a BRA.

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.¹⁸⁵

- There were 6,856 transmission outage requests submitted in the first four months of 2020/2021 planning period. Of the requested outages, 75.2 percent of the requested outages were planned for less than or equal to five days and 11.4 percent of requested outages were planned for greater than 30 days. Of the requested outages, 46.8 percent were late according to the rules in PJM's Manual 3.

Section 12 Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.¹⁸⁶ (Priority: Low. First reported 2013. Status: Partially adopted, 2012.)
- 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. First reported 2018. Status: Adopted, 2019.)

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.)

¹⁸⁴ Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

¹⁸⁵ See PJM, "PJM Manual 03: Transmission Operations," Rev. 57 (May 29, 2020).

¹⁸⁶ 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 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 the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing 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 increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

Transmission Competition

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

and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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: Adopted 2020.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. New recommendation. Status: Not adopted.)

Cost Allocation

- 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.¹⁸⁷ (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

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

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled 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

¹⁸⁷ See the 2015 *State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning, at p. 463, Cost Allocation Issues.

alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current benefit/cost analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The MMU recommends that the market efficiency process be eliminated.

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 nonincumbent 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 nonincumbent transmission investment. Issues related to data

access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. 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 asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for of a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

If it is retained, 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 definition of benefits should also be reevaluated.

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.

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 ARR

Auction Revenue Rights

Market Structure

- **Residual ARRs.** 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 four months of the 2020/2021 planning period, PJM allocated a total of 16,997.8 MW of residual ARRs with a total target allocation of \$3.6 million, up from 11,162.7 MW in the first four months of the 2019/2020 planning period, with a total target allocation of \$2.7 million.

- **ARR Reassignment for Retail Load Switching.** There were 13,606 MW of ARRs associated with \$78,900 of revenue that were reassigned in the first four months of the 2020/2021 planning period. There were 18,913 MW of ARRs associated with \$223,800 of revenue that were reassigned for the same time frame of the 2019/2020 planning period.

Market Performance

- **Revenue Adequacy.** For the first four months of the 2020/2021 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were \$509.1 million, while PJM collected \$670.5 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. The allocation of surplus congestion revenue provides for revenue adequacy for FTRs first, and any remaining revenues at the end of the planning period are allocated to ARR holders. For the 2019/2020 planning period, the ARR target allocations were \$752.2 million while PJM collected \$982.0 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.
- **ARRs as an Offset to Congestion.** ARRs have historically not served as an effective way to return all congestion revenues to load. For the first four months of the 2020/2021 planning period, 50.6 percent of total congestion was offset by ARR credit allocations to ARR holders. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. The goal of the ARR/FTR market design should be to ensure that load has the rights to 100 percent of the congestion revenues. The cumulative offset was 75.0 percent based on the rules that were in place for each planning period. Load has been underpaid by \$2.2 billion from the 2011/2012 planning period through the first four months of the 2020/2021 planning period.

Financial Transmission Rights

Market Structure

- **Monthly Balance of Planning Period FTR Auctions.** The structure of the Monthly Balance of Planning Period FTR Auctions was changed effective with the 2020/2021 planning period. The new structure makes available the FTRs for each remaining month in the planning period. The prior design made available the FTRs for the next three individual months and then any eligible quarters. Beginning in the 2020/2021 planning period any individual remaining calendar month is available for bids or

offers. For example, in the June auction June through May are available as individual periods. In the January auction, January through May are available as individual periods.

- **Sell Offers.** In a given auction, market participants can sell FTRs that they have acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2020/2021 planning period, total participant FTR sell offers were 8,033,682 MW.
- **Buy Bids.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2020/2021 planning period were 17,505,199 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 84.5 percent of prevailing flow and 87.1 percent of counter flow FTRs for January through September, 2020. Financial entities owned 74.4 percent of all prevailing and counter flow FTRs, including 67.5 percent of all prevailing flow FTRs and 83.3 percent of all counter flow FTRs during the period from January through September 2020.

Market Behavior

- **FTR Forfeitures.** Under the modified FTR forfeiture rules, total FTR forfeitures were \$22.1 million for the period January 19, 2017, through September 30, 2020.
- **Credit.** There were three collateral defaults in the first nine months of 2020 for a total of \$34,410. There were 22 payment defaults in the first nine months of 2020 not involving GreenHat Energy, LLC for a total of \$31,796. GreenHat Energy accrued payment defaults of \$15.6 million in the first nine months of 2020 for a total of \$162.6 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.¹⁸⁸ In addition, PJM added the settlement fee and claimant payee funds to the default allocation, resulting in allocations of \$12.5 million and \$5.0 million for a total of \$180.1 million.

¹⁸⁸ See the 2019 Quarterly State of the Market Report for PJM: January through June for a more complete explanation of credit issues that occurred in 2019.

Market Performance

- **Volume.** In the first four months of the 2020/2021 planning period, Monthly Balance of Planning Period FTR Auctions cleared 2,720,662 MW (15.5 percent) of FTR buy bids and 1,357,952 MW (16.9 percent) of FTR sell offers. For the first four months of the 2019/2020 planning period, Monthly Balance of Planning Period FTR Auctions cleared 1,588,345 MW (16.6 percent) of FTR buy bids and 832,832 MW (21.5 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods of the first four months of the 2020/2021 planning period was \$0.14.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated \$20.8 million in net revenue for all FTRs of the first four months of the 2020/2021 planning period, down from \$27.9 million for the same time period in the 2018/2019 planning period.
- **Revenue Adequacy.** FTRs were paid at 100.0 percent of the target allocation level for the first four months of the 2020/2021 planning period, including the distribution of the current surplus revenue.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of the FTR. In the first four months of 2020/2021 planning period, physical entities made \$38.0 million profits on FTRs purchased directly (not self scheduled), up from \$2.1 million losses for the same time period in the 2019/2020 planning period and financial entities made \$98.4 million including GreenHat's losses, up from \$5.6 million profits for the same time period in the 2019/2020 planning period.

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 all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a network design in which the rights to actual congestion are assigned directly to load by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, the Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, 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 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.¹⁸⁹ (Priority: High. First reported 2015. Status: Not 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 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 a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple

¹⁸⁹ See "PJM Manual 6: Financial Transmission Rights," Rev. 254 (July 23, 2020).

daily price divided by 24. (Priority: High. First reported 2018. Status: Adopted, 2019. Pending at FERC.)

- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported Q2, 2020. Status: Not adopted.)
- The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately. (Priority: High. New recommendation. Status: PJM planning to implement.)

Section 13 Conclusion

Solutions

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 security constrained LMP markets. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

The current path based design should be replaced with a network design in which the rights to actual congestion are assigned directly to load by node. The assigned right is to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the network congestion or sell the right through auctions.

Issues

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 and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

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

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

Load should never be required to subsidize payments to FTR holders, regardless of the reason.¹⁹⁰ The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.¹⁹¹ 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. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and reduced 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 pays for the physical transmission system, pays in excess of generator revenues and pays negative balancing congestion again. The result is that load gets back less than total congestion. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There was no reason to impose these costs on load.

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

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 50.0 percent of total congestion costs for the 2017/2018 planning period rather

¹⁹⁰ Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.

¹⁹¹ See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

than the 60.5 percent offset that would have occurred under the prior rules, a difference of \$125.8 million.

A subsequent rule change was implemented by PJM that modified the allocation of surplus auction revenue to the benefit of load. Beginning with the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up to the point of revenue adequacy, and then distributed to ARR holders.¹⁹² However, under the rules, ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. The new rules do not fully recognize ARR holders' rights to surplus congestion revenue. With this rule in effect for the first four months of the 2020/2021 planning period, ARRs and FTRs offset 50.6 percent of total congestion rather than 50.2 percent.

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

¹⁹² 163 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

¹ OATT Attachment M § IV.D.

² *Id.*

³ *Id.*

⁴ *Id.*

⁵ OATT Attachment M § VI.A.

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," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.⁶

In this *2020 Quarterly State of the Market Report for PJM: January through September*, the MMU includes ten new recommendations.

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

New Recommendations from Section 3, Energy Market

- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved Fuel Cost Policy. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to have an approved Fuel Cost Policy. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 4, Energy Uplift

- The MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 12, Generation and Transmission Planning

- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. New recommendation. Status: Not adopted.)

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

- The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately. (Priority: High. New recommendation. Status: PJM planning to implement.)

Complete List of Current MMU Recommendations

The recommendations are explained in each section of the report.

Section 3, Energy Market

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when 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.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the 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 2018. Status: Adopted 2020.)
- 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 2018. Status: Adopted 2020.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved Fuel Cost Policy. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to have an approved Fuel Cost Policy. (Priority: Medium. New recommendation. Status: Not adopted.)

Cost-Based Offers

- 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 the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in Cost Development Guidelines. (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 2020.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- 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, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior

time in the real-time market. (Priority: High. New recommendation. Status: Not adopted.)

- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, and during high load conditions such as cold and hot weather alerts or more severe emergencies, that 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, in order to ensure effective market power mitigation, that PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. First reported 2019. 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.⁷ (Priority: Medium. First reported 2012. Status: Not adopted.)

⁷ This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

Capacity Performance Resources

- The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially 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 at a defined zonal or higher level. (Priority: Medium. First reported 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 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. First reported 2018. 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. First reported 2018. Status: Not adopted.)

- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Not adopted.)
- 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: Adopted 2020.)
- 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 not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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: 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.^{8 9} (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)

⁸ 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.

⁹ There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <<http://www.pjm.com/Glossary.aspx>>.

- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the 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.)
- The MMU recommends that PJM model generators' operating transitions, including modeling soak time for units with a steam turbine and configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported Q1, 2020. 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: Adopted, 2019.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule

availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)

- 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, scheduled approach. (Priority: High. First reported 2018. Status: Not adopted.)

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. 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 2018. 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: Partially adopted, 2019.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based

on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)

- The MMU recommends the elimination of day-ahead 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.)
- 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 2018.¹⁰)
- 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 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.¹¹)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends 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 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. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation. (Priority: Medium. New recommendation. Status: Not adopted.)

¹⁰ 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*, Volume 2, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

¹¹ On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. PJM began posting unit specific uplift reports on May 1, 2019.

Section 5, Capacity Market

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.^{12 13} (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.^{14 15} 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

¹² See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

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

¹⁴ See PJM Interconnection, LLC, Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

¹⁵ See the 2019 State of the Market Report for PJM, Volume 2, Section 7: Net Revenue.

is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported 2017. Status: Not adopted.)

- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be reviewed. (Priority: Medium. First reported 2019. 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.¹⁶ (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.¹⁷ (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.)

¹⁶ Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000, -001; EL18-178 (October 2, 2018).

¹⁷ 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 the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate be left at its current level. 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 MSOC. 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 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 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit which is not capable of supplying energy consistent with its day-ahead offer which should equal its ICAP, reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

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: Not 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 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.¹⁸ (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 operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.¹⁹ (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends limited, extended summer and annual demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component

¹⁸ See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

¹⁹ 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-c.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.

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.²⁰)
- 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. First reported 2018. Status: Not adopted.)

²⁰ PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency 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. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported Q1 2020. Status: Not adopted.)

Section 7, Net Revenue

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Adopted 2020.)

Section 8, Environmental and Renewables

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over REC markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. First reported 2018. Status: Not adopted.)

- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 9, Interchange Transactions

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

to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that 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: High. First reported 2013. Status: Partially adopted, Q2 2020.)
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SouthIMP/EXP interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends changing the assignment of the Saskatchewan Power Company and Manitoba Hydro balancing authorities from the Northwest interface pricing point to the MISO interface pricing point and eliminating the Northwest interface pricing point from the day-ahead and real-time energy markets. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the NCMPAIMP and NCMPAEXP interface pricing points. It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. (Priority: High. First reported Q2, 2020. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing

authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)

- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a

deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 10, Ancillary Services

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.²¹)
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.²² FERC rejected.²³)
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.²⁴)

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

²² This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.

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

²⁴ *Id.*

- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.²⁵)
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.²⁶)
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that PJM replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: 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 2018. Status: Not adopted.)
- The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources 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

²⁵ *Id.*²⁶ *Id.*

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: Adopted April 2019.)
- 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 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: 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 mitigate market power. (Priority: Low. First reported 2009. Modified, 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. The PJM capacity and energy markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. The CRF rates for units going into service since the change in the tax code should incorporate applicable changes to depreciation treatment and tax rates. The CRF rates for units constructed prior to the new tax law and to which the new tax law depreciation rules did not apply should incorporate only the applicable changes to the tax rate. The black start units should be required to commit to providing black start service for the life of the unit. (Priority: High. First reported Q2, 2020. 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 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 2018. Status: Not adopted.)
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019.²⁷ Status: Partially adopted.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.²⁸ (Priority: Low. First reported 2013. Status: Partially adopted, 2012.)
- 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. First reported 2018. Status: Adopted, 2019.)

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

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

²⁸ 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>.

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 the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing 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 increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are

used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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: Adopted 2020.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. New recommendation. Status: Not adopted.)

Cost Allocation

- 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.²⁹ (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

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

²⁹ See the 2015 State of the Market Report for PJM, Volume 2, Section 12: Generation and Transmission Planning, at p. 463, Cost Allocation Issues.

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled 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 all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a network design in which the rights to actual congestion are assigned directly to load by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, the Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on

counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)

- The MMU recommends that, under the current FTR design, the full capability of the transmission system be allocated as ARR holders 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 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.³⁰ (Priority: High. First reported 2015. Status: Not 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 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 a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the 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. First reported 2018. Status: Adopted, 2019. Pending at FERC.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported Q2, 2020. Status: Not adopted.)
- The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately. (Priority: High. New recommendation. Status: PJM planning to implement.)

³⁰ See "PJM Manual 6: Financial Transmission Rights," Rev. 254 (July 23, 2020).

Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2020.

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 aggregate energy market in the first nine months of 2020 was unconcentrated by FERC HHI standards. Average HHI was 723 with a minimum of 520 and a maximum of 1083 in the first nine months of 2020. The peaking segment of supply was highly concentrated. The fact that the average HHI and the maximum hourly HHI are in the unconcentrated range does not mean that the aggregate market was competitive in all hours. 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 definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.

- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market.
- PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's core functions is to identify actual or potential market design flaws.¹ The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. 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.² 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. Units with market power have positive markups, which means that the cost-

¹ OATT Attachment M (PJM Market Monitoring Plan).

² 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.

based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of \$1,000 per MWh.

Overview

Supply and Demand

Market Structure

- **Supply.** Supply includes physical generation, imports and virtual transactions. The maximum average on peak hourly offered real-time supply was 152,122 MW for the 2020 summer, and 152,553 MW for the 2019 summer. In the first nine months of 2020, 1,248.4 MW of new resources were added in the energy market, and 2,469.0 MW of internal resources and 457 MW of pseudo tied resources retired.

PJM average hourly real-time cleared generation in the first nine months of 2020 decreased by 3.5 percent from the first nine months of 2019, from 95,531 MWh to 92,226 MWh.

PJM average hourly day-ahead cleared supply in the first nine months of 2020, including INCs and up to congestion transactions, decreased by 3.1 percent from the first nine months of 2019, from 118,913 MWh to 115,205 MWh.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load in the first nine months of 2020 was 141,449 MWh in the HE 1700 on July 20, 2020, which was 6,778 MWh, 4.6 percent, lower than the PJM peak load in the first nine months of 2019, which was 148,228 MWh in the HE 1800 on July 19, 2019.

PJM average hourly real-time demand in the first nine months of 2020 decreased by 4.4 percent from the first nine months of 2019, from 89,834 MWh to 85,886 MWh. PJM average hourly day-ahead demand in the first nine months of 2020, including DECs and up to congestion transactions, decreased by 3.8 percent from the first nine months of 2019, from 114,133 MWh to 109,850 MWh.

Market Behavior

- **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. In the first nine months of 2020, 16.4 percent of real-time load was supplied by bilateral contracts, 24.0 percent by spot market purchases and 59.7 percent by self supply. Compared to the first nine months of 2019, reliance on bilateral contracts increased by 1.0 percentage points, reliance on spot market purchases decreased by 0.8 percentage points and reliance on self supply decreased by 0.2 percentage points.
- **Generator Offers.** Generator offers are categorized as pool scheduled and self scheduled. Units which are available for economic commitment are pool scheduled. 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 offered MW, up to economic maximum output, in the first nine months of 2020, 63.7 percent were offered to be pool scheduled, 32.4 percent above economic minimum and 31.3 percent at the economic minimum. For self scheduled units, 14.2 percent were offered as self

scheduled at a fixed output, and 22.1 percent were offered as self scheduled and dispatchable.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW increased by 8.1 percent and cleared MW decreased by 14.4 percent in the first nine months of 2020. The hourly average submitted decrement offer MW increased by 18.5 percent and cleared MW decreased by 5.5 percent in the first nine months of 2020. The hourly average submitted up to congestion bid MW decreased by 21.1 percent and cleared MW decreased by 0.1 percent in the first nine months of 2020.

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2020, coal units provided 19.0 percent, nuclear units 33.7 percent and natural gas units 40.6 percent of total generation. Compared to the first nine months of 2019, generation from coal units decreased 24.9 percent, generation from natural gas units increased 9.5 percent and generation from nuclear units decreased 1.5 percent. The trend toward more energy from natural gas and less from coal accelerated in the first nine months of 2020.
- **Fuel Diversity.** The fuel diversity of energy generation in the first nine months of 2020, measured by the fuel diversity index for energy (FDI_e), decreased 2.2 percent compared to the first nine months of 2019.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first nine months of 2020, coal units were 17.3 percent and natural gas units were 73.6 percent of marginal resources. In the first nine months of 2019, coal units were 26.3 percent and natural gas units were 68.4 percent of marginal resources.

In the PJM Day-Ahead Energy Market, in the first nine months of 2020, up to congestion transactions were 53.8 percent, INCs were 12.4 percent, DECs were 17.6 percent, and generation resources were 16.1 percent of

marginal resources. In the first nine months of 2019, up to congestion transactions were 57.7 percent, INCs were 12.9 percent, DEC bids were 18.4 percent, and generation resources were 10.9 percent of marginal resources.

- **Prices.** PJM real-time and day-ahead energy market prices were at the lowest level in the history of PJM markets during the first nine months of 2020. Both the weather and COVID-19 played a role in this significant drop in prices.

PJM real-time energy market prices decreased in the first nine months of 2020. The load-weighted, average real-time LMP was 23.1 percent lower in the first nine months of 2020 than in the first nine months of 2019, \$21.22 per MWh versus \$27.60 per MWh.

PJM day-ahead energy market prices decreased in the first nine months of 2020. The load-weighted, average day-ahead LMP was 24.4 percent lower in the first nine months of 2020 than in the first nine months of 2019, \$20.95 per MWh versus \$27.70 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in the first nine months of 2020, 24.6 percent of the load-weighted LMP was the result of coal costs, 39.8 percent was the result of gas costs and 1.80 percent was the result of the cost of emission allowances.

In the PJM Day-Ahead Energy Market, in the first nine months of 2020, 25.3 percent of the load-weighted LMP was the result of coal costs, 17.9 percent was the result of gas costs, 15.4 percent was the result of INC offers, 23.0 percent was the result of DEC bids, and 3.4 percent was the result of up to congestion transaction offers.

- **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 \$0.23 per MWh in the first nine months of 2020, and -\$0.11 per MWh in the first nine months of 2019. 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 two intervals with five minute shortage pricing in the first nine months of 2020. There were no emergency actions that resulted in Performance Assessment Intervals in the first nine months of 2020.
- There were 1,143 five minute intervals, or 1.4 percent of all five minute intervals in the first nine months of 2020 for which at least one solved RT SCED case showed a shortage of reserves, and 416 five minute intervals, or 0.5 percent of all five minute intervals in the first nine months of 2020 for which more than one solved RT SCED case showed a shortage of reserves. PJM triggered shortage pricing for two five minute intervals.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated.
- **Local Market Power.** For six out of the top 10 congested facilities (by real-time binding hours) in the first nine months of 2020, the number of suppliers providing constraint relief is three or less. There is a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure is not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.2 percent in the first nine months of 2019 to 1.6 percent in the first

nine months of 2020. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.6 percent in the first nine months of 2019 to 1.0 percent in the first nine months of 2020. 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 the first nine months of 2020, nine control zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours remained at 0.0 percent in the first nine months of 2019 and 2020. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours remained at 0.0 percent in the first nine months of 2019 and 2020.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** One unit qualified for an FMU adder for the months of September and October, 2019. In the first nine months of 2020, five units qualified for an FMU adder in at least one month.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first nine months of 2020, in the PJM Real-Time Energy Market, 98.4 percent of marginal units had offer prices less than \$50 per MWh. While markups in the real-time market were generally low, some marginal units did have substantial markups. The highest markup for any marginal unit in the first nine

months of 2020 was more than \$200 per MWh when using unadjusted cost-based offers.

In the first nine months of 2020, in the PJM Day-Ahead Energy Market, 99.3 percent of marginal generating units had offer prices less than \$50 per MWh. Markups in the day-ahead market were generally low. The highest markup for any marginal unit in the day-ahead market in the first nine months of 2020 was more than \$70 per MWh when using unadjusted cost-based offers.

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

The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power. Markup for coal and gas fired units decreased in the first nine months of 2020.

Market Performance

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

In the PJM Real-Time Energy Market in the first nine months of 2020, the unadjusted markup component of LMP was \$0.61 per MWh or 2.9 percent of the PJM load-weighted, average LMP. August had the highest unadjusted peak markup component, \$2.88 per MWh, or 9.7 percent of the real-time, peak hour load-weighted, average LMP. There were 28 hours in the first nine months of 2020 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded the 99th percentile of the hourly markup contribution or \$30.83 per MWh.

In the PJM Day-Ahead Energy Market, INCs, DEC and UTCs have zero markups. In the first nine months of 2020, the unadjusted markup

component of LMP resulting from generation resources was -\$0.15 per MWh or -0.7 percent of the PJM day-ahead load-weighted average LMP. August had the highest unadjusted peak markup component, \$0.70 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.

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 6.0 percent of marginal unit intervals in the first nine months of 2020 the marginal unit had local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.
- **Markup and Aggregate Market Power.** In the summer of 2020, pivotal suppliers in the aggregate market set prices with high markups for some real-time market intervals.

Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when 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.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the 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 2018. Status: Adopted 2020.)
- 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 2018. Status: Adopted 2020.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved Fuel Cost Policy. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to have an approved Fuel Cost Policy. (Priority: Medium. New recommendation. Status: Not adopted.)

Cost-Based Offers

- 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 the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in Cost Development Guidelines. (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 2020.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- 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, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, and during high load conditions such as cold and hot weather alerts or more severe emergencies, that 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, in order to ensure effective market power mitigation, that PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. First reported 2019. 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.³ (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially 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 at a defined zonal or higher level. (Priority: Medium. First reported 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 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. First reported 2018. 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. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)

³ This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Not adopted.)
- 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: Adopted 2020.)
- 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 not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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: 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.^{4 5} (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from

⁴ 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.

⁵ There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <<http://www.pjm.com/Glossary.aspx>>.

the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)

- The MMU recommends that PJM increase the 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.)
- The MMU recommends that PJM model generators' operating transitions, including modeling soak time for units with a steam turbine and configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported Q1, 2020. 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: Adopted, 2019.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- 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, scheduled approach. (Priority: High. First reported 2018. Status: Not adopted.)

Virtual Bids and Offers

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

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2020, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

PJM average hourly real-time cleared generation decreased by 3,305 MWh, 3.5 percent, and peak load decreased by 6,778 MWh, 4.6 percent, in the first nine months of 2020 compared to the first nine months of 2019. Both the weather and COVID-19 played a role in this significant drop in demand. 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. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.⁶ 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. Many of 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, under the PJM Market Rules, is not currently correct. The definition, that energy costs must be related to electric production, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs.

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 at a given time. 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 the first nine months of 2020 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. Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices have been a primary cause of low PJM energy market prices. There is no evidence to support the need for a significant change to the calculation of LMP, such as fast start pricing or the extended ORDC. 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, because PJM is not implementing scarcity pricing when there is scarcity. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address the design of RT SCED/LPC, scarcity pricing, operator actions and the design of reserve markets. Implementing scarcity pricing when there is scarcity is a basic first step. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

⁶ The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

When the real-time security constrained economic dispatch (RT SCED) solution indicates a shortage of reserves, it should be used in calculating real-time prices and those prices should be applied to the market interval for which RT SCED calculated the shortage and during which resources followed associated dispatch instructions. 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 RT SCED cases used for resource dispatch and the RT SCED cases used to calculate real-time prices. Alignment of resource dispatch with pricing and settlements requires reducing the RT SCED ramp time to five minutes to match the five minute settlement interval. PJM should fix its current operating practices and ensure consistency and transparency regarding approval of RT 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 PJM defined inputs to the dispatch tools, particularly the RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create price spikes through transmission line limit violations or restrictions on the resources available to resolve constraints. The automated adjustment of ramp rates by PJM, called Degree of Generator Performance (DGP), modifies the values offered by generators and limits the MW available to the RT SCED. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

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 prioritizes minimizing uplift over minimizing production costs. The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff will be created by PJM's fast start pricing proposal as approved by FERC and would be created in a much more extensive form by PJM's convex hull pricing proposal and reserve pricing proposal.

Units that start in one hour are not fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM will pay new forms of uplift in an attempt to counter the distorted incentives. But without reducing the dispatch period from 10 to five minutes, the new uplift payments will not correspond to following dispatch. The magnitude of the new payments and their effects on behavior are not well understood.

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 the 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, as in PJM's ORDC proposal, is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, 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. Administrative scarcity pricing that establishes scarcity pricing in about 85 percent of hours, as PJM's ORDC proposal would, is not scarcity pricing but simply a revenue enhancement mechanism. When combined with PJM's failure to address the energy and ancillary services offset in the capacity market, PJM's ORDC filing is not consistent with efficient market design and is even more clearly just a revenue enhancement mechanism.

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 the first nine months of 2020 or prior years. In the first nine months of 2020, marginal units were predominantly combined cycle gas generators with low fuel costs. The frequency of combined cycle gas units as the marginal unit type has risen rapidly, from 29.3 percent in 2016 to 66.0 percent in the first nine months of 2020. Overdue improvements in generator modeling in the energy market would allow PJM to more efficiently commit and dispatch combined cycle plants and to fully reflect the flexibility of these units. New combined cycle units placed competitive pressure on less efficient generators, and the market reliably served load with less congestion, less uplift, and less markup in marginal offers than in the first nine months of 2019. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Given the structure of the energy market which can permit the exercise of aggregate and local market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2020.

Supply and Demand

Market Structure

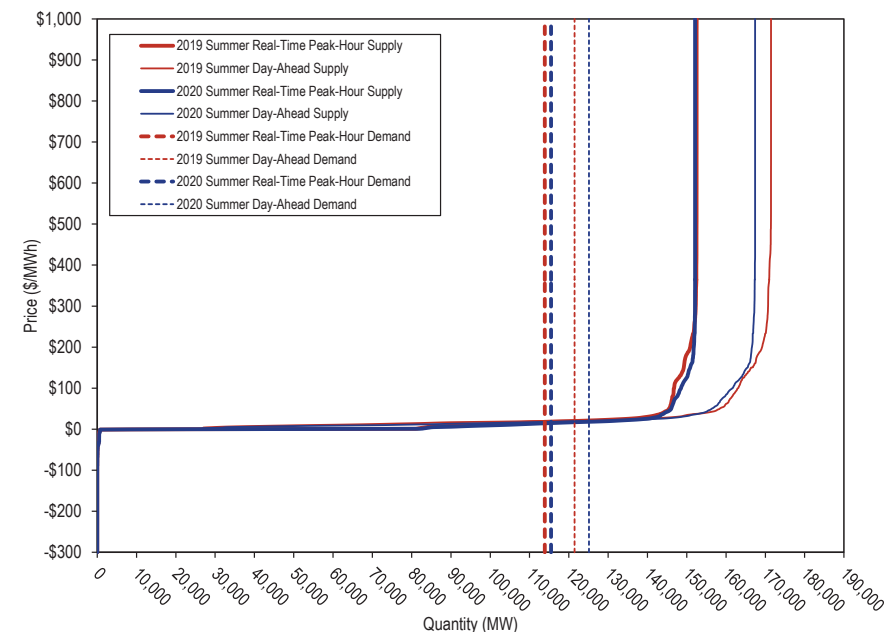
Supply

Supply includes physical generation, imports and virtual transactions.

In the first nine months of 2020, 1,248.4 MW of new resources were added in the energy market, and 2,469.0 MW of resources and 457 MW of pseudo tied resources were retired. Figure 3-1 shows the average real-time and day-ahead supply curves in the summer of 2019 and 2020.^{7 8 9} The real-time supply curve shows the average of on peak hourly offers. The real-time supply curve includes available MW from units that are online or offline and available to generate power in one hour or less. The day-ahead supply curve shows the average of all hourly offers.

Figure 3-2 shows the typical dispatch range.

Figure 3-1 Hourly real-time and aggregate day-ahead supply curve comparison: 2019 summer and 2020 summer



⁷ Real-time generation offers and real-time import MWh are included.

⁸ Real-time load and export MWh are included.

⁹ The summer supply curve period is from June 1 to August 31.

Figure 3-2 Typical dispatch range of supply curves

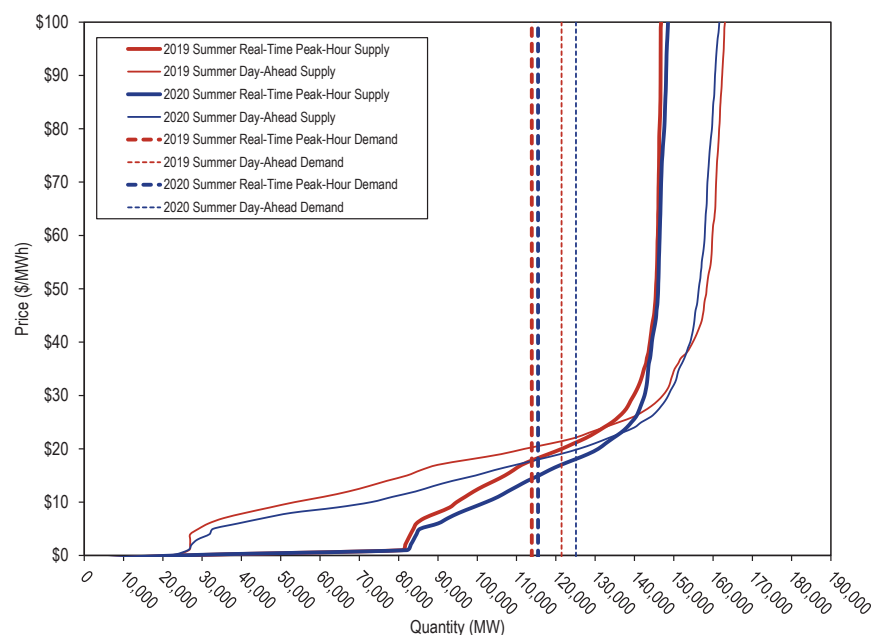


Table 3-2 shows the price elasticity of real-time supply for the on peak hours in the 2019 and 2020 summer by load level. The value of 2019 is higher than 2020 from 75 to 115 GWh.

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

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

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

Table 3-2 Price Elasticity of Supply

GWh	Elasticity of Supply	
	2019 Summer	2020 Summer
Min - 75	0.020	0.026
75 - 95	0.302	0.256
95 - 115	0.415	0.353
115 - Max	0.003	0.003

Real-Time Supply

The maximum average on-peak hourly offered real-time supply was 152,122 MW for the 2020 summer and 152,553 MW for the 2019 summer. The available supply at a defined time is less than the total capacity of the PJM system because real-time supply at a defined time is limited by unit ramp limits and start times.

PJM average hourly real-time cleared generation in the first nine months of 2020 decreased by 3.5 percent from the first nine months of 2019, from 95,531 MWh to 92,226 MWh.¹⁰

PJM average hourly real-time cleared supply including imports in the first nine months of 2020 decreased by 3.8 percent from the first nine months of 2019, from 96,659 MWh to 92,983 MWh.

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

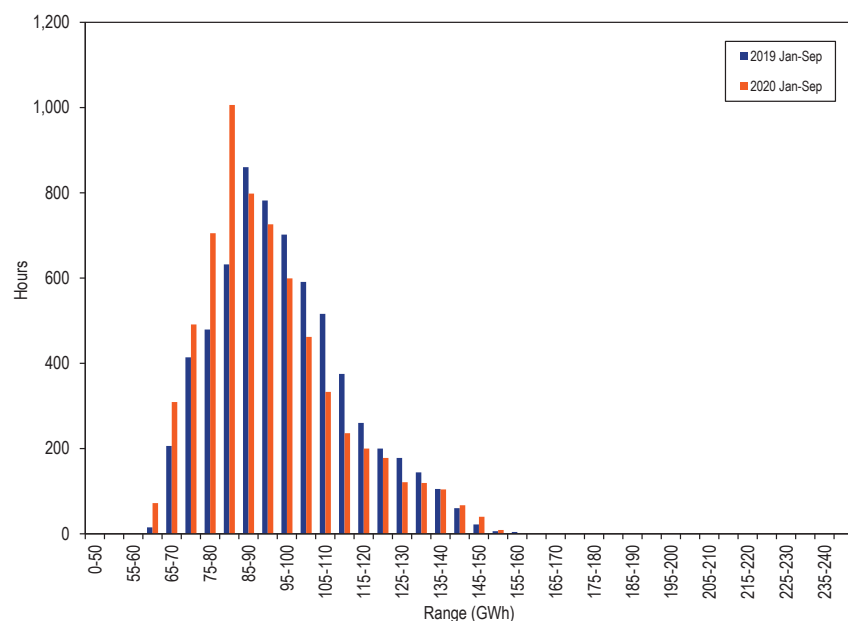
- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a specific unit.
- **Import.**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

¹⁰ Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

PJM Real-Time Supply Frequency

Figure 3-3 shows the hourly distribution of PJM real-time generation plus imports for the first nine months of 2019 and 2020. The hours of generation less than 85 GWh increased significantly, while the hours of generation more than 85 GWh decreased in 2020.

Figure 3-3 Distribution of real-time generation plus imports: January through September, 2019 and 2020¹¹



¹¹ Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Supply

Table 3-3 shows real-time hourly supply summary statistics for the first nine months of the 20 year period from 2001 through 2020.

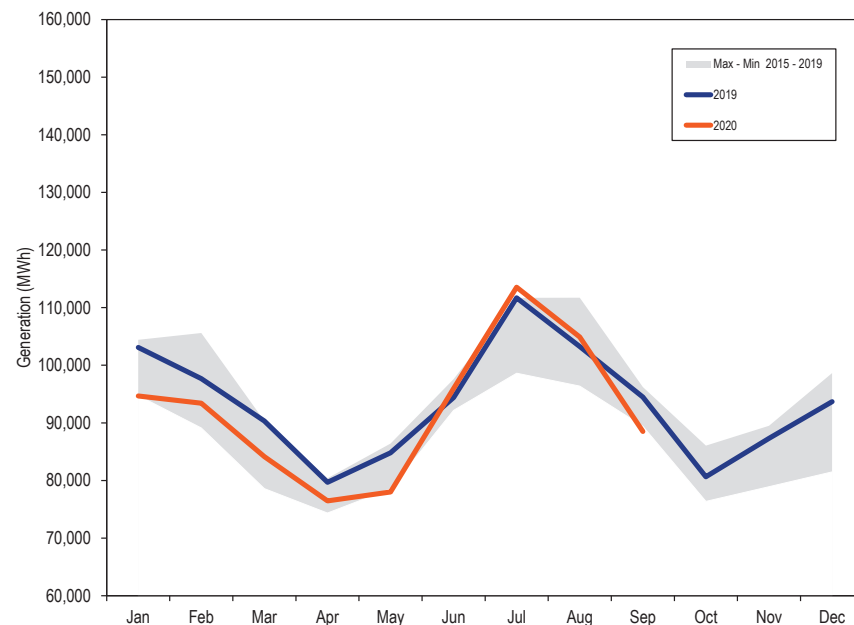
Table 3-3 Average hourly real-time generation and real-time generation plus imports: January through September, 2001 through 2020

PJM Real-Time Supply (MWh)					Year-to-Year Change			
Jan-Sep	Generation		Imports		Generation		Imports	
	Standard	Deviation	Standard	Deviation	Standard	Deviation	Standard	Deviation
Jan-Sep	Generation	Deviation	Supply	Deviation	Generation	Deviation	Supply	Deviation
2001	30,304	5,216	33,299	5,571	NA	NA	NA	NA
2002	34,467	8,217	38,207	8,540	13.7%	57.5%	14.7%	53.3%
2003	37,211	6,556	40,815	6,526	8.0%	(20.2%)	6.8%	(23.6%)
2004	45,888	11,035	49,990	11,185	23.3%	68.3%	22.5%	71.4%
2005	81,095	16,710	86,330	17,216	76.7%	51.4%	72.7%	53.9%
2006	84,260	14,696	88,621	15,399	3.9%	(12.1%)	2.7%	(10.5%)
2007	87,297	14,853	91,647	15,668	3.6%	1.1%	3.4%	1.7%
2008	85,241	14,203	90,621	14,646	(2.4%)	(4.4%)	(1.1%)	(6.5%)
2009	78,850	14,242	83,986	14,728	(7.5%)	0.3%	(7.3%)	0.6%
2010	84,086	16,346	88,876	17,001	6.6%	14.8%	5.8%	15.4%
2011	86,966	17,369	91,746	18,276	3.4%	6.3%	3.2%	7.5%
2012	90,367	16,893	95,726	17,810	3.9%	(2.7%)	4.3%	(2.5%)
2013	90,432	15,792	95,639	16,729	0.1%	(6.5%)	(0.1%)	(6.1%)
2014	92,449	16,002	97,922	17,064	2.2%	1.3%	2.4%	2.0%
2015	91,901	16,711	97,896	17,863	(0.6%)	4.4%	(0.0%)	4.7%
2016	92,799	19,003	96,907	19,067	1.0%	13.7%	(1.0%)	6.7%
2017	91,658	15,964	93,639	16,216	(1.2%)	(16.0%)	(3.4%)	(15.0%)
2018	95,561	17,506	97,588	17,747	4.3%	9.7%	4.2%	9.4%
2019	95,531	17,206	96,659	17,378	(0.0%)	(1.7%)	(1.0%)	(2.1%)
2020	92,226	17,790	92,983	17,883	(3.5%)	3.4%	(3.8%)	2.9%

PJM Real-Time, Monthly Average Generation

Figure 3-4 compares the real-time, monthly average hourly generation in 2019 and the first nine months of 2020 with the five year range. As a result of weather and COVID-19, the monthly average hourly generation was lower than the minimum of the past five years in January, May and September, but was higher than the maximum of the past five years in July as a result of weather.

Figure 3-4 Real-time monthly average hourly generation: January 2019 through September 2020



Day-Ahead Supply

PJM average hourly day-ahead cleared supply in the first nine months of 2020, including INCs and up to congestion transactions, decreased by 3.1 percent from the first nine months of 2019, from 118,913 MWh to 115,205 MWh. When imports are added, PJM average hourly, day-ahead cleared supply in the first nine months of 2020 decreased by 3.2 percent from the first nine months of 2019, from 119,249 MWh to 115,386 MWh.

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

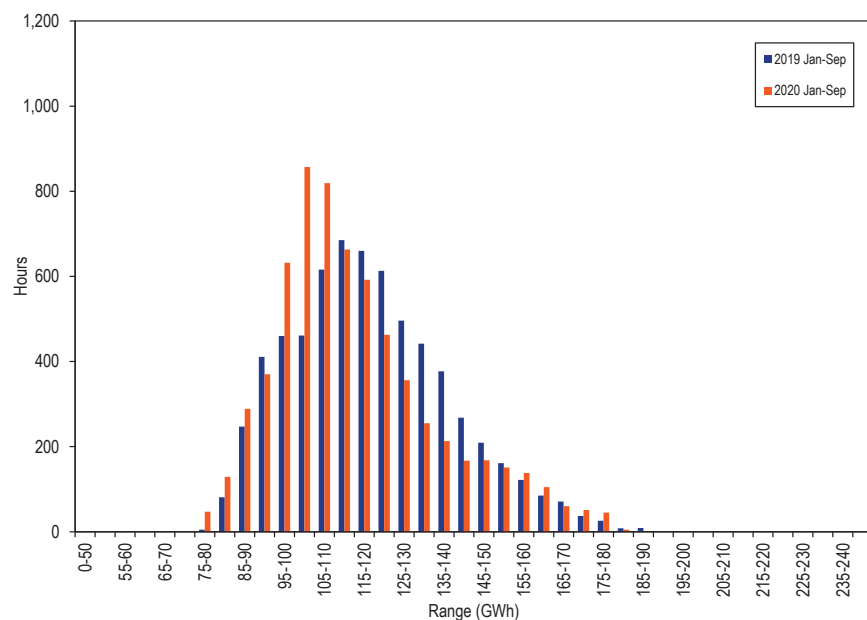
- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the minimum.

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

PJM Day-Ahead Supply Duration

Figure 3-5 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for the first nine months of 2019 and 2020.

Figure 3-5 Distribution of day-ahead supply plus imports: January through September, 2019 and 2020¹²



¹² Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Supply

Table 3-4 presents day-ahead hourly supply summary statistics for the first nine months of each year in the 20 year period from 2001 through 2020.

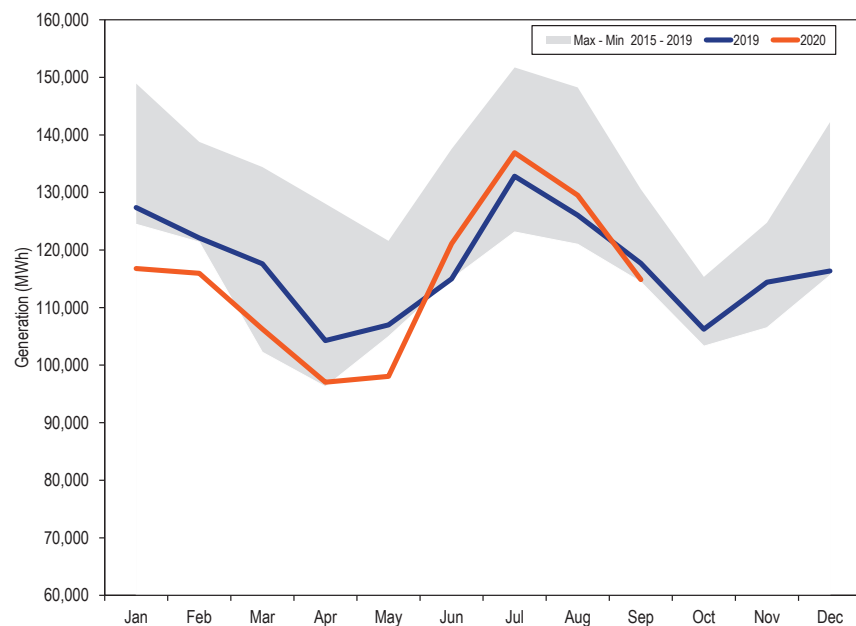
Table 3-4 Average hourly day-ahead supply and day-ahead supply plus imports: January through September, 2001 through 2020

Jan-Sep	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	27,519	4,839	28,279	4,911	NA	NA	NA	NA
2002	30,080	10,982	30,629	10,992	9.3%	126.9%	8.3%	123.8%
2003	40,024	9,079	40,556	9,066	33.1%	(17.3%)	32.4%	(17.5%)
2004	56,103	13,380	56,799	13,349	40.2%	47.4%	40.0%	47.2%
2005	94,437	18,671	96,315	18,963	68.3%	39.5%	69.6%	42.1%
2006	100,888	18,061	103,029	18,071	6.8%	(3.3%)	7.0%	(4.7%)
2007	110,300	17,561	112,575	17,752	9.3%	(2.8%)	9.3%	(1.8%)
2008	107,367	16,601	109,811	16,717	(2.7%)	(5.5%)	(2.5%)	(5.8%)
2009	98,527	17,462	101,123	17,526	(8.2%)	5.2%	(7.9%)	4.8%
2010	108,309	23,295	111,059	23,464	9.9%	33.4%	9.8%	33.9%
2011	116,988	22,722	119,488	23,015	8.0%	(2.5%)	7.6%	(1.9%)
2012	135,213	18,553	137,670	18,788	15.6%	(18.3%)	15.2%	(18.4%)
2013	148,489	18,858	150,785	19,073	9.8%	1.6%	9.5%	1.5%
2014	161,137	23,922	163,431	24,080	8.5%	26.9%	8.4%	26.2%
2015	116,975	20,289	119,349	20,502	(27.4%)	(15.2%)	(27.0%)	(14.9%)
2016	133,089	23,414	134,881	23,403	13.8%	15.4%	13.0%	14.1%
2017	133,377	20,602	134,000	20,710	0.2%	(12.0%)	(0.7%)	(11.5%)
2018	116,068	21,950	116,471	21,939	(13.0%)	6.5%	(13.1%)	5.9%
2019	118,913	20,009	119,249	19,989	2.5%	(8.8%)	2.4%	(8.9%)
2020	115,205	20,611	115,386	20,577	(3.1%)	3.0%	(3.2%)	2.9%

PJM Day-Ahead, Monthly Average Supply

Figure 3-6 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions for the first nine months of 2019 and 2020 with the historic five year range. In January, February and May of 2020, the average supply was lower than the minimum of the previous five years.

Figure 3-6 Day-ahead monthly average hourly supply: January 2019 through September 2020



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for the first nine months of 2019 and 2020, for day-ahead and real-time supply. The last two columns of Table 3-5 are the day-ahead supply minus the real-time supply. The first of these columns is the total physical day-ahead generation less the total physical real-time generation and the second of these columns is the total day-ahead supply less the total real-time supply.

Table 3-5 Day-ahead and real-time supply (MWh): January through September, 2019 and 2020

	Jan-Sep	Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
		Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2019	95,616	2,866	20,430	337	119,249	95,531	96,659	85	22,590
	2020	92,347	2,443	20,414	181	115,386	92,226	92,983	121	22,403
Median	2019	93,534	2,735	20,316	295	117,016	93,083	94,316	451	22,700
	2020	88,682	2,381	20,289	150	110,997	88,622	89,446	60	21,551
Standard Deviation	2019	17,824	1,018	4,442	228	19,989	17,206	17,378	619	2,611
	2020	18,695	866	3,911	168	20,577	17,790	17,883	905	2,693
Peak Average	2019	105,288	3,357	21,849	289	130,783	104,446	105,631	842	25,153
	2020	101,768	2,750	21,200	170	125,889	100,618	101,422	1,150	24,466
Peak Median	2019	103,456	3,300	21,695	223	128,196	102,364	103,558	1,091	24,638
	2020	98,564	2,707	20,987	133	121,844	97,190	98,247	1,374	23,597
Peak Standard Deviation	2019	15,486	996	4,249	225	17,004	15,492	15,648	(6)	1,356
	2020	17,984	895	3,869	156	20,001	17,540	17,656	443	2,345
Off-Peak Average	2019	87,159	2,436	19,190	378	109,164	87,737	88,814	(578)	20,350
	2020	84,004	2,171	19,719	192	106,086	84,795	85,510	(791)	20,575
Off-Peak Median	2019	84,599	2,337	19,038	345	106,758	85,398	86,319	(799)	20,439
	2020	81,404	2,130	19,630	155	103,610	82,431	83,213	(1,027)	20,397
Off-Peak Standard Deviation	2019	15,249	824	4,231	223	16,678	14,657	14,834	592	1,843
	2020	14,983	739	3,815	177	16,123	14,380	14,426	603	1,698

Figure 3-7 shows the average cleared volumes of day-ahead supply and real-time supply by hour of the day for the first nine months of 2020. The day-ahead supply consists of cleared MW of physical generation, imports, increment offers and up to congestion transactions. The real-time supply consists of cleared MW of physical generation and imports.

Figure 3-7 Day-ahead and real-time supply (Average volumes by hour of the day): January through September, 2020

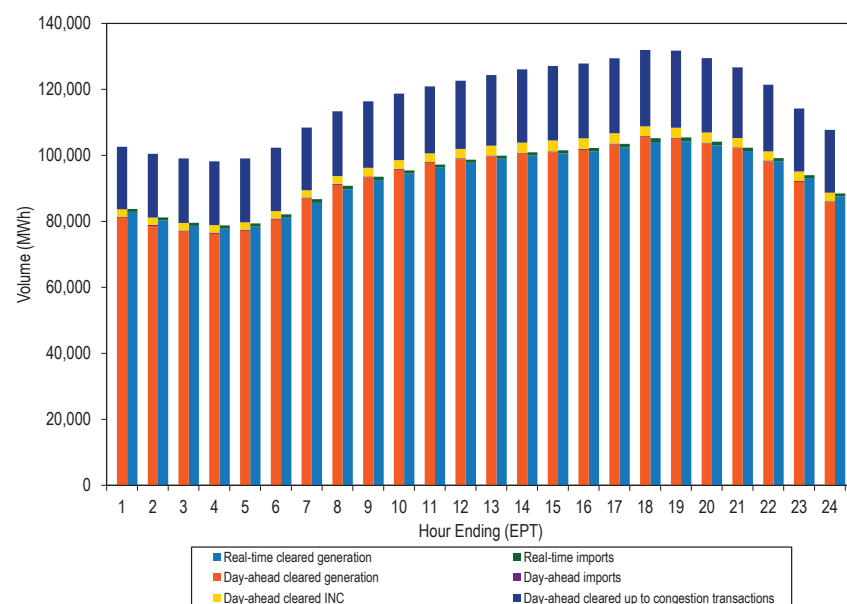
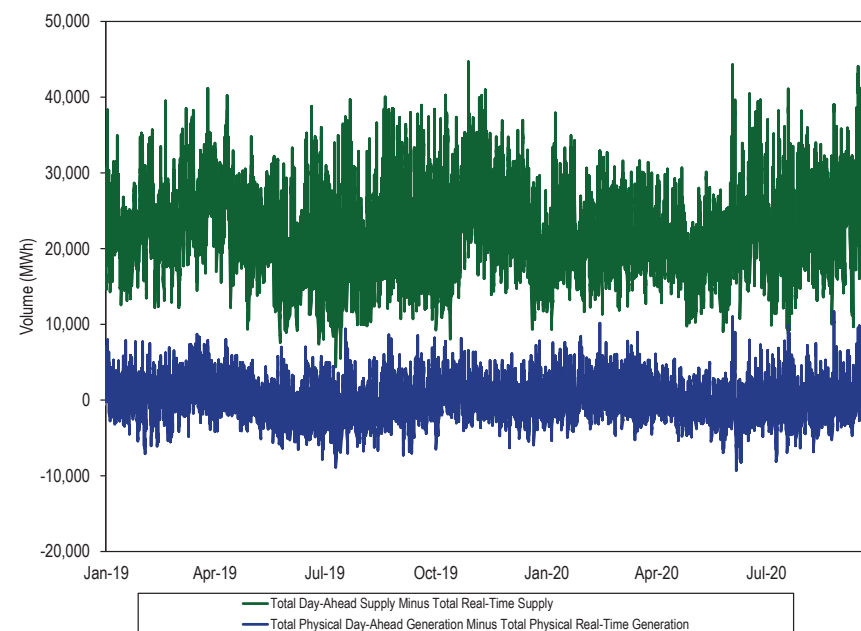


Figure 3-8 shows the difference between the day-ahead and real-time average daily supply in 2019 and the first nine months of 2020.

Figure 3-8 Difference between day-ahead and real-time supply (Average daily volumes): January 2019 through September 2020



Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports and, in the day-ahead energy market, includes virtual transactions.¹³

The PJM system real-time hourly peak load in the first nine months of 2020 was 141,449 MWh in the HE 1700 on July 20, 2020, which was 6,778 MWh, or 4.6 percent, less than the peak load in the first nine months of 2019, 148,228 MWh in the HE 1800 on July 31, 2019.

Table 3-6 shows the peak loads for the first nine months of 1999 through 2020.

Table 3-6 Actual footprint peak loads: January through September, 1999 through 2020^{14 15}

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, July 06	17	51,714	NA	NA
2000	Wed, August 09	17	49,462	(2,252)	(4.4%)
2001	Thu, August 09	15	54,030	4,568	9.2%
2002	Wed, August 14	16	64,126	10,096	18.7%
2003	Fri, August 22	16	61,670	(2,456)	(3.8%)
2004	Tue, August 03	17	77,950	16,280	26.4%
2005	Tue, July 26	16	134,017	56,067	71.9%
2006	Wed, August 02	17	144,904	10,887	8.1%
2007	Wed, August 08	16	136,368	(8,535)	(5.9%)
2008	Mon, June 09	17	127,216	(9,153)	(6.7%)
2009	Mon, August 10	17	123,900	(3,315)	(2.6%)
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%
2019	Fri, July 19	18	148,228	1,185	0.8%
2020	Mon, July 20	17	141,449	(6,778)	(4.6%)

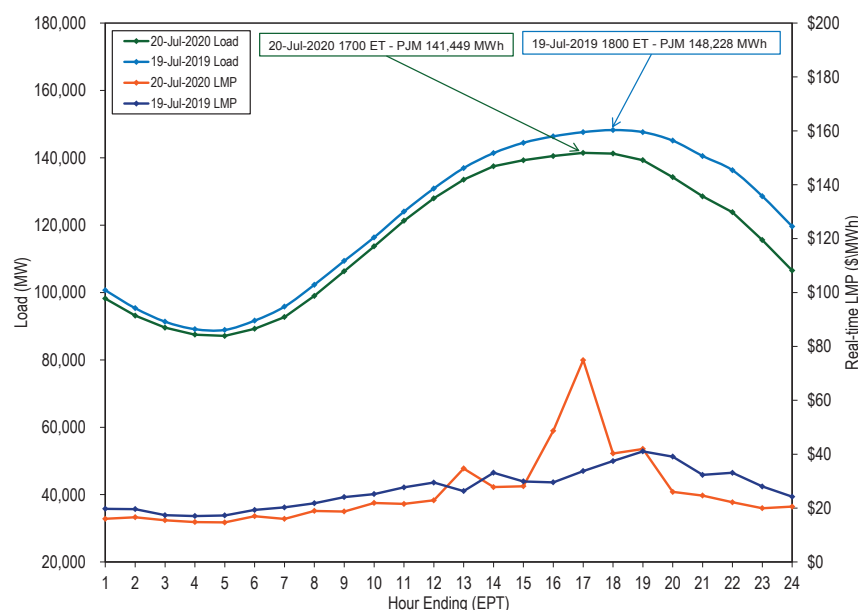
¹³ PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based on PJM Manual 19: Load Forecasting and Analysis, Attachment A: Load Drop Estimate Guidelines.

¹⁴ 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>.

¹⁵ 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.

Figure 3-9 compares prices and load on the peak load days in the first nine months of 2019 and 2020. The average real-time LMP for the July 20, 2020, peak load hour was \$74.91 and for the July 19, 2019 peak load hour it was \$37.47.

Figure 3-9 Peak load day comparison: Friday, July 19, 2019 and Monday, July 20, 2020



Real-Time Demand

PJM average hourly real-time demand in the first nine months of 2020 decreased by 4.4 percent from the first nine months of 2019, from 89,834 MWh to 85,886 MWh.¹⁶ PJM average hourly real-time demand including exports in the first nine months of 2020 decreased by 3.8 percent from the first nine months of 2019, from 94,918 MWh to 91,356 MWh. Both the weather and COVID-19 played a role in this significant drop in demand.

¹⁶ Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

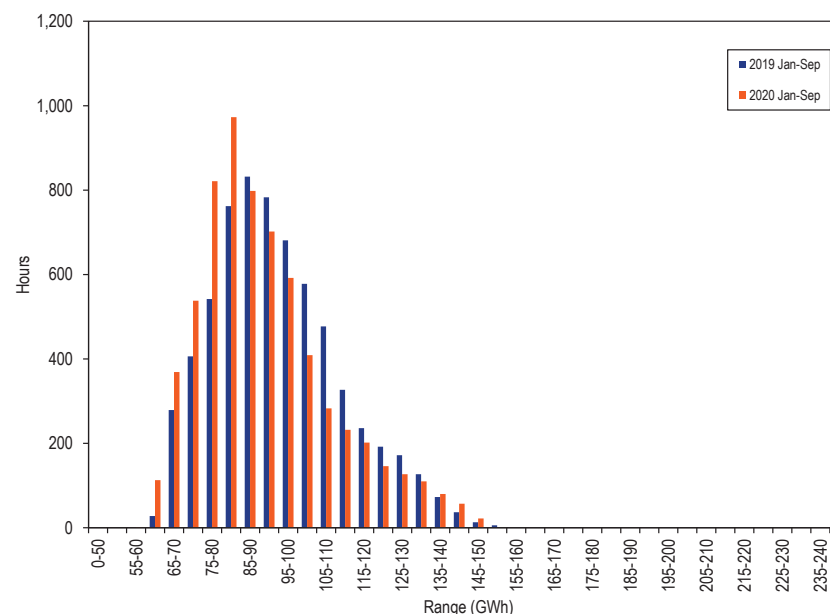
In the PJM Real-Time Energy Market, there are two types of demand:

- **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 3-10 shows the distribution of hourly PJM real-time load plus exports for the first nine months of 2019 and 2020.¹⁷

Figure 3-10 Distribution of real-time accounting load plus exports: January through September, 2019 and 2020¹⁸



¹⁷ 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>.

¹⁸ Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Load

Table 3-7 presents real-time hourly demand summary statistics for the first nine months of 2001 through 2020.¹⁹ Real-time load in the first nine months of 2020 reached its lowest level for the comparable period since 2011.

Table 3-7 Real-time load and real-time load plus exports: January through September, 2001 through 2020

Jan-Sep	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	31,060	6,156	32,900	5,861	NA	NA	NA	NA
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	51.5%
2003	37,996	7,187	39,965	7,120	6.4%	(17.3%)	7.0%	(19.8%)
2004	45,294	10,512	49,176	11,556	19.2%	46.3%	23.0%	62.3%
2005	78,235	17,541	85,295	17,794	72.7%	66.9%	73.4%	54.0%
2006	80,717	15,568	87,326	16,147	3.2%	(11.2%)	2.4%	(9.3%)
2007	83,114	15,386	89,390	16,008	3.0%	(1.2%)	2.4%	(0.9%)
2008	80,611	14,389	87,788	14,893	(3.0%)	(6.5%)	(1.8%)	(7.0%)
2009	76,954	13,879	82,118	14,360	(4.5%)	(3.5%)	(6.5%)	(3.6%)
2010	81,068	16,209	86,994	16,687	5.3%	16.8%	5.9%	16.2%
2011	83,762	17,604	89,628	17,799	3.3%	8.6%	3.0%	6.7%
2012	88,687	17,431	93,763	17,329	5.9%	(1.0%)	4.6%	(2.6%)
2013	89,123	16,384	93,647	16,254	0.5%	(6.0%)	(0.1%)	(6.2%)
2014	90,567	16,662	96,015	16,518	1.6%	1.7%	2.5%	1.6%
2015	91,857	17,211	96,102	17,300	1.4%	3.3%	0.1%	4.7%
2016	90,599	18,183	95,340	18,571	(1.4%)	5.6%	(0.8%)	7.3%
2017	87,243	16,008	91,954	15,794	(3.7%)	(12.0%)	(3.6%)	(15.0%)
2018	91,905	17,064	95,795	17,245	5.3%	6.6%	4.2%	9.2%
2019	89,834	16,794	94,918	16,924	(2.3%)	(1.6%)	(0.9%)	(1.9%)
2020	85,886	17,201	91,356	17,464	(4.4%)	2.4%	(3.8%)	3.2%

¹⁹ Accounting load is used because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through the incorporation of marginal loss pricing in LMP.

PJM Real-Time, Monthly Average Load

Figure 3-11 compares the real-time, monthly average loads in 2019 and the first nine months of 2020, with the historic five year range. The monthly average loads in the first nine months of 2020, were lower than the minimum of the past five years in January, March, April, May and September, but higher than the maximum of the past five years in July.

Figure 3-11 Real-time monthly average hourly load: January 2019 through September 2020

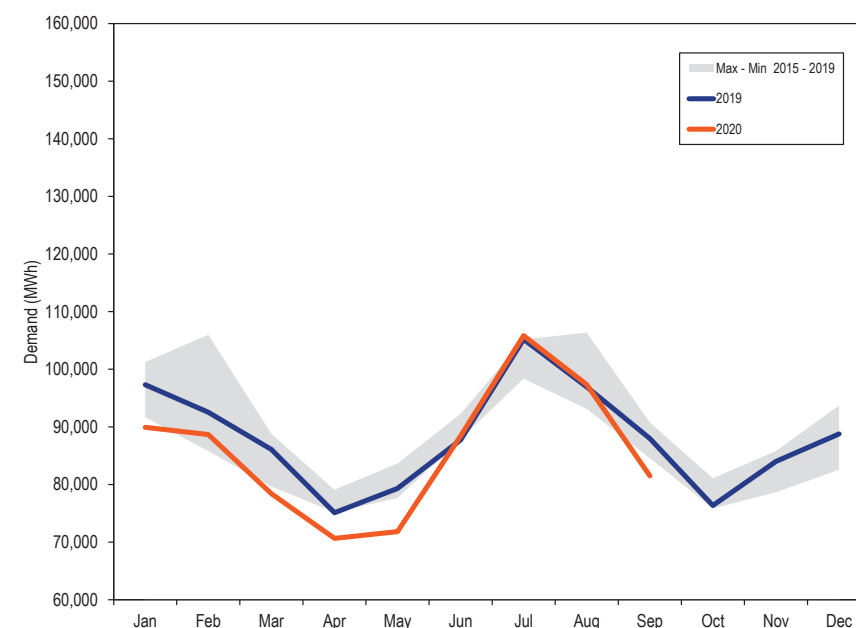
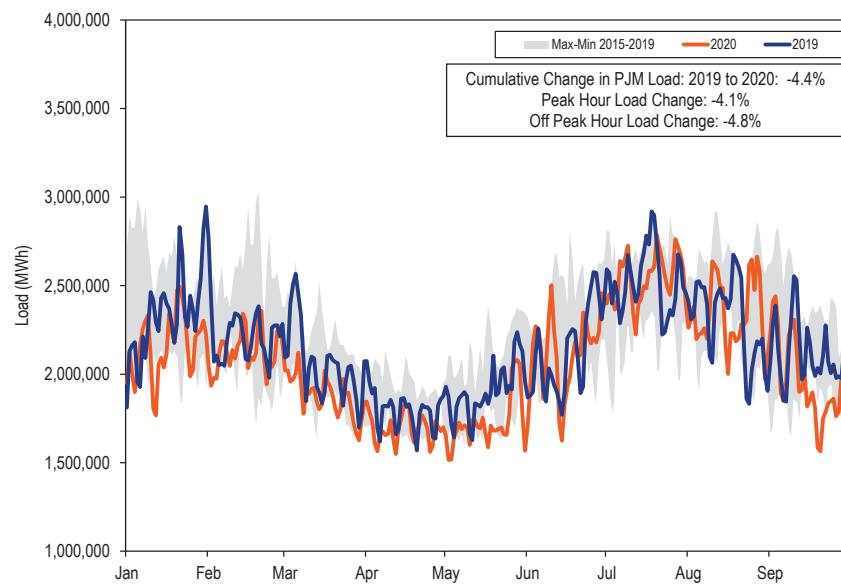


Figure 3-12 compares the real-time, average daily loads in 2019 and the first nine months of 2020, with the historic five year range. On a cumulative basis, real-time daily load declined by 4.4 percent in the first nine months of 2020 compared to the first nine months of 2019.

Figure 3-12 Real-time daily load: January through September, 2019 and 2020



PJM real-time load is significantly affected by weather conditions. Table 3-8 compares the PJM monthly heating and cooling degree days in 2019 and the first nine months of 2020.²⁰ Heating degree days decreased 10.1 percent compared to the first nine months of 2019. Cooling degree days increased 0.1 percent compared to the first nine months of 2019.

Table 3-8 Heating and cooling degree days: January 2019 through September 2020

	2019		2020		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	909	0	698	0	(23.3%)	0.0%
Feb	688	0	652	0	(5.2%)	0.0%
Mar	607	0	385	0	(36.6%)	0.0%
Apr	145	0	279	0	92.1%	0.0%
May	23	90	105	59	363.0%	(33.9%)
Jun	0	210	0	262	0.0%	24.9%
Jul	0	423	0	464	0.0%	9.7%
Aug	0	312	0	342	0.0%	9.7%
Sep	0	211	13	120	0.0%	(43.3%)
Oct	100	31				
Nov	576	0				
Dec	675	0				
Jan-Sep	2,372	1,246	2,131	1,247	(10.1%)	0.1%

PJM real-time load was generally lower in the first nine months of 2020 than in the first nine months of 2019, and, in spring 2020, was frequently lower than the minimum of the past five years. The weather and COVID-19 both contributed to the result.

²⁰ A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.

Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Figure 3-13 and Figure 3-14 show the real-time daily load and the weather normalized load for 2019 and the first nine months of 2020.

Weather normalized load is calculated using the historic relationship between PJM daily load and HDD, CDD, and time of year for 2015 through 2018. Figure 3-13 shows that the weather normalized load is very close to actual load under normal market conditions in 2019. Figure 3-14 shows that from March through May 2020, the actual load was significantly less than the weather normalized load. The difference was the impact of changes in the pattern and level of activity as a result of COVID-19 and associated policy responses.

Figure 3-13 Real-time daily load and weather normalized load: 2019

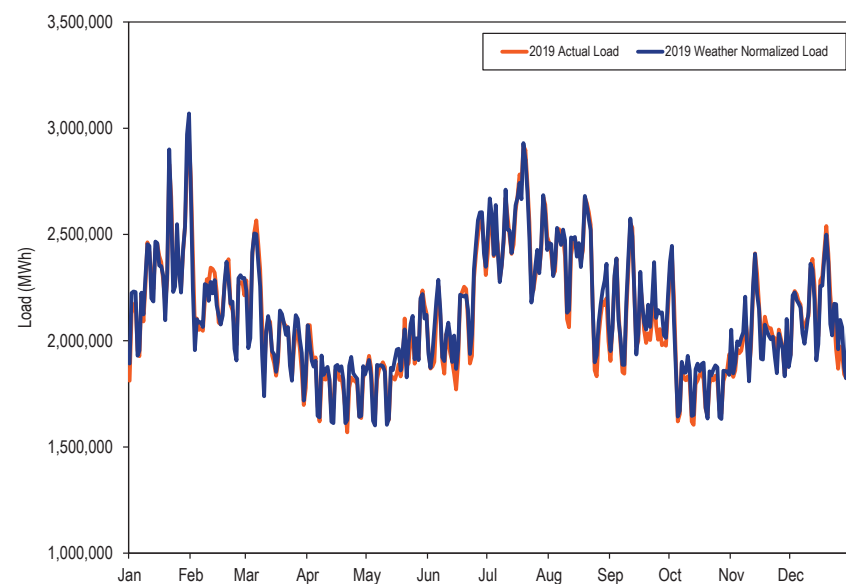


Figure 3-14 Real-time daily load and weather normalized load: January through September, 2020

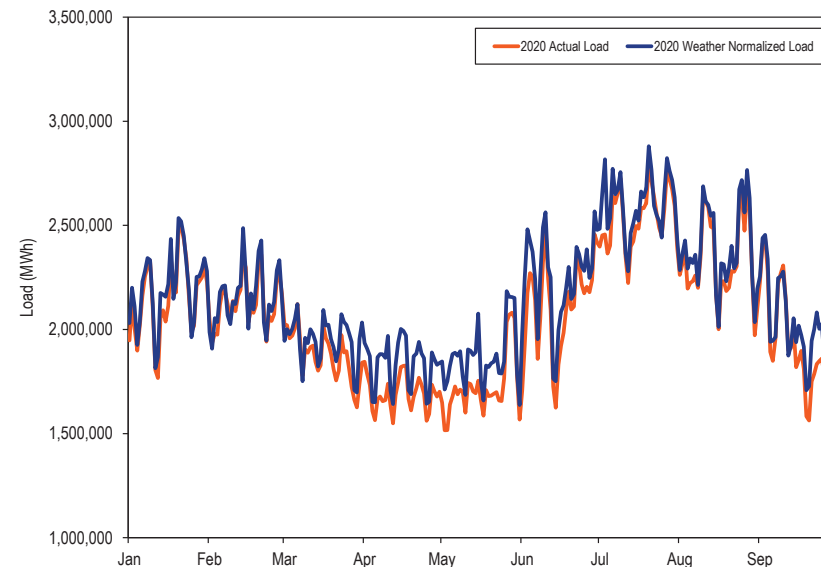


Table 3-9 compares the total monthly actual load and the weather normalized load. The difference increased in 2020.

Table 3-9 Actual Load less Weather Normalized Load: January 2019 through September 2020

	2019			2020		
	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference
Jan	72,405,320	72,846,056	(0.6%)	66,905,774	68,256,113	(2.0%)
Feb	62,176,069	61,581,587	1.0%	61,717,353	62,471,212	(1.2%)
Mar	63,964,185	63,697,555	0.4%	58,258,178	60,459,812	(3.6%)
Apr	54,064,759	54,471,968	(0.7%)	50,864,950	55,116,626	(7.7%)
May	59,002,657	59,391,808	(0.7%)	53,430,088	57,904,128	(7.7%)
Jun	63,176,026	64,421,443	(1.9%)	63,666,037	67,406,845	(5.5%)
Jul	78,266,354	78,376,631	(0.1%)	78,749,183	80,856,404	(2.6%)
Aug	72,114,112	73,043,672	(1.3%)	72,425,029	74,173,773	(2.4%)
Sep	63,336,261	64,602,899	(2.0%)	58,683,018	60,988,913	(3.8%)
Oct	56,811,067	57,485,940	(1.2%)			
Nov	60,560,333	60,431,775	0.2%			
Dec	66,051,844	66,183,659	(0.2%)			
Jan-Sep	588,505,744	592,433,619	(0.7%)	564,699,610	587,633,826	(3.9%)

Day-Ahead Demand

PJM average hourly day-ahead demand in the first nine months of 2020, including DECs and up to congestion transactions, decreased by 3.8 percent from the first nine months of 2019, from 114,133 MWh to 109,850 MWh. When exports are added, PJM average hourly day-ahead demand in the first nine months of 2020 decreased by 3.3 percent from the first nine months of 2019, from 117,048 MWh to 113,188 MWh.

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

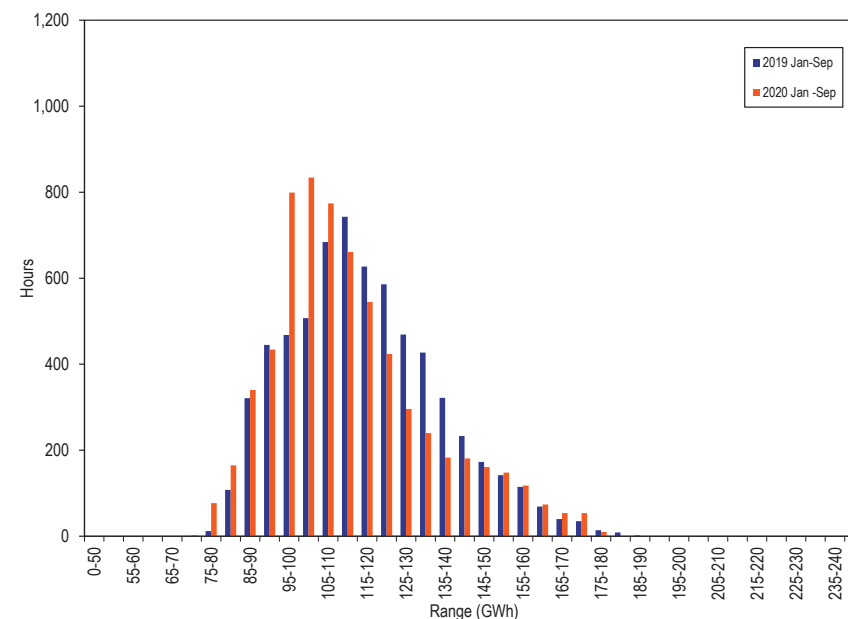
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of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

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

PJM Day-Ahead Demand Duration

Figure 3-15 shows the hourly distribution of PJM day-ahead demand for the first nine months of 2019 and 2020.

Figure 3-15 Distribution of day-ahead demand plus exports: January through September, 2019 and 2020²¹



²¹ Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Demand

Table 3-10 presents day-ahead hourly demand summary statistics for the first nine months of 2001 through 2020.

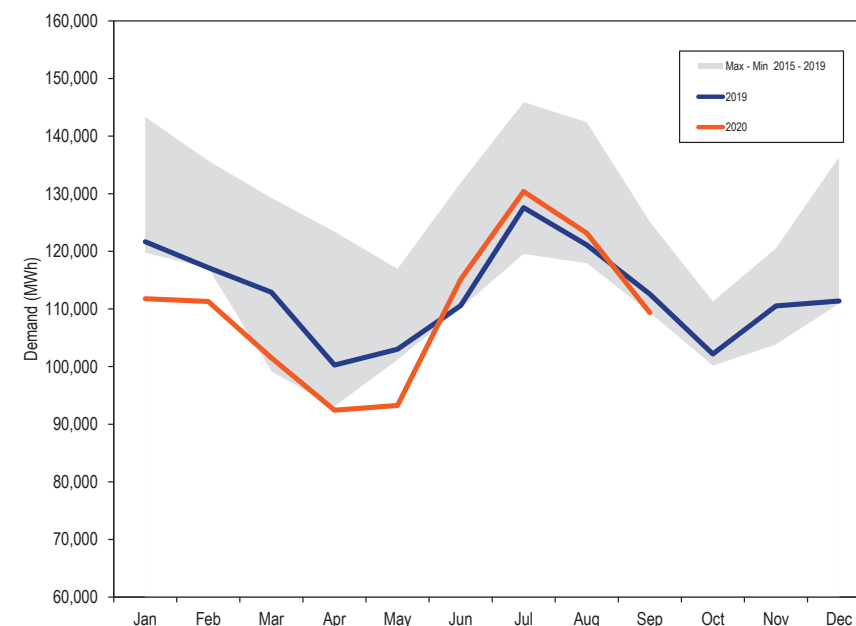
Table 3-10 Average hourly day-ahead demand and day-ahead demand plus exports: January through September, 2001 through 2020

Jan-Sep	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
	Standard Demand	Standard Deviation	Standard Demand	Standard Deviation	Standard Demand	Standard Deviation	Standard Demand	Standard Deviation
2001	33,944	7,016	34,444	6,817	NA	NA	NA	NA
2002	41,634	11,073	41,726	11,120	22.7%	57.8%	21.1%	63.1%
2003	45,371	8,377	45,477	8,354	9.0%	(24.3%)	9.0%	(24.9%)
2004	55,830	13,319	56,558	13,753	23.1%	59.0%	24.4%	64.6%
2005	93,525	19,126	96,302	19,455	67.5%	43.6%	70.3%	41.5%
2006	99,403	18,165	102,520	18,687	6.3%	(5.0%)	6.5%	(3.9%)
2007	107,295	17,580	110,711	17,949	7.9%	(3.2%)	8.0%	(3.9%)
2008	103,586	16,618	107,169	16,810	(3.5%)	(5.5%)	(3.2%)	(6.3%)
2009	96,020	16,995	99,084	17,117	(7.3%)	2.3%	(7.5%)	1.8%
2010	105,018	22,972	109,113	23,286	9.4%	35.2%	10.1%	36.0%
2011	113,724	22,444	117,533	22,651	8.3%	(2.3%)	7.7%	(2.7%)
2012	132,494	18,115	135,840	18,235	16.5%	(19.3%)	15.6%	(19.5%)
2013	145,139	18,667	148,444	18,696	9.5%	3.0%	9.3%	2.5%
2014	156,542	23,584	160,425	23,533	7.9%	26.3%	8.1%	25.9%
2015	113,555	19,789	116,912	19,957	(27.5%)	(16.1%)	(27.1%)	(15.2%)
2016	129,048	22,492	132,405	22,801	13.6%	13.7%	13.3%	14.2%
2017	128,453	20,002	131,572	20,158	(0.5%)	(11.1%)	(0.6%)	(11.6%)
2018	111,589	21,194	114,373	21,392	(13.1%)	6.0%	(13.1%)	6.1%
2019	114,133	19,233	117,048	19,465	2.3%	(9.3%)	2.3%	(9.0%)
2020	109,850	19,762	113,188	20,089	(3.8%)	2.7%	(3.3%)	3.2%

PJM Day-Ahead, Monthly Average Demand

Figure 3-16 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2019 and first nine months of 2020 with the historic five-year range.

Figure 3-16 Day-ahead monthly average hourly demand: January 2019 through September 2020



Real-Time and Day-Ahead Demand

Table 3-11 presents summary statistics for the first nine months of 2019 and 2020 day-ahead and real-time demand. The last two columns of Table 3-11 are the day-ahead demand minus the real-time demand: the first column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load; and the second column is the total day-ahead demand less the total real-time demand.

Table 3-11 Cleared day-ahead and real-time demand (MWh): January through September, 2019 and 2020

										Day-Ahead Less Real-Time	
Day-Ahead								Real-Time			
		Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Jan-Sep Average	2019	88,424	1,309	3,970	20,430	2,915	117,048	89,834	94,918	(102)	22,130
	2020	84,075	1,188	4,173	20,414	3,338	113,188	85,886	91,356	(623)	21,832
Median	2019	86,655	1,320	3,595	20,316	2,799	114,900	87,550	92,608	424	22,292
	2020	81,371	1,189	3,542	20,289	3,271	108,962	82,712	87,910	(153)	21,052
Standard Deviation	2019	16,136	234	1,705	4,442	782	19,465	16,794	16,924	(423)	2,541
	2020	16,381	255	2,241	3,911	785	20,089	17,201	17,464	(565)	2,625
Peak Average	2019	97,584	1,437	4,418	21,849	3,016	128,305	98,591	103,696	431	24,609
	2020	92,407	1,307	5,059	21,200	3,493	123,466	94,095	99,601	(382)	23,865
Peak Median	2019	95,861	1,461	4,123	21,695	2,943	125,655	96,633	101,682	689	23,973
	2020	90,307	1,328	4,544	20,987	3,412	119,567	91,764	96,495	(129)	23,072
Peak Standard Deviation	2019	13,858	224	1,715	4,249	826	16,575	14,902	15,226	(819)	1,350
	2020	15,520	274	2,349	3,869	820	19,500	16,777	17,231	(983)	2,269
Off-Peak Average	2019	80,415	1,196	3,578	19,190	2,827	107,206	82,178	87,242	(567)	19,963
	2020	76,696	1,083	3,388	19,719	3,200	104,086	78,616	84,054	(837)	20,032
Off-Peak Median	2019	78,444	1,203	3,214	19,038	2,707	104,883	79,913	84,865	(266)	20,018
	2020	74,675	1,086	2,922	19,630	3,185	101,653	76,437	81,773	(676)	19,879
Off-Peak Standard Deviation	2019	13,515	179	1,596	4,231	731	16,197	14,453	14,419	(759)	1,778
	2020	13,296	181	1,808	3,815	724	15,745	14,006	14,096	(529)	1,649

Figure 3-17 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first nine months of 2020. 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 3-17 Day-ahead and real-time demand (Average hourly volumes): January through September, 2020

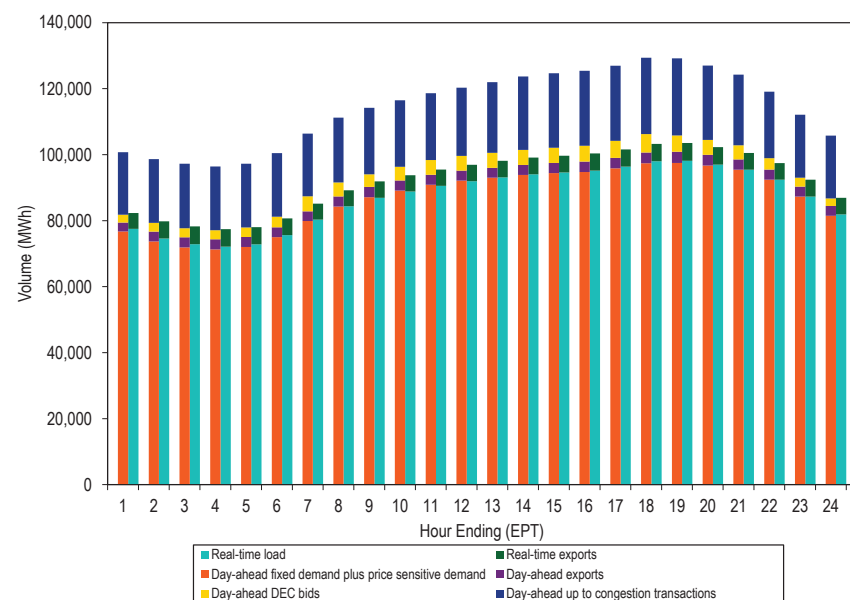
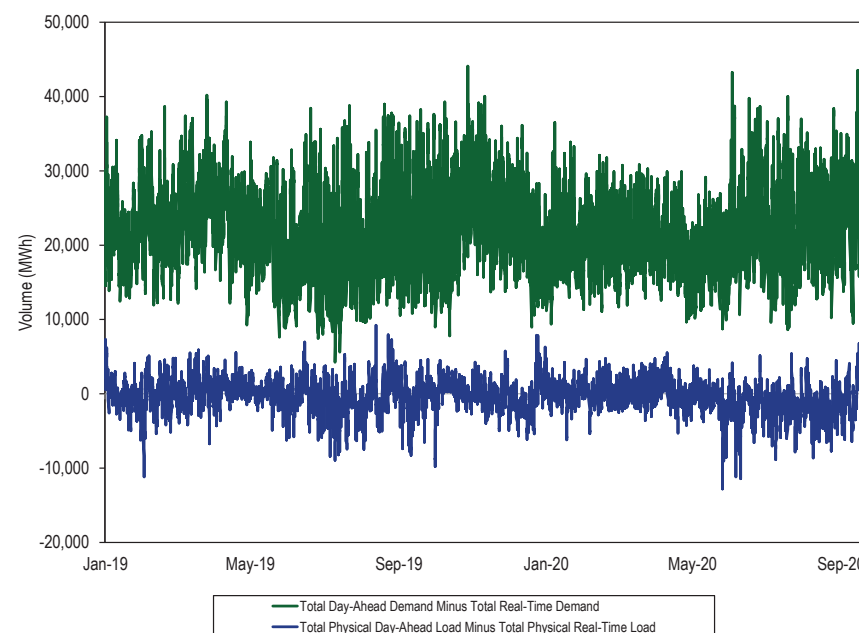


Figure 3-18 shows the difference between the day-ahead and real-time average daily demand for 2019 and the first nine months of 2020.

Figure 3-18 Difference between day-ahead and real-time demand (Average daily volumes): 2019 through September 2020



Market Behavior

Supply and Demand: Load and Spot Market

Participants in the PJM Real-Time and Day-Ahead Energy Markets 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).

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 InSchedule transactions referred to as wholesale load responsibility (WLR), retail load responsibility (RLR) transactions and generation responsibility. 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. 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 and day-ahead energy markets for each hour.

Real-Time Load and Spot Market

Table 3-12 shows the monthly average share of real-time load served by each parent company's self supply, bilateral contracts and spot purchases in the first nine months of 2019 and 2020. In the first nine months of 2020, 16.4 percent of real-time load was supplied by bilateral contracts, 24.0 percent by spot market purchase and 59.7 percent by self supply. Compared with the first nine months of 2019, reliance on bilateral contracts increased by 1.0 percentage points, reliance on spot supply decreased by 0.8 percentage points and reliance on self supply decreased by 0.2 percentage points.

Table 3-12 Sources of real-time supply: January 2019 through September 2020²²

	2019			2020			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	15.4%	23.9%	60.7%	17.1%	24.7%	58.2%	1.7%	0.8%	(2.5%)
Feb	15.4%	25.2%	59.4%	16.6%	23.8%	59.6%	1.2%	(1.3%)	0.1%
Mar	15.2%	27.5%	57.4%	16.9%	23.8%	59.3%	1.8%	(3.7%)	2.0%
Apr	16.7%	24.8%	58.5%	17.2%	21.5%	61.3%	0.4%	(3.3%)	2.9%
May	16.0%	24.3%	59.7%	17.2%	21.6%	61.1%	1.2%	(2.6%)	1.5%
Jun	15.0%	23.8%	61.1%	15.9%	23.3%	60.7%	0.9%	(0.5%)	(0.4%)
Jul	14.4%	23.8%	61.8%	15.3%	25.5%	59.2%	1.0%	1.7%	(2.7%)
Aug	15.3%	24.1%	60.6%	15.9%	24.4%	59.7%	0.6%	0.3%	(0.9%)
Sep	15.5%	25.5%	58.9%	16.1%	25.7%	58.3%	0.5%	0.1%	(0.7%)
Oct	16.7%	27.7%	55.6%						
Nov	15.7%	28.6%	55.6%						
Dec	19.8%	22.6%	57.6%						
Jan-Sep	15.4%	24.7%	59.9%	16.4%	24.0%	59.7%	1.0%	(0.8%)	(0.2%)

²² Table 3-12 and Table 3-13 were calculated as of October 15, 2020. The values may change slightly as billing values are updated by PJM.

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can use not only their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but also virtual resources to meet their load serving obligations in the day-ahead market in any hour. Virtual supply is treated as supply in the day-ahead market and virtual demand is treated as demand in the day-ahead market.

Table 3-13 shows the monthly average share of day-ahead demand served by each parent company's self supply, bilateral contracts and spot purchases in the first nine months of 2019 and 2020. In the first nine months of 2020, 15.5 percent of day-ahead demand was supplied by bilateral contracts, 24.3 percent by spot market purchases and 60.2 percent by self supply. Compared with the first nine months of 2019, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply decreased by 0.6 percentage points, and reliance on self supply decreased by 0.3 percentage points.

Table 3-13 Sources of day-ahead supply: January 2019 through September 2020

	2019			2020			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	14.5%	24.0%	61.5%	16.2%	24.5%	59.3%	1.6%	0.5%	(2.1%)
Feb	14.6%	24.9%	60.5%	15.6%	23.5%	60.9%	1.0%	(1.4%)	0.5%
Mar	14.3%	27.2%	58.5%	15.7%	24.0%	60.3%	1.4%	(3.3%)	1.9%
Apr	15.8%	25.2%	59.0%	16.2%	22.5%	61.3%	0.3%	(2.7%)	2.4%
May	14.8%	25.2%	60.0%	16.1%	22.8%	61.1%	1.3%	(2.4%)	1.1%
Jun	14.2%	24.4%	61.4%	15.1%	24.1%	60.8%	0.9%	(0.3%)	(0.5%)
Jul	13.9%	23.8%	62.3%	14.6%	25.6%	59.8%	0.7%	1.8%	(2.5%)
Aug	14.7%	24.2%	61.1%	15.1%	24.8%	60.0%	0.4%	0.7%	(1.1%)
Sep	14.8%	25.9%	59.3%	15.1%	26.3%	58.6%	0.3%	0.4%	(0.7%)
Oct	15.9%	27.8%	56.3%						
Nov	14.9%	28.2%	56.8%						
Dec	19.0%	22.3%	58.7%						
Jan-Sep	14.6%	24.9%	60.5%	15.5%	24.3%	60.2%	0.9%	(0.6%)	(0.3%)

Generator Offers

Generator offers are categorized as pool scheduled (Table 3-14) or self scheduled (Table 3-15).²³ Units which are available for economic commitment are pool scheduled. Units which are self scheduled to generate fixed output are must run and not dispatchable. 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 3-14 and Table 3-15 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 above the economic range of a unit are categorized as emergency MW. Emergency MW offered above the self scheduled or dispatchable 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 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 lowest commitment cost offer is used.

Table 3-14 shows the proportion of day-ahead MW offered by pool scheduled units, by unit type and by offer price range, in the first nine months of 2020. Pool scheduled units offer with an economic commitment status. For example, 42.0 percent of all CC offer MW were the economic minimum offered MW, and 37.3 percent of CC offer MW 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, including the economic minimum and emergency MW. For example, 83.5 percent of all CC unit offers were pool scheduled, including the 42.0 percent of economic minimum MW and 4.1 percent of emergency MW offered by CC units. The dispatchable range of a unit is between the economic minimum and emergency range. For example, 37.4 percent of all CC unit offers have an economic dispatch range. The all pool scheduled 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, 25.3 percent of offer MW were pool scheduled offers in the \$0 to

²³ 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.

\$200 per MWh price range. The total column in the all pool scheduled offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first nine months of 2020, 28.0 percent of all pool scheduled offers had an economic dispatch range.

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.

Table 3-14 Distribution of day-ahead MW for pool scheduled unit offer prices: January through September, 2020

Unit Type	Economic Minimum	Dispatchable (Range)						Emergency	Total
		(\$200) - \$0	\$0 - \$200	\$200 - \$400	\$400 - \$600	\$600 - \$800	\$800 - \$1,000		
CC	42.0%	0.0%	37.3%	0.1%	0.0%	0.0%	0.0%	4.1%	83.5%
CT	63.3%	0.0%	27.7%	0.9%	0.1%	0.0%	0.0%	7.2%	99.1%
Diesel	38.9%	0.0%	20.7%	1.9%	0.0%	0.0%	0.0%	15.9%	77.4%
Nuclear	6.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.7%
Pumped Storage	0.0%	0.0%	4.3%	0.0%	0.0%	0.0%	0.0%	41.4%	45.7%
Run of River	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Solar	0.1%	0.0%	13.4%	0.0%	0.0%	0.0%	0.0%	0.0%	13.5%
Steam - Coal	21.7%	0.0%	27.7%	0.0%	0.0%	0.0%	0.0%	1.4%	50.9%
Steam - Other	31.2%	0.0%	49.5%	1.7%	0.0%	0.0%	0.0%	3.1%	85.6%
Wind	1.0%	0.0%	7.7%	0.0%	0.0%	0.0%	0.0%	1.0%	9.7%
All Pool Scheduled Offers	31.3%	0.0%	25.3%	0.3%	0.0%	0.0%	0.0%	4.4%	63.7%

Table 3-15 shows the proportion of day-ahead offered MW by unit type that were self scheduled, and that were self scheduled and dispatchable by price range, for the first nine months of 2020. 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, 16.5 percent of all CC 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 1.1 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 14.2 percent of all offers and self scheduled and dispatchable units accounted for 21.0 percent of all offers. The total column in the all self scheduled offers row is the proportion of all MW offers that were

Table 3-15 Distribution of day-ahead MW for self scheduled and dispatchable unit offer prices: January through September, 2020

Unit Type	Self Scheduled		Self Scheduled and Dispatchable (Range)								Total
	Must Run	Emergency	Economic Minimum	(\$200) - \$0	\$0 - \$200	\$200 - \$400	\$400 - \$600	\$600 - \$800	\$800 - \$1,000	Emergency	
CC	0.2%	0.1%	8.4%	0.0%	6.7%	0.0%	0.0%	0.0%	0.0%	1.1%	16.5%
CT	0.1%	0.0%	0.4%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.1%	0.9%
Diesel	13.2%	4.6%	1.6%	0.0%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	20.4%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	64.3%	0.0%	22.8%	0.0%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	89.5%
Pumped Storage	4.1%	6.2%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.6%
Run of River	79.8%	19.2%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	99.6%
Solar	12.6%	8.7%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	22.1%
Steam - Coal	1.8%	0.7%	21.8%	0.0%	22.6%	0.0%	0.0%	0.0%	0.0%	2.1%	49.0%
Steam - Other	2.7%	0.4%	5.3%	0.0%	3.1%	0.1%	0.0%	0.0%	0.0%	0.7%	12.3%
Wind	5.1%	5.1%	2.3%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	2.3%	15.5%
All Self-Scheduled Offers	13.5%	0.7%	12.2%	0.0%	7.9%	0.0%	0.0%	0.0%	0.0%	0.9%	36.3%

Hourly Offers and Intraday Offer Updates

All participants are able to make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Participants that have opted in can only make updates if their fuel cost policy defines the intraday offer update process. Table 3-16 shows the daily average number of units that make hourly offers, that opted in to intraday offer updates and that make intraday offer updates. In the first nine months of 2020, an average of 307 units per day made hourly offers, the same level as in the first nine months of 2019. In the first nine months of 2020, 388 units opted in for intraday offer updates, an increase of 20 units from the first nine months of 2019. In the first nine months of 2020, an average of 135 units made intraday offer updates each day, a decrease of seven units from the first nine months of 2019.

Table 3-16 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: January through September, 2019 and 2020

	Fuel Type	2019	2020	Difference
Hourly Offers	Natural Gas	286	289	3
	Other Fuels	21	18	(3)
	Total	307	307	0
Opt In	Natural Gas	330	340	10
	Other Fuels	38	48	10
	Total	368	388	20
Intraday Offer Updates	Natural Gas	135	129	(6)
	Other Fuels	7	6	(1)
	Total	142	135	(7)

Parameter Limited Schedules

Cost-Based Offers

All capacity resources in PJM are required to submit at least one cost-based offer. For the 2018/2019 and 2019/2020 Delivery Years, PJM procured two types of capacity resources, capacity performance resources and base capacity resources. For the 2020/2021 Delivery Year, PJM procured only capacity performance resources. 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.

The MMU recommends that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions.²⁴ Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the cost-based parameter limited schedule when a resource fails the TPS test. The current implementation is not consistent with the goal of having

²⁴ See Protest of the Independent Market Monitor for PJM, Docket No. ER20-995 (February 25, 2020).

parameter limited schedules, which is to prevent the use of inflexible operating parameters to exercise market power.

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market when units are committed after failing the TPS test for transmission constraints in the first nine months of 2020. Table 3-17 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-17 shows that 30.6 percent of unit hours for units that failed the TPS test were committed on their price-based schedules that were less flexible than their cost-based schedules.

Table 3-17 Parameter mitigation for units failing TPS test: January through September, 2020

Day-ahead commitment for units that failed TPS test	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than cost	26,020	30.6%
Committed on price schedule as flexible as cost	8,220	9.7%
Total committed on price schedule without parameter limits	34,240	40.2%
Committed on cost (cost capped)	49,841	58.6%
Committed on price PLS	1,013	1.2%
Total committed on PLS schedules (cost or price PLS)	50,854	59.8%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in regions where a cold or hot weather alert was declared in the first nine months of 2020. PJM declared cold weather alerts on three days and hot weather alerts on 19 days in the first nine months of 2020.²⁵ The analysis includes units with a CP commitment in the zones where the cold and hot weather alerts were declared. Base capacity resources are subject to commitment on the price PLS schedule during hot weather alerts and not during cold weather alerts. Table 3-18 shows that 28.5 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.

²⁵ 2020 Quarterly State of the Market Report for PJM: January through September, Section 3: Energy Market, at Emergency Procedures.

Table 3-18 Parameter mitigation during weather alerts: January through September, 2020

Day-ahead commitment during hot and cold weather alerts	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than PLS	31,736	28.5%
Committed on price schedule as flexible as PLS	30,101	27.0%
Total committed on price schedule without parameter limits	61,837	55.4%
Committed on cost (cost capped)	3,228	2.9%
Committed on price PLS	46,485	41.7%
Total committed on PLS schedules (cost or price PLS)	49,713	44.6%

Currently, there are no rules in the PJM tariff or manuals that limit the markup attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed and during high load conditions such as cold and hot weather alerts or more severe emergencies, 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. This recommendation would ensure that market power that results from inflexible parameters is mitigated during high load conditions and when a market seller fails the TPS test, consistent with the goal of having parameter limited schedules.

Parameter Limits

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 were 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, are either capacity performance or base capacity resources. Beginning June 1, 2020, all capacity resources, including resources in FRR capacity plans, are capacity performance 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 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.

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for boiler based steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and a best practices equipment configuration.

The PJM process for the review of unit specific parameter limit adjustments is generally described in Manual 11: Energy and Ancillary Services Market Operations. The standards used by PJM to review the requests are currently not described in the tariff or PJM manuals. The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources.

Only certain technology types are subject to limits on operating parameters in their parameter limited schedules.²⁶ 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 3-19 shows, for the delivery year beginning June 1, 2020, the number of units that submitted and had approved unit specific parameter limit adjustments, and the number of units that used the default parameter limits published by PJM. Table 3-19 shows that 85.3 percent of subcritical coal steam units and 88.4 percent of supercritical coal steam units had an adjustment approved to one or more parameter limits from the default limits published by PJM, while only 31.6 percent of combined cycle units, and 35.0 percent of frame combustion turbine units, and 24.2 percent of aero

derivative combustion turbine units had an adjustment approved to one or more parameter limits from the default limits published by PJM.

Table 3-19 Adjusted unit specific parameter limit statistics: delivery year 2020/2021

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percentage of Units with One or More Adjusted Parameter Limits
Aero CT	125	40	24.2%
Frame CT	178	96	35.0%
Combined Cycle	80	37	31.6%
Reciprocating Internal Combustion Engines	68	3	4.2%
Solid Fuel NUG	36	6	14.3%
Oil and Gas Steam	10	15	60.0%
Subcritical Coal Steam	10	58	85.3%
Supercritical Coal Steam	5	38	88.4%
Pumped Storage	10	0	0.0%

Real-Time Values

The MMU recommends that PJM market rules recognize the difference between operational parameters that indicate to PJM operators what a unit is capable of during the operating day and the parameters that result in uplift payments. The parameters provided to PJM operators each day should reflect what units are physically capable of so that operators 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, but there are problems with the implementation, because it does not recognize that some parameters result in withholding, without affecting uplift payments.

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

²⁶ 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>>.

payments, unless the market seller can justify such operation based on an actual constraint.²⁷

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) or minimum run time or minimum down time 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, start time parameter, minimum run time and minimum down time parameters, a longer real-time value decreases the likelihood of the unit being committed at all, and may prohibit unit commitment in real time, making the RTV a mechanism for exercising market power through withholding and for failing to meet the obligations of capacity resources.

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 compensated identically in the capacity market. If a market seller makes an economic decision to not staff the unit or to not have remote start capability, and uses 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.

²⁷ See PJM Operating Agreement, Schedule 1, Section 3.2.3 (e).

Generator Flexibility Incentives under Capacity Performance

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.²⁸ The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.²⁹ 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.³⁰

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of taking on performance risk. The June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical limits, the June 9th Order weakened the incentives for units to be flexible and weakened the assignment of performance risk to generation owners. Contractual limits, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

The fact that a contract may be entered into by two willing parties does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome or that such a contract can reasonably impose costs on customers who were not party to the contract. The actual contractual terms are a function of the incentives and interests of the parties, who may be affiliates or have market power. The fact that a just and

²⁸ 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).

²⁹ *Id.* at P 439.

³⁰ *Id.* at P 440.

reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 9th Order will increase energy market uplift payments substantially. While some uplift is necessary and efficient in an LMP market, this uplift is not. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The MMU recommends that capacity performance resources 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 extreme cold weather conditions, and recently, during hot weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity. In the first nine months of 2020, there were eight units in PJM that experienced gas pipeline restrictions leading to requests for 24 hour minimum run time on their parameter limited schedules.

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.

The MMU observed instances when generators submitted temporary parameter exceptions based on claimed pipeline constraints even though these constraints are based on the nature of the transportation service that the generator procured from the pipeline. In some instances, generators requested temporary exceptions based on ratable take requirements stated in pipeline tariffs, even though the requirement is not enforced by the pipelines on a routine basis. If a unit were to be dispatched uneconomically using the inflexible parameters, the unit would receive make whole payments based on these temporary exceptions. The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced or on inferior transportation service procured by the generator.

Virtual Offers and Bids

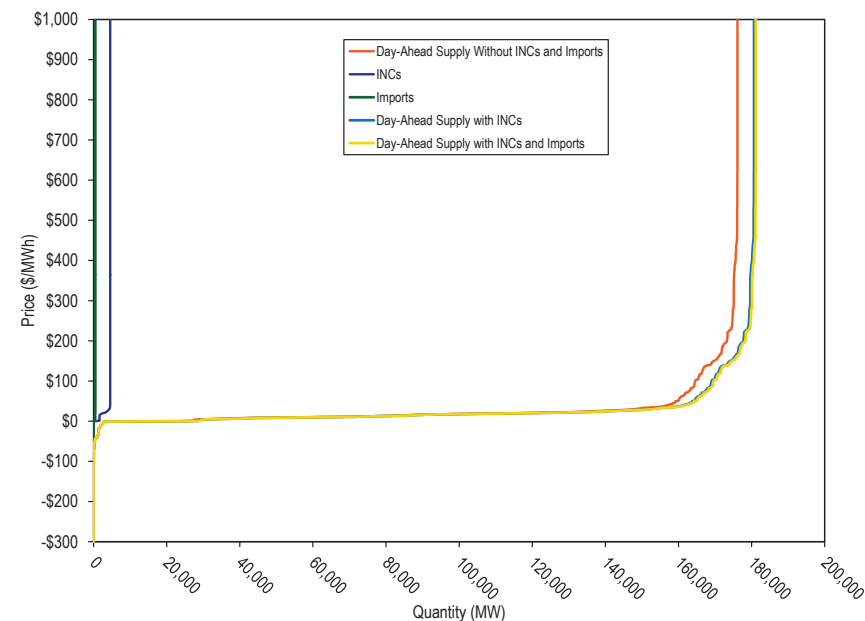
There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Energy Market and such offers and bids may be marginal.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Because virtual positions do not require physical generation or load, participants must buy or sell out of their virtual positions at real-time energy market prices. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, interfaces and residual aggregate metered load nodes, and limiting the eligible bidding points for INCs and DECs to the same nodes plus active generation and load nodes.³¹ Up to congestion transactions may be submitted between any two buses on a list of 47 buses eligible for up to congestion

transaction bidding.³² Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-19 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2020.

Figure 3-19 Day-ahead aggregate supply curves: 2020 example day



³² 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/~media/etools/oasis/references/oasis-source-sink-link.xlsx.

³¹ 162 FERC ¶ 61,139.

Figure 3-20 shows example PJM day-ahead aggregate supply curves for the typical dispatch price range.

Figure 3-20 Typical dispatch price range for day-ahead aggregate supply curves: 2020 example day

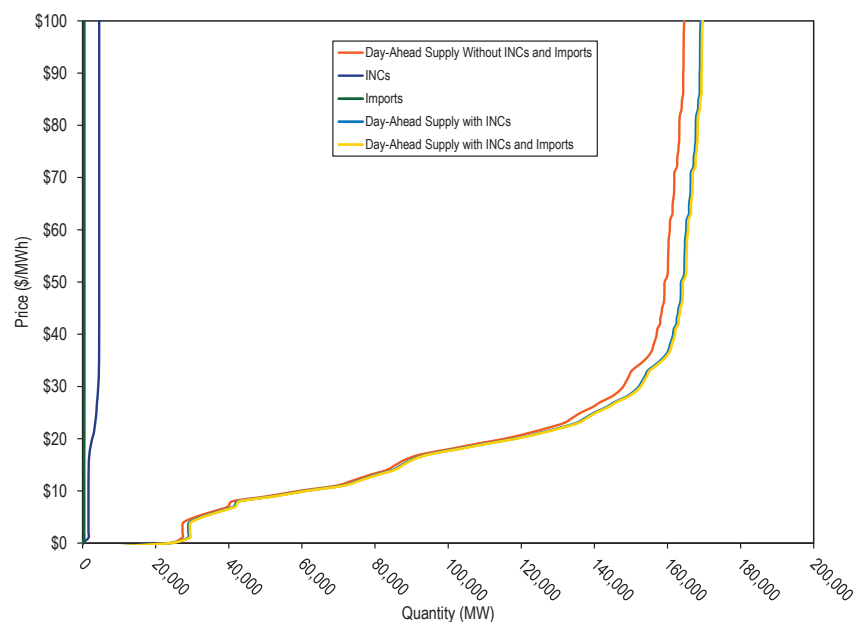


Table 3-20 shows the hourly average number of cleared and submitted increment offers and decrement bids by month from January 2019 through September 2020. The hourly average submitted increment MW increased by 8.1 percent and cleared increment MW decreased by 14.4 percent, from 6,358 MW and 2,855 MW in the first nine months of 2019 to 6,8796 MW and 2,443 MW in the first nine months of 2020. The hourly average submitted decrement MW increased by 18.5 percent and cleared decrement MW decreased by 5.5 percent, from 7,267 MW and 3,955 MW in the first nine months of 2019 to 8,610 MW and 4,173 MW in the first nine months of 2020.

Table 3-20 Average hourly number of cleared and submitted INCs and DECs by month: January 2019 through September 2020

Year		Increment Offers				Decrement Bids			
		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2019	Jan	2,934	6,777	282	1,122	3,856	7,149	215	834
2019	Feb	2,895	5,776	260	1,029	3,441	6,115	197	781
2019	Mar	2,973	5,961	268	1,057	3,319	6,830	181	859
2019	Apr	3,048	6,008	286	1,060	3,104	6,226	154	733
2019	May	3,107	6,468	273	1,082	4,236	6,903	178	726
2019	Jun	2,892	6,363	226	977	4,408	7,245	226	863
2019	Jul	2,655	6,712	202	1,051	4,544	9,223	251	1,086
2019	Aug	2,577	6,573	220	1,100	3,744	7,056	217	860
2019	Sep	2,715	6,737	221	972	5,046	8,790	255	900
2019	Oct	3,034	6,967	283	1,141	3,218	7,226	186	776
2019	Nov	3,373	7,896	304	1,261	2,745	6,930	187	831
2019	Dec	2,482	6,398	232	995	2,782	6,455	191	694
2019	Annual	2,889	6,558	255	1,071	3,704	7,186	203	829
2020	Jan	2,684	6,395	261	1,063	2,547	5,856	187	662
2020	Feb	2,544	7,043	233	1,046	2,990	6,653	222	702
2020	Mar	2,435	7,119	258	1,069	3,203	7,688	251	762
2020	Apr	2,655	7,738	299	1,167	3,400	8,312	261	840
2020	May	2,695	6,931	254	1,050	4,361	8,257	307	814
2020	Jun	2,353	7,185	235	1,011	5,140	9,843	404	1,083
2020	Jul	2,247	6,936	252	1,071	5,515	11,233	436	1,293
2020	Aug	1,915	6,084	209	973	5,148	10,165	451	1,217
2020	Sep	2,472	6,486	254	1,150	5,217	9,414	468	1,156
2020	Jan-Sep	2,443	6,876	251	1,066	4,173	8,610	332	949

Table 3-21 shows the average hourly number of up to congestion transactions and the average hourly MW from January 2019 through September 2020. In the first nine months of 2020, the average hourly submitted and cleared up to congestion MW decreased by 21.1 percent and 0.1 percent, compared to the first nine months of 2019.

Table 3-21 Average hourly cleared and submitted up to congestion bids by month: January 2019 through September 2020

		Up to Congestion			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2019	Jan	20,624	65,533	1,219	2,489
2019	Feb	21,341	66,240	1,005	2,013
2019	Mar	23,205	75,760	1,045	2,144
2019	Apr	21,323	63,388	872	1,669
2019	May	19,407	59,684	862	1,713
2019	Jun	18,598	51,678	1,021	1,953
2019	Jul	19,197	56,161	1,128	2,265
2019	Aug	20,247	58,841	1,254	2,550
2019	Sep	20,005	74,494	1,136	2,523
2019	Oct	22,233	75,107	1,093	2,302
2019	Nov	23,678	77,890	1,019	2,265
2019	Dec	20,567	55,020	1,040	2,104
2019	Annual	20,864	64,952	1,059	2,168
2020	Jan	19,106	37,533	1,127	2,087
2020	Feb	19,415	40,281	1,100	2,133
2020	Mar	19,513	40,998	990	1,970
2020	Apr	18,267	37,298	955	1,859
2020	May	18,028	41,503	1,122	2,425
2020	Jun	23,038	59,520	1,403	2,726
2020	Jul	21,014	64,376	1,227	2,539
2020	Aug	22,478	63,368	1,159	2,306
2020	Sep	22,900	65,866	1,136	2,315
2020	Jan-Sep	20,414	50,110	1,135	2,263

Table 3-22 shows the average hourly number of day-ahead import and export transactions and the average hourly MW from January 2019 through September 2020. In the first nine months of 2020, the average hourly submitted and cleared import transaction MW decreased by 38.6 and 33.1 percent, and the average hourly submitted and cleared export transaction MW increased by 14.4 and 14.9 percent, compared to the first nine months of 2019.

Table 3-22 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2019 through September 2020

		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
2019	Jan	545	653	7	9	3,569	3,593	22	22
2019	Feb	564	671	6	8	3,169	3,182	17	18
2019	Mar	387	449	5	7	2,675	2,686	15	15
2019	Apr	255	288	4	5	2,483	2,496	15	15
2019	May	279	298	3	4	2,426	2,458	15	15
2019	Jun	291	308	3	4	2,790	2,806	17	17
2019	Jul	283	311	4	5	3,075	3,106	15	15
2019	Aug	277	303	3	4	2,907	2,923	16	16
2019	Sep	162	177	3	3	3,163	3,193	17	17
2019	Oct	433	463	4	5	2,694	2,721	15	15
2019	Nov	540	563	5	6	2,205	2,214	12	12
2019	Dec	468	505	4	6	3,133	3,144	25	25
2019	Annual	373	414	4	6	2,857	2,876	17	17
2020	Jan	427	445	5	6	3,034	3,041	28	28
2020	Feb	324	346	4	5	2,737	2,742	29	29
2020	Mar	254	269	3	4	3,084	3,085	27	27
2020	Apr	173	188	2	3	3,057	3,062	25	25
2020	May	207	231	3	4	3,075	3,080	23	23
2020	Jun	159	152	2	2	3,782	3,798	31	31
2020	Jul	83	112	2	2	3,907	3,922	31	31
2020	Aug	100	128	2	2	3,909	3,920	29	29
2020	Sep	118	115	2	2	3,424	3,448	28	28
2020	Jan-Sep	225	234	3	4	3,338	3,348	28	28

Table 3-23 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal from January 2019 through September 2020.

Table 3-23 Type of day-ahead marginal resources: January 2019 through September 2020

	2019						2020					
	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	13.4%	0.3%	59.1%	17.4%	9.9%	0.0%	27.7%	0.1%	44.7%	10.6%	16.9%	0.0%
Feb	11.7%	0.1%	60.0%	15.4%	12.8%	0.0%	20.7%	0.1%	48.5%	12.5%	18.2%	0.0%
Mar	9.3%	0.1%	60.5%	17.0%	13.1%	0.0%	19.5%	0.0%	52.2%	14.7%	13.6%	0.0%
Apr	8.3%	0.1%	64.9%	14.8%	11.9%	0.0%	18.2%	0.0%	49.3%	16.6%	15.9%	0.0%
May	9.9%	0.1%	53.1%	21.0%	15.9%	0.0%	16.6%	0.1%	55.2%	15.2%	13.0%	0.0%
Jun	10.5%	0.0%	49.0%	23.7%	16.8%	0.0%	14.1%	0.0%	60.8%	15.5%	9.6%	0.0%
Jul	9.1%	0.0%	51.5%	26.0%	13.4%	0.0%	11.8%	0.1%	57.4%	20.4%	10.3%	0.0%
Aug	13.0%	0.1%	63.1%	14.1%	9.6%	0.0%	10.5%	0.0%	55.3%	24.9%	9.2%	0.0%
Sep	14.0%	0.1%	60.5%	13.4%	12.0%	0.0%	13.1%	0.1%	54.8%	21.9%	10.1%	0.0%
Oct	16.4%	0.1%	55.9%	13.8%	13.8%	0.0%						
Nov	16.2%	0.0%	57.9%	13.2%	12.8%	0.0%						
Dec	23.2%	0.1%	55.2%	10.9%	10.5%	0.0%						
Annual	12.7%	0.1%	57.4%	17.0%	12.8%	0.0%	16.1%	0.1%	53.8%	17.6%	12.4%	0.0%

Figure 3-21 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from January 2005 through September 2020.

Figure 3-21 Monthly bid and cleared INCs, DEC and UTCs (MW): January 2005 through September 2020

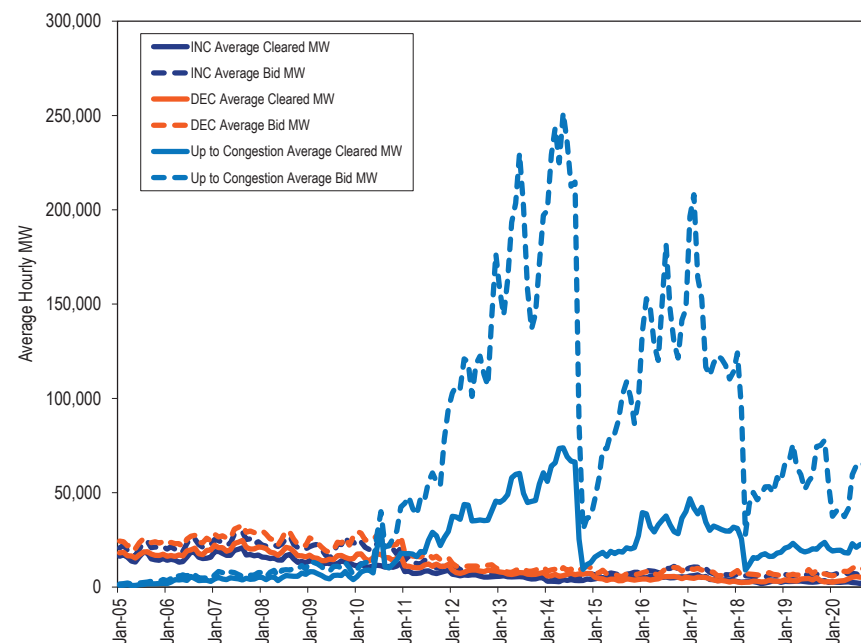
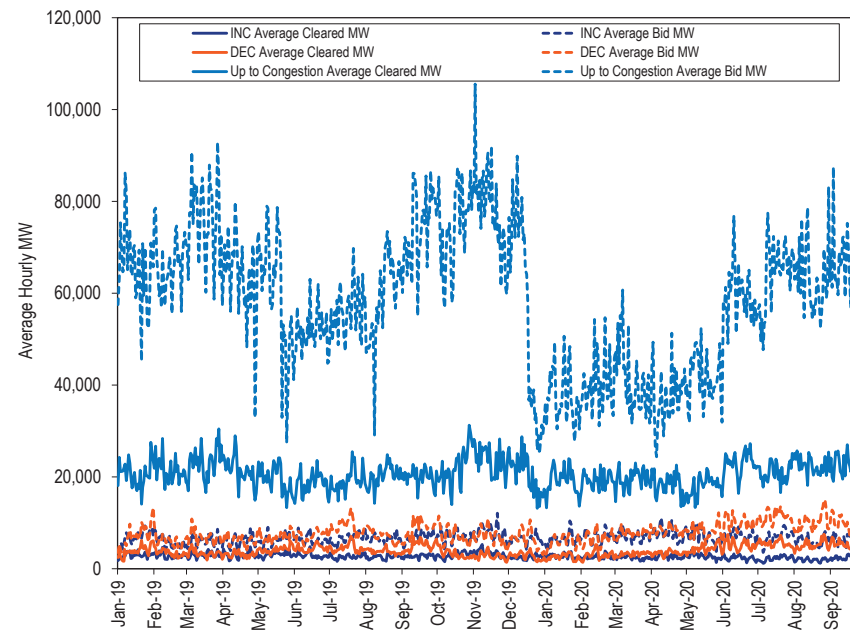


Figure 3-22 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 1, 2019 through September 30, 2020.

Figure 3-22 Daily bid and cleared INCs, DEC, and UTCs (MW): January 2019 through September 2020



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 3-24 shows, in the first nine months of 2019 and 2020, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-24 INC and DEC bids and cleared MWh by type of parent organization (MWh): January through September, 2019 and 2020

Category	2019 (Jan-Sep)				2020 (Jan-Sep)			
	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	76,619,225	85.5%	37,243,904	83.2%	88,757,936	87.2%	35,467,302	81.7%
Physical	12,966,527	14.5%	7,537,530	16.8%	12,972,844	12.8%	7,966,000	18.3%
Total	89,585,752	100.0%	44,781,434	100.0%	101,730,780	100.0%	43,433,302	100.0%

Table 3-25 shows, in the first nine months of 2019 and 2020, the total up to congestion bids and cleared MWh by type of parent organization.

Table 3-25 Up to congestion transactions by type of parent organization (MWh): January through September, 2019 and 2020

Category	2019 (Jan-Sep)				2020 (Jan-Sep)			
	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	401,937,939	96.6%	125,408,762	93.7%	292,911,459	88.9%	117,702,630	87.7%
Physical	14,071,633	3.4%	8,448,962	6.3%	36,561,672	11.1%	16,522,121	12.3%
Total	416,009,572	100.0%	133,857,724	100.0%	329,473,130	100.0%	134,224,751	100.0%

Table 3-26 shows in the first nine months of 2019 and 2020, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-26 Import and export transactions by type of parent organization (MW): January through September, 2019 and 2020

Category	2019 (Jan-Sep)			2020 (Jan-Sep)	
	Total Import and Export MW	Percent		Total Import and Export MW	Percent
Day-Ahead					
Financial	5,915,726	27.8%		7,879,558	38.2%
Physical	15,386,934	72.2%		12,739,439	61.8%
Total	21,302,659	100.0%		20,618,997	100.0%
Real-Time					
Financial	9,749,353	24.0%		10,928,264	30.2%
Physical	30,937,695	76.0%		25,268,728	69.8%
Total	40,687,048	100.0%		36,196,992	100.0%

Table 3-27 shows increment offers and decrement bids by top 10 locations in the first nine months of 2019 and 2020.

Table 3-27 Virtual offers and bids by top 10 locations (MW): January through September, 2019 and 2020

2019 (Jan-Sep)					2020 (Jan-Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
MISO	INTERFACE	92,458	5,480,232	5,572,690	MISO	INTERFACE	40,963	6,249,294	6,290,257
WESTERN HUB	HUB	974,342	1,456,731	2,431,073	WESTERN HUB	HUB	491,170	2,067,115	2,558,285
AEP-DAYTON HUB	HUB	431,099	771,311	1,202,410	AEP-DAYTON HUB	HUB	235,156	1,169,498	1,404,653
LINDENVFT	INTERFACE	27,083	1,164,030	1,191,114	BGE_RESID_AGG	RESIDUAL METERED EDC	225,156	1,049,465	1,274,621
DOM_RESID_AGG	RESIDUAL METERED EDC	196,888	932,152	1,129,040	DOM_RESID_AGG	RESIDUAL METERED EDC	140,252	957,543	1,097,795
DOMINION HUB	HUB	460,460	581,642	1,042,102	NORTHWEST	INTERFACE	596,464	152,419	748,883
SOUTHIMP	INTERFACE	958,877	0	958,877	NEW JERSEY HUB	HUB	408,714	303,323	712,037
N ILLINOIS HUB	HUB	428,538	521,707	950,245	PECO_RESID_AGG	RESIDUAL METERED EDC	513,491	177,954	691,445
BGE_RESID_AGG	RESIDUAL METERED EDC	184,216	692,349	876,565	NYIS	INTERFACE	562,884	126,271	689,154
NYIS	INTERFACE	571,531	200,621	772,153	N ILLINOIS HUB	HUB	275,624	382,788	658,412
Top ten total		4,325,493	11,800,775	16,126,267			3,489,874	12,635,669	16,125,543
PJM total		18,774,506	26,006,928	44,781,434			16,064,224	27,437,759	43,501,982
Top ten total as percent of PJM total		23.0%	45.4%	36.0%			21.7%	46.1%	37.1%

Table 3-28 shows up to congestion transactions by import bids for the top 10 locations and associated profits at each path in the first nine months of 2019 and 2020.³³

Table 3-28 Cleared up to congestion import bids by top 10 source and sink pairs (MW): January through September, 2019 and 2020

2019 (Jan-Sep)							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	3,672,891	\$2,624,342	(\$1,008,392)	\$1,615,950
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	2,267,861	\$1,168,166	(\$602,967)	\$565,200
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	2,118,015	\$1,937,641	(\$1,056,650)	\$880,991
NYIS	INTERFACE	RECO_RESID_AGG	AGGREGATE	1,430,149	(\$484,469)	\$675,323	\$190,854
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	1,214,494	\$169,568	\$530,215	\$699,783
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	1,017,897	\$247,481	(\$164,126)	\$83,355
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	903,699	\$483,274	(\$96,332)	\$386,942
SOUTHIMP	INTERFACE	AEP GEN HUB	HUB	758,037	\$1,224,095	(\$730,682)	\$493,413
SOUTHIMP	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	671,711	\$471,888	(\$115,309)	\$356,579
NORTHWEST	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	537,544	\$471,504	(\$22,757)	\$448,746
Top ten total				14,592,297	\$8,313,490	(\$2,591,677)	\$5,721,814
PJM total				28,290,352	\$16,511,901	(\$6,245,518)	\$10,266,384
Top ten total as percent of PJM total				51.6%	50.3%	41.5%	55.7%
2020 (Jan-Sep)							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	3,619,492	\$2,799,055	(\$1,530,939)	\$1,268,116
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	3,243,735	\$2,585,246	(\$1,009,193)	\$1,576,053
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	1,851,417	\$1,501,158	(\$991,825)	\$509,332
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	1,123,353	(\$744,961)	\$629,420	(\$115,541)
NYIS	INTERFACE	RECO_RESID_AGG	AGGREGATE	962,528	(\$337,087)	\$361,009	\$23,922
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	960,756	(\$21,145)	\$620,424	\$599,279
SOUTHIMP	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	690,430	(\$94,291)	\$136,156	\$41,866
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	626,033	\$571,965	(\$364,315)	\$207,650
NORTHWEST	INTERFACE	AEP-DAYTON HUB	HUB	604,248	\$731,513	(\$344,272)	\$387,241
NORTHWEST	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	536,686	\$286,865	(\$36,716)	\$250,149
Top ten total				14,218,678	\$7,278,319	(\$2,530,250)	\$4,748,069
PJM total				24,337,217	\$8,322,944	(\$924,665)	\$7,398,280
Top ten total as percent of PJM total				58.4%	87.4%	273.6%	64.2%

³³ 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 3-29 shows up to congestion transactions by export bids for the top 10 locations and associated profits at each path in the first nine months of 2019 and 2020.

Table 3-29 Cleared up to congestion export bids by top 10 source and sink pairs (MW): January through September, 2019 and 2020

2019 (Jan-Sep)							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	1,846,088	\$1,383,522	\$869,684	\$2,253,206
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	1,618,617	\$1,088,917	(\$348,429)	\$740,488
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	1,405,388	\$278,839	\$679,091	\$957,930
CHICAGO HUB	HUB	NIPSCO	INTERFACE	1,063,992	\$978,025	\$366,039	\$1,344,064
CHICAGO HUB	HUB	MISO	INTERFACE	739,298	\$211,933	(\$148,459)	\$63,474
AEP GEN HUB	HUB	SOUTHEXP	INTERFACE	711,021	(\$951,226)	\$1,885,040	\$933,814
CHICAGO GEN HUB	HUB	MISO	INTERFACE	518,556	\$41,936	\$37,577	\$79,513
N ILLINOIS HUB	HUB	MISO	INTERFACE	490,740	\$82,582	(\$144,049)	(\$61,467)
N ILLINOIS HUB	HUB	SOUTHEXP	INTERFACE	486,524	(\$29,001)	\$200,765	\$171,764
CHICAGO GEN HUB	HUB	NORTHWEST	INTERFACE	396,963	(\$433,776)	\$555,526	\$121,750
Top ten total				9,277,187	\$2,651,751	\$3,952,784	\$6,604,535
PJM total				15,943,796	(\$247,518)	\$10,144,990	\$9,897,472
Top ten total as percent of PJM total				58.2%	(1,071.3%)	39.0%	66.7%
2020 (Jan-Sep)							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	1,565,759	\$1,394,315	(\$951,202)	\$443,113
COMED_RESID_AGG	AGGREGATE	MISO	INTERFACE	1,060,646	(\$325,990)	\$616,438	\$290,449
COMED_RESID_AGG	AGGREGATE	NORTHWEST	INTERFACE	964,493	(\$1,182,161)	\$2,569,062	\$1,386,900
CHICAGO HUB	HUB	NIPSCO	INTERFACE	709,858	\$303,801	(\$170,272)	\$133,529
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	549,227	\$204,334	(\$54,058)	\$150,276
CHICAGO HUB	HUB	MISO	INTERFACE	517,140	(\$271,470)	\$380,568	\$109,097
CHICAGO GEN HUB	HUB	MISO	INTERFACE	474,702	(\$352,753)	\$455,228	\$102,475
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	409,116	\$318,507	(\$296,361)	\$22,146
COMED_RESID_AGG	AGGREGATE	SOUTHEXP	INTERFACE	347,746	(\$36,637)	\$217,554	\$180,917
N ILLINOIS HUB	HUB	SOUTHEXP	INTERFACE	330,103	\$134,120	(\$2,172)	\$131,948
Top ten total				6,928,790	\$186,066	\$2,764,784	\$2,950,850
PJM total				11,725,320	(\$1,366,970)	\$5,543,338	\$4,176,368
Top ten total as percent of PJM total				59.1%	(13.6%)	49.9%	70.7%

Table 3-30 shows up to congestion transactions by wheel bids and associated profits at each path for the top 10 locations in the first nine months of 2019 and 2020.

Table 3-30 Cleared up to congestion wheel bids by top 10 source and sink pairs (MW): January through September, 2019 and 2020

2019 (Jan-Sep)							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	1,781,084	\$1,130,395	\$53,205	\$1,183,599
MISO	INTERFACE	NIPSCO	INTERFACE	1,758,144	\$1,645,884	(\$194,491)	\$1,451,394
MISO	INTERFACE	SOUTHEXP	INTERFACE	889,111	(\$959,623)	\$3,152,146	\$2,192,524
NORTHWEST	INTERFACE	MISO	INTERFACE	869,753	\$837,161	(\$470,939)	\$366,222
MISO	INTERFACE	NORTHWEST	INTERFACE	581,756	\$274,179	\$64,171	\$338,350
SOUTHIMP	INTERFACE	MISO	INTERFACE	354,465	\$454,176	(\$261,645)	\$192,531
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	297,721	\$230,377	\$556,152	\$786,529
NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	262,102	\$456,506	(\$146,641)	\$309,865
LINDENVFT	INTERFACE	HUDSONTP	INTERFACE	194,779	\$94,362	(\$42,611)	\$51,751
IMO	INTERFACE	SOUTHEXP	INTERFACE	184,970	\$10,997	\$517,445	\$528,443
Top ten total				7,173,885	\$4,174,415	\$3,226,792	\$7,401,208
PJM total				8,420,422	\$4,306,298	\$2,939,003	\$7,245,301
Top ten total as percent of PJM total				85.2%	96.9%	109.8%	102.2%
2020 (Jan-Sep)							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	MISO	INTERFACE	1,717,422	\$1,581,021	(\$612,251)	\$968,770
MISO	INTERFACE	NIPSCO	INTERFACE	746,976	\$230,632	(\$156,299)	\$74,333
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	674,341	\$339,914	(\$111,066)	\$228,849
SOUTHIMP	INTERFACE	MISO	INTERFACE	673,943	(\$343,803)	\$319,076	(\$24,727)
LINDENVFT	INTERFACE	HUDSONTP	INTERFACE	639,106	(\$86,942)	\$203,006	\$116,064
MISO	INTERFACE	SOUTHEXP	INTERFACE	587,489	\$183,161	(\$85,798)	\$97,363
NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	265,988	\$58,105	(\$171,180)	(\$113,075)
MISO	INTERFACE	NORTHWEST	INTERFACE	192,999	\$44,905	\$12,964	\$57,870
SOUTHIMP	INTERFACE	NORTHWEST	INTERFACE	78,432	\$25,283	\$60,548	\$85,831
NEPTUNE	INTERFACE	HUDSONTP	INTERFACE	60,041	\$27,041	(\$45,830)	(\$18,789)
Top ten total				5,636,737	\$2,059,318	(\$586,829)	\$1,472,488
PJM total				6,344,691	\$1,884,061	(\$500,900)	\$1,383,161
Top ten total as percent of PJM total				88.8%	109.3%	117.2%	106.5%

The top 10 internal up to congestion transaction locations were 22.3 percent of the PJM total internal up to congestion transaction MW in the first nine months of 2020.

Table 3-31 shows up to congestion transactions by internal bids for the top 10 locations and associated profits at each path in the first nine months of 2019 and 2020. The total internal UTC profits increased by \$7.3 million, from \$5.5 million in the first nine months of 2019 to \$12.8 million in the first nine months of 2020. The total internal cleared MW increased by 10.6 million MW, or 13.1 percent, from 81.2 million MW in the first nine months of 2019 to 91.8 million MW in the first nine months of 2020.

Table 3-31 Cleared up to congestion internal bids by top 10 source and sink pairs (MW): January through September, 2019 and 2020

2019 (Jan-Sep)							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	1,987,576	\$56,715	(\$350,761)	(\$294,047)
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	1,710,830	\$1,190,773	(\$624,876)	\$565,897
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	1,688,489	\$18,599	\$313,596	\$332,194
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	1,534,526	\$127,249	(\$43,063)	\$84,185
AEP GEN HUB	HUB	AEP-DAYTON HUB	HUB	1,353,911	\$578,741	(\$433,479)	\$145,263
AEP GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	1,251,621	\$674,656	(\$693,980)	(\$19,324)
N ILLINOIS HUB	HUB	CHICAGO HUB	HUB	1,013,611	(\$245,478)	\$367,797	\$122,319
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	1,005,492	\$764,059	(\$481,265)	\$282,793
CHICAGO GEN HUB	HUB	AEPIIM_RESID_AGG	AGGREGATE	992,387	(\$9,936)	\$464,675	\$454,739
AECO_RESID_AGG	AGGREGATE	VINELAND_RESID_AGG	AGGREGATE	900,369	(\$583,798)	\$104,069	(\$479,728)
Top ten total				13,438,811	\$2,571,580	(\$1,377,287)	\$1,194,292
PJM total				81,203,154	\$19,532,924	(\$13,994,452)	\$5,538,471
Top ten total as percent of PJM total				16.5%	13.2%	9.8%	21.6%
2020 (Jan-Sep)							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	3,290,217	\$9,705	\$395,985	\$405,691
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	2,794,862	\$323,613	\$253,123	\$576,736
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	2,717,744	\$245,412	(\$167,099)	\$78,313
N ILLINOIS HUB	HUB	AEPIIM_RESID_AGG	AGGREGATE	2,163,636	(\$610,413)	\$1,268,431	\$658,017
COMED_RESID_AGG	AGGREGATE	AEPIIM_RESID_AGG	AGGREGATE	2,045,907	(\$708,181)	\$1,858,039	\$1,149,858
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	1,567,160	\$197,726	(\$341,920)	(\$144,194)
CHICAGO HUB	HUB	AEPIIM_RESID_AGG	AGGREGATE	1,553,945	\$22,065	\$529,233	\$551,298
CHICAGO GEN HUB	HUB	AEPIIM_RESID_AGG	AGGREGATE	1,541,215	(\$17,153)	\$521,475	\$504,322
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	1,520,836	(\$20,096)	(\$71,037)	(\$91,133)
ATSI GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	1,286,946	(\$547,546)	\$1,104,717	\$557,171
Top ten total				20,482,469	(\$1,104,869)	\$5,350,946	\$4,246,078
PJM total				91,817,523	(\$11,464,972)	\$24,276,203	\$12,811,232
Top ten total as percent of PJM total				22.3%	9.6%	22.0%	33.1%

Table 3-32 shows the number of source-sink pairs that were offered and cleared monthly for January 1, 2019 through September 30, 2020.

Table 3-32 Number of offered and cleared source and sink pairs: January 2019 through September 2020

Daily Number of Source-Sink Pairs					
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2019	Jan	1,693	1,893	1,527	1,712
2019	Feb	1,701	1,881	1,496	1,733
2019	Mar	1,673	1,806	1,506	1,653
2019	Apr	1,555	1,806	1,395	1,653
2019	May	1,584	1,856	1,424	1,718
2019	Jun	1,770	1,970	1,601	1,797
2019	Jul	1,767	1,950	1,635	1,819
2019	Aug	1,880	2,034	1,690	1,879
2019	Sep	1,891	2,007	1,702	1,842
2019	Oct	1,837	1,935	1,607	1,756
2019	Nov	1,796	1,984	1,576	1,700
2019	Dec	1,687	1,935	1,507	1,769
2019	Annual	1,736	1,921	1,555	1,753
2020	Jan	1,658	1,942	1,523	1,857
2020	Feb	1,710	1,975	1,568	1,725
2020	Mar	1,789	2,013	1,591	1,832
2020	Apr	1,804	1,978	1,567	1,760
2020	May	1,913	2,126	1,681	1,900
2020	Jun	1,974	2,111	1,803	2,020
2020	Jul	1,886	2,085	1,749	1,970
2020	Aug	1,760	1,993	1,575	1,854
2020	Sep	1,656	1,851	1,498	1,641
2020	Jan-Sep	1,719	1,977	1,561	1,805

Table 3-33 Cleared up to congestion transactions by type (MW): January through September, 2019 and 2020

2019 (Jan-Sep)					
Cleared Up to Congestion Bids					
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	14,592,297	9,277,187	7,173,885	13,438,811	44,482,179
PJM total (MW)	28,290,352	15,943,796	8,420,422	81,203,154	133,857,724
Top ten total as percent of PJM total	51.6%	58.2%	85.2%	16.5%	33.2%
PJM total as percent of all up to congestion transactions	21.1%	11.9%	6.3%	60.7%	100.0%
2020 (Jan-Sep)					
Cleared Up to Congestion Bids					
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	14,218,678	6,928,790	5,636,737	20,482,469	47,266,674
PJM total (MW)	24,337,217	11,725,320	6,344,691	91,817,523	134,224,751
Top ten total as percent of PJM total	58.4%	59.1%	88.8%	22.3%	35.2%
PJM total as percent of all up to congestion transactions	18.1%	8.7%	4.7%	68.4%	100.0%

Table 3-33 and Figure 3-23 show total cleared up to congestion transactions by type in the first nine months of 2019 and 2020. Total up to congestion transactions in the first nine months of 2020 increased by 0.3 percent from 133.9 million MW in the first nine months of 2019 to 134.2 million MW in the first nine months of 2020. Internal up to congestion transactions in the first nine months of 2020 were 68.4 percent of all up to congestion transactions compared to 60.7 percent in the first nine months of 2019.

Figure 3-23 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.³⁴ 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. 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, 2018.³⁵ 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. UTC activity has increased, following that reduction.

³⁴ See 162 FERC ¶ 61,139 (2018).

³⁵ *Id.*

Figure 3-23 Monthly cleared up to congestion transactions by type (MW): January 2005 through September 2020

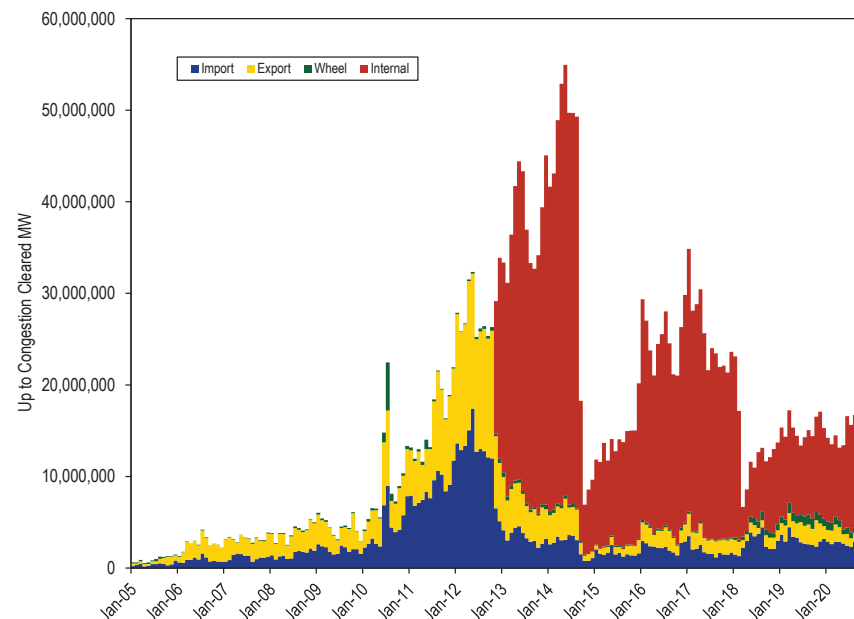
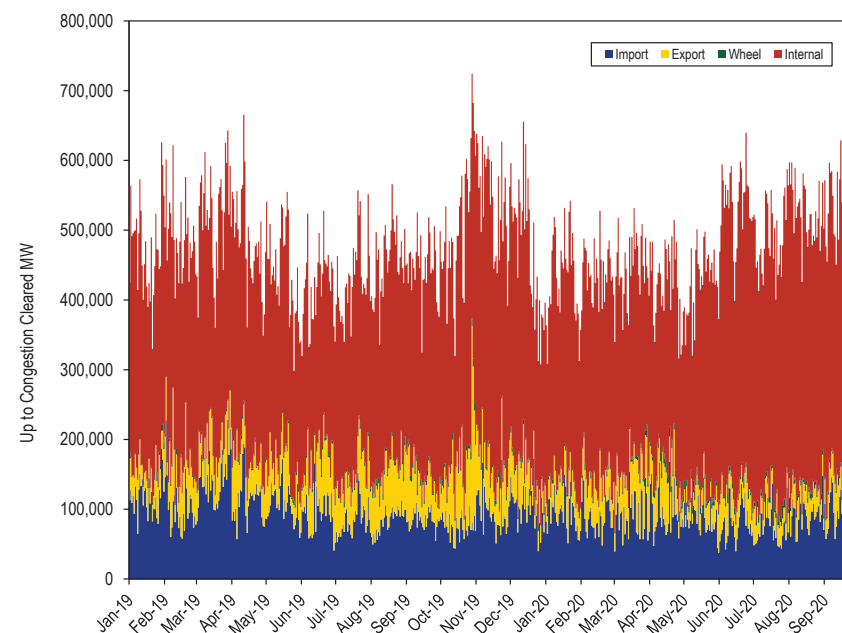


Figure 3-24 shows the daily cleared up to congestion MW by transaction type from January 1, 2019 through September 30, 2020.

Figure 3-24 Daily cleared up to congestion transaction by type (MW): January 2019 through September 2020



One of the goals of the February 2018 FERC order accepting PJM's proposal limiting UTC bidding to hubs, interfaces and residual aggregate metered load nodes, and limiting INC and DEC bidding to the same nodes plus active generation nodes, was to limit the opportunities for traders to profit from opportunities for false arbitrage in which price spreads between DA and RT result from differences in the models used to operate each market that cannot be corrected through virtual bidding.³⁶ A key assumption underlying the order

³⁶ PJM Interconnection, LLC, "Proposed Revisions To Reduce Bidding Points for Virtual Transactions," ER18-88, October 17, 2017, at 9-10: "Discrepancies between the models can occur for various reasons despite PJM's best attempts to minimize them...Because individual nodes are more highly impacted by modeling discrepancies than aggregated locations due to averaging, they are often locations where Virtual Transactions can profit. Profits collected by Virtual Transactions in these cases lead to additional costs for PJM members without any benefits."

is that the limited set of nodes available for virtual trading is sufficiently protected from such trades because price spreads resulting from modeling differences are mitigated by the averaging of prices over a large number of buses at aggregate nodes.³⁷ This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational differences between DA and RT since the February 2018 order.

The assumption that modeling differences are averaged out over aggregate nodes does not reflect the current list of available UTC bidding nodes. The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. MMU recommends eliminating UTC bidding at the following nodes: DPLEASTON_RESID_AGG, PENNPOWER_RESID_AGG, UGI_RESID_AGG, SMECO_RESID_AGG, and VINELAND_RESID_AGG. Prices at larger aggregate nodes can also be affected by transmission constraints, especially when constraints are violated and transmission penalty factors are applied in RT. Even when the same constraints are modeled in DA and RT, constraint violations in RT may result from differences in the DA and RT operational environments such as intra hourly ramping limitations, changes to constraint limits, and unit commitments and decommitments. Price spreads due to modeling or operational differences can be in the tens to hundreds of dollars, even when averaged over an aggregate node, and may persist for days or weeks. Virtual traders can often identify and profit from price spreads resulting from systematic modeling and operational differences between DA and RT affecting specific generators or aggregate nodes. The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues.

³⁷ 162 FERC ¶ 61,139, at 35-36: "We accept PJM's proposal to limit eligible bidding points for UTCs to hubs, residual metered load, and interfaces. First, we agree with the IMM's statement that PJM's proposal to limit the UTC bid locations to interfaces, zones, and hubs will minimize false arbitrage opportunities for UTCs currently being pursued through penny bids, as the effect of modeling differences between the day-ahead and real-time markets are minimized at these aggregates."

Market Performance

PJM locational marginal prices (LMPs) are a direct measure of market performance. The market performs optimally when the market structure provides incentives for market participants to behave competitively. In a competitive market, prices equal the short run marginal cost of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

LMP

The behavior of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources, surrogate constraints for reactive power and generator stability, or influence prices through manual interventions such as load biasing, changing constraint limits and penalty factors, and committing reserves beyond the requirement.

Real-time and day-ahead energy market load-weighted prices were 23.1 percent and 24.4 percent lower in the first nine months of 2020 than in the first nine months of 2019. As a combined result of weather, COVID-19 related demand reductions, and low gas prices, energy prices were lower in the first nine months of 2020 than in any comparable period since the beginning of PJM markets on April 1, 1999.

PJM real-time energy market prices decreased in the first nine months of 2020 compared to the first nine months of 2019. The average LMP was 24.1 percent lower in the first nine months of 2020 than in the first nine months of 2019, \$19.95 per MWh versus \$26.30 per MWh. The load-weighted average real-time LMP was 23.1 percent lower in the first nine months of 2020 than in the first nine months of 2019, \$21.22 per MWh versus \$27.60 per MWh.

The real-time load-weighted average LMP for the first nine months of 2020 was 14.8 percent lower than the real-time fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2020. If fuel and emission costs in the first nine months of 2020 had been the same as in the first nine months of 2019, holding everything else constant, the load-weighted LMP would have been higher, \$24.91 per MWh instead of the observed \$21.22 per MWh.

PJM day-ahead energy market prices decreased in the first nine months of 2020 compared to the first nine months of 2019. The day-ahead average LMP was 25.3 percent lower in the first nine months of 2020 than in the first nine months of 2019, \$19.72 per MWh versus \$26.41 per MWh. The day-ahead load-weighted average LMP was 24.4 percent lower in the first nine months of 2020 than in the first nine months of 2019, \$20.95 per MWh versus \$27.70 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 curve.³⁸ 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.³⁹

LMP may, at times, be set by transmission penalty factors, which exceed \$1,000 per MWh. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, the transmission limits may be violated in the market dispatch solution. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

38 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.

39 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).

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.⁴⁰

PJM Real-Time, Average LMP

Table 3-34 shows the PJM real-time, average LMP for the first nine months of 1998 through 2020.⁴¹

Table 3-34 Real-time, average LMP (Dollars per MWh): January through September, 1998 through 2020

(Jan-Sep)	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	\$23.18	\$16.86	\$36.00	NA	NA	NA
1999	\$31.65	\$18.77	\$83.28	36.6%	11.3%	131.3%
2000	\$25.88	\$18.22	\$23.70	(18.2%)	(2.9%)	(71.5%)
2001	\$36.00	\$25.48	\$51.30	39.1%	39.9%	116.4%
2002	\$28.13	\$20.70	\$23.92	(21.9%)	(18.8%)	(53.4%)
2003	\$40.42	\$33.68	\$26.00	43.7%	62.7%	8.7%
2004	\$43.85	\$39.99	\$21.82	8.5%	18.7%	(16.1%)
2005	\$54.69	\$44.53	\$33.67	24.7%	11.4%	54.3%
2006	\$51.79	\$43.50	\$34.93	(5.3%)	(2.3%)	3.7%
2007	\$57.34	\$49.40	\$35.52	10.7%	13.6%	1.7%
2008	\$71.94	\$61.33	\$41.64	25.4%	24.2%	17.2%
2009	\$37.42	\$33.00	\$17.92	(48.0%)	(46.2%)	(57.0%)
2010	\$46.13	\$37.89	\$26.99	23.3%	14.8%	50.6%
2011	\$45.79	\$37.05	\$32.25	(0.7%)	(2.2%)	19.5%
2012	\$32.45	\$28.78	\$21.94	(29.1%)	(22.3%)	(32.0%)
2013	\$37.30	\$32.44	\$22.84	15.0%	12.7%	4.1%
2014	\$52.72	\$36.06	\$74.17	41.3%	11.2%	224.8%
2015	\$35.96	\$27.88	\$30.75	(31.8%)	(22.7%)	(58.5%)
2016	\$27.43	\$23.61	\$15.73	(23.7%)	(15.3%)	(48.8%)
2017	\$28.79	\$25.28	\$16.81	5.0%	7.1%	6.9%
2018	\$36.52	\$27.26	\$33.22	26.8%	7.8%	97.6%
2019	\$26.30	\$23.39	\$17.69	(28.0%)	(14.2%)	(46.8%)
2020	\$19.95	\$17.87	\$10.48	(24.1%)	(23.6%)	(40.7%)

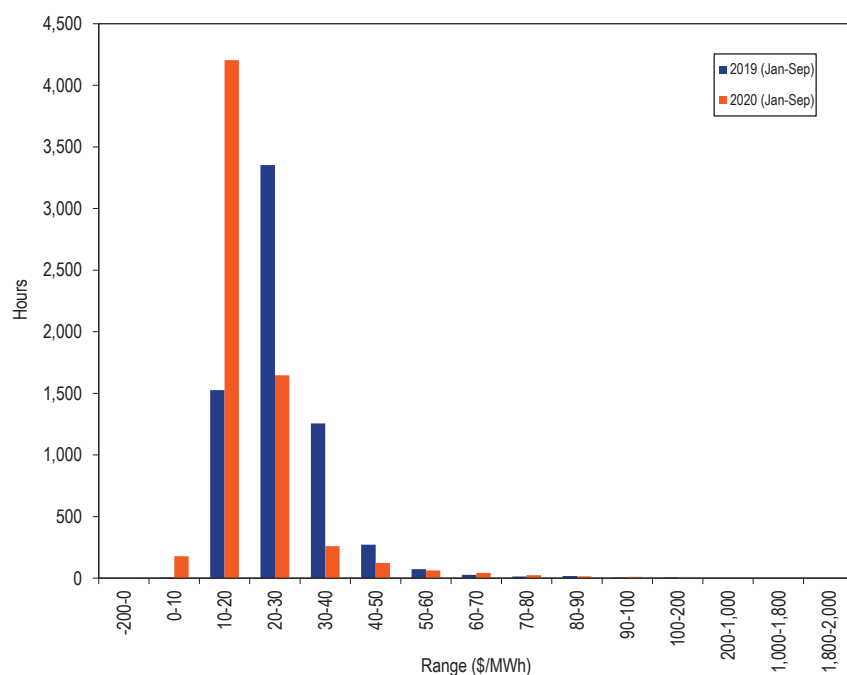
40 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

41 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

PJM Real-Time Average LMP Duration

Figure 3-25 shows the hourly distribution of PJM real-time average LMP for the first nine months of 2019 and 2020.

Figure 3-25 Average LMP for the Real-Time Energy Market: January through September, 2019 and 2020



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 3-35 shows the PJM real-time, load-weighted, average LMP for the first nine months of 1998 through 2020.

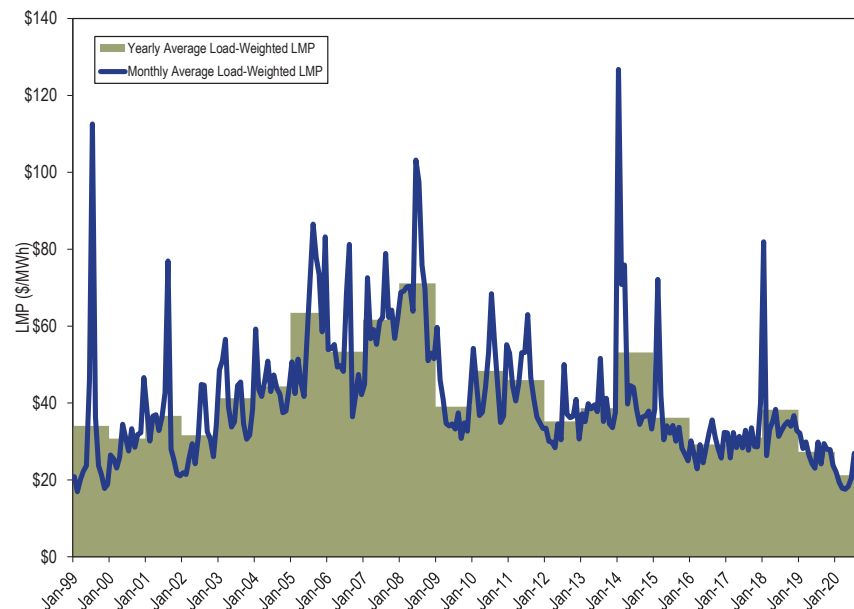
Table 3-35 Real-time, load-weighted, average LMP (Dollars per MWh): January through September, 1998 through 2020

(Jan-Sep)	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	\$26.06	\$18.20	\$44.65	NA	NA	NA
1999	\$38.65	\$20.02	\$104.17	48.3%	10.0%	133.3%
2000	\$28.49	\$19.30	\$26.89	(26.3%)	(3.6%)	(74.2%)
2001	\$40.96	\$28.18	\$64.57	43.8%	46.0%	140.1%
2002	\$31.95	\$23.09	\$29.14	(22.0%)	(18.1%)	(54.9%)
2003	\$43.57	\$38.17	\$26.53	36.3%	65.3%	(9.0%)
2004	\$46.44	\$43.03	\$21.89	6.6%	12.7%	(17.5%)
2005	\$60.44	\$50.10	\$36.52	30.2%	16.4%	66.9%
2006	\$56.39	\$46.82	\$40.70	(6.7%)	(6.5%)	11.4%
2007	\$61.83	\$55.12	\$37.98	9.7%	17.7%	(6.7%)
2008	\$77.27	\$66.73	\$43.80	25.0%	21.1%	15.3%
2009	\$39.57	\$34.57	\$19.04	(48.8%)	(48.2%)	(56.5%)
2010	\$49.91	\$40.33	\$29.65	26.2%	16.7%	55.7%
2011	\$49.48	\$38.72	\$37.02	(0.9%)	(4.0%)	24.8%
2012	\$35.02	\$29.84	\$25.44	(29.2%)	(22.9%)	(31.3%)
2013	\$39.75	\$33.61	\$26.47	13.5%	12.6%	4.0%
2014	\$58.60	\$37.93	\$86.22	47.4%	12.8%	225.8%
2015	\$38.94	\$29.09	\$33.95	(33.5%)	(23.3%)	(60.6%)
2016	\$29.32	\$24.60	\$17.13	(24.7%)	(15.4%)	(49.6%)
2017	\$30.36	\$26.26	\$18.81	3.5%	6.7%	9.8%
2018	\$39.43	\$28.78	\$36.82	29.9%	9.6%	95.7%
2019	\$27.60	\$24.23	\$18.69	(30.0%)	(15.8%)	(49.2%)
2020	\$21.22	\$18.66	\$11.53	(23.1%)	(23.0%)	(38.3%)

PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 3-26 shows the PJM real-time monthly and annual load-weighted LMP for January 1999 through September 2020.

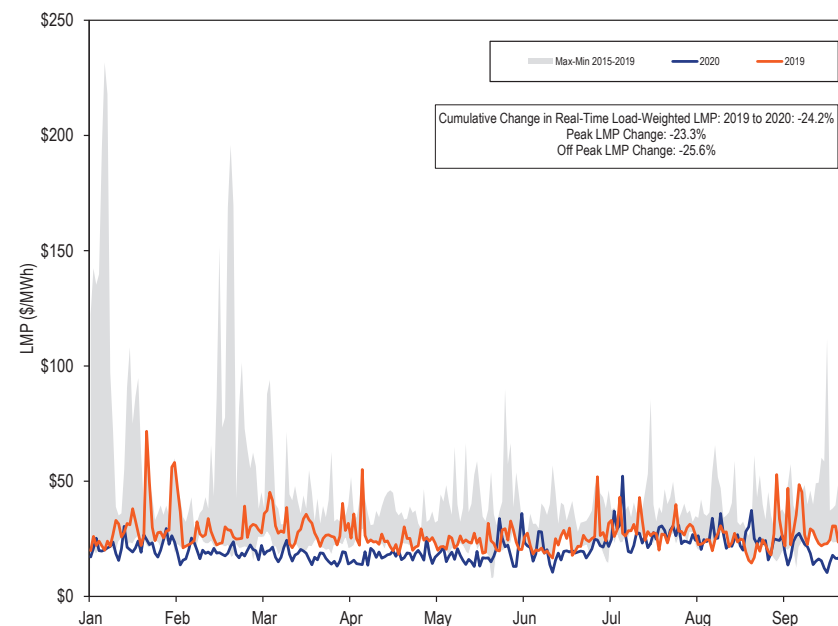
Figure 3-26 Real-time, monthly and annual, load-weighted, average LMP: January 1999 through September 2020



PJM Real-Time, Daily, Load-Weighted, Average LMP

Figure 3-27 shows the PJM real-time daily load-weighted LMP for the first nine months of 2019 and 2020.

Figure 3-27 Real-time, daily, load-weighted, average LMP: January through September, 2019 and 2020



PJM Real-Time, Monthly, Inflation Adjusted Load-Weighted, Average LMP

Figure 3-28 shows the PJM real-time monthly load-weighted, average LMP and inflation adjusted monthly load-weighted, average LMP from January 1998 through September 2020.⁴² Table 3-36 shows the PJM real-time load-weighted, average LMP and inflation adjusted load-weighted, average LMP for the first nine months of every year from 1998 through 2020. The PJM

⁴² 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 October 13, 2020)

real-time inflation adjusted load-weighted, average LMP for the first nine months of 2020 was the lowest value since PJM real-time markets started on April 1, 1999 at \$13.27 per MWh. The real-time inflation adjusted monthly load-weighted, average LMP for April 2020 was the lowest monthly value since PJM markets started in April 1999 at \$11.08 per MWh.

Figure 3-28 Real-time, monthly, load-weighted, average LMP unadjusted and adjusted for inflation: January 1998 through September 2020

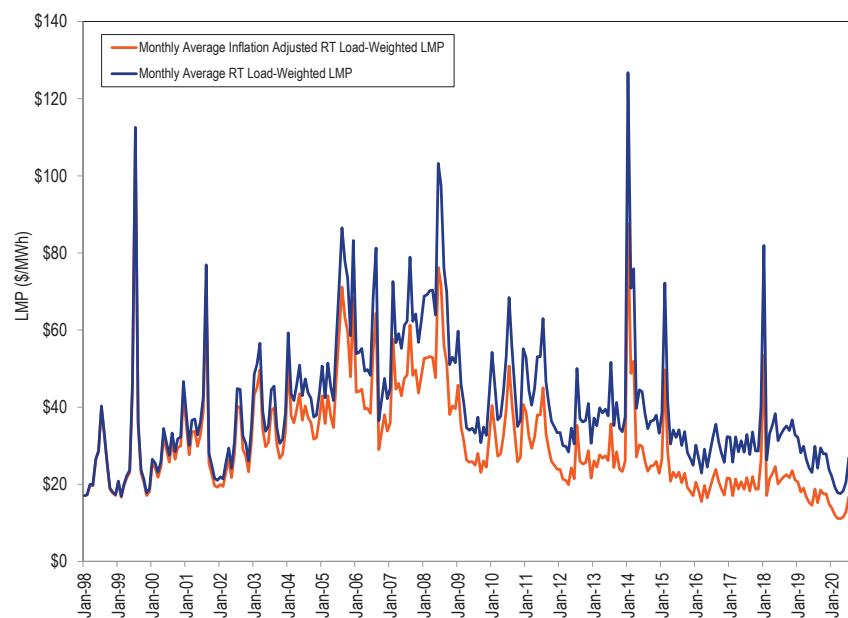


Table 3-36 Real-time, load-weighted, average LMP unadjusted and adjusted for inflation: January through September, 1998 through 2020

	Load-Weighted, Average LMP (Jan-Sep)	Inflation Adjusted Load-Weighted, Average LMP (Jan-Sep)
1998	\$26.06	\$25.86
1999	\$38.65	\$37.55
2000	\$28.49	\$26.82
2001	\$40.96	\$37.39
2002	\$31.95	\$28.72
2003	\$43.57	\$38.33
2004	\$46.44	\$39.85
2005	\$60.44	\$50.09
2006	\$56.39	\$45.16
2007	\$61.83	\$48.36
2008	\$77.27	\$57.70
2009	\$39.57	\$29.93
2010	\$49.91	\$37.04
2011	\$49.48	\$35.59
2012	\$35.02	\$24.68
2013	\$39.75	\$27.58
2014	\$58.60	\$40.11
2015	\$38.94	\$26.60
2016	\$29.32	\$19.77
2017	\$30.36	\$20.05
2018	\$39.43	\$25.45
2019	\$27.60	\$17.49
2020	\$21.22	\$13.27

Real-Time Dispatch and Pricing

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).⁴³ The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

The dispatch of reserves in LPC determines whether PJM implements scarcity pricing. Scarcity pricing transparency requires greater transparency around

⁴³ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Rev. 109 (Oct. 15, 2020)

the processes used to determine load bias in RT SCED, to approve RT SCED cases, and the use of RT SCED cases by LPC.

Real-Time SCED and LPC

LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. RT SCED solves to meet load and reserve requirements forecast at a future point in time, called the target time. On average, PJM operators approve more than one RT SCED case per five minute target time to send dispatch signals to resources. PJM uses a subset of these approved RT SCED cases in LPC to calculate real-time LMPs. As a result, a number of dispatch directives are not reflected in real-time energy market prices. Generally, LPC uses the latest available approved RT SCED case to calculate prices, regardless of the target dispatch time of the RT SCED case. However, LPC assigns the prices to a five minute interval that does not contain the target time of the RT SCED case it used.⁴⁴

Table 3-37 shows, on a monthly basis for the first nine months of 2020, the number of RT SCED case solutions, the number of solutions that were approved and the number and percent of approved solutions used in LPC. Until February 24, 2020, RT SCED was automatically executed every three minutes with operators having the ability to execute additional cases in between the automatically executed cases. Beginning February 24, 2020, PJM changed the RT SCED automatic execution frequency to once every four minutes. On June 22, 2020, PJM changed the RT SCED execution frequency to once every five minutes. PJM operators continue to have the ability to execute additional RT SCED cases. PJM retains the discretion to change the automatic RT SCED execution frequency at any time, as the frequency is not documented in the PJM market rules. Each execution of RT SCED produces three solutions, using three different levels of load bias. Since prices are calculated every five minutes while three SCED solutions are produced every three to five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period. PJM operators approve a subset of RT SCED solutions to send dispatch signals to resources at an irregular frequency. This lack of a direct and regular connection between the dispatch signal and

the price signal weakens the incentives to follow dispatch by generators, especially when RT SCED solutions that reflect shortage pricing are not used in calculating real-time prices in LPC.

Table 3-37 shows that in the first nine months of 2020 only 79.4 percent of approved RT SCED case solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices. The percent of approved solutions used for pricing increased from 69.0 percent to 78.7 percent from February to March and further increased to 88.6 percent in July with the decrease in the frequency of executed RT SCED cases.

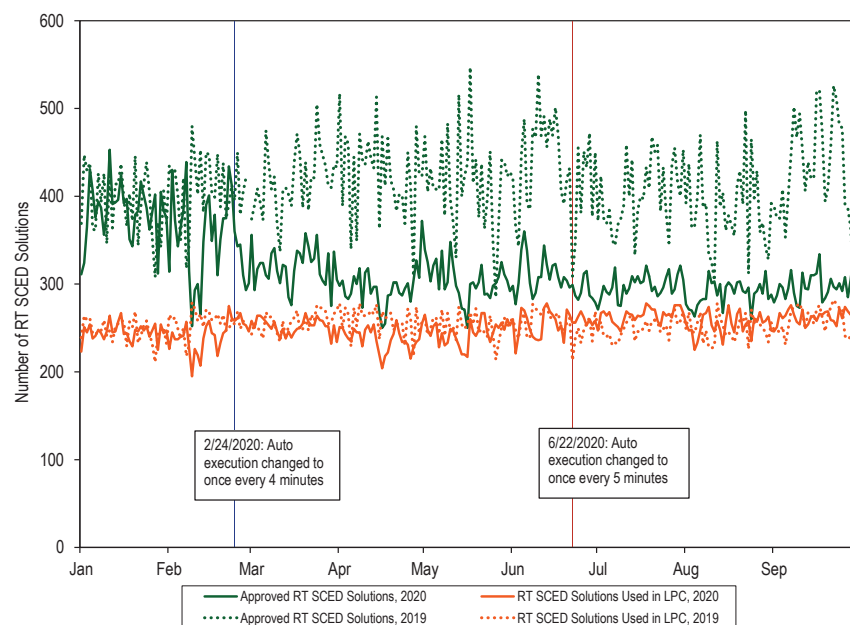
Figure 3-29 shows the daily number of RT SCED cases approved by PJM operators to send dispatch signals to resources and the subset of approved RT SCED cases that were used in LPC to calculate LMPs in the first nine months of 2019 and 2020, and the dates when the frequency of RT SCED auto execution was changed. Figure 3-29 shows that changing the auto execution frequency of RT SCED from once every three minutes to once every four minutes on February 24 reduced the number of approved RT SCED cases used to send dispatch signals in 2020 compared to 2019. This change in the frequency of approved solutions reduced the difference between the number of approved solutions and the number of solutions used in pricing in 2020 relative to 2019.

Table 3-37 RT SCED cases solved, approved and used in pricing: January through September, 2020

Month (2020)	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions
Jan	51,022	11,860	7,612	64.2%
Feb	46,247	10,149	7,005	69.0%
Mar	38,680	9,914	7,799	78.7%
Apr	36,543	8,888	7,132	80.2%
May	36,648	9,416	7,590	80.6%
Jun	34,327	9,165	7,666	83.6%
Jul	30,342	9,241	8,190	88.6%
Aug	30,775	8,962	7,868	87.8%
Sep	30,632	8,972	7,881	87.8%
Total	335,216	86,567	68,743	79.4%

⁴⁴ On October 15, 2020, PJM updated its pricing process to use an approved RT SCED case that solves for the same target time as the end of each five minute pricing interval to calculate LMPs applicable for that five minute interval.

Figure 3-29 Daily RT SCED solutions approved for dispatch signals and solutions used in pricing: January through September, 2019 and 2020



PJM's process for solving and approving RT SCED cases, and selecting approved RT SCED cases to use in LPC to calculate LMPs has inconsistencies that lead to downstream impacts for energy and reserve dispatch and settlements. PJM does not link dispatch and settlement intervals. RT SCED moved from automatically executing a case every three minutes to every five minutes in the first nine months of 2020, and cases are approved irregularly, while settlements are linked to five minute intervals. RT SCED solves the dispatch problem for a target time that is generally 10 to 14 minutes in the future. An RT SCED case is approved and sends dispatch signals to generators based on a 10 minute ramp time. The look ahead time for the load forecast and the look ahead time for the resource dispatch target do not match, and a new RT SCED case overrides the previously approved case before resources have time to achieve the previous target dispatch. In the first nine months of

2020, the interval that was priced in LPC was consistently before the target time from the RT SCED case used for the dispatch signal. LPC took the most recently approved RT SCED case to calculate LMPs. For example, the LPC case that calculates prices for the interval ending 10:05 EPT used an approved RT SCED case that sent MW dispatch signals for the target time of 10:10 EPT. This discrepancy creates a mismatch between the MW dispatch and real-time LMPs and undermines generators' incentive to follow dispatch. Under new RT SCED changes, PJM resolves the mismatch between LPC and the RT SCED target time, but prices no longer apply at the time when resources receive and follow that dispatch signal.⁴⁵ The timing remains incorrect until all three (the pricing interval, the dispatch interval, and the RT SCED target time) all correspond to one another.

The extent to which dispatch instructions from approved SCED solutions are reflected in concurrent prices in the PJM Real-Time Energy Market can be measured by comparing the start and end times when the dispatch instructions from the RT SCED solution were effective with the start and end times when the corresponding prices applied. The start time for a dispatch instruction is the time at which PJM approves the RT SCED solution, which triggers sending the resulting dispatch instructions to resources. The end time for a dispatch instruction is the time when the next RT SCED solution is approved. Dispatch and pricing would be perfectly aligned if the start and end times of the dispatch instructions from an approved RT SCED solution matched with the start and end times of the LPC pricing interval that used the same RT SCED solution. In a perfectly aligned five minute market, these times would both be five minutes in duration. However, RT SCED uses a 10 minute ramp time to dispatch resources, while LPC applies prices calculated to five minute intervals.

Table 3-38 shows the average duration of the period when dispatch instructions corresponded to the prevailing prices in the first nine months of 2020. PJM used the latest approved RT SCED solution available at the time of LPC execution, regardless of the SCED target time, to calculate prices for the current five minute pricing interval. The average duration of correspondence

⁴⁵ See Docket No. ER19-2573-000.

ranged from 3 minutes 11 seconds to 3 minutes 37 seconds from January through September, 2020, varying with changes to the frequency of automatic RT SCED execution. The percent of time that prices were consistent with the dispatch instructions was 67.2 to 69.9 percent, on average. This is far from the goal of 100 percent correspondence between five minute dispatch instructions and prices.

Table 3-38 Dispatch instructions reflected in prices: January through September, 2020

Period	RT SCED Automatic Execution Frequency	Dispatch Duration Reflected in Prices (Minutes:Seconds)	Percent Dispatch Duration Reflected in Prices
Jan 1, 2020 - Feb 23, 2020	Every 3 minutes	03:11	67.9%
Feb 24, 2020 - Jun 22, 2020	Every 4 minutes	03:27	67.2%
Jun 23, 2020 - Sep 30, 2020	Every 5 minutes	03:37	69.9%

For correct price signals and compensation, energy (LMP) and ancillary service pricing should align with the dispatch solution that is the basis for those prices and with the actual physical dispatch period during which that dispatch solution is realized for each and every real-time market interval.⁴⁶ This will only happen if RT SCED and LPC both use a five minute ramp time, consistent with the five minute real-time settlement period in PJM. The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. This will result in prices used to settle energy for the five minute interval that ends at the RT SCED dispatch target time.

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC cases with modified inputs. The PJM OATT allows for posting of recalculated real-time prices no later than 17:00 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 17:00

⁴⁶ See *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 (2016).

of the second business day following the operating day.⁴⁷ Table 3-39 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 2019 and 2020. In the first nine months of 2020, PJM recalculated LMPs for 804 five minute intervals or 1.02 percent of the total 78,900 five minute intervals in the first nine months. On August 3 and August 4 2020, PJM systems experienced a widespread outage. For nearly two hours on August 3 and for one hour on August 4, PJM dispatched resources manually. PJM later reconstructed LMPs based on the manual dispatch instructions that were sent out during the outage period.

Table 3-39 Number of five minute interval real-time prices recalculated: January 2019 through September 2020

Month	2019		2020	
	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated
January	8,928	10	8,928	193
February	8,064	14	8,352	12
March	8,916	51	8,916	110
April	8,640	19	8,640	50
May	8,928	19	8,928	37
June	8,640	28	8,640	64
July	8,928	69	8,928	67
August	8,928	79	8,928	251
September	8,640	45	8,640	20
October	8,928	115		
November	8,652	74		
December	8,928	11		
Total	105,120	534	78,900	804

Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.⁴⁸

⁴⁷ OA Schedule 1 § 1.10.8(e).

⁴⁸ See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of day-ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Day-Ahead, Average LMP

Table 3-40 shows the PJM day-ahead, average LMP in the first nine months of 2000 through 2020.

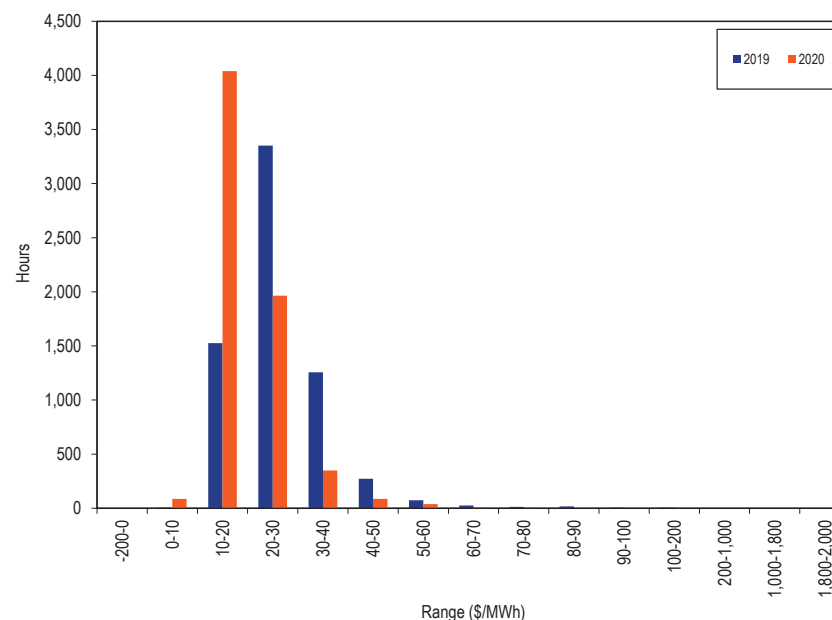
Table 3-40 Day-ahead, average LMP (Dollars per MWh): January through September, 2000 through 2020

(Jan-Sep)	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	\$28.19	\$21.10	\$19.10	NA	NA	NA
2001	\$36.07	\$30.02	\$34.25	28.0%	42.3%	79.4%
2002	\$28.29	\$22.54	\$19.09	(21.6%)	(24.9%)	(44.3%)
2003	\$41.20	\$38.24	\$22.02	45.6%	69.7%	15.4%
2004	\$42.64	\$42.07	\$17.47	3.5%	10.0%	(20.7%)
2005	\$54.48	\$46.67	\$28.83	27.8%	10.9%	65.1%
2006	\$50.45	\$46.32	\$24.93	(7.4%)	(0.8%)	(13.5%)
2007	\$54.24	\$51.40	\$24.95	7.5%	11.0%	0.1%
2008	\$71.43	\$66.38	\$33.11	31.7%	29.2%	32.7%
2009	\$37.35	\$35.29	\$14.32	(47.7%)	(46.8%)	(56.8%)
2010	\$45.81	\$41.03	\$19.59	22.7%	16.3%	36.8%
2011	\$45.14	\$40.20	\$22.68	(1.5%)	(2.0%)	15.7%
2012	\$32.16	\$30.10	\$14.54	(28.8%)	(25.1%)	(35.9%)
2013	\$37.50	\$34.70	\$16.96	16.6%	15.3%	16.6%
2014	\$53.76	\$39.92	\$58.98	43.4%	15.0%	247.8%
2015	\$36.67	\$30.56	\$25.21	(31.8%)	(23.4%)	(57.3%)
2016	\$27.90	\$25.23	\$11.37	(23.9%)	(17.4%)	(54.9%)
2017	\$28.90	\$26.60	\$10.73	3.6%	5.4%	(5.6%)
2018	\$36.04	\$29.75	\$25.12	24.7%	11.8%	134.2%
2019	\$26.41	\$24.76	\$9.58	(26.7%)	(16.8%)	(61.9%)
2020	\$19.72	\$18.47	\$6.99	(25.3%)	(25.4%)	(27.0%)

PJM Day-Ahead Average LMP Duration

Figure 3-30 shows the hourly distribution of PJM day-ahead average LMP in the first nine months of 2019 and 2020.

Figure 3-30 Average LMP for the Day-Ahead Energy Market: January through September, 2019 and 2020



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 3-41 shows the PJM day-ahead, load-weighted, average LMP in the first nine months of 2000 through 2020.

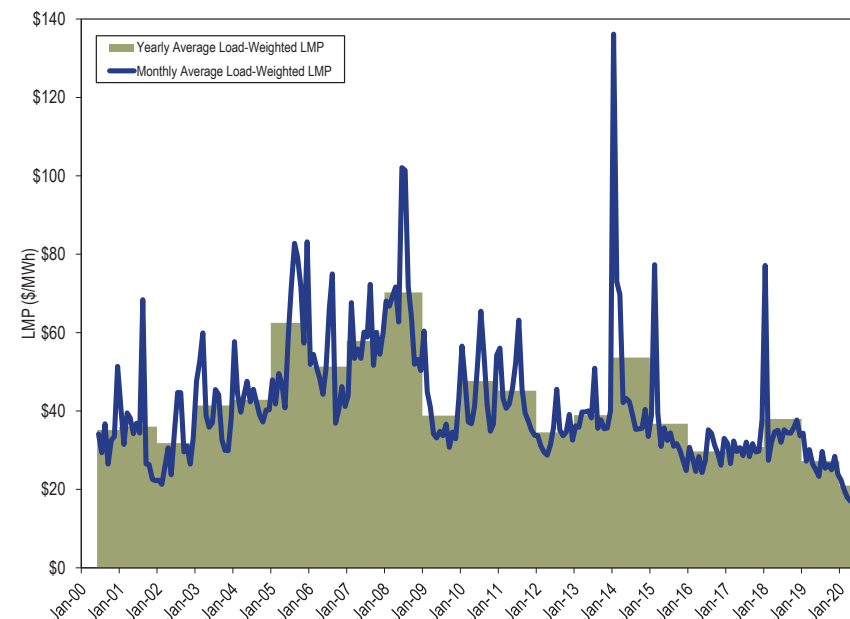
Table 3-41 Day-ahead, load-weighted, average LMP (Dollars per MWh): January through September, 2000 through 2020

(Jan-Sep)	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	NA	NA	NA	NA	NA	NA
2001	\$39.88	\$32.68	\$42.01	NA	NA	NA
2002	\$32.29	\$25.22	\$22.81	(19.0%)	(22.8%)	(45.7%)
2003	\$44.11	\$41.51	\$22.34	36.6%	64.6%	(2.1%)
2004	\$44.59	\$44.47	\$17.40	1.1%	7.1%	(22.1%)
2005	\$59.51	\$51.33	\$31.13	33.5%	15.4%	78.9%
2006	\$54.19	\$48.87	\$28.35	(8.9%)	(4.8%)	(8.9%)
2007	\$57.79	\$55.62	\$26.07	6.6%	13.8%	(8.0%)
2008	\$75.96	\$70.35	\$35.19	31.5%	26.5%	35.0%
2009	\$39.35	\$36.92	\$14.98	(48.2%)	(47.5%)	(57.4%)
2010	\$49.12	\$43.33	\$21.35	24.8%	17.4%	42.6%
2011	\$48.34	\$42.35	\$26.54	(1.6%)	(2.3%)	24.3%
2012	\$34.29	\$31.17	\$17.12	(29.1%)	(26.4%)	(35.5%)
2013	\$39.49	\$35.96	\$19.90	15.1%	15.4%	16.3%
2014	\$59.09	\$42.08	\$67.27	49.6%	17.0%	238.0%
2015	\$39.51	\$32.15	\$28.05	(33.1%)	(23.6%)	(58.3%)
2016	\$29.69	\$26.60	\$12.38	(24.8%)	(17.3%)	(55.8%)
2017	\$30.26	\$27.95	\$11.59	1.9%	5.1%	(6.4%)
2018	\$38.71	\$31.62	\$27.75	27.9%	13.1%	139.5%
2019	\$27.70	\$25.85	\$10.40	(28.4%)	(18.3%)	(62.5%)
2020	\$20.95	\$19.23	\$7.75	(24.4%)	(25.6%)	(25.4%)

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 3-31 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 1, 2000 through September 30, 2020.⁴⁹

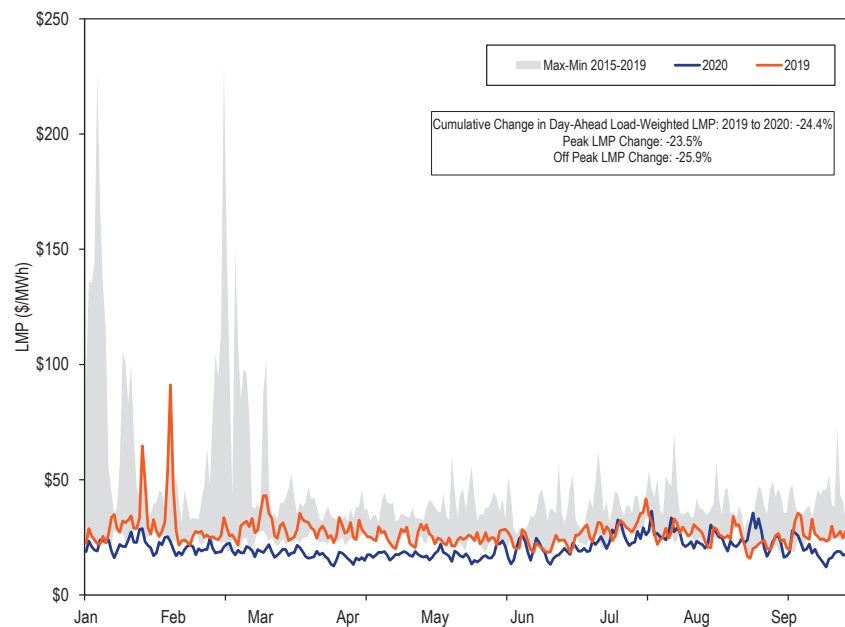
Figure 3-31 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through September 2020



⁴⁹ 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.

Figure 3-32 shows the PJM day-ahead daily load-weighted LMP for the first nine months of 2019 and 2020 compared to the historic five year price range.

Figure 3-32 Day-ahead, daily, load-weighted, average LMP: January through September, 2019 and 2020

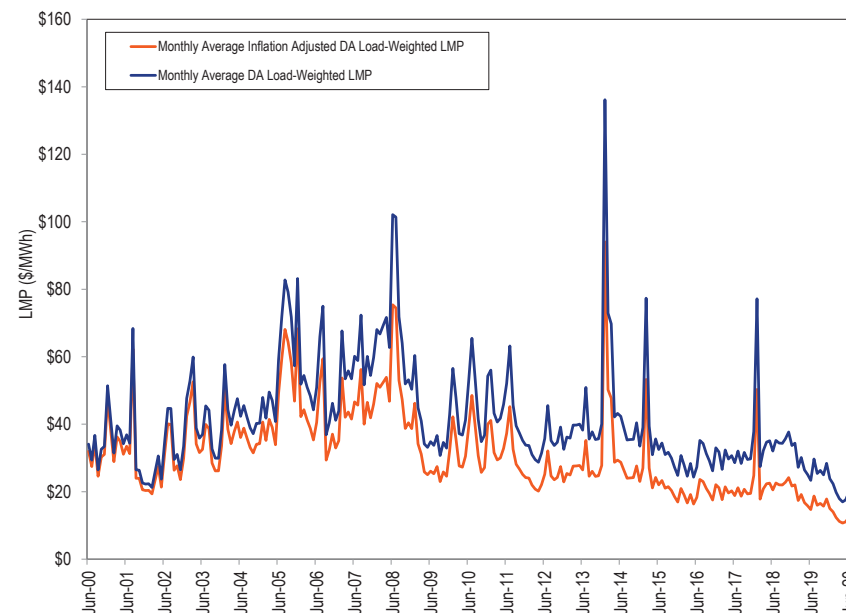


PJM Day-Ahead, Monthly, Inflation Adjusted Load-Weighted, Average LMP

Figure 3-33 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through September 2020.⁵⁰ Table 3-42 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for the first nine months of every year from 2001 through 2020. The PJM day-ahead inflation adjusted load-weighted average LMP for first nine

months of 2020 was the lowest first nine month value (\$13.09 per MWh) since PJM day-ahead markets started in 2000. The day-ahead inflation adjusted monthly load-weighted average LMP for April 2020 (\$10.70 per MWh) was the lowest monthly value since the day-ahead markets started.

Figure 3-33 Day-ahead, monthly, load-weighted, average LMP unadjusted and inflation adjusted: June 2000 through September 2020



⁵⁰ 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 October 13, 2020).

Table 3-42 Day-ahead, yearly, load-weighted, average LMP unadjusted and inflation adjusted: January through September, 2001 through 2020

	Load-Weighted, Average LMP (Jan-Sep)	Inflation Adjusted Load-Weighted, Average LMP (Jan-Sep)
2000	\$31.81	\$29.74
2001	\$39.88	\$36.41
2002	\$32.29	\$29.02
2003	\$44.11	\$38.81
2004	\$44.59	\$38.26
2005	\$59.51	\$49.32
2006	\$54.19	\$43.40
2007	\$57.79	\$45.19
2008	\$75.96	\$56.73
2009	\$39.35	\$29.77
2010	\$49.12	\$36.46
2011	\$48.34	\$34.79
2012	\$34.29	\$24.17
2013	\$39.49	\$27.40
2014	\$59.09	\$40.45
2015	\$39.51	\$26.99
2016	\$29.69	\$20.03
2017	\$30.26	\$19.99
2018	\$38.71	\$24.98
2019	\$27.70	\$17.55
2020	\$20.95	\$13.09

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 uplift charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags

in response time and modeling differences, 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, DEC and UTCs allow participants to profit from price differences between the day-ahead and real-time energy market. 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. 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 3-43 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 the first nine months of 2019 and 2020. In the first nine months of 2020, 50.6 percent of all cleared UTC transactions were net profitable. Of

cleared UTC transactions, 61.8 percent were profitable on the source side and 38.4 were profitable on the sink side but only 7.3 percent were profitable on both the source and sink side.

Table 3-43 Cleared UTC profitability by source and sink point: January through September, 2019 and 2020⁵¹

(Jan-Sep)	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
2019	6,953,487	3,399,845	4,656,194	2,329,766	450,234	48.9%	67.0%	33.5%	6.5%
2020	7,465,316	3,780,403	4,615,744	2,865,255	543,347	50.6%	61.8%	38.4%	7.3%

Table 3-44 shows the number of cleared INC and DEC transactions and the number of profitable cleared transactions in the first nine months of 2019 and 2020. Of cleared INC and DEC transactions in the first nine months of 2020, 64.2 percent of INCs were profitable and 39.7 percent of DEC were profitable.

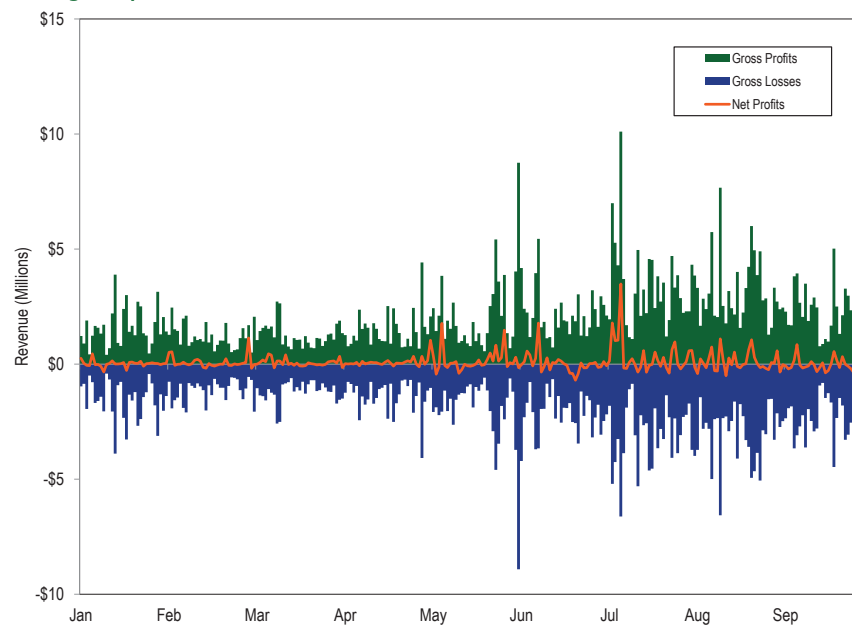
Table 3-44 Cleared INC and DEC profitability: January through September, 2019 and 2020

(Jan-Sep)	Profitable INC			Profitable DEC		
	Cleared INC	Profitable INC	Percent	Cleared DEC	Profitable DEC	Profitable DEC Percent
2019	1,628,241	1,105,533	67.9%	1,364,023	482,371	35.4%
2020	1,647,638	1,058,116	64.2%	2,184,367	866,237	39.7%

⁵¹ Calculations exclude PJM administrative charges.

Figure 3-34 shows total UTC daily gross profits, the sum of all positive profit UTC transactions, gross losses, the sum of all negative profit UTC transactions, and net profits and losses in the first nine months of 2020.

Figure 3-34 UTC daily gross profits and losses and net profits: January through September, 2020⁵²



⁵² Calculations exclude PJM administrative charges.

Figure 3-35 shows the cumulative UTC daily profits for each year from 2013 through September 2020.

Figure 3-35 Cumulative daily UTC profits: 2013 through September 2020

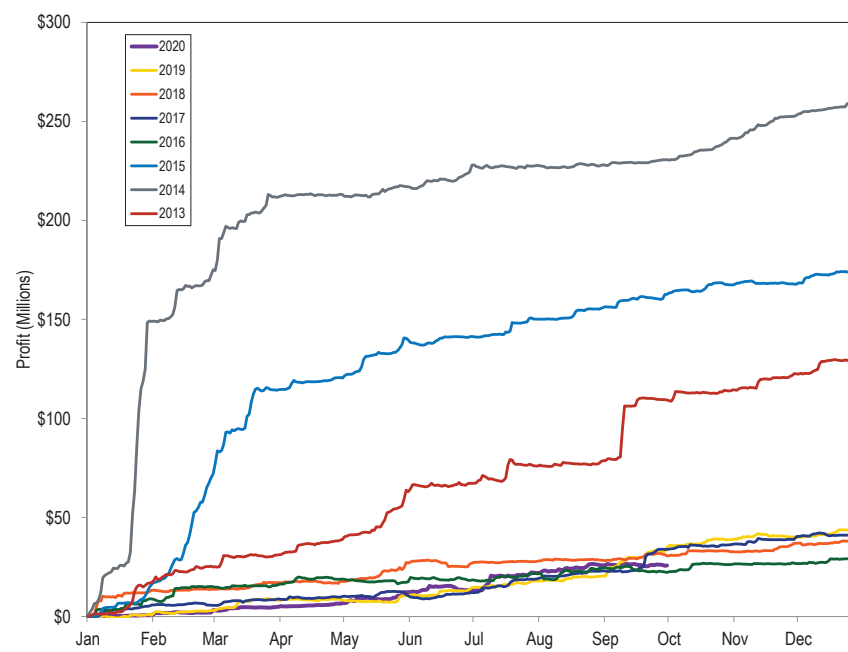


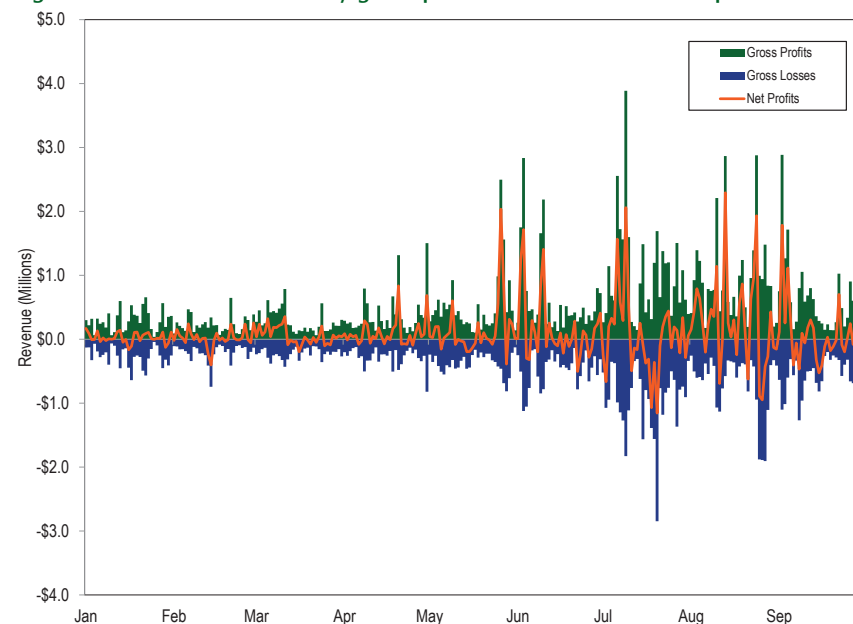
Table 3-45 shows UTC profits by month for 2013 through June 2020. May 2016, September 2016, February 2017, June 2018 and September 2020 were the only months in this seven year period in which monthly profits were negative.

Table 3-45 UTC profits by month: January 2013 through September 2020

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	\$17,048,654	\$8,304,767	\$5,629,392	\$7,560,773	\$25,219,947	\$3,484,372	\$8,781,526	\$2,327,168	\$31,160,618	\$4,393,583	\$8,730,701	\$6,793,990	\$129,435,490
2014	\$148,973,434	\$23,235,621	\$39,448,716	\$1,581,786	\$3,851,636	\$7,353,460	\$3,179,356	\$287,824	\$2,727,763	\$10,889,817	\$11,042,443	\$6,191,101	\$258,762,955
2015	\$16,132,319	\$53,830,098	\$44,309,656	\$6,392,939	\$19,793,475	\$824,817	\$8,879,275	\$5,507,608	\$6,957,012	\$4,852,454	\$392,876	\$6,620,581	\$174,493,110
2016	\$8,874,363	\$6,118,477	\$1,119,457	\$2,768,591	(\$1,333,563)	\$841,706	\$3,128,346	\$3,200,573	(\$2,518,408)	\$4,216,717	\$254,684	\$3,271,368	\$29,942,312
2017	\$5,716,757	(\$17,860)	\$3,083,167	\$944,939	\$1,245,988	\$868,400	\$7,053,390	\$4,002,063	\$10,960,012	\$2,360,817	\$2,716,950	\$15,936,217	\$54,870,839
2018	\$13,184,346	\$506,509	\$3,410,577	\$688,796	\$9,499,735	(\$768,614)	\$1,163,380	\$692,736	\$2,845,649	\$1,452,515	\$4,339,363	\$1,358,446	\$38,373,436
2019	\$574,901	\$2,407,307	\$5,287,985	\$332,036	\$1,833,879	\$3,382,009	\$4,066,461	\$2,442,971	\$12,599,278	\$5,914,042	\$1,171,145	\$3,722,403	\$43,734,418
2020	\$664,972	\$2,497,856	\$1,720,037	\$1,865,139	\$5,508,276	\$1,123,429	\$8,573,276	\$3,957,296	(\$141,240)				\$25,769,040

Figure 3-36 shows total INC and DEC daily gross profits, the sum of all positive profit transactions, gross losses, the sum of all negative profit transactions, and net profits and losses in the first nine months of 2020.

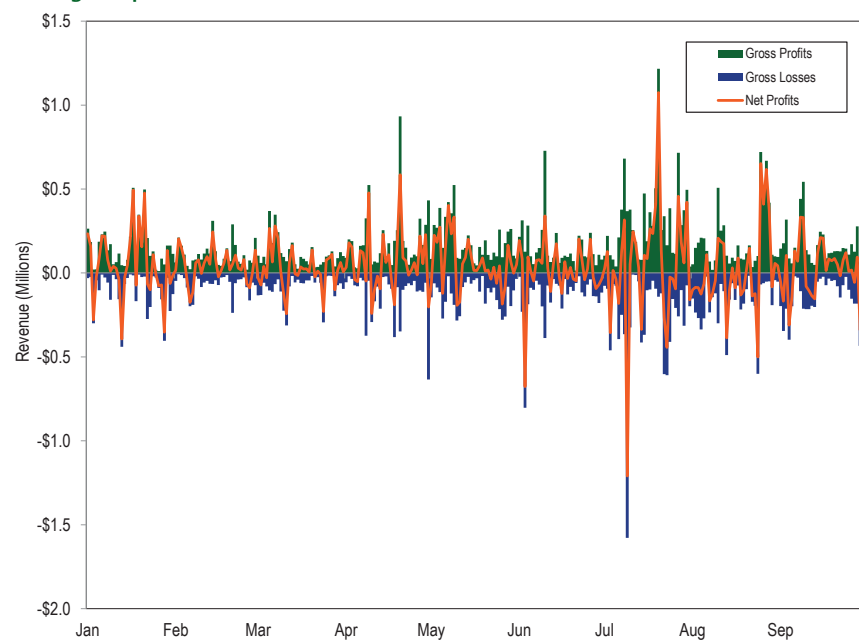
Figure 3-36 INC and DEC daily gross profits and losses and net profits: January through September, 2020⁵³



⁵³ Calculations exclude PJM administrative charges.

Figure 3-37 shows total INC daily gross profits and losses and net profits and losses in the first nine months of 2020.

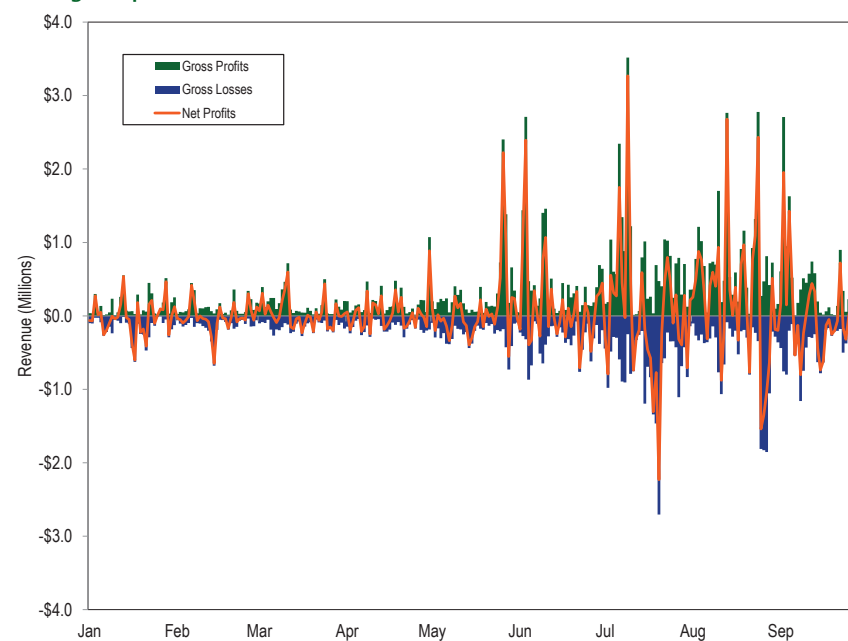
Figure 3-37 INC daily gross profits and losses and net profits: January through September, 2020⁵⁴



⁵⁴ Calculations exclude PJM administrative charges.

Figure 3-38 shows total DEC daily gross profits and losses and net profits and losses in the first nine months of 2020.

Figure 3-38 DEC daily gross profits and losses and net profits: January through September, 2020⁵⁵



⁵⁵ Calculations exclude PJM administrative charges.

Figure 3-39 shows the cumulative INC and DEC daily profits for January 1, through September 30, 2020.

Figure 3-39 Cumulative daily INC and DEC profits: January through September, 2020

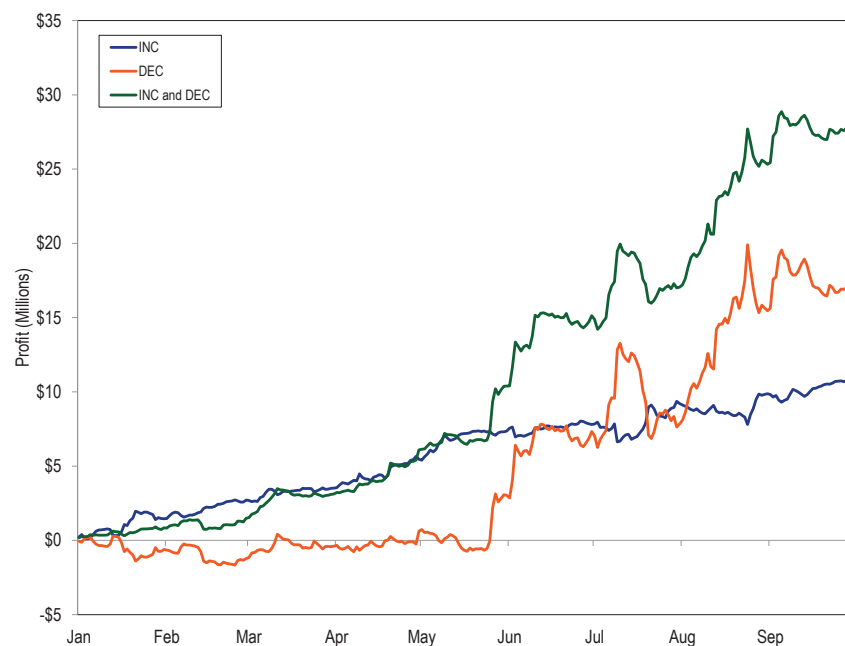


Table 3-46 shows INC and DEC profits by month for January through September 2020.

Table 3-46 INC and DEC profits by month: January through September, 2020

	January	February	March	April	May	June	July	August	September	Total
INC	\$1,455,089	\$1,259,625	\$803,233	\$1,944,109	\$1,893,382	\$452,115	\$1,402,597	\$659,910	\$749,252	\$10,619,313
DEC	(\$614,734)	(\$606,579)	\$833,364	\$1,017,052	\$2,404,925	\$4,289,805	\$522,583	\$7,609,006	\$1,857,777	\$17,313,199
INC and DEC	\$840,356	\$653,046	\$1,636,597	\$2,961,161	\$4,298,306	\$4,741,920	\$1,925,180	\$8,268,916	\$2,607,029	\$27,932,511

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, about modeling differences and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes. PJM markets do not provide a mechanism that could ever result in convergence in the presence of modeling differences.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the day-ahead energy market. Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis.

Table 3-47 shows that the difference between the average real-time price and the average day-ahead price was $-\$0.11$ per MWh in the first nine months of 2019 and $\$0.23$ per MWh in the first nine months of 2020. The difference between average peak real-time price and the average peak day-ahead price was $-\$0.32$ per MWh in the first nine months of 2019 and $\$0.32$ per MWh in the first nine months of 2020.

Table 3-47 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2019 and 2020⁵⁶

	2019 (Jan-Sep)				2020 (Jan-Sep)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	\$26.41	\$26.30	(\$0.11)	(0.4%)	\$19.72	\$19.95	\$0.23	1.2%
Median	\$24.76	\$23.39	(\$1.37)	(5.8%)	\$18.47	\$17.87	(\$0.60)	(3.4%)
Standard deviation	\$9.58	\$17.69	\$8.11	45.9%	\$6.99	\$10.48	\$3.49	33.3%
Peak average	\$30.72	\$30.39	(\$0.32)	(1.1%)	\$23.13	\$23.46	\$0.32	1.4%
Peak median	\$28.38	\$26.03	(\$2.34)	(9.0%)	\$20.96	\$20.10	(\$0.86)	(4.3%)
Peak standard deviation	\$9.98	\$20.67	\$10.69	51.7%	\$7.43	\$12.33	\$4.90	39.8%
Off peak average	\$22.63	\$22.71	\$0.08	0.3%	\$16.69	\$16.85	\$0.16	0.9%
Off peak median	\$21.24	\$20.53	(\$0.71)	(3.5%)	\$15.86	\$15.68	(\$0.18)	(1.2%)
Off peak standard deviation	\$7.37	\$13.61	\$6.25	45.9%	\$4.87	\$7.21	\$2.34	32.5%

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 3-48 shows the difference between the real-time load-weighted and the day-ahead load-weighted energy market prices for the first nine months of 2001 through 2020.

Table 3-48 Day-ahead load-weighted and real-time load-weighted average LMP (Dollars per MWh): January through September, 2001 through 2020

(Jan-Sep)	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	\$36.07	\$36.00	(\$0.07)	(0.2%)
2002	\$28.29	\$28.13	(\$0.16)	(0.6%)
2003	\$41.20	\$40.42	(\$0.77)	(1.9%)
2004	\$42.64	\$43.85	\$1.22	2.9%
2005	\$54.48	\$54.69	\$0.21	0.4%
2006	\$50.45	\$51.79	\$1.34	2.7%
2007	\$54.24	\$57.34	\$3.10	5.7%
2008	\$71.43	\$71.94	\$0.51	0.7%
2009	\$37.35	\$37.42	\$0.08	0.2%
2010	\$45.81	\$46.13	\$0.32	0.7%
2011	\$45.14	\$45.79	\$0.65	1.4%
2012	\$32.16	\$32.45	\$0.29	0.9%
2013	\$37.50	\$37.30	(\$0.20)	(0.5%)
2014	\$53.76	\$52.72	(\$1.04)	(1.9%)
2015	\$36.67	\$35.96	(\$0.70)	(1.9%)
2016	\$27.90	\$27.43	(\$0.47)	(1.7%)
2017	\$28.90	\$28.79	(\$0.11)	(0.4%)
2018	\$36.04	\$36.52	\$0.48	1.3%
2019	\$26.41	\$26.30	(\$0.11)	(0.4%)
2020	\$19.72	\$19.95	\$0.23	1.2%

⁵⁶ The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 3-49 includes frequency distributions of the differences between PJM real-time, load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the first nine months of 2019 and 2020.

Table 3-49 Frequency distribution by hours of real-time, load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): January through September, 2019 and 2020

LMP	2019 (Jan-Sep)		2020 (Jan-Sep)	
	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%	0	0.00%
(\$150) to (\$100)	0	0.00%	0	0.00%
(\$100) to (\$50)	5	0.08%	0	0.00%
(\$50) to \$0	4,400	67.24%	4,086	62.14%
\$0 to \$50	2,102	99.33%	2,467	99.67%
\$50 to \$100	22	99.66%	20	99.97%
\$100 to \$150	14	99.88%	1	99.98%
\$150 to \$200	1	99.89%	1	100.00%
\$200 to \$250	3	99.94%	0	100.00%
\$250 to \$300	1	99.95%	0	100.00%
\$300 to \$350	1	99.97%	0	100.00%
\$350 to \$400	0	99.97%	0	100.00%
\$400 to \$450	0	99.97%	0	100.00%
\$450 to \$500	0	99.97%	0	100.00%
\$500 to \$750	2	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 3-40 shows the hourly differences between day-ahead and real-time hourly LMP in the first nine months of 2020.

Figure 3-40 Real-time hourly LMP minus day-ahead hourly LMP: January through September, 2020

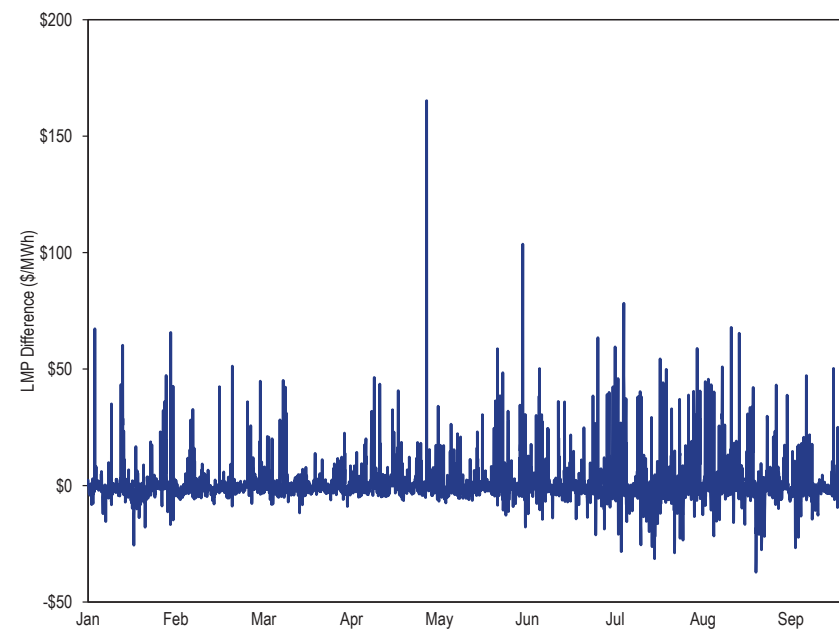
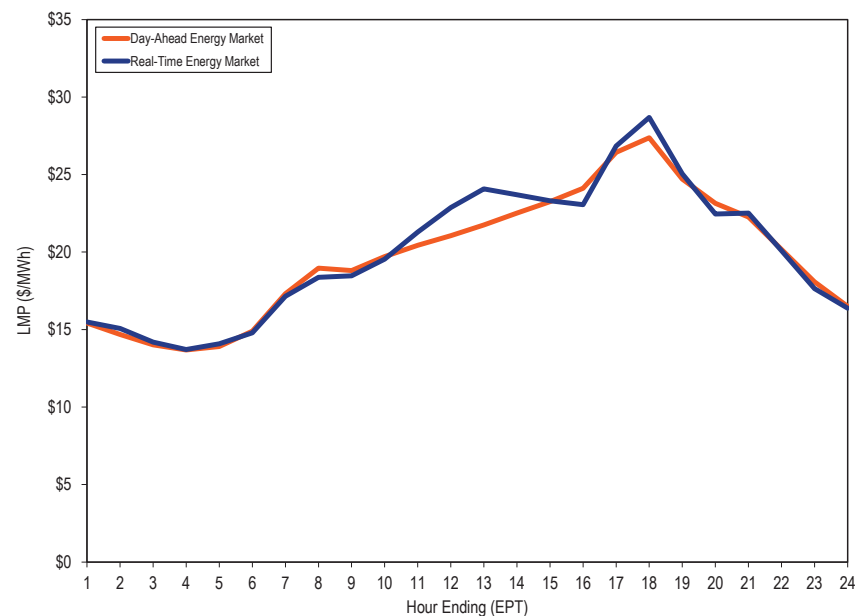


Figure 3-41 shows day-ahead and real-time load-weighted LMP on an average hourly basis for the first nine months of 2020. Hour ending 13 had the largest difference between the DA and RT load-weighted LMP, at \$2.34 per MWh, and hour ending 4 had the smallest difference at \$0.03 per MWh.

Figure 3-41 System hourly average LMP: January through September, 2020



Zonal LMP and Dispatch

Table 3-50 shows zonal real-time, and real-time, load-weighted, average LMP in the first nine months of 2019 and 2020.

Table 3-50 Zonal real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through September, 2019 and 2020

Zone	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change
AECO	\$24.61	\$17.80	(27.7%)	\$25.95	\$19.26	(25.8%)
AEP	\$26.94	\$20.53	(23.8%)	\$28.19	\$21.65	(23.2%)
APS	\$26.71	\$20.75	(22.3%)	\$28.02	\$22.01	(21.4%)
ATSI	\$26.96	\$20.94	(22.3%)	\$28.12	\$22.37	(20.4%)
BGE	\$29.11	\$22.91	(21.3%)	\$31.03	\$24.97	(19.5%)
ComEd	\$24.04	\$18.50	(23.0%)	\$25.20	\$19.87	(21.2%)
DAY	\$27.87	\$21.30	(23.6%)	\$29.32	\$22.63	(22.8%)
DEOK	\$26.88	\$20.46	(23.9%)	\$28.23	\$21.71	(23.1%)
DLCO	\$27.64	\$20.85	(24.6%)	\$29.16	\$22.16	(24.0%)
Dominion	\$26.43	\$19.70	(25.5%)	\$29.26	\$22.17	(24.3%)
DPL	\$26.59	\$21.12	(20.6%)	\$27.79	\$22.85	(17.8%)
EKPC	\$26.46	\$20.33	(23.2%)	\$28.07	\$21.53	(23.3%)
JCPL	\$24.58	\$18.10	(26.4%)	\$26.10	\$19.73	(24.4%)
Met-Ed	\$25.43	\$19.14	(24.7%)	\$26.92	\$20.65	(23.3%)
OVEC	\$25.97	\$19.89	(23.4%)	\$26.33	\$19.98	(24.1%)
PECO	\$24.30	\$17.50	(28.0%)	\$25.67	\$18.64	(27.4%)
PENELEC	\$25.54	\$19.47	(23.8%)	\$26.56	\$20.48	(22.9%)
Pepco	\$28.15	\$21.21	(24.7%)	\$29.79	\$22.77	(23.5%)
PPL	\$23.89	\$17.66	(26.1%)	\$25.21	\$18.63	(26.1%)
PSEG	\$24.89	\$18.03	(27.6%)	\$26.06	\$19.13	(26.6%)
RECO	\$25.09	\$18.47	(26.4%)	\$26.37	\$20.05	(24.0%)
PJM	\$26.30	\$19.95	(24.1%)	\$27.60	\$21.22	(23.1%)

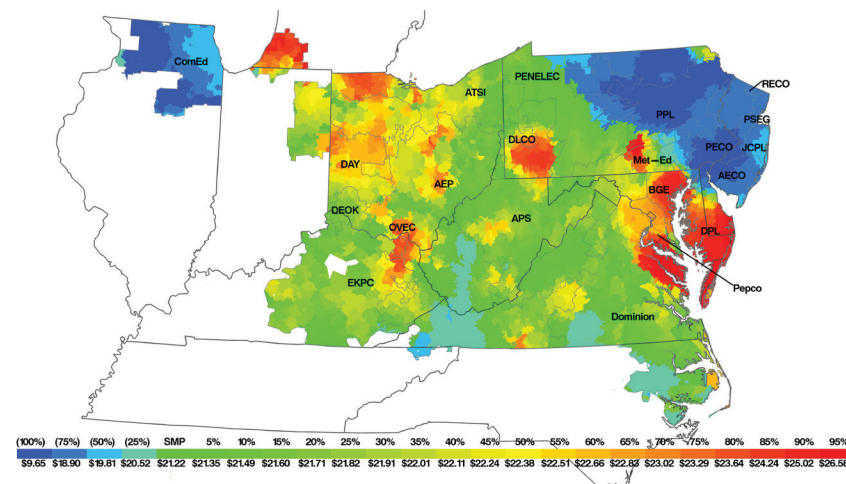
Table 3-51 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in the first nine months of 2019 and 2020.

Table 3-51 Zonal day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): January through September, 2019 and 2020

Zone	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change
AECO	\$24.55	\$17.50	(28.7%)	\$25.76	\$18.88	(26.7%)
AEP	\$26.92	\$20.34	(24.4%)	\$28.23	\$21.46	(24.0%)
APS	\$26.92	\$20.35	(24.4%)	\$28.22	\$21.51	(23.8%)
ATSI	\$27.24	\$20.44	(25.0%)	\$28.42	\$21.59	(24.0%)
BGE	\$29.48	\$22.75	(22.8%)	\$31.38	\$24.66	(21.4%)
ComEd	\$24.26	\$18.57	(23.5%)	\$25.35	\$19.81	(21.9%)
DAY	\$28.01	\$21.30	(24.0%)	\$29.43	\$22.64	(23.1%)
DEOK	\$27.28	\$20.57	(24.6%)	\$28.77	\$21.93	(23.8%)
DLCO	\$28.04	\$20.74	(26.0%)	\$29.70	\$22.13	(25.5%)
Dominion	\$26.12	\$18.76	(28.2%)	\$28.73	\$20.86	(27.4%)
DPL	\$26.86	\$20.70	(22.9%)	\$28.02	\$22.24	(20.6%)
EKPC	\$26.43	\$20.17	(23.7%)	\$28.11	\$21.67	(22.9%)
JCPL	\$24.47	\$17.63	(28.0%)	\$25.75	\$18.96	(26.4%)
Met-Ed	\$25.08	\$18.61	(25.8%)	\$26.35	\$19.96	(24.3%)
OVEC	\$25.98	\$19.79	(23.8%)	\$29.70	\$21.04	(29.2%)
PECO	\$24.04	\$17.28	(28.1%)	\$25.19	\$18.35	(27.2%)
PENELEC	\$25.97	\$19.38	(25.4%)	\$27.38	\$20.70	(24.4%)
Pepco	\$28.61	\$21.19	(25.9%)	\$30.33	\$22.83	(24.7%)
PPL	\$23.86	\$17.44	(26.9%)	\$25.05	\$18.35	(26.8%)
PSEG	\$24.81	\$17.73	(28.5%)	\$25.94	\$18.78	(27.6%)
RECO	\$25.34	\$18.17	(28.3%)	\$26.78	\$19.73	(26.3%)
PJM	\$26.41	\$19.72	(25.3%)	\$27.70	\$20.95	(24.4%)

Figure 3-42 is a map of the real-time, load-weighted, average LMP in the first nine months of 2020. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP.

Figure 3-42 Real-time, load-weighted, average LMP: January through September, 2020



Net Generation by Zone

Figure 3-43 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2020. Figure 3-43 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. Table 3-52 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2019 and 2020.

Figure 3-43 Map of real-time generation, less real-time load, by zone: January through September, 2020⁵⁷

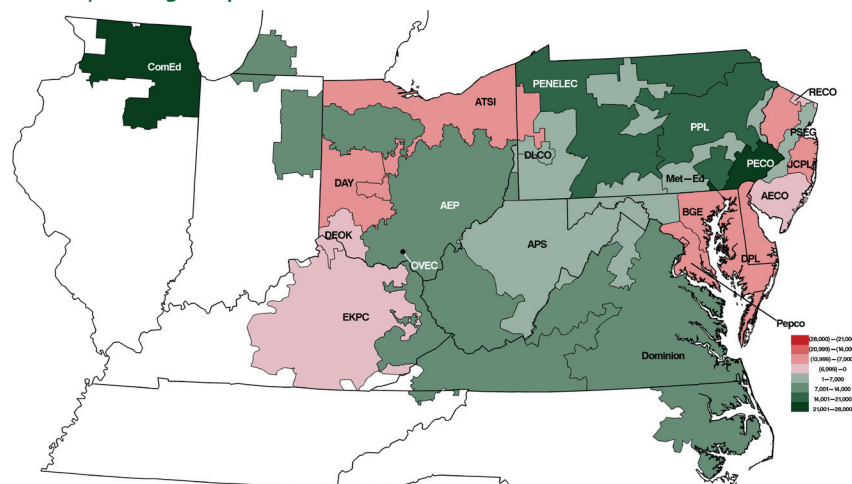


Table 3-52 Real-time generation less real-time load by zone (GWh): January through September, 2019 and 2020

Zonal Generation and Load (GWh)						
Jan-Sep	2019			2020		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	4,628.6	7,706.6	(3,078.0)	2,927.2	7,349.9	(4,422.7)
AEP	112,736.6	95,294.1	17,442.5	103,165.6	90,941.6	12,224.0
APS	38,336.0	37,010.6	1,325.3	36,509.9	35,358.0	1,151.9
ATSI	30,033.3	49,525.0	(19,491.6)	33,957.4	47,350.2	(13,392.8)
BGE	13,670.1	23,908.7	(10,238.6)	12,275.1	22,688.8	(10,413.7)
ComEd	101,601.2	71,864.4	29,736.8	96,705.0	69,523.7	27,181.3
DAY	827.8	13,057.7	(12,230.0)	760.9	12,416.0	(11,655.1)
DEOK	15,239.3	20,554.2	(5,314.9)	13,686.1	19,433.7	(5,747.6)
Dominion	76,091.4	76,949.2	(857.9)	82,005.0	74,742.5	7,262.5
DPL	4,265.1	14,052.0	(9,786.9)	4,352.6	13,563.6	(9,211.0)
DLCO	12,577.3	10,224.9	2,352.4	11,753.0	9,852.0	1,901.0
EKPC	5,218.7	9,579.6	(4,360.9)	6,267.9	9,235.7	(2,967.8)
JCPL	8,811.3	16,953.4	(8,142.2)	6,811.0	16,573.5	(9,762.5)
Met-Ed	18,219.4	11,731.7	6,487.7	15,674.6	11,368.0	4,306.6
OVEC	8,169.2	97.9	8,071.3	6,438.6	83.4	6,355.2
PECO	52,836.8	30,342.4	22,494.4	56,344.3	28,667.0	27,677.3
PENELEC	30,321.2	12,649.6	17,671.6	28,158.2	12,366.5	15,791.7
Pepco	9,092.4	22,660.4	(13,567.9)	8,901.6	20,765.2	(11,863.5)
PPL	48,893.1	30,485.2	18,407.8	46,712.3	29,618.3	17,093.9
PSEG	34,257.8	32,754.0	1,503.8	32,982.8	31,729.9	1,252.9
RECO	0.0	1,104.0	(1,104.0)	0.0	1,072.0	(1,072.0)

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

⁵⁷ 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>.

withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during intervals when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during intervals when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-53 shows PJM generation by fuel source in GWh for the first nine months of 2019 and 2020. In the first nine months of 2020, generation from coal units decreased 24.9 percent, generation from natural gas units increased 9.5 percent, and generation from oil increased 1.8 percent compared to the first nine months of 2019. Wind and solar output rose by 9.2 percent compared to the first nine months of 2019, supplying 3.4 percent of PJM energy in the first nine months of 2020. Output from coal fell twice as much as total PJM output, but was offset by the increase in output from natural gas.

Table 3-53 Generation (By fuel source (GWh)): January through September, 2019 and 2020^{58 59 60}

	2019 (Jan – Sep)		2020 (Jan – Sep)		Change in Output
	GWh	Percent	GWh	Percent	
Coal	155,308.3	24.5%	116,574.1	19.0%	(24.9%)
Bituminous	132,915.7	21.0%	106,220.5	17.3%	(20.1%)
Sub Bituminous	17,661.8	2.8%	6,484.5	1.1%	(63.3%)
Other Coal	4,730.8	0.7%	3,869.1	0.6%	(18.2%)
Nuclear	210,542.6	33.2%	207,426.7	33.7%	(1.5%)
Gas	229,892.5	36.2%	251,391.8	40.9%	9.4%
Natural Gas CC	211,827.6	33.4%	229,053.6	37.2%	8.1%
Natural Gas CT	11,853.2	1.9%	14,769.8	2.4%	24.6%
Natural Gas Other Units	4,601.8	0.7%	6,060.9	1.0%	31.7%
Other Gas	1,609.9	0.3%	1,507.5	0.2%	(6.4%)
Hydroelectric	13,415.7	2.1%	12,948.4	2.1%	(3.5%)
Pumped Storage	3,785.4	0.6%	3,944.5	0.6%	4.2%
Run of River	8,528.3	1.3%	7,819.9	1.3%	(8.3%)
Other Hydro	1,102.0	0.2%	1,184.0	0.2%	7.4%
Wind	16,973.8	2.7%	17,990.2	2.9%	6.0%
Waste	3,253.2	0.5%	3,298.2	0.5%	1.4%
Oil	1,551.8	0.2%	1,579.4	0.3%	1.8%
Heavy Oil	101.6	0.0%	73.1	0.0%	(28.1%)
Light Oil	226.3	0.0%	225.3	0.0%	(0.4%)
Diesel	68.1	0.0%	23.9	0.0%	(64.9%)
Other Oil	1,155.8	0.2%	1,257.2	0.2%	8.8%
Solar, Net Energy Metering	2,260.3	0.4%	3,007.0	0.5%	33.0%
Battery	15.1	0.0%	27.0	0.0%	78.9%
Biofuel	1,017.9	0.2%	721.0	0.1%	(29.2%)
Total	634,231.1	100.0%	614,963.9	100.0%	(3.0%)

⁵⁸ All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, power to run pumped hydro pumps or power to charge batteries.

⁵⁹ Net Energy Metering is combined with Solar due to data confidentiality reasons.

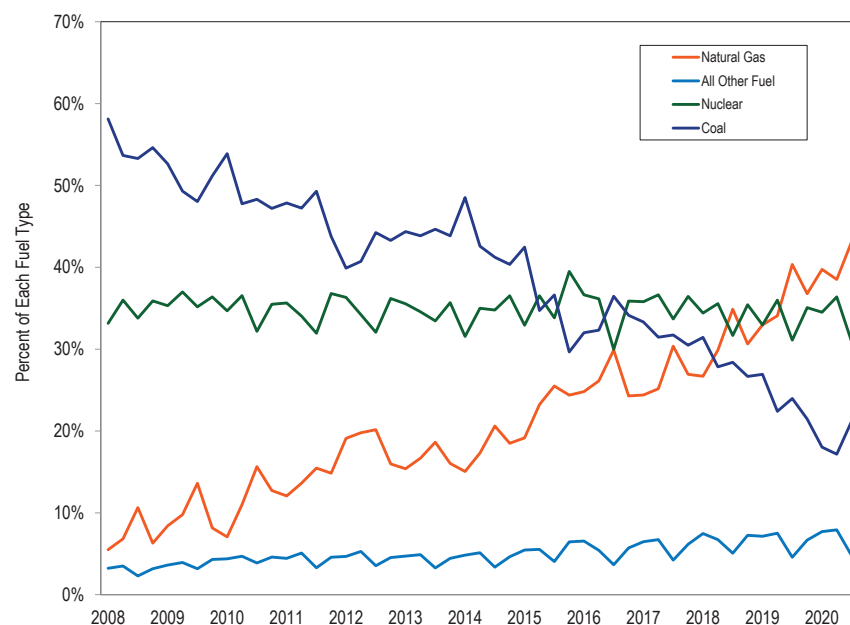
⁶⁰ Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

Table 3-54 Monthly generation (By fuel source (GWh)): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	13,301.6	12,829.4	9,998.2	7,986.2	9,746.6	13,983.2	19,592.9	17,666.9	11,469.3	116,574.1
Bituminous	12,414.8	11,741.5	9,255.7	7,144.5	9,154.6	12,865.0	17,474.9	15,775.6	10,393.7	106,220.5
Sub Bituminous	348.1	570.5	340.4	452.2	295.2	834.4	1,661.9	1,389.1	592.6	6,484.5
Other Coal	538.6	517.3	402.2	389.5	296.8	283.7	456.1	502.1	482.9	3,869.1
Nuclear	25,012.5	22,067.6	22,062.1	20,904.1	22,691.8	23,638.2	24,158.5	24,192.5	22,699.4	207,426.7
Gas	28,107.6	25,976.7	26,074.6	21,799.1	21,613.3	28,264.2	38,435.5	34,183.3	26,937.7	251,391.8
Natural Gas CC	26,839.6	25,157.8	25,188.7	20,970.9	20,094.7	24,960.9	31,183.8	29,734.4	24,922.9	229,053.6
Natural Gas CT	736.3	482.7	614.0	544.9	1,029.3	2,166.3	4,804.6	2,862.7	1,529.0	14,769.8
Natural Gas Other Units	343.8	159.1	83.4	108.3	314.3	987.9	2,294.9	1,433.8	335.4	6,060.9
Other Gas	187.9	177.1	188.6	174.9	174.9	149.1	152.1	152.5	150.4	1,507.5
Hydroelectric	1,474.0	1,558.7	1,489.8	1,410.3	1,651.6	1,571.4	1,380.4	1,318.9	1,093.3	12,948.4
Pumped Storage	370.7	309.2	324.9	273.5	447.8	495.3	654.1	603.9	465.1	3,944.5
Run of River	1,014.4	1,127.3	1,082.5	1,078.5	1,085.5	908.7	511.4	512.3	499.4	7,819.9
Other Hydro	88.9	122.2	82.4	58.3	118.3	167.4	215.0	202.8	128.7	1,184.0
Wind	2,589.6	2,564.5	2,739.5	2,679.8	2,261.8	1,662.4	959.8	925.9	1,606.9	17,990.2
Waste	366.3	297.0	391.2	357.9	380.3	352.5	400.5	389.9	362.6	3,298.2
Oil	128.2	159.1	165.2	160.2	152.9	165.9	307.8	178.1	162.0	1,579.4
Heavy Oil	0.0	0.0	0.0	0.0	0.0	0.0	24.9	14.2	33.9	73.1
Light Oil	10.8	6.4	2.2	2.2	3.7	29.9	132.5	26.0	11.7	225.3
Diesel	7.5	0.2	0.3	0.1	0.0	1.5	10.3	2.4	1.6	23.9
Other Oil	109.9	152.6	162.8	157.9	149.2	134.5	140.1	135.5	114.8	1,257.2
Solar, Net Energy Metering	187.3	208.8	288.5	363.0	401.1	424.0	455.5	359.5	319.3	3,007.0
Battery	2.0	2.4	3.6	3.0	3.0	3.1	3.4	3.4	3.1	27.0
Biofuel	84.7	101.9	102.2	36.6	46.8	66.2	96.3	91.7	94.7	721.0
Total	71,253.7	65,766.2	63,314.9	55,700.0	58,949.2	70,131.1	85,790.5	79,310.2	64,748.3	614,963.9

Figure 3-44 shows generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2008.

Figure 3-44 Share of generation by fuel source: January 2008 through September 2020



Fuel Diversity

Figure 3-45 shows the fuel diversity index (FDI_c) for PJM energy generation.⁶¹ The FDI_c 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_c is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_c 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_c are the 10 primary fuel sources in Table 3-54 with nonzero generation values. As fuel diversity has increased,

⁶¹ 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.

seasonality in the FDI_c has decreased and the FDI_c has exhibited less volatility. Since 2012, the monthly FDI_c has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 35.4 percent from 2012 through 2019. A significant drop in the FDI_c 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.⁶² 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 19.0 percent for the first nine months of 2020. Gas generation as a share of total generation was 7.4 percent for 2008 and 40.9 percent for the first nine months of 2020. Wind generation as a share of total generation was 0.5 percent for 2008 and 2.9 percent for the first nine months of 2020.

The average FDI_c decreased 2.2 percent for the first nine months of 2020 compared to the first nine months of 2019. The FDI_c was also used to measure the impact on fuel diversity of potential retirements. A total of 9,543.0 MW of coal, CT, diesel, and nuclear capacity were identified as being at risk of retirement.⁶³ Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance.⁶⁴ There are 4,556.0 MW of generation that have requested retirement after September 30, 2020.⁶⁵ The at risk units and other generators with deactivation notices generated 33,611.6 GWh in the first nine months of 2020. The dashed line in Figure 3-45 shows a counterfactual result for FDI_c assuming the 33,611.6 GWh of generation from at risk units and other generators with deactivation notices were replaced by gas generation. The FDI_c for the first nine months of 2020 under the counterfactual assumption would have been 2.2 percent lower than the actual FDI_c .

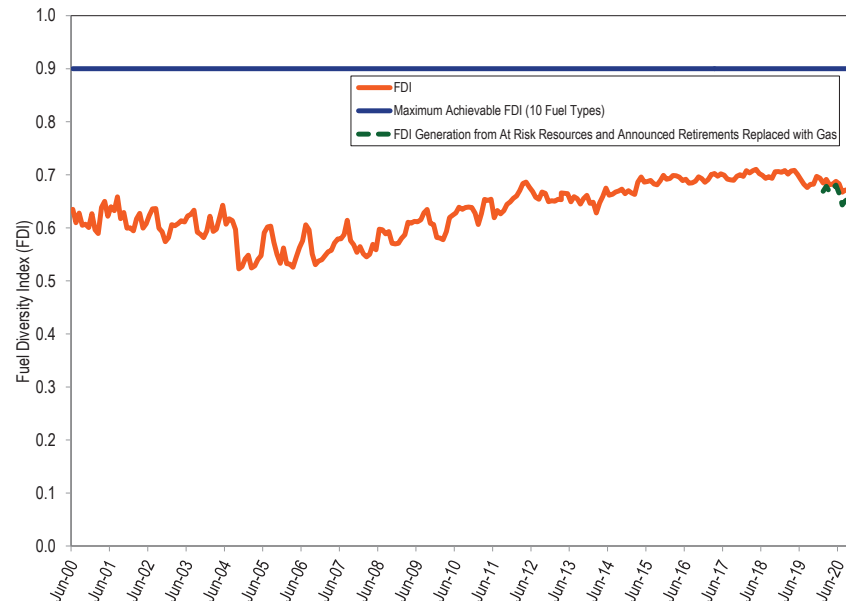
⁶² See the 2019 State of the Market Report for PJM, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

⁶³ See the 2019 State of the Market Report for PJM, Volume 2, Section 7: Net Revenue, Units at Risk.

⁶⁴ See PJM. OATT: § V "Generation Deactivation."

⁶⁵ See 2020 Quarterly State of the Market Report for PJM: January through September, Section 12: Generation and Transmission Planning, Table 12-9.

Figure 3-45 Fuel diversity index for monthly generation: June 2000 through September 2020



Natural Gas Supply Issues

A combination of pipeline transportation and natural gas supplies is needed to deliver natural gas to power plants. A generator could purchase a delivered service in which the seller bundles both the transportation and fuel to make deliveries to the plant. The delivered service could be purchased on either a term contract or a spot basis. A generator could secure pipeline transportation for part or all of the supplies needed to run the plant and purchase commodity natural gas separately with a term supply contract or through daily purchases in the spot market. Other options are also possible.

The increase in natural gas fired capacity in PJM has highlighted issues with the dependence of the PJM system reliability on the fuel transportation arrangements entered into by generators. The risks to the fuel supply for gas

generators, including the risk of interruptible supply on cold days and the ability to get gas on short notice during times of critical pipeline operations, creates risks for the bulk power system. PJM should collect data on each individual generator's fuel supply arrangements, and analyze the associated locational and regional risks to reliability.

In 2019 and the first nine months of 2020, 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 constrained operating conditions determined by the pipeline. 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.

Types of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs,

based on their offers. Marginal resource designation is not limited to physical resources in the day-ahead energy market. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market that can set price via their offers and bids.

Table 3-55 shows the type of fuel used and technology by marginal resources in the real-time energy market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2020, coal units were 17.3 percent and natural gas units were 73.6 percent of marginal resources. In the first nine months of 2020, natural gas combined cycle units were 66.0 percent of marginal resources. In the first nine months of 2019, coal units were 26.3 percent and natural gas units were 68.5 percent of the total marginal resources. In the first nine months of 2019, natural gas combined cycle units were 60.8 percent of the total marginal resources. In the first nine months of 2020, 93.6 percent of the wind marginal units had negative offer prices, 6.4 percent had zero offer prices and none had positive offer prices. In the first nine months of 2019, 92.9 percent of the wind marginal units had negative offer prices, 6.5 percent had zero offer prices and 0.6 percent of wind marginal units had positive offer prices.

The proportion of marginal nuclear units increased from 1.17 percent in the first nine months of 2019 to 1.46 percent in the first nine months of 2020. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-55 Type of fuel used and technology (By real-time marginal units): January through September, 2016 through 2020⁶⁶

Fuel	Technology	(Jan - Sep)				
		2016	2017	2018	2019	2020
Gas	CC	29.25%	44.83%	53.45%	60.79%	66.03%
Coal	Steam	46.21%	32.53%	27.26%	26.32%	17.30%
Gas	CT	7.05%	4.55%	7.80%	6.38%	5.74%
Wind	Wind	2.67%	8.44%	2.56%	2.92%	5.64%
Gas	Steam	5.01%	3.19%	1.68%	1.28%	1.84%
Uranium	Steam	0.92%	1.25%	1.04%	1.17%	1.46%
Oil	CT	7.51%	4.11%	4.58%	0.47%	1.11%
Other	Solar	0.03%	0.15%	0.12%	0.08%	0.40%
Oil	Steam	0.05%	0.02%	0.29%	0.03%	0.07%
Other	Steam	0.12%	0.18%	0.15%	0.07%	0.04%
Municipal Waste	Steam	0.01%	0.02%	0.04%	0.02%	0.01%
Landfill Gas	CT	0.01%	0.00%	0.02%	0.01%	0.01%
Oil	RICE	0.96%	0.32%	0.42%	0.00%	0.00%
Oil	CC	0.03%	0.00%	0.13%	0.02%	0.00%
Municipal Waste	RICE	0.00%	0.00%	0.00%	0.00%	0.00%
Gas	Fuel Cell	0.00%	0.01%	0.00%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.03%	0.03%	0.00%	0.00%	0.00%
Gas	RICE	0.10%	0.34%	0.41%	0.00%	0.00%

⁶⁶ The unit type RICE refers to Reciprocating Internal Combustion Engines.

Figure 3-46 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 3-46 Type of fuel used (By real-time marginal units): January through September, 2004 through 2020

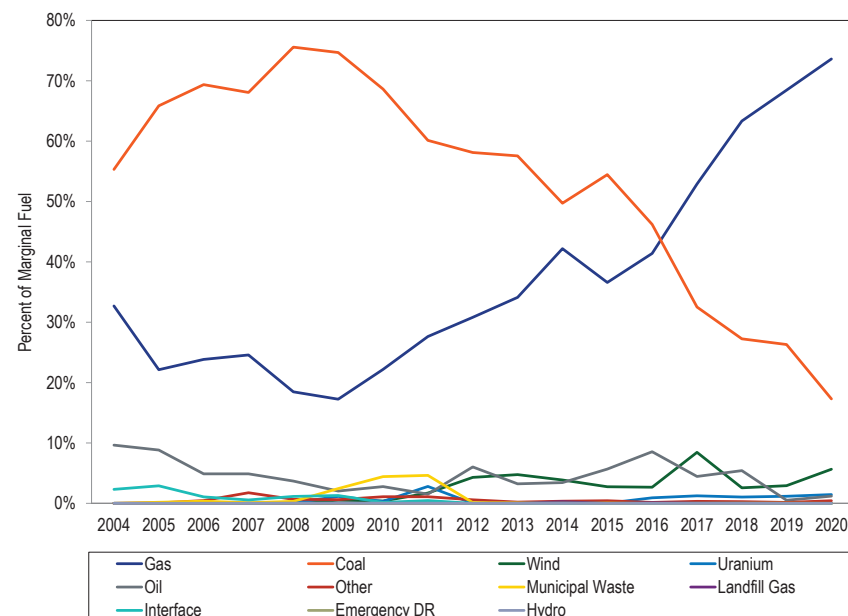


Table 3-56 shows the type of fuel used and technology where relevant, of marginal resources in the day-ahead energy market. In the first nine months of 2020, up to congestion transactions were 53.8 percent of marginal resources. Up to congestion transactions were 57.7 percent of marginal resources in the first nine months of 2019.

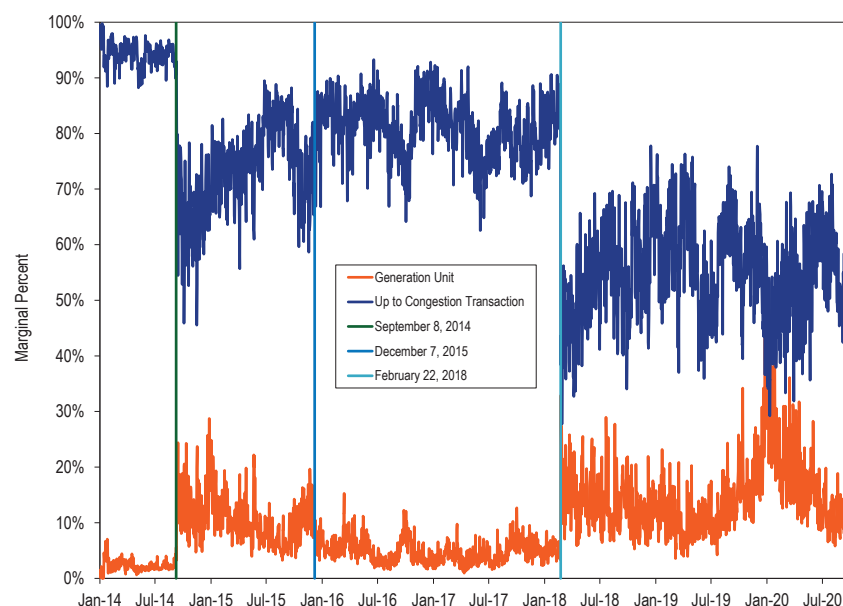
Table 3-56 Day-ahead marginal resources by type/fuel used and technology: January through September, 2016 through 2020

Type/Fuel	Technology	(Jan - Sep)				
		2016	2017	2018	2019	2020
Up to Congestion Transaction	NA	81.19%	79.84%	63.90%	57.70%	53.81%
DEC	NA	8.82%	10.03%	16.06%	18.41%	17.64%
INC	NA	4.22%	5.49%	9.24%	12.86%	12.41%
Gas	CC	2.16%	1.99%	5.08%	5.92%	9.90%
Coal	Steam	2.42%	1.74%	4.57%	4.23%	4.83%
Gas	Steam	0.43%	0.37%	0.32%	0.39%	0.40%
Wind	Wind	0.04%	0.17%	0.16%	0.10%	0.24%
Gas	CT	0.05%	0.03%	0.20%	0.10%	0.24%
Uranium	Steam	0.09%	0.06%	0.12%	0.06%	0.23%
Oil	CT	0.52%	0.19%	0.04%	0.04%	0.09%
Dispatchable Transaction	NA	0.05%	0.03%	0.13%	0.10%	0.08%
Other	Steam	0.01%	0.00%	0.01%	0.01%	0.05%
Gas	RICE	0.00%	0.02%	0.05%	0.04%	0.05%
Other	Solar	0.00%	0.00%	0.03%	0.02%	0.01%
Oil	Steam	0.00%	0.00%	0.05%	0.01%	0.01%
Municipal Waste	RICE	0.01%	0.00%	0.00%	0.01%	0.01%
Price Sensitive Demand	NA	0.00%	0.00%	0.02%	0.00%	0.00%
Oil	RICE	0.00%	0.01%	0.00%	0.00%	0.00%
Oil	CC	0.00%	0.00%	0.02%	0.00%	0.00%
Water	Hydro	0.00%	0.01%	0.00%	0.00%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-47 shows, for the day-ahead energy market from January 2014 through September 2020, the daily proportion of marginal resources that were up to congestion transactions and/or generation units. The UTC share decreased from 57.7 percent in the first nine months of 2019 to 53.8 percent in the first nine months of 2020.

The average number of up to congestion bids submitted in the day-ahead energy market increased by 5.2 percent, from 51,594 bids per day in the first nine months of 2019 to 54,299 bids per day in the first nine months of 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 0.1 percent, from 490,421 MWh per day in the first nine months of 2019, to 489,871 MWh per day in the first nine months of 2020.

Figure 3-47 Day-ahead marginal up to congestion transaction and generation units: January 2014 through September 2020



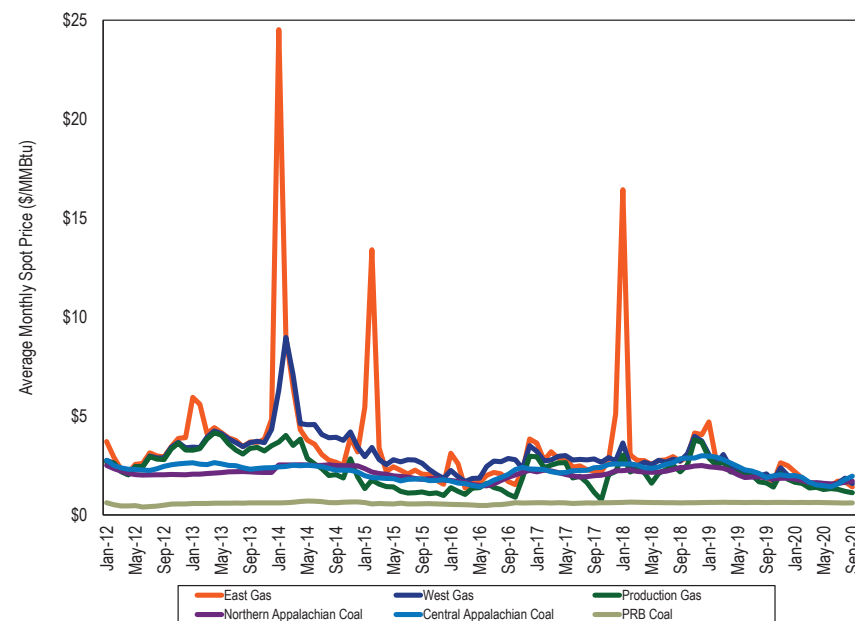
Fuel Price Trends and LMP

In a competitive market, changes in LMP follow changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of short run marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs also contribute to changes in the marginal cost of marginal units.

Figure 3-48 shows fuel prices in PJM for 2012 through the first nine months of 2020. Natural gas prices decreased in the first nine months of 2020 compared to the first nine months of 2019. The price of natural gas in the Marcellus Shale production area is lower than in other areas of PJM. A number of new

combined cycle plants have located in the production area since 2016. In the first nine months of 2020, the price of production gas was 37.8 percent lower than in the first nine months of 2019. The price of eastern natural gas was 36.5 percent lower and the price of western natural gas was 31.7 percent lower. The price of Northern Appalachian coal was 21.7 percent lower; the price of Central Appalachian coal was 31.4 percent lower; and the price of Powder River Basin coal was 1.8 percent lower.⁶⁷ The price of ULSD NY Harbor Barge was 41.2 percent lower.

Figure 3-48 Spot average fuel price comparison: January 2012 through September 2020⁶⁸ (\$/MMBtu)



⁶⁷ Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily indices. Western natural gas prices are the average of Columbia Appalachia and Chicago Citygate daily indices. Production gas prices are the average of Dominion South Point, Tennessee Zone 4, and Transco Leidy Line receipts daily indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

⁶⁸ This figure is modified from the corresponding figure in the 2020 Quarterly State of the Market Report for PJM: January through June, which included an error.

Table 3-57 compares the PJM real-time fuel-cost adjusted, load-weighted, average LMP in the first nine months of 2020 to the load-weighted, average LMP in the first nine months of 2019.⁶⁹ The real-time, load-weighted average LMP in the first nine months of 2020 decreased by \$6.38 or -23.1 percent from the real-time load-weighted, average LMP in the first nine months of 2019. The real-time load-weighted, average LMP for the first nine months of 2020 was 14.8 percent lower than the real-time fuel-cost adjusted, load-weighted average LMP for the first nine months of 2020. The real-time, fuel-cost adjusted, load-weighted average LMP for the first nine months of 2020 was 9.8 percent lower than the real-time load-weighted, average LMP for the first nine months of 2019. If fuel and emissions costs in the first nine months of 2020 had been the same as in the first nine months of 2019, holding the market dispatch constant, the real-time, load-weighted, average LMP in the first nine months of 2020 would have been higher, \$24.91 per MWh, than the observed \$21.22 per MWh. Only 57.7 percent of the decrease in real-time, load-weighted, average LMP, \$3.68 per MWh out of \$6.38 per MWh, is directly attributable to fuel costs. Contributors to the other \$2.70 per MWh are decreased load, adjusted dispatch, including adjustments to dispatch due to changes in relative fuel costs among units, and lower markups.

Table 3-57 Real-time, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): January through September, 2019 and 2020

	2020 Fuel-Cost Adjusted, Load-Weighted LMP	2020 Load-Weighted LMP	Change	Percent Change
Average	\$24.91	\$21.22	(\$3.68)	(14.8%)
	2019 Load-Weighted LMP	2020 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	\$27.60	\$24.91	(\$2.70)	(9.8%)
	2019 Load-Weighted LMP	2020 Load-Weighted LMP	Change	Change
Average	\$27.60	\$21.22	(\$6.38)	(23.1%)

Table 3-58 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 the first nine months of 2020. Table 3-58 shows that lower natural gas prices explain 81.6 percent of the fuel-cost related decrease in the real-time

annual, load-weighted, average LMP in the first nine months of 2020 from the first nine months of 2019.

Table 3-58 Share of change in fuel-cost adjusted LMP (\$/MWh) by fuel type: January through September, 2020 adjusted to 2019 fuel prices

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Gas	(\$3.00)	81.6%
Coal	(\$0.64)	17.4%
Oil	(\$0.04)	1.0%
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	(\$3.68)	100.0%

Components of LMP

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and 10 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, SO₂ and CO₂ emission credits, emission rates for NO_x, emission rates for SO₂ and emission rates for CO₂. The CO₂ emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland, and New Jersey.⁷⁰ 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.

⁶⁹ The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO₂ and SO₂ costs.

⁷⁰ New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020.

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 the SCED solution does not meet the reserve requirements, PJM should invoke shortage pricing. During 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 3-59 shows the frequency and average shadow price of transmission constraints in PJM. In the first nine months of 2020, there were 125,493 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly four percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit.⁷¹ In the first nine months of 2020, the average shadow price of transmission constraints when the line limit was violated was nearly 16.7 times higher than when the transmission constraint was binding at its limit.

Table 3-59 Frequency and average shadow price of transmission constraints: January through September, 2019 and 2020

Description	Frequency (Constraint Intervals)		Average Shadow Price	
	2019	2020	2019	2020
	(Jan - Sep)	(Jan - Sep)	(Jan - Sep)	(Jan - Sep)
PJM Internal Violated Transmission Constraints	4,653	5,383	\$1,488.52	\$1,481.01
PJM Internal Binding Transmission Constraints	59,363	92,535	\$100.08	\$88.51
Market to Market Transmission Constraints	32,820	27,575	\$233.61	\$231.08
All Transmission Constraints	96,836	125,493	\$212.05	\$179.57

Transmission penalty factors should be applied without discretion. Penalty factors should be set high enough so that they do not act to suppress prices based on available generator solutions. 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. The Commission approved the PJM and MISO joint filing to remove the constraint relaxation logic for market to market constraints on March 6, 2020. PJM and MISO implemented the changes to their dispatch software in the second half of 2020. PJM continues the practice of discretionary reduction in line ratings.

Table 3-60 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM real-time market. In the first nine months of 2020, there were 3,384 or 63 percent of internal violated transmission constraint intervals in the real-time market with transmission penalty factor equal to the default \$2,000 per MWh.

⁷¹ The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

Table 3-60 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): January through September, 2019 and 2020

Description	2019 (Jan – Sep)			2020 (Jan – Sep)		
	\$2,000 per MWh (Default)	Above \$2,000 per MWh	Below \$2,000 per MWh	\$2,000 per MWh (Default)	Above \$2,000 per MWh	Below \$2,000 per MWh
PJM Internal Violated Transmission Constraints	3,203	70	1,380	3,384	88	1,911
PJM Internal Binding Transmission Constraints	56,230	696	2,437	84,544	155	7,836
Market to Market Transmission Constraints	6,557	3	26,260	2,195	-	25,380
All Transmission Constraints	65,990	769	30,077	90,123	243	35,127

Transmission constraint penalty factors frequently set prices when PJM models a surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. Changes to the surrogate constraint limit that exceed the unit's ability to reduce output cause constraint violations. Constraint violations also occur when the unit follows the regulation signal or increases its minimum operating parameters above the surrogate constraint limit. Prices set at the \$2,000 per MWh penalty factor are not useful signals to the market under these conditions and create false arbitrage opportunities for virtuals.

PJM uses CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead and real-time market solutions. In the event PJM commits a resource that is uneconomic and/or offered with inflexible parameters, PJM uses CT pricing logic to model a constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to force the resource to be marginal in the PJM market solution.⁷² Frequently, PJM dispatchers also manually override the transmission violation penalty factor of the constraint to closely match the offer price of the resource to artificially control the shadow price of the constraint. Table 3-61 shows the frequency of CT pricing logic used in the PJM real-time market. In the first nine months of 2020, there were 6,163 constraint intervals in the real-time market where CT pricing logic was used. In the PJM CT pricing logic, there could be one or multiple resources paired with a constraint.

⁷² PJM dispatchers generally log the resources paired with a constraint in the CT pricing logic. The data presented is based on PJM dispatcher logs.

PJM's use of CT pricing logic is inconsistent with the efficient market dispatch and pricing. For the same reason, in 2019 FERC declared CT pricing logic to be unjust and unreasonable.⁷³ PJM should discontinue the use of CT pricing logic, regardless of whether the new fast-start pricing process is in place.

Table 3-61 Frequency of CT pricing logic used in the real-time market (constraint intervals): January through September, 2019 and 2020

Month	2019	2020
Jan	650	231
Feb	744	167
Mar	691	122
Apr	378	173
May	1,362	632
Jun	574	825
Jul	1,460	842
Aug	1,725	1,189
Sep	2,027	1,982
Oct	2,301	-
Nov	2,229	-
Dec	835	-
Total	14,976	6,163

The components of LMP are shown in Table 3-62, including markup using unadjusted cost-based offers.⁷⁴ Table 3-62 shows that in the first nine months of 2020, 24.6 percent of the load-weighted LMP was the result of coal costs, 39.8 percent was the result of gas costs and 1.8 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, markup was 2.9 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

⁷³ *PJM Interconnection, LLC*, 167 FERC ¶ 61,058 (April 18, 2019) at P.69.

⁷⁴ 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>.

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 failed to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The NA component is the cumulative effect of excluding those five minute intervals. The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in the first nine months of 2020 and the first nine months of 2019.

Table 3-62 Components of real-time (Unadjusted), load-weighted, average LMP: January through September, 2019 and 2020

Element	2019 (Jan - Sep)		2020 (Jan - Sep)		Change Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
Gas	\$11.75	42.6%	\$8.44	39.8%	(2.8%)
Coal	\$7.39	26.8%	\$5.21	24.6%	(2.2%)
Constraint Violation Adder	\$1.49	5.4%	\$1.68	7.9%	2.5%
Ten Percent Adder	\$2.11	7.7%	\$1.63	7.7%	0.0%
Variable Maintenance			\$1.38	6.5%	0.4%
Variable Operations	\$1.69	6.1%	\$0.85	4.0%	4.0%
Markup	\$1.79	6.5%	\$0.61	2.9%	(3.6%)
NA	\$0.31	1.1%	\$0.50	2.4%	1.2%
CO ₂ Cost	\$0.22	0.8%	\$0.37	1.8%	1.0%
LPA Rounding Difference	\$0.14	0.5%	\$0.16	0.8%	0.3%
Ancillary Service Redispatch Cost	\$0.21	0.8%	\$0.14	0.7%	(0.1%)
Oil	\$0.06	0.2%	\$0.08	0.4%	0.2%
Increase Generation Adder	\$0.11	0.4%	\$0.07	0.3%	(0.1%)
Opportunity Cost Adder	\$0.09	0.3%	\$0.07	0.3%	(0.0%)
Scarcity Adder	\$0.26	1.0%	\$0.02	0.1%	(0.9%)
LPA-SCED Differential	\$0.01	0.0%	\$0.01	0.1%	0.0%
NO _x Cost	\$0.02	0.1%	\$0.01	0.0%	(0.0%)
Market-to-Market Adder	\$0.00	0.0%	\$0.00	0.0%	0.0%
SO ₂ Cost	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Other	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Uranium	\$0.00	0.0%	\$0.00	0.0%	0.0%
Renewable Energy Credits	(\$0.02)	(0.1%)	(\$0.00)	(0.0%)	0.1%
Landfill Gas	\$0.00	0.0%	(\$0.01)	(0.0%)	(0.0%)
Decrease Generation Adder	(\$0.05)	(0.2%)	(\$0.02)	(0.1%)	0.1%
Total	\$27.60	100.0%	\$21.22	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 3-62 and Table 3-64), markup is simply the difference

between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-63 and Table 3-65), 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 3-63, including markup using adjusted cost-based offers.

Table 3-63 Components of real-time (Adjusted), load-weighted, average LMP: January through September, 2019 and 2020

Element	2019 (Jan - Sep)		2020 (Jan - Sep)		Change Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
Gas	\$11.75	42.6%	\$8.44	39.8%	(2.8%)
Coal	\$7.39	26.8%	\$5.21	24.6%	(2.2%)
Markup	\$3.90	14.1%	\$2.25	10.6%	(3.5%)
Constraint Violation Adder	\$1.49	5.4%	\$1.68	7.9%	2.5%
Variable Maintenance			\$1.38	6.5%	0.4%
Variable Operations	\$1.69	6.1%	\$0.85	4.0%	4.0%
NA	\$0.31	1.1%	\$0.50	2.4%	1.2%
CO ₂ Cost	\$0.22	0.8%	\$0.37	1.8%	1.0%
LPA Rounding Difference	\$0.14	0.5%	\$0.16	0.8%	0.3%
Ancillary Service Redispatch Cost	\$0.21	0.8%	\$0.14	0.7%	(0.1%)
Oil	\$0.06	0.2%	\$0.08	0.4%	0.2%
Increase Generation Adder	\$0.11	0.4%	\$0.07	0.3%	(0.1%)
Opportunity Cost Adder	\$0.09	0.3%	\$0.07	0.3%	(0.0%)
Scarcity Adder	\$0.26	1.0%	\$0.02	0.1%	(0.9%)
LPA-SCED Differential	\$0.01	0.0%	\$0.01	0.1%	0.0%
NO _x Cost	\$0.02	0.1%	\$0.01	0.0%	(0.0%)
Market-to-Market Adder	\$0.00	0.0%	\$0.00	0.0%	0.0%
SO ₂ Cost	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Ten Percent Adder	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Other	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Uranium	\$0.00	0.0%	\$0.00	0.0%	0.0%
Renewable Energy Credits	(\$0.02)	(0.1%)	(\$0.00)	(0.0%)	0.1%
Landfill Gas	\$0.00	0.0%	(\$0.01)	(0.0%)	(0.0%)
Decrease Generation Adder	(\$0.05)	(0.2%)	(\$0.02)	(0.1%)	0.1%
Total	\$27.60	100.0%	\$21.22	100.0%	0.0%

Components of Day-Ahead, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into their components including fuel costs, emission costs, variable operation and maintenance costs, markup, 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.

Table 3-64 shows the components of the PJM day-ahead, annual, load-weighted, average LMP. In the first nine months of 2020, 25.3 percent of the load-weighted LMP was the result of coal costs, 17.9 percent of the load-weighted LMP was the result of gas costs, 23.0 percent was the result of DEC bid costs, 15.4 percent was the result of INC bid costs and 3.4 percent was the result of the up to congestion transaction costs.

Table 3-64 Components of day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): January through September, 2019 and 2020

Element	2019 (Jan – Sep)		2020 (Jan – Sep)		Change Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
Coal	\$6.13	22.1%	\$5.30	25.3%	3.2%
DEC	\$5.86	21.2%	\$4.81	23.0%	1.8%
Gas	\$5.48	19.8%	\$3.76	17.9%	(1.8)%
INC	\$5.90	21.3%	\$3.24	15.4%	(5.8)%
Ten Percent Cost Adder	\$1.30	4.7%	\$1.10	5.3%	0.6%
Variable Maintenance Cost	\$1.22	4.4%	\$0.96	4.6%	0.1%
Variable Operating Cost	\$0.00	0.0%	\$0.74	3.5%	3.5%
Up to Congestion Transaction	\$0.62	2.2%	\$0.71	3.4%	1.1%
CO ₂	\$0.14	0.5%	\$0.25	1.2%	0.7%
DASR LOC Adder	\$0.00	0.0%	\$0.11	0.5%	0.5%
Constrained Off	\$0.00	0.0%	\$0.04	0.2%	0.2%
Oil	\$0.02	0.1%	\$0.02	0.1%	0.0%
NO _x	\$0.01	0.1%	\$0.01	0.0%	(0.0)%
Price Sensitive Demand	\$0.01	0.1%	\$0.01	0.0%	(0.0)%
Dispatchable Transaction	\$0.33	1.2%	\$0.01	0.0%	(1.1)%
DASR Offer Adder	\$0.00	0.0%	\$0.00	0.0%	(0.0)%
SO ₂	\$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%
Municipal Waste	\$0.00	0.0%	(\$0.00)	(0.0)%	(0.0)%
Wind	(\$0.02)	(0.1)%	(\$0.00)	(0.0)%	0.1%
Markup	\$0.67	2.4%	(\$0.15)	(0.7)%	(3.1)%
NA	\$0.00	0.0%	\$0.04	0.2%	0.2%
Total	\$27.70	100.0%	\$20.95	100.0%	(0.0)%

Table 3-65 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.

Table 3-65 Components of day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): January through September, 2019 and 2020

Element	2019 (Jan - Sep)		2020 (Jan - Sep)		Change Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
Coal	\$6.13	22.1%	\$5.30	25.3%	3.2%
DEC	\$5.86	21.2%	\$4.81	23.0%	1.8%
Gas	\$5.48	19.8%	\$3.76	17.9%	(1.8%)
INC	\$5.90	21.3%	\$3.24	15.4%	(5.8%)
Variable Maintenance Cost	\$1.22	4.4%	\$0.96	4.6%	0.1%
Markup	\$1.96	7.1%	\$0.95	4.5%	(2.5%)
Variable Operating Cost	\$0.00	0.0%	\$0.74	3.5%	3.5%
Up to Congestion Transaction	\$0.62	2.2%	\$0.71	3.4%	1.1%
CO ₂	\$0.14	0.5%	\$0.25	1.2%	0.7%
DASR LOC Adder	\$0.00	0.0%	\$0.11	0.5%	0.5%
Constrained Off	\$0.00	0.0%	\$0.04	0.2%	0.2%
Oil	\$0.02	0.1%	\$0.02	0.1%	0.0%
NO _x	\$0.01	0.1%	\$0.01	0.0%	(0.0%)
Price Sensitive Demand	\$0.01	0.1%	\$0.01	0.0%	(0.0%)
Dispatchable Transaction	\$0.33	1.2%	\$0.01	0.0%	(1.1%)
DASR Offer Adder	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
SO ₂	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Other	\$0.01	0.0%	\$0.00	0.0%	(0.0%)
Ten Percent Cost Adder	\$0.01	0.0%	\$0.00	0.0%	(0.0%)
Uranium	\$0.00	0.0%	\$0.00	0.0%	0.0%
Municipal Waste	\$0.00	0.0%	(\$0.00)	(0.0%)	(0.0%)
Wind	(\$0.02)	(0.1%)	(\$0.00)	(0.0%)	0.1%
NA	\$0.00	0.0%	\$0.04	0.2%	0.2%
Total	\$27.70	100.0%	\$20.95	100.0%	0.0%

Scarcity

PJM's energy market experienced five minute shortage pricing for two five minute intervals on one day in the first nine months of 2020. Table 3-66 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first nine months of 2019 and 2020. In the first nine months of 2020, there were no emergency actions that triggered a Performance Assessment Interval (PAI). The day with shortage pricing intervals did not correspond to the days with emergency alerts.

Table 3-66 Summary of emergency events declared: January through September, 2019 and 2020

Event Type	Number of days events declared	
	Jan - Sep, 2019	Jan - Sep, 2020
Cold Weather Alert	9	3
Hot Weather Alert	15	19
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	14	1
Energy export recalls from PJM capacity resources	0	0

Figure 3-49 shows the number of days that weather and capacity emergency alerts were issued in PJM during the first nine months from 2016 through 2020. Figure 3-50 shows the number of days emergency warnings were issued or actions taken in PJM during the first nine months from 2016 through 2020.

Figure 3-49 Declared emergency alerts: January through September, 2016 through 2020

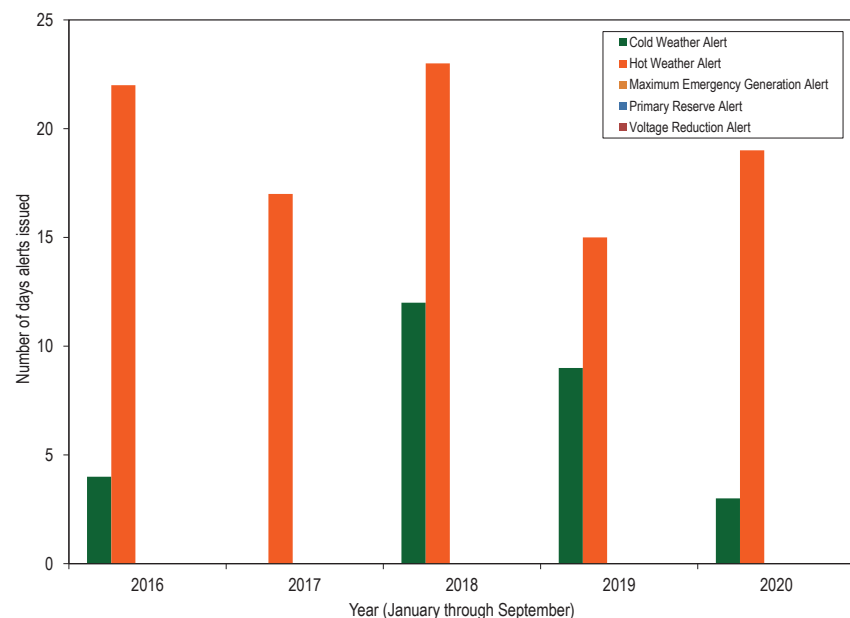
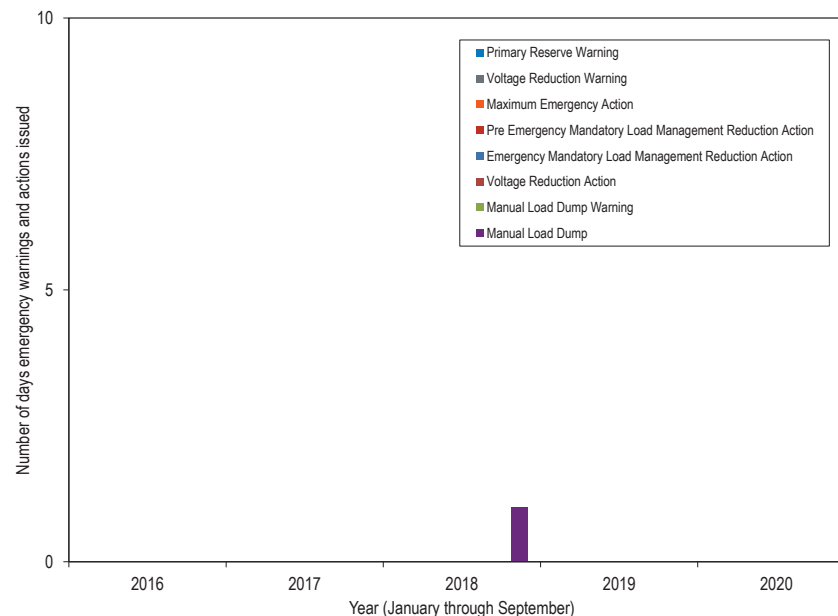


Figure 3-50 Declared emergency warnings and actions: January through September, 2016 through 2020



Emergency Procedures

PJM declares alerts at least a day prior to the operating day to warn members of possible emergency actions that could be taken during the operating day. In real time, on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

Table 3-67 provides a description of PJM declared emergency procedures.^{75 76 77 78}

Table 3-67 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.

⁷⁵ See PJM. "Manual 13: Emergency Operations," Rev. 76 (March 26, 2020), Section 3.3 Cold Weather Alert.

⁷⁶ See PJM. "Manual 13: Emergency Operations," Rev. 76 (March 26, 2020), Section 3.4 Hot Weather Alert.

⁷⁷ See PJM. "Manual 13: Emergency Operations," Rev. 76 (March 26, 2020), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.

⁷⁸ See PJM. "Manual 13: Emergency Operations," Rev. 76 (March 26, 2020), 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-68 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first nine months of 2020.

Table 3-68 Declared emergency alerts, warnings and actions: January through September, 2020

Date	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and 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
1/19/2020	ComEd													
1/20/2020	ComEd													
1/21/2020	ComEd													
6/22/2020		Mid-Atlantic												
6/23/2020		Mid-Atlantic and Dominion												
7/3/2020		PJM RTO												
7/6/2020		PJM RTO												
7/7/2020		PJM RTO												
7/8/2020		Mid-Atlantic and Western												
7/9/2020		Mid-Atlantic and Western												
7/18/2020		PJM RTO												
7/19/2020		PJM RTO												
7/20/2020		PJM RTO												
7/21/2020		Mid-Atlantic and Southern												
7/22/2020		Mid-Atlantic and Southern												
7/26/2020		Mid-Atlantic and Southern												
7/27/2020		Mid-Atlantic and Southern												
7/28/2020		Mid-Atlantic and Southern												
7/29/2020		Mid-Atlantic												
7/30/2020		Mid-Atlantic												
8/26/2020		ComEd												
8/27/2020		ComEd, Mid-Atlantic and Dominion												

Power Balance Constraint Violation

On October 1, 2019, the power balance constraint was violated in 11 approved RT SCED solutions. On February 16, 2020, the power balance constraint was violated in one approved RT SCED solution which was used to set prices for three five minute intervals. On April 21, 2020, the power balance constraint was violated in one approved RT SCED solution. In the RT SCED optimization, the power balance constraint enforces the requirement that total dispatched generation (supply) equals the sum total of forecasted load, losses and net interchange (demand). The power balance constraint is violated when supply is less than demand. In some cases, the power balance constraint is violated while the reserve requirements are satisfied.

The current process for meeting energy and reserve requirements in real time, and pricing the system conditions when RT SCED forecasts that energy supply is less than the demand for energy and reserves, is opaque and not defined in the PJM governing documents. It is unclear whether and how PJM would convert reserves to energy before violating power balance. It is unclear whether and when PJM would use its authority under the tariff to curtail exports from PJM capacity resources to meet the power balance constraint. It is unclear whether PJM would maintain a minimum level of synchronized reserves even

if that would result in a controlled load shed. The current RT SCED does not have a mechanism to convert inflexible reserves procured by ASO to energy to satisfy the power balance constraint.⁷⁹ SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the currently defined logic meets transmission constraint limits and reserve requirements but violates the power balance constraint, and does not reflect this constraint violation in prices. This logic, if correctly described, is not consistent with basic economics. The overall solution is complex and must be integrated with the approach to scarcity pricing.

The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding.

Table 3-69 shows the number of five minute intervals for which the RT SCED solutions used to set prices did not balance demand and supply. Subsequently, PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In the first nine months of 2020, there were four 5 minute intervals using RT SCED solutions with a violated power balance constraint.

Table 3-69 Number of five minute intervals using RT SCED solutions with violated power balance constraint by year

Year	Number of five minute intervals
2013	-
2014	655
2015	71
2016	42
2017	31
2018	16
2019	36
2020	4

⁷⁹ Inflexible reserves are those reserves that clear in the hour ahead Ancillary Service Optimizer (ASO) but cannot be dispatched in the real time dispatch tool, RT SCED.

Balancing Ratio for Local Emergency Events

The balancing ratio is theoretically defined as the ratio of actual load and reserve requirements in an area during an emergency event to the total committed capacity in the area. In the case of the PAIs declared in 2018 that were triggered due to transmission outages in limited locations, 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.⁸⁰ It is not 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. PJM calculated the balancing ratio for the localized load shed that occurred in the AEP Edison area in 2018 and used the average balancing ratio during the event to calculate the capacity market seller offer cap for all LDAs for the 2022/2023 Delivery Year.⁸¹ 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 zonal or higher level.

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. Scarcity pricing is a mechanism for signaling scarcity conditions through energy prices. Under the PJM rules that were in place through September 30, 2012, scarcity pricing resulted from high offers by individual

⁸⁰ 2018 State of the Market Report for PJM: Volume 2, Section 3: Energy Market, at Scarcity, pp. 201 – 202.

⁸¹ See PJM, "Capacity Market Seller Offer Cap Values," (March 15, 2019), which can be accessed at <<https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-cp-market-seller-offer-cap-values.ashx?la=en?>>.

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. Shortage pricing is an administrative scarcity pricing mechanism in which PJM sets a high energy price at a predetermined level when the system operates with less real-time reserves than required.

In the first nine months of 2020, there were two 5 minute intervals with shortage pricing in PJM.

With Order No. 825, the Commission required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.⁸² Prior to May 11, 2017, if the dispatch tools (Intermediate-Term SCED and Real-Time SCED) reflected a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes), it was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. PJM did not implement the rule as intended in Order No. 825, because RT SCED can indicate a shortage that PJM does not use in pricing. In January 2019, PJM updated its business rules in Manual 11 to describe PJM's implementation of the five minute shortage pricing process. PJM Manual 11 states that shortage pricing is triggered when an approved RT SCED case that was used in the Locational Pricing Calculator (LPC) indicates a shortage of reserves.

Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data do not show a shortage of reserves.⁸³

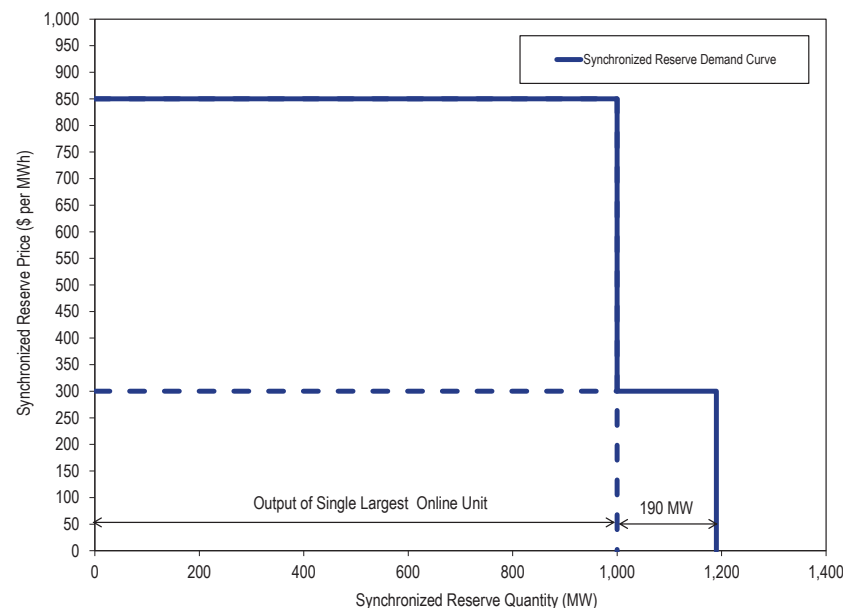
⁸² 155 FERC ¶ 61,276 ("Order No. 825") at P 162.

⁸³ 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).

Operating Reserve Demand Curves

Since July 12, 2017, the PJM synchronized reserve requirement in a reserve zone or a subzone is the actual output of the single largest online unit in that reserve zone or subzone. The primary reserve requirement in a reserve zone or a subzone is 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 is priced at \$850 per MWh. The second step of the primary and synchronized reserve demand curves extends the 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 3-51 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 3-51 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 an administrative price for estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-51 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 shortage prices set by the ORDC are added to LMP during shortages. When multiple reserve products are short or when reserves are short in multiple zones, the ORDC prices are additive. Currently, the highest possible scarcity

adder is \$3,400 per MWh, which is the \$850 per MWh price times four, for two reserve products (synchronized reserve and nonsynchronized reserve) and two zones (RTO and MAD).

Table 3-70 shows five example scenarios, under the current ORDCs, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce LMPs at sample nodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone. In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones, that results in the \$3,400 per MWh scarcity adder in MAD. In scenario C, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones, that results in the \$3,400 per MWh scarcity adder, and a violated transmission constraint with a \$2,000 per MWh penalty factor that results in a \$5,450 per MWh LMP at a node in MAD.⁸⁴

⁸⁴ The impact of the transmission constraint penalty factor at a node depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a dfax of 1.0.

Table 3-70 Additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

Scenario	Energy Component of LMP	Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		Transmission Constraint Penalty Factor	Total LMP in MAD	Total LMP outside MAD
		RTO	MAD	RTO	MAD			
A	\$50	\$850	\$0	\$0	\$0	\$0	\$900	\$900
B	\$50	\$850	\$850	\$850	\$850	\$0	\$3,450	\$1,750
C	\$50	\$850	\$850	\$850	\$850	\$2,000	\$5,450	\$3,750
D	\$1,000	\$850	\$850	\$850	\$850	\$2,000	\$6,400	\$4,700
E	\$1,750	\$850	\$850	\$850	\$850	\$2,000	\$7,150	\$5,450

Changes to the ORDC, approved by FERC and planned for implementation in 2022, will increase the price for reserve quantities less than the reserve requirement to \$2,000 per MWh. For each reserve quantity greater than the reserve requirement, PJM will multiply an assumed probability of a reserve shortage, based on historic forecast error, by \$2,000 per MWh, creating an extended downward sloping ORDC. The extended ORDC is an administratively determined reserve price that will be added to LMP, as a scarcity pricing adder, when no shortage exists. The \$2,000 per MWh price is unjustified because the highest possible energy offer is only \$1,000 per MWh. Only in the rare circumstances when short run marginal costs exceed \$1,000 per MWh is a higher ORDC price justified.

The highest possible scarcity adder increases under the planned changes to the ORDC. The highest possible scarcity adder will be \$10,000 per MWh, which is the \$2,000 per MWh price times five. The five products are the synchronized and nonsynchronized reserve products for RTO and MAD Zones plus a new secondary 30 minute reserve product for the RTO Zone.

Table 3-71 shows example scenarios, under the ORDCs planned for implementation in 2022, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone. In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and reserve shortage for secondary reserve in the RTO Zone that results in the \$10,000 per MWh scarcity adder in MAD. In scenario C, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones, reserve shortage for secondary reserve in the RTO Zone, that results in the \$10,000 per MWh scarcity adder, and a violated transmission constraint with a \$2,000 per MWh penalty factor that resulted in a \$12,050 per MWh LMP at a pnode in MAD.

Table 3-71 Additive penalty factors under shortage conditions and transmission constraint violations

Scenario	Energy Component of LMP	Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		Secondary Reserve Penalty Factor	Transmission Constraint Penalty Factor	Total LMP in MAD	Total LMP outside MAD
		RTO	MAD	RTO	MAD	RTO			
A	\$50	\$2,000	\$200	\$200	\$200	\$0	\$0	\$2,650	\$2,250
B	\$50	\$2,000	\$2,000	\$2,000	\$2,000	\$2,000	\$0	\$10,050	\$6,050
C	\$50	\$2,000	\$2,000	\$2,000	\$2,000	\$2,000	\$2,000	\$12,050	\$8,050
D	\$1,000	\$2,000	\$2,000	\$2,000	\$2,000	\$2,000	\$2,000	\$13,000	\$9,000
E	\$1,750	\$2,000	\$2,000	\$2,000	\$2,000	\$2,000	\$2,000	\$13,750	\$9,750

Operator Actions

Actions taken by PJM operators to maintain reliability, such as committing more reserves than required, may suppress reserve prices. The need to commit more reserves could instead be directly reflected in the ORDC when operational issues arise, allowing the market to efficiently account for the reliability commitment in the energy and reserves markets. Instead, the new ORDC will be inflated at all times based on average historical forecast error that may or may not have resulted in operator actions to commit additional reserves.

Locational Reserve Requirements

In addition to the construction of the operating reserve demand curves to reflect the value of maintaining reserves and avoiding a loss of load event, the modeling of reserve requirements should reflect locational needs and should price operator actions to, for example, commit more reserves when specific needs arise.

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. On most days, the MAD Subzone is no longer relevant. PJM may need to maintain or operate resources in other local areas to maintain local reliability. Currently, these units are committed out of market for reliability reasons, or the reserve need is modeled as an artificial closed loop interface 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 correctly reflected in prices. A more efficient way to reflect these requirements would be to have locational reserve requirements that are adjusted based on PJM forecasts and reliability studies.

Reserve Shortages in 2020

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solutions to determine how many of the RT SCED solutions indicated a shortage of any of the reserve products (synchronized reserve and primary reserve at RTO Reserve Zone and MAD Reserve Subzone), how many of these solutions 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 3-72 shows the number and percent of RT SCED solutions 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 RT SCED solutions with shortage that were approved by PJM, and the number and percent of the RT SCED solutions with shortage that were used in LPC to calculate real-time prices.

Table 3-72 shows that, in the first nine months of 2020, PJM operators approved two RT SCED solutions that indicated a shortage of reserves, from a total of 1,908 RT SCED solutions that indicated shortage. Among the two approved RT SCED solutions with reserve shortage, only one was used in LPC for LMPs and reserve clearing prices. The single shortage solution was used in LPC for two consecutive five minute intervals. In comparison, in the first nine months of 2019, PJM operators approved 35 solutions that indicated a shortage of reserves, from a total of 4,166 RT SCED solutions that indicated shortage. It is unclear what criteria PJM operators use to approve the RT SCED solutions to send dispatch signals to resources. The RT SCED approval process remains inconsistent and undefined.

Table 3-72 RT SCED cases with reserve shortage: January through September, 2020

Month (2020)	Number of RT SCED Solutions	Number of RT SCED Solutions With Reserve Shortage	Number of Approved RT SCED Solutions With Reserve Shortage	Number of Approved RT SCED Solutions With Reserve Shortage Used in LPC	Solutions With Reserve Shortage as Percent of Total RT SCED Solutions	Approved RT SCED Solutions With Reserve Shortage as Percent of RT SCED Solutions With Shortage	RT SCED Solutions With Shortage Used in LPC as Percent of RT SCED Solutions With Shortage
Jan	51,022	337	0	0	0.7%	0.0%	0.0%
Feb	46,247	186	0	0	0.4%	0.0%	0.0%
Mar	38,680	282	0	0	0.7%	0.0%	0.0%
Apr	36,543	420	2	1	1.1%	0.5%	0.2%
May	36,648	167	0	0	0.5%	0.0%	0.0%
Jun	34,327	169	0	0	0.5%	0.0%	0.0%
Jul	30,342	136	0	0	0.4%	0.0%	0.0%
Aug	30,775	115	0	0	0.4%	0.0%	0.0%
Sep	30,632	96	0	0	0.3%	0.0%	0.0%
Total	335,216	1,908	2	1	0.6%	0.1%	0.1%

While there were 1,908 RT SCED solutions that indicated shortage, the number of RT SCED target times for which RT SCED indicated shortage was only 1,143. This is because PJM solves multiple RT SCED cases with three solutions per case, for each five minute target time.^{85 86}

The MMU analyzed the target times for which one or more RT SCED case solutions indicated a shortage of one or more reserve products. Table 3-73 shows, for each month of 2020, the total number of target times, the number of target times for which at least one RT SCED solution showed a shortage of reserves, the number of target times for which more than one RT SCED solution showed a shortage of reserves, and the number of five minute pricing intervals for which the LPC solution showed a shortage of reserves. Table 3-73 shows that 1,143 target times, or 1.4 percent of all five minute target times in the first nine months of 2020, had at least one RT SCED solution showing a shortage of reserves, and 416 target times, or 0.5 percent of all five minute target times in the first nine months of 2020, had more than one RT SCED solution showing a shortage of reserves.

⁸⁵ A case is executed when it begins to solve. Most but not all cases are solved. RT SCED cases take about one to two minutes to solve.

⁸⁶ PJM updated the RT SCED execution frequency to solve one case for each five minute target time beginning June 22, 2020.

Table 3-73 Five minute SCED target times and pricing intervals with shortage: January through September, 2019 and 2020

Year, Month	Number of Five Minute Intervals	Number of Target Times With At Least One SCED Solution Short of Reserves	Percent Target Times With At Least One SCED Solution Short of Reserves	Number of Target Times With Multiple SCED Solutions Short of Reserves	Percent Target Times With Multiple SCED Solutions Short of Reserves	Number of Five Minute Intervals With Shortage Prices in LPC	Percent RT SCED Target Times With Reserve Shortage With Shortage Prices in LPC
2019 Jan	8,928	87	1.0%	34	0.4%	3	3.4%
2019 Feb	8,064	184	2.3%	79	1.0%	0	0.0%
2019 Mar	8,916	347	3.9%	173	1.9%	10	2.9%
2019 Apr	8,640	424	4.9%	217	2.5%	7	1.7%
2019 May	8,928	203	2.3%	94	1.1%	0	0.0%
2019 Jun	8,640	233	2.7%	93	1.1%	0	0.0%
2019 Jul	8,928	312	3.5%	134	1.5%	3	1.0%
2019 Aug	8,928	218	2.5%	85	1.0%	0	0.0%
2019 Sep	8,640	288	3.4%	131	1.5%	4	1.4%
2019 Oct	8,928	284	3.2%	139	1.6%	3	1.1%
2019 Nov	8,652	283	3.3%	125	1.4%	1	0.4%
2019 Dec	8,928	183	2.0%	101	1.1%	2	1.1%
2019 Total	105,120	3,046	2.9%	1,405	1.3%	33	1.1%
2020 Jan	8,928	172	1.9%	89	1.0%	0	0.0%
2020 Feb	8,352	94	1.1%	44	0.5%	0	0.0%
2020 Mar	8,916	173	1.9%	66	0.7%	0	0.0%
2020 Apr	8,640	208	2.4%	99	1.1%	2	1.0%
2020 May	8,928	113	1.3%	36	0.4%	0	0.0%
2020 Jun	8,640	114	1.3%	30	0.3%	0	0.0%
2020 Jul	8,928	110	1.2%	17	0.2%	0	0.0%
2020 Aug	8,928	95	1.1%	14	0.2%	0	0.0%
2020 Sep	8,640	64	0.7%	21	0.2%	0	0.0%
2020 Jan – Sep	78,900	1,143	1.4%	416	0.5%	2	0.2%

While a single RT SCED solution indicating a shortage for a target time among multiple RT SCED solutions that solved for that target time could be the result of operator load bias or erroneous inputs, it is less likely that a target time with multiple RT SCED solutions indicating shortage was the result of an error. There were two 5 minute intervals with shortage pricing that occurred in the first nine months of 2020, while there were 416 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. In the first nine months of 2019, out of 2,307 target times for which one or more RT SCED solutions indicated a shortage of reserves, there were 27 five minute intervals in LPC, or 1.2 percent, with shortage pricing. In the first nine months of 2020, out of 1,143 target times for which one or more RT SCED solutions indicated a shortage of reserves, there were two five minute intervals in LPC, or 0.2 percent, with shortage pricing.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions. 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.

Shortage Pricing Intervals in LPC

There were two five minute intervals with shortage pricing in the first nine months of 2020, compared to 27 intervals in the first nine months of 2019, in PJM. In both intervals on April 30, 2020, shortage pricing was triggered only due to synchronized reserves at the RTO level being short of the extended synchronized reserve requirement. Table 3-74 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 intervals with shortage pricing. The clearing price for synchronized reserves during these intervals, at \$850 per MWh, reflects the maximum price in the ORDC for synchronized reserves in the RTO Zone.

Table 3-74 RTO Synchronized Reserve Shortage Intervals: January through September, 2020

Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	RTO Synchronized Reserve Clearing Price (\$/MWh)
30-Apr-20 12:05	1,817.2	1,614.6	202.6	\$850.0
30-Apr-20 12:10	1,817.2	1,614.6	202.6	\$850.0

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or RT SCED software, such as tier 1 bias or operator load bias. For shortage pricing to be accurate, there must be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.⁸⁷

⁸⁷ See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make simplifications and assumptions using the tools available. Most of these actions taken by generators and by PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM manuals do not provide sufficient clarity regarding the actions PJM dispatchers can take when generators do not follow dispatch.

In the energy and reserve markets, the actions that both generators and PJM dispatchers take have a direct impact on the amount of supply available for

energy and reserves and the prices for energy and reserves. These flaws in PJM's models do not allow PJM to accurately calculate the amount of reserves available. PJM does not accurately model discontinuities in generator ramp rates, such as duct burners on combined cycle plants. PJM's generator models do not account for the complexities that

may result in generators underperforming their submitted ramp rates. Instead of addressing these complexities through generator modeling improvements, PJM relies on a nontransparent method of adjusting generator parameters, called Degree of Generator Performance (DGP).^{88 89} PJM also fails to accurately model unit starts. The market software does not account for the energy output a resource produces prior to reaching its economic minimum output level, during its soak time.

PJM adjusts ramp rates using DGP, deselects specific units from providing reserves, and overrides the dispatch signal to certain units to set the dispatch signal equal to actual resource output. These manual interventions are, at best, rough approximations of the capability of generators and result in an inaccurate measurement of reserves.

⁸⁸ See "PJM Manual 12: Balancing Operations," Rev. 40 (March 26, 2020) Attachment A, P78. "PJM Manual 11: Energy and Ancillary Services Market Operations," does not mention the use of DGP in the market clearing engine.

⁸⁹ PJM published a whitepaper that defines DGP and describes its use, which can be accessed at <http://www.pjm.com/~media/etools/oasis/system-information/generation-performance-monitor-and-degree-of-generator-performance-white-paper.ashx> (July 2, 2020).

Competitive Assessment

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM energy market in the first nine months of 2020 indicates low concentration in the base load segment, moderate concentration in the intermediate segment, and high concentration in the peaking segment.⁹⁰ 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 and the maximum hourly HHI are in the unconcentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate a highly concentrated market structure. 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 the first nine months of 2020, 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 Herfindahl-Hirschman Index (HHI) concentration ratio is calculated by summing the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs are based on the real-time energy output of generators adjusted with scheduled imports (Table 3-75).

⁹⁰ 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.

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 indicate 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 for the baseload, intermediate and peaking segments of generation supply are based on hourly energy market shares, unadjusted for imports.

FERC's Merger Policy Statement defines levels of concentration by HHI level. The market is unconcentrated if the market HHI is below 1000, the HHI if there were 10 firms with equal market shares. The market is moderately concentrated if the market HHI is between 1000 and 1800. The market is highly concentrated if the market HHI is greater than 1800, the HHI if there were between five and six firms with equal market shares.⁹¹

PJM HHI Results

Calculations for hourly HHI indicate that by FERC standards, the PJM energy market during the first nine months of 2020 was unconcentrated (Table 3-75).

Table 3-75 Hourly energy market HHI: January through September, 2019 and 2020⁹²

	Hourly Market HHI (Jan - Sep, 2019)	Hourly Market HHI (Jan - Sep, 2020)
Average	773	723
Minimum	572	520
Maximum	1098	1083
Highest market share (One hour)	26%	27%
Average of the highest hourly market share	19%	18%
# Hours	6,551	6,575
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

⁹¹ See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263 mimeo at 80 (1996).

⁹² This analysis includes all hours in the first nine months of 2019 and 2020, regardless of congestion.

Table 3-76 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first nine months of 2019 and 2020. The PJM energy market was unconcentrated overall with low concentration in the baseload segment, moderate concentration in the intermediate segment, and high concentration in the peaking segment.

Table 3-76 Hourly energy market HHI (By supply segment): January through September, 2019 and 2020

	Jan - Sep, 2019			Jan - Sep, 2020		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	659	808	1120	608	763	1120
Intermediate	694	1803	9237	719	1772	6441
Peak	701	6241	10000	633	6366	10000

Figure 3-52 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first nine months of 2020.⁹³

Figure 3-52 Fuel source distribution in unit segments: January through September, 2020⁹⁴

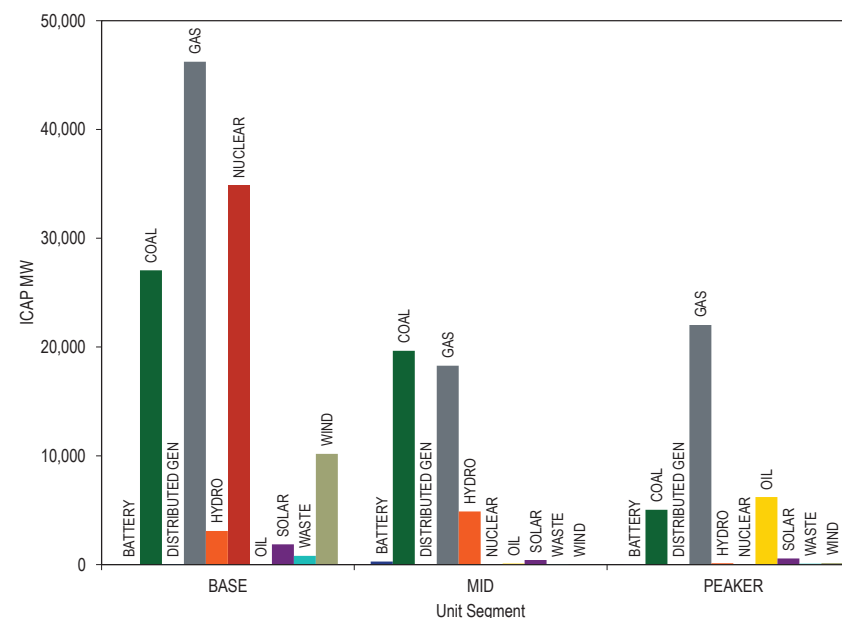


Figure 3-53 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking in the first nine months from 2016 through 2020. Figure 3-53 shows that the total ICAP of coal fired units in PJM that are classified as baseload has been steadily decreasing and the total ICAP of gas fired units in PJM that are classified as baseload is steadily increasing, based on operating history for the period from the first nine months of 2016 through 2020. In the first nine months of 2019, the ICAP of gas fired units classified as baseload exceeded the ICAP of coal fired units classified as baseload for the first time.

⁹³ The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the ICAP value of wind and solar units is derated from the nameplate capacity to reflect their effective load carrying capability.

⁹⁴ 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 3-53 Unit segment classification by fuel: January through September, 2016 through 2020

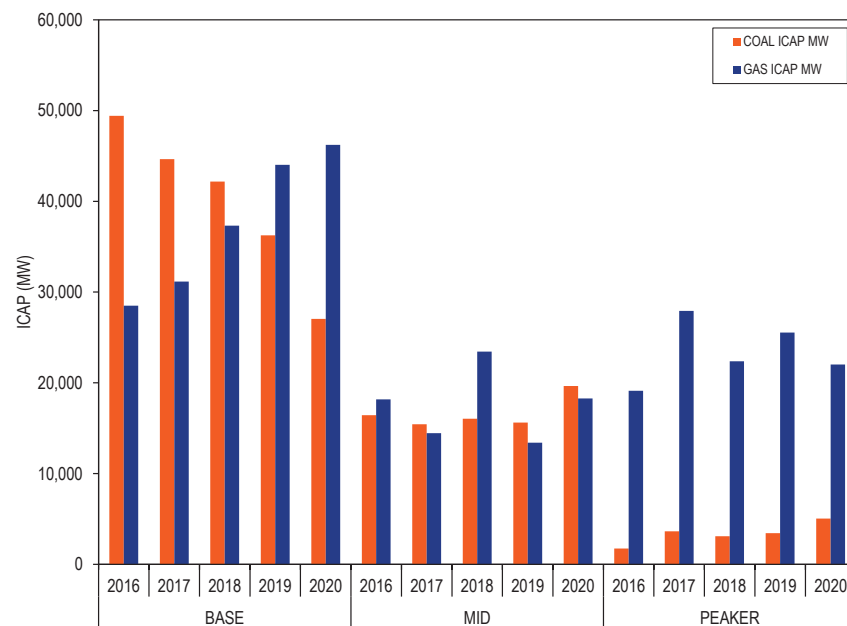
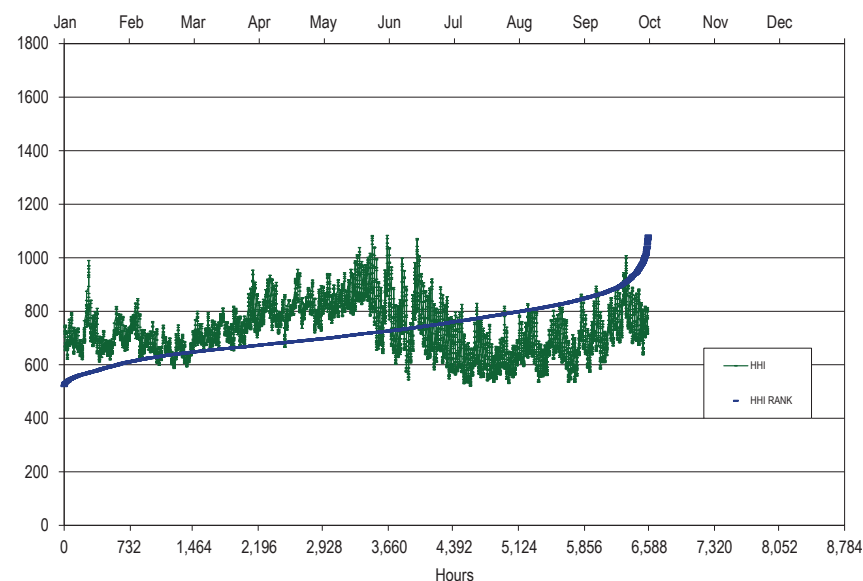


Figure 3-54 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2020.

Figure 3-54 Hourly energy market HHI: January through September, 2020



Market-Based Rates

Participation in the PJM market using offers that exceed costs requires market-based rate approval from FERC, which reviews the market-based rate authority of PJM market sellers on a triennial schedule to ensure that market sellers do not have market power or that market power is appropriately mitigated. The current triennial review for PJM nontransmission owning utilities began in June 2020. The next triennial review for PJM transmission owners will begin in December 2022.

With Order No. 861, FERC no longer uses structural market power assessments to determine whether sellers have market power in the PJM markets. Instead,

FERC relies on a rebuttable presumption that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.⁹⁵

The MMU has recommended since 2015 that changes to the offer capping process for the energy market are needed to ensure effective market power mitigation of units that fail the TPS test. The MMU has found that the capacity market is not competitive because the default Market Seller Offer Cap (MSOC) is inflated due to the use of an inaccurate estimate for the expected number of Performance Assessment Intervals (PAIs).⁹⁶ With these results and the supporting evidence, the MMU has challenged the rebuttable presumption of sufficient market power mitigation for the pending triennial review filings and recommended that conditions limiting sellers to cost-based energy offers and a revised capacity market offer cap be required until improvements are made to the offer capping processes in the energy and capacity markets so that suppliers cannot exercise market power.⁹⁷

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.”⁹⁸

FERC applies tests set forth in the 1996 Merger Policy Statement.^{99 100}

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, FERC applies a five step framework, which includes: (1) defining the market; (2) analyzing market concentration; (3) analyzing mitigative effects of new entry; (4) assessing efficiency gains; and (5) assessing viability of the parties without a merger. FERC also applies a Competitive Analysis Screen.¹⁰¹

The MMU reviews proposed mergers based on analysis of the impact of the merger or acquisition on market power given actual market conditions. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU’s review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is contrast to the typical merger filing that uses predefined local markets rather than the actual local markets. The MMU routinely files comments including such analyses.¹⁰² The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.¹⁰³ FERC has considered the MMU’s analysis in reviewing mergers.¹⁰⁴

The MMU also reviews transactions that involve ownership changes of PJM generation resources that are submitted to the Commission pursuant to section 203 of the Federal Power Act. Table 3-77 shows transactions that involved an entire generation unit or unit owner that were completed in the first nine months of 2020, as reported to the Commission. Table 3-78 shows transactions that involved transfers of partial unit ownership that were completed in the first nine months of 2020, as reported to the Commission.¹⁰⁵

95 *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, 168 FERC ¶ 61,040 (“Order No. 861”) (July 18, 2019).

96 See “Complaint of the Independent Market Monitor for PJM”, Docket No. EL19-47, (February 21, 2019), which can be accessed at <https://www.monitoringanalytics.com/Filings/2019/IMM_Complaint_Docket_No_EL19-XXX_20190221.pdf>.

97 See, for example, “Protest of the Independent Market Monitor for PJM,” Docket No. ER10-1556 (August 28, 2020).

98 18 U.S.C. § 824b.

99 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).

100 FERC has an open but inactive docket where the guidelines are under review. See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.

101 In February 2019, in response to 2017 amendments to Section 203 of the Federal Power Act, the Commission issued Order No. 855, implementing a \$10,000,000 minimum value for transactions requiring the Commission’s review. See 166 FERC ¶ 61,120 (2019).

102 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC20-49 (June 1, 2020).

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

104 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).

105 The transaction completion date is based on the notices of consummation submitted to the Commission.

Table 3-77 Completed transfers of entire PJM resources: January through September, 2020

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
FE Coal and Nuclear (Mansfield(retired), Sammis, Eastlake 6, Pleasants, Davis Besse, Perry, Beaver Valley)	FirstEnergy Generation	Avenue Capital (15-20%), Nuveen Asset Management (35 - 40%)	February 27, 2020	EC19-123
Energy Center Dover	Clearway Thermal LLC (Global Infrastructure Management LLC)	DB Energy Assets (DCO Energy and Basalt Infrastructure Partners)	March 2, 2020	EC19-142
Krayn Wind	Krayn Wind LLC	Oppidum Capital, S.L.	March 4, 2020	EC20-26
Beech Ridge Wind	Invenergy	Southern Power	May 1, 2020	EC20-27
Panda Liberty, Panda Patriot	Panda Power Funds	EIG, Carlyle Group	June 17, 2020	EC20-33
Longview Power	Ascribe Capital LLC, KKR Credit Advisors LLC, Seaport Global Securities, Tennenbaum Capital Partners, LLC & Others	Trilogy Portfolio Company, R&F Market LLC, Cetus Capital LLC, Eaton Vance Management & Others	July 30, 2020	EC20-70

Table 3-78 Completed transfers of partial ownership of PJM resources: January through September, 2020

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Yards Creek (50%)	PSEG	LS Power Development LLC	September 8, 2020	EC20-49
Fowler Ridge Wind Farm (50%)	Dominion Energy, Inc.	BP P.L.C.	September 29, 2020	EC20-81

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.¹⁰⁶ Such mitigation is designed to mitigate behavior over the long term, in addition to or instead of imposing short term asset divestiture requirements.

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.

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate market includes sufficient competing sellers

to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the generation at a similar price. This assumption requires that the total demand for energy can be met without the

supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not always correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.¹⁰⁷ 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

¹⁰⁷ 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).

¹⁰⁶ See 138 FERC ¶ 61,167 at P 19.

prices is not competing to meet the demand for energy.¹⁰⁸ 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 DEC. 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 3-55 shows the number of days in 2019 and in the first nine months of 2020 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers for the day-ahead energy market. One supplier was singly pivotal on the summer peak days in 2019 and 2020 and on August 26, 2020. Two suppliers were jointly pivotal on 35 days in 2019 and on 93 days in the first nine months of 2020. Three suppliers were jointly pivotal on 228 days in 2019 and on 219 days in the first nine months of 2020, despite average HHIs at persistently unconcentrated levels. In 2019 and 2020, the highest levels of aggregate market power occurred in the third quarter, PJM's peak load season. Outside the summer months, the frequency of pivotal suppliers increased on high demand days in the first week of October 2019 and around the Martin Luther King Jr. Day holiday in 2019 and 2020. The frequency of pivotal suppliers increased in the first nine months of 2020.

Figure 3-55 Days with pivotal suppliers and numbers of pivotal suppliers in the day-ahead energy market by quarter

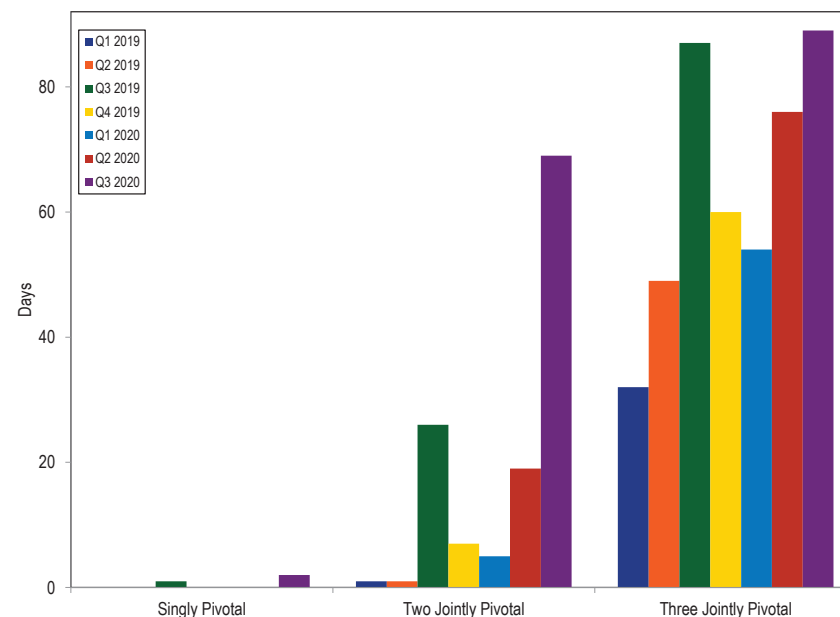


Table 3-79 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in the first nine months of 2020. The largest pivotal supplier was singly pivotal on two days in the first nine months of 2020. All of the top 10 suppliers were one of two pivotal suppliers on at least 13 days in the first nine months of 2020. All of the top 10 suppliers were one of three pivotal suppliers on at least 106 days in the first nine months of 2020.

¹⁰⁸ 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.

Table 3-79 Day-ahead market pivotal supplier frequency: January through September, 2020

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier		Days Jointly Pivotal with Two Other Suppliers	
			Percent of Days	Percent of Days	Percent of Days	Percent of Days
1	2	0.7%	91	33.2%	218	79.6%
2	0	0.0%	87	31.8%	219	79.9%
3	0	0.0%	84	30.7%	219	79.9%
4	0	0.0%	55	20.1%	169	61.7%
5	0	0.0%	47	17.2%	192	70.1%
6	0	0.0%	24	8.8%	154	56.2%
7	0	0.0%	23	8.4%	144	52.6%
8	0	0.0%	14	5.1%	120	43.8%
9	0	0.0%	14	5.1%	111	40.5%
10	0	0.0%	13	4.7%	106	38.7%

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.¹⁰⁹ If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based or price-based offers. Units are committed and dispatched on price-based offers,

¹⁰⁹ 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>.

if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

Local market power mitigation is implemented in both the day-ahead and real-time energy markets. However, the implementation of the TPS test and offer capping differ in the day-ahead and real-time energy markets.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether one, two or three suppliers are jointly pivotal in a defined local market. The TPS test is applied 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.

A metric to describe the number of local markets created by transmission constraints and the applicability of the TPS is the number of hours that each transmission constraint was binding in the real-time energy market over a period, by zone.

In the first nine months of 2020, the 500 kV system, the AEP, APS, ATSI, BGE, ComEd, Dominion, Met-Ed, PENELEC, and PPL Control Zones, and MISO experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from an interface constraint (Table 3-80).¹¹⁰ The AECO, DAY, DEOK, DLCO, DPL, EKPC, JCPL, OVEC, PECO, Pepco, PSEG, and RECO Control Zones did not have constraints binding for 75 or more hours in the first nine months of 2020. Table 3-80 shows that the 500 kV system and MISO experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from a binding interface constraint in every year from January through September, 2009 through 2020. The DAY, DEOK,

¹¹⁰ A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the Control Zones including AECO, BGE, DPL, JCPC, Met-Ed, PECO, PENELEC, Pepco, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

OVEC, and RECO Control Zones did not experience congestion resulting from one or more constraints binding for 75 or more hours or resulting from any binding interface constraint in any year from January through September, 2009 through 2020.

Table 3-80 Congestion hours resulting from one or more constraints binding for 75 or more hours or from an interface constraint: January through September, 2009 through 2020

	(Jan - Sep)											
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
500 kV System	2,026	2,755	2,383	254	652	1,370	722	700	289	458	1,216	1,767
AECO	149	0	88	0	0	0	0	383	0	0	78	0
AEP	878	281	1,409	0	711	1,460	1,705	402	333	948	0	739
APS	198	270	0	0	0	170	451	79	0	81	0	208
ATSI	101	0	0	1	13	255	408	0	415	1,866	237	263
BGE	90	99	0	1,501	316	1,142	3,079	4,789	772	1,861	205	2,399
ComEd	576	1,294	97	736	1,490	1,536	1,284	2,380	556	511	0	923
DAY	0	0	0	0	0	0	0	0	0	0	0	0
DEOK	0	0	0	0	0	0	0	0	0	0	0	0
DLCO	156	342	0	209	0	219	617	0	0	0	0	0
Dominion	310	483	596	200	0	0	1,202	647	80	136	0	475
DPL	0	0	0	126	88	503	1,138	1,329	326	295	0	0
EKPC	0	0	0	0	0	0	0	0	0	159	0	0
EXT	0	0	0	0	0	0	0	0	743	0	0	0
JCPL	0	0	0	0	0	0	79	0	0	0	0	0
Met-Ed	0	0	0	0	0	0	182	0	0	1,163	182	514
MISO	3,554	1,624	3,617	6,953	8,214	9,908	6,334	6,825	3,610	3,604	2,761	1,966
NYISO	0	0	0	0	167	121	149	1,374	332	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	256	944	414	606	713	130	83	0
PENELEC	0	0	0	0	0	1,441	1,187	451	1,415	935	952	1,469
Pepco	0	0	0	137	85	39	0	0	0	0	0	0
PPL	176	0	0	146	188	147	0	0	581	0	682	638
PSEG	368	479	605	259	1,462	1,795	2,463	168	98	226	174	0
RECO	0	0	0	0	0	0	0	0	0	0	0	0

The local market structure in the real-time energy market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first nine months of 2020.¹¹¹ 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

¹¹¹ See the *MMU Technical Reference for PJM Markets*, p. 38 "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

constraints because IT SCED looks ahead to target times that are in the near future to solve for constraints that could be binding, using the load forecast for those times. IT SCED solves for target times that occur at 15 minute time increments, unlike RT SCED that solves for every five minute time increment. The TPS statistics shown in this section present the data from the IT SCED TPS solution. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 3-81 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 3-82 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the 10 constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-81 and Table 3-82 include analysis of all the tests for every target time where IT SCED determined that constraint relief was needed for each of the constraints shown. The same target time can be evaluated by multiple IT SCED cases at different look ahead times. Each 15 minute target time is solved by 12 different IT SCED cases at different look ahead times.

Table 3-81 Three pivotal supplier test details for interface constraints: January through September, 2020

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AP South	Peak	320	599	16	4	12
	Off Peak	125	509	15	8	7
CPL - DOM	Peak	100	266	6	0	6
	Off Peak	85	197	6	0	5
PA Central	Peak	38	347	4	1	4
	Off Peak	64	350	4	0	4

Table 3-82 Three pivotal supplier test details for top 10 congested constraints: January through September, 2020

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bagley – Graceton	Peak	80	133	12	4	8
	Off Peak	67	129	12	5	7
Lenox – North Meshoppen	Peak	12	39	2	0	2
	Off Peak	6	33	2	0	2
PA Central	Peak	38	347	4	1	4
	Off Peak	64	350	4	0	4
Sub 85 – Sub 18	Peak	23	11	2	0	2
	Off Peak	22	11	2	0	2
Three Mile Island	Peak	77	92	10	2	8
	Off Peak	90	121	12	3	9
Logtown – North Delphos	Peak	24	47	1	0	1
	Off Peak	28	36	1	0	1
East Towanda – Hillside	Peak	22	58	2	0	2
	Off Peak	12	55	2	0	2
Ironwood – North Lebanon	Peak	64	107	1	0	1
	Off Peak	66	110	1	0	1
Paradise – BR Tap	Peak	29	4	2	0	2
	Off Peak	32	4	2	0	2
Graceton – Safe Harbor	Peak	68	91	11	3	9
	Off Peak	44	85	10	4	6

The three pivotal supplier test is applied every time the IT SCED solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for offer capping. Steam unit offers that are offer capped in the day-ahead energy market continue to be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time. Steam unit offers that are not offer capped in the day-ahead energy market continue to not be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time.¹¹² 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

¹¹² If a steam unit were to lower its cost-based offer in real-time, it would become eligible for offer capping based on the online TPS test.

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.

Units committed in the day-ahead market often fail the TPS test in the real-time market when they are redispatched to provide relief to transmission constraints, even though they did not fail the TPS test in the day-ahead market. These units are able to set prices with a positive markup in the real-time market. Units that cleared the day-ahead market on their price based schedule were evaluated to identify the units whose offers were mitigated in real-time and the units that cleared on price offers in real-time despite failing the real-time TPS test. Table 3-83 shows that 0.4 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-83 shows that 7.0 percent of unit hours that cleared the day-ahead market on their price based offer cleared on their price based offer in real-time despite failing the real-time TPS test.

Table 3-83 Day-Ahead committed units that cleared real-time: January through September, 2020

Period	Day Ahead Price Based Unit Hours That Cleared Real-Time on Cost	Day Ahead Price Based Unit Hours That Cleared Real-Time on Price	Day Ahead Price Based Unit Hours That Failed Real-Time TPS and Cleared Real-Time on Price	Percent Day Ahead Price Based Unit Hours That Cleared Real-Time on Cost	Percent Day Ahead Price Based Unit Hours That Failed Real-Time TPS and Cleared Real-Time on Price
Jan - Sep, 2020	8,868	1,973,836	138,726	0.4%	7.0%

The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market.

Table 3-84 and Table 3-85 provide, for the identified constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. Tests where there was at least one offline unit or an online unit eligible for offer capping are considered tests that could have resulted in offer capping. 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 3-84 Summary of three pivotal supplier tests applied for interface constraints: January through September, 2020

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
AP South	Peak	62	50	81%	0	0%	0%
	Off Peak	6	6	100%	0	0%	0%
CPL - DOM	Peak	2,185	2,151	98%	2	0%	0%
	Off Peak	1,008	1,007	NA	1	NA	NA
PA Central	Peak	14,757	10,097	68%	2	0%	0%
	Off Peak	15,314	10,499	69%	4	0%	0%

Table 3-85 Summary of three pivotal supplier tests applied for top 10 congested constraints: January through September, 2020

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
Bagley – Graceton	Peak	30,836	30,368	98%	201	1%	1%
	Off Peak	20,027	19,821	99%	122	1%	1%
Lenox – North Meshoppen	Peak	17,538	12,958	74%	2	0%	0%
	Off Peak	11,732	4,713	40%	0	0%	0%
PA Central	Peak	14,757	10,097	68%	2	0%	0%
	Off Peak	15,314	10,499	69%	4	0%	0%
Sub 85 – Sub 18	Peak	5,072	1,042	21%	0	0%	0%
	Off Peak	9,597	1,209	13%	0	0%	0%
Three Mile Island	Peak	11,462	11,085	97%	27	0%	0%
	Off Peak	3,489	3,422	98%	2	0%	0%
Logtown – North Delphos	Peak	6,641	99	1%	0	0%	0%
	Off Peak	5,250	65	1%	0	0%	0%
East Towanda – Hillside	Peak	5,568	4,222	76%	1	0%	0%
	Off Peak	3,023	1,511	50%	0	0%	0%
Ironwood – North Lebanon	Peak	7,193	1,294	18%	0	0%	0%
	Off Peak	5,614	639	11%	0	0%	0%
Paradise – BR Tap	Peak	3,755	1,216	32%	2	0%	0%
	Off Peak	2,176	870	40%	0	0%	0%
Graceton – Safe Harbor	Peak	2,401	2,352	98%	18	1%	1%
	Off Peak	6,541	6,511	100%	4	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.

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.¹¹³

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

Given the ability to submit offer curves with different markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high

¹¹³ See PJM Operating Agreement Schedule 1 § 6.4.1(g).

markup at higher output levels. Figure 3-56 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 3-56 Offers with varying markups at different MW output levels

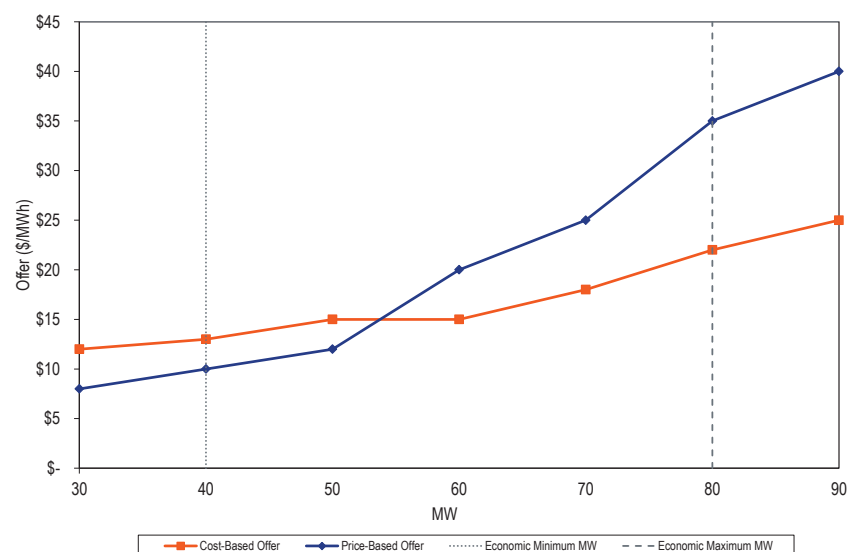


Table 3-86 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves in the PJM Day-Ahead and Real-Time Energy Markets, in the first nine months of 2020. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, and they may elect to offer price-based offers, but are not required to do so.

Table 3-86 Units offered with crossing curves in the day-ahead and real-time energy markets: January through September, 2020

2020	Day-Ahead			Real-Time		
	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves
Jan	85,517	837,768	10.2%	81,143	778,951	10.4%
Feb	83,756	794,904	10.5%	78,559	733,533	10.7%
Mar	94,462	854,242	11.1%	86,233	752,204	11.5%
Apr	86,611	824,640	10.5%	76,431	721,582	10.6%
May	102,154	846,408	12.1%	89,419	739,992	12.1%
Jun	109,159	816,144	13.4%	100,921	765,834	13.2%
Jul	122,209	843,408	14.5%	115,707	798,708	14.5%
Aug	134,955	842,616	16.0%	127,447	793,736	16.1%
Sep	121,858	811,944	15.0%	111,939	734,013	15.3%
Total	940,681	7,472,074	12.6%	867,799	6,818,553	12.7%

Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade mitigation. For example, a unit may 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. Table 3-87 shows the number and percent of unit schedule hours when units offered lower minimum run times in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-87 Units offered with lower minimum run time on price compared to cost but with positive markup in the day-ahead and real-time energy markets: January through September, 2020

2020	Day-Ahead			Real-Time		
	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost
Jan	27,504	837,768	3.3%	22,246	778,951	2.9%
Feb	25,392	794,904	3.2%	20,879	733,533	2.8%
Mar	26,751	854,242	3.1%	21,182	752,204	2.8%
Apr	25,920	824,640	3.1%	20,264	721,582	2.8%
May	29,160	846,408	3.4%	22,615	739,992	3.1%
Jun	30,576	816,144	3.7%	26,330	765,834	3.4%
Jul	31,992	843,408	3.8%	27,994	798,708	3.5%
Aug	32,064	842,616	3.8%	27,452	793,736	3.5%
Sep	31,680	811,944	3.9%	25,027	734,013	3.4%
Total	261,039	7,472,074	3.5%	213,989	6,818,553	3.1%

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 3-57 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 3-57 Offers with a positive markup but different economic minimum MW

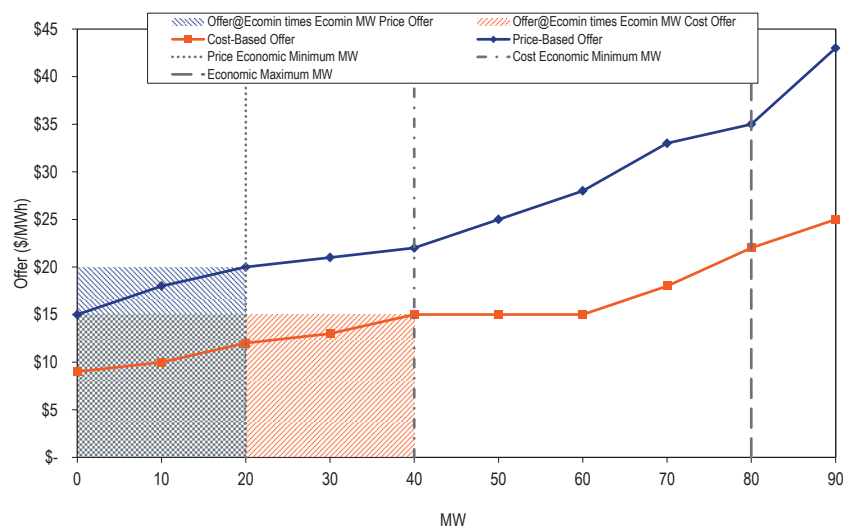


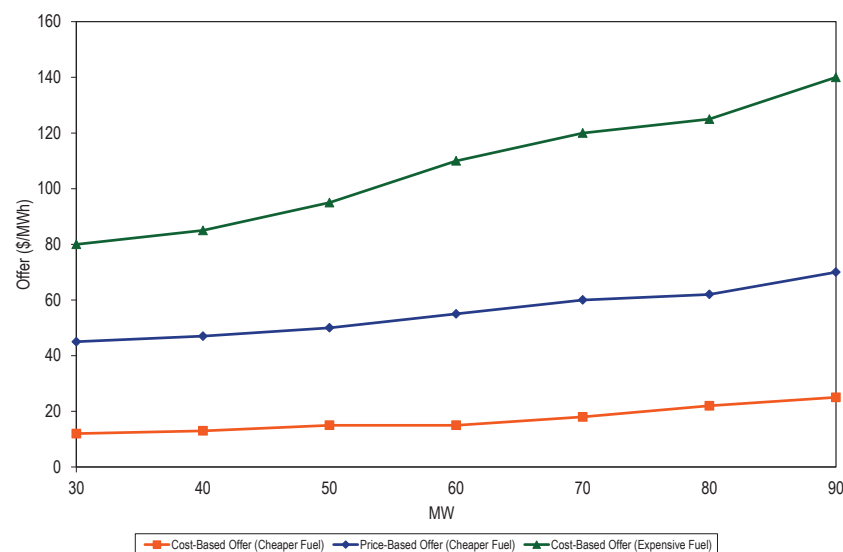
Table 3-88 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-88 Units offered with lower economic minimum MW on price compared to cost but with positive markup in the day-ahead and real-time energy markets: January through September, 2020

2020	Day-Ahead			Real-Time		
	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost
Jan	168	837,768	0.0%	144	778,951	0.0%
Feb	216	794,904	0.0%	48	733,533	0.0%
Mar	96	854,242	0.0%	96	752,204	0.0%
Apr	72	824,640	0.0%	72	721,582	0.0%
May	168	846,408	0.0%	168	739,992	0.0%
Jun	168	816,144	0.0%	168	765,834	0.0%
Jul	142	843,408	0.0%	134	798,708	0.0%
Aug	216	842,616	0.0%	223	793,736	0.0%
Sep	168	811,944	0.0%	286	734,013	0.0%
Total	1,414	7,472,074	0.0%	1,339	6,818,553	0.0%

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 3-58 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 3-58 Dual fuel unit offers



These issues can be solved by simple rule changes.¹¹⁴ 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 3-90. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. Until November 1, 2017, only uncommitted resources, started to relieve a transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.¹¹⁵ Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer.

The offer capping percentages shown in Table 3-89 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.¹¹⁶ 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

¹¹⁴ 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.

¹¹⁵ See OAIT Attachment K Appendix § 6.4.1.

¹¹⁶ Prior to the 2018 *Quarterly State of the Market Report for PJM: January through June*, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

dispatched on their cost-based offer subsequent to a real-time hourly offer update. This is reflected in the slightly higher rate of offer capping in the real-time energy market in since 2017

Table 3-89 Offer capping statistics – energy only: January through September, 2016 to 2020

(Jan-Sep)	Real-Time		Day-Ahead	
	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2016	0.4%	0.3%	0.0%	0.1%
2017	0.3%	0.1%	0.0%	0.1%
2018	1.0%	0.5%	0.1%	0.1%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.3%

Table 3-90 shows the offer capping percentages including units committed to provide constraint relief and units committed for reliability reasons, including reactive support. PJM created closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs in the closed loop interfaces, 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 3-89. Prior to closed loop interfaces, these units were considered as committed for reactive support, and were included in the offer capping statistics for reliability in Table 3-91.

Table 3-90 Offer capping statistics for energy and reliability: January through September, 2016 to 2020

(Jan-Sep)	Real-Time		Day-Ahead	
	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2016	0.4%	0.3%	0.1%	0.1%
2017	0.4%	0.4%	0.1%	0.3%
2018	1.2%	0.8%	0.2%	0.4%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.4%

Table 3-91 shows the offer capping percentages for units committed for reliability reasons, including units committed for reactive support. The data in Table 3-91 is the difference between the offer cap percentages shown in Table 3-90 and Table 3-89.

Table 3-91 Offer capping statistics for reliability: January through September, 2016 to 2020

(Jan-Sep)	Real-Time		Day-Ahead	
	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2016	0.0%	0.0%	0.1%	0.0%
2017	0.1%	0.3%	0.1%	0.2%
2018	0.1%	0.3%	0.1%	0.2%
2019	0.0%	0.0%	0.0%	0.0%
2020	0.0%	0.0%	0.0%	0.0%

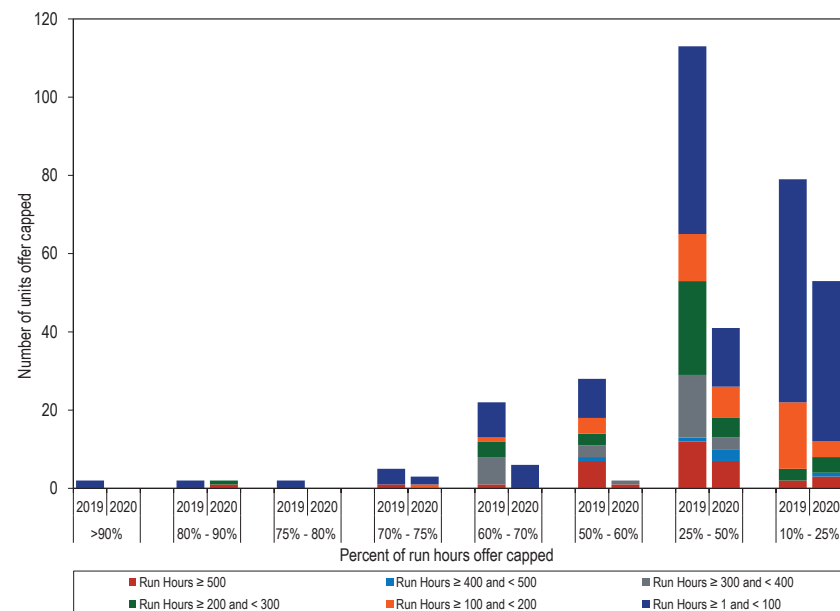
Table 3-92 presents data on the frequency with which units were offer capped in the first nine months of 2019 and 2020 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons. Table 3-92 shows that no units were offer capped for 90 percent or more of their run hours in the first nine months of 2020 compared to two units in the first nine months of 2019.

Table 3-92 Real-time offer capped unit statistics: January through September, 2019 and 2020

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Offer-Capped Hours					
	Jan - Sep	Hours		Hours		Hours
		Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200
90%	2019	0	0	0	0	0
	2020	0	0	0	0	0
80% and < 90%	2019	0	0	0	0	0
	2020	1	0	0	1	0
75% and < 80%	2019	0	0	0	0	0
	2020	0	0	0	0	0
70% and < 75%	2019	1	0	0	0	0
	2020	0	0	0	0	1
60% and < 70%	2019	1	0	7	4	1
	2020	0	0	0	0	0
50% and < 60%	2019	7	1	3	3	4
	2020	1	0	1	0	0
25% and < 50%	2019	12	1	16	24	12
	2020	7	3	3	5	8
10% and < 25%	2019	2	0	0	3	17
	2020	3	1	0	4	4

Figure 3-59 shows the frequency with which units were offer capped in the first nine months of 2019 and 2020 for failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons.

Figure 3-59 Real-time offer capped unit statistics: January through September, 2019 and 2020



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 $(\text{Price} - \text{Cost})/\text{Price}$.¹¹⁷ The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is

¹¹⁷ 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 $(\text{Price} - \text{Cost})/\text{Price}$ when price is greater than cost, and $(\text{Price} - \text{Cost})/\text{Cost}$ when price is less than cost.

higher than the cost-based offer price. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup Index

Table 3-93 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost-based offers. Table 3-94 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.¹¹⁸ 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.

Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and components of operating and maintenance costs that are not short run marginal costs. The PJM market rules permit the 10 percent adder and maintenance costs, which are not short run marginal costs, under the definition of cost-

¹¹⁸ 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.

based offers. Actual market behavior reflects the fact that neither is part of a competitive offer and neither is a short run marginal cost.¹¹⁹

In the first nine months of 2020, 98.4 percent of marginal units had offer prices less than \$50 per MWh. The average dollar markups of units with offer prices less than \$10 was negative (-\$1.16 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between \$10 and \$15 was positive (\$0.22 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM market rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first nine months of 2020, none had offer prices above \$400 per MWh. Among the units that were marginal in the first nine months of 2019, less than one percent had offer prices greater than \$400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2020 was more than \$200, while the highest markup in the first nine months of 2019 was more than \$450.

Table 3-93 Average, real-time marginal unit markup index (By offer price category unadjusted): January through September, 2019 and 2020

Offer Price Category	2019 (Jan - Sep)			2020 (Jan - Sep)		
	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< \$10	(0.01)	(\$2.94)	4.8%	(0.05)	(\$1.16)	13.8%
\$10 to \$15	(0.02)	(\$0.33)	11.5%	0.03	\$0.22	40.2%
\$15 to \$20	0.06	\$0.74	30.8%	0.00	(\$0.34)	29.9%
\$20 to \$25	0.01	(\$0.01)	30.9%	0.03	(\$0.05)	10.6%
\$25 to \$50	0.07	\$1.62	19.7%	0.12	\$3.26	3.9%
\$50 to \$75	0.37	\$21.65	1.0%	0.53	\$31.06	0.4%
\$75 to \$100	0.56	\$48.16	0.4%	0.52	\$44.59	0.2%
\$100 to \$125	0.33	\$35.45	0.3%	0.09	\$10.25	0.6%
\$125 to \$150	0.43	\$58.89	0.1%	0.02	\$2.58	0.4%
>= \$150	0.07	\$16.08	0.6%	0.36	\$59.98	0.2%

¹¹⁹ See PJM, "Manual 15: Cost Development Guidelines," Rev. 35 (April 24, 2020).

Table 3-94 Average, real-time marginal unit markup index (By offer price category adjusted): January through September, 2019 and 2020

Offer Price Category	2019 (Jan - Sep)			2020 (Jan - Sep)		
	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< \$10	0.02	(\$2.64)	4.8%	0.01	(\$0.58)	13.8%
\$10 to \$15	0.07	\$0.93	11.5%	0.11	\$1.37	40.2%
\$15 to \$20	0.14	\$2.30	30.8%	0.09	\$1.26	29.9%
\$20 to \$25	0.10	\$2.02	30.9%	0.11	\$1.93	10.6%
\$25 to \$50	0.15	\$4.18	19.7%	0.19	\$5.72	3.9%
\$50 to \$75	0.42	\$24.93	1.0%	0.57	\$33.51	0.4%
\$75 to \$100	0.60	\$51.52	0.4%	0.56	\$48.50	0.2%
\$100 to \$125	0.40	\$42.01	0.3%	0.18	\$19.63	0.6%
\$125 to \$150	0.48	\$65.89	0.1%	0.12	\$14.50	0.4%
\$150 to \$400	0.16	\$29.79	0.5%	0.42	\$69.67	0.2%
>= \$400	0.20	\$87.44	0.0%	0.00	\$0.00	0.0%

Table 3-95 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.¹²⁰ Table 3-96 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types. In the first nine months of 2020, using unadjusted cost-based offers for coal units, 56.47 percent of marginal coal units had negative markups. In the first nine months of 2020, using adjusted cost-based offers for coal units, 34.56 percent of marginal coal units had negative markups.

Table 3-95 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): January through September, 2019 and 2020

Type/Fuel	2019 (Jan - Sep)			2020 (Jan - Sep)		
	Negative	Zero	Positive	Negative	Zero	Positive
Coal	52.12%	23.67%	24.20%	56.47%	22.10%	21.43%
Gas	33.06%	14.94%	52.00%	35.59%	6.52%	57.88%
Oil	1.88%	96.94%	1.18%	3.11%	96.53%	0.36%

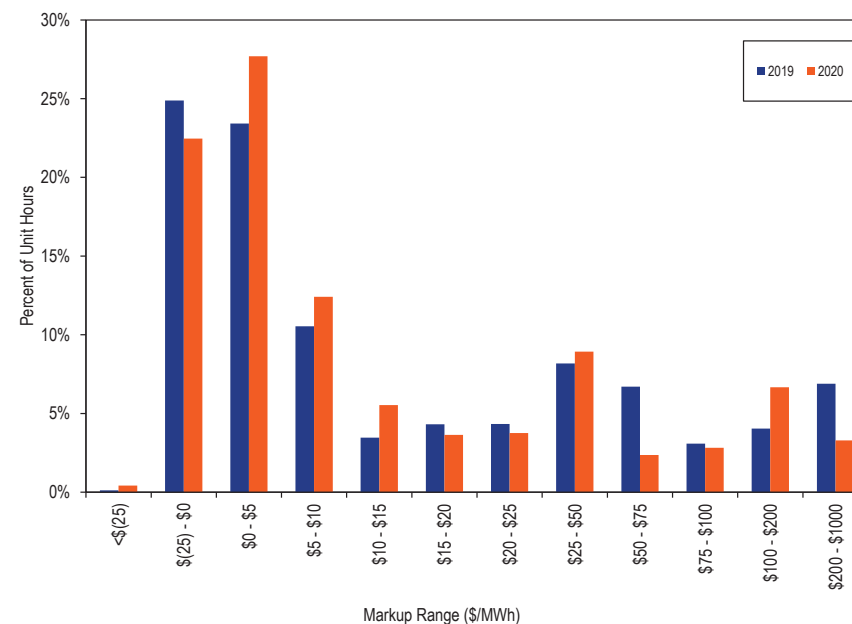
¹²⁰ Other fuel types were excluded based on data confidentiality rules.

Table 3-96 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): January through September, 2019 and 2020

Type/Fuel	2019 (Jan - Sep)			2020 (Jan - Sep)		
	Negative	Zero	Positive	Negative	Zero	Positive
Coal	34.96%	18.81%	46.23%	34.56%	17.71%	47.73%
Gas	12.41%	7.69%	79.90%	21.90%	4.91%	73.20%
Oil	0.47%	96.94%	2.59%	2.89%	66.06%	31.05%

Figure 3-60 shows the frequency distribution of hourly markups for all gas units offered in the first nine months of 2019 and 2020 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used in the frequency distributions.¹²¹ Of the gas units offered in the PJM market in the first nine months of 2020, 22.8 percent of gas unit-hours had a maximum markup that was negative. More than 10.0 percent of gas fired unit-hours had a maximum markup above \$100 per MWh. The number of gas units with markups from \$200 to \$1,000 per MWh decreased due to increases in the maintenance costs allowable in cost-based offers, not a decrease in the offer level and not a decrease in the markups.

Figure 3-60 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through September, 2019 and 2020



¹²¹ The categories in the frequency distribution were chosen so as to maintain data confidentiality.

Figure 3-61 shows the frequency distribution of hourly markups for all coal units offered in the first nine months of 2019 and 2020 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first nine months of 2020, 48.5 percent of coal unit-hours had a maximum markup that was negative or equal to zero, increasing from 40.9 in the first nine months of 2019.

Figure 3-61 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through September, 2019 and 2020

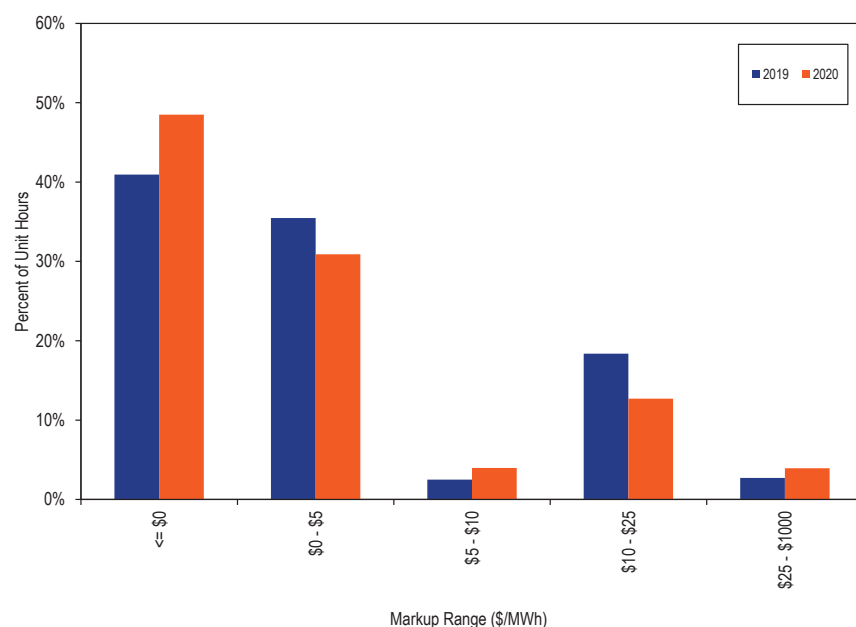
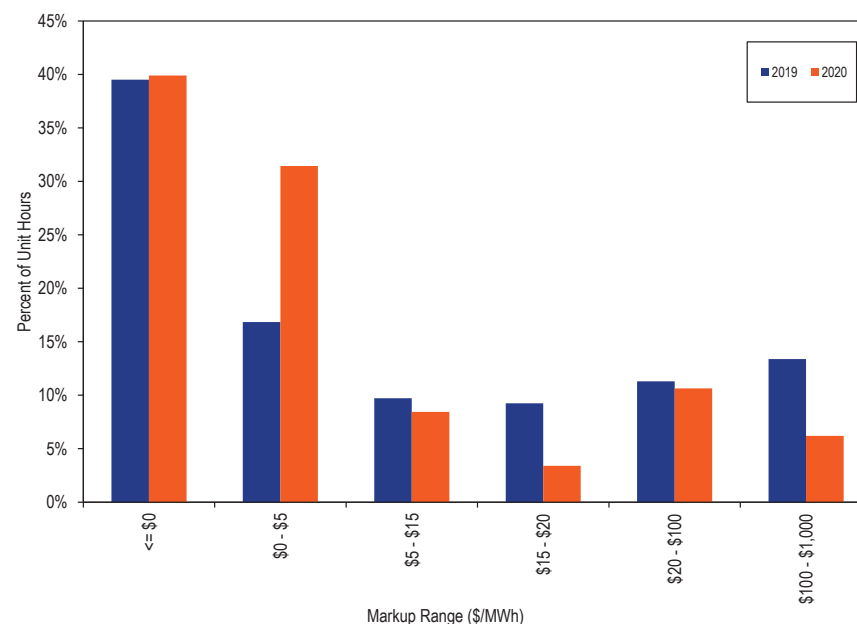


Figure 3-62 shows the frequency distribution of hourly markups for all offered oil units in the first nine months of 2019 and 2020 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first nine months of 2020, 39.9 percent of oil unit-hours had a maximum markup that was negative or equal to zero. More than 6.2 percent of oil fired unit-hours had a maximum markup above \$100 per MWh. The number of oil units with

markups from \$100 to \$1,000 per MWh decreased due to increases in the maintenance costs allowable in cost-based offers, not a decrease in the offer level and not a decrease in the markups.

Figure 3-62 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through September, 2019 and 2020

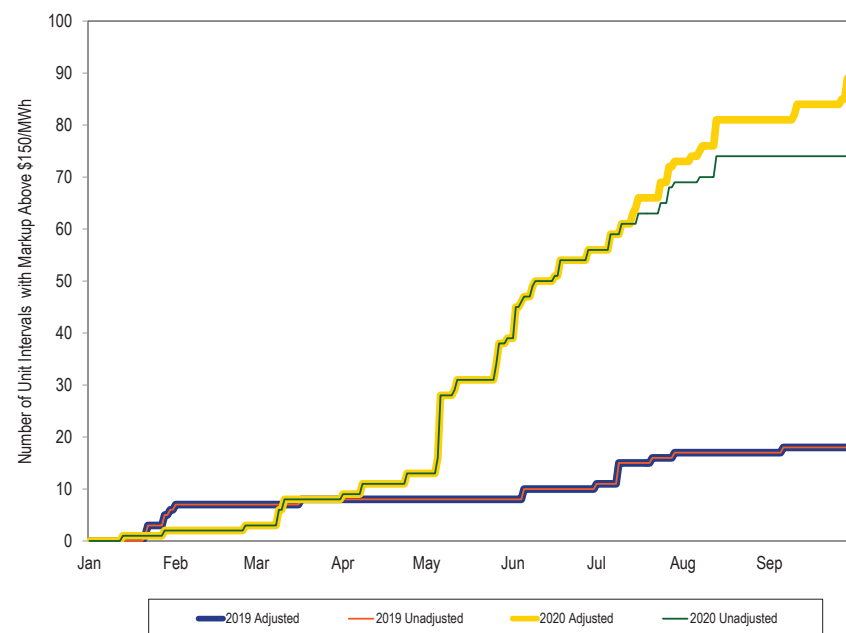


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 3-63 shows the number of marginal unit intervals in the first nine months of 2020 and 2019 with markup above \$150 per MWh.

Figure 3-63 Cumulative number of unit intervals with markups above \$150 per MWh: January through September, 2019 and 2020



Day-Ahead Markup Index

Table 3-97 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 the first nine months of 2020, 94.7 percent of marginal generating units had offer prices less than \$25 per MWh. The average dollar markups of units with offer prices less than \$10 was negative (-\$0.61 per MWh) when using unadjusted cost-based offers. The average dollar markups

of units with offer prices between \$10 and \$15 was positive (\$0.78 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 the first nine months of 2019 and 2020, 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 the first nine months of 2020 was more than \$70 per MWh while the highest markup in the first nine months of 2019 was more than \$90 per MWh.

Table 3-97 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through September, 2019 and 2020

Offer Price Category	2019 (Jan - Sep)			2020 (Jan - Sep)		
	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< \$10	0.50	\$0.59	2.1%	(0.01)	(\$0.61)	9.2%
\$10 to \$15	0.00	(\$0.06)	7.0%	0.08	\$0.78	33.8%
\$15 to \$20	0.06	\$0.92	28.9%	0.10	\$1.37	38.5%
\$20 to \$25	0.02	\$0.21	34.2%	0.02	(\$0.06)	13.1%
\$25 to \$50	0.05	\$1.38	26.2%	0.05	\$1.28	4.6%
\$50 to \$75	0.17	\$9.28	0.9%	0.18	\$11.02	0.2%
\$75 to \$100	0.35	\$32.13	0.1%	0.30	\$24.65	0.0%
\$100 to \$125	0.52	\$53.65	0.1%	(0.01)	(\$0.78)	0.1%
\$125 to \$150	0.32	\$45.31	0.1%	0.00	\$0.00	0.2%
>= \$150	0.06	\$10.11	0.4%	0.01	\$1.49	0.2%

Table 3-98 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers. In the first nine months of 2020, 38.5 percent of marginal generating units had offers between \$15 and \$20 per MWh, and the average dollar markup and the average markup index were both positive. The average markup index decreased from 0.53 in the first nine months of 2019, to 0.06 in the first nine months of 2020 in the offer price category less than \$10.

Table 3-98 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through September, 2019 and 2020

Offer Price Category	2019 (Jan – Sep)			2020 (Jan – Sep)		
	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< \$10	0.53	\$0.75	2.1%	0.06	(\$0.08)	9.2%
\$10 to \$15	0.09	\$1.17	7.0%	0.15	\$1.88	33.8%
\$15 to \$20	0.14	\$2.46	28.9%	0.18	\$2.80	38.5%
\$20 to \$25	0.10	\$2.22	34.2%	0.10	\$1.94	13.1%
\$25 to \$50	0.13	\$3.95	26.2%	0.13	\$3.90	4.6%
\$50 to \$75	0.24	\$13.53	0.9%	0.26	\$15.44	0.2%
\$75 to \$100	0.41	\$37.34	0.1%	0.30	\$25.30	0.0%
\$100 to \$125	0.56	\$58.19	0.1%	0.01	\$0.64	0.1%
\$125 to \$150	0.38	\$53.81	0.1%	0.02	\$3.17	0.2%
>= \$150	0.14	\$24.40	0.4%	0.09	\$15.37	0.2%

No Load and Start Cost Markup

Generator energy offers in PJM are comprised of three parts, an incremental energy offer curve, no load cost and start cost. In cost-based offers, all three parts are capped at the level allowed by Schedule 2 of the Operating Agreement, the Cost Development Guidelines (Manual 15) and Fuel Cost Policies approved by PJM. In price-based offers, the incremental energy offer curve is capped at \$1,000 per MWh (unless the verified cost-based offer exceeds \$1,000 per MWh, but cannot exceed \$2,000 per MWh). The no load and start costs in price-based offers can be price-based or cost-based. If price-based is selected, the no load and start costs do not have a cap. If cost-based is selected, the cap is the same as the cap of the no load and start costs in the cost-based offers. Table 3-99 shows the caps on the three parts of cost-based and price-based offers.

Table 3-99 Cost-based and price-based offer caps

	No Load and Start			
Offer Type	Cost Option	Incremental Offer Curve Cap	No Load Cost Cap	Start Cost Cap
Cost-Based	Cost-Based	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies		
Price-Based	Cost-Based	\$1,000/MWh or based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies if verified cost-based offer exceeds \$1,000/MWh but no more than \$2,000/MWh.	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies
	Price-Based		No cap but can only be changed twice a year.	No cap but can only be changed twice a year.

Generators are allowed to choose price-based or cost-based no load cost and start costs twice a year. The choice is fixed for six months (April through September and October through March). Table 3-100 shows the number of units that chose the cost-based option and the price-based option. In the first nine months of 2020, 91 percent of all generators that submitted no load or start costs chose to have cost-based no load and start costs in their price-based offers, 8 percentage points higher than in the first nine months of 2019.

Table 3-100 Number of units selecting cost-based and price-based no load and start costs

No Load and Start Cost Option	Jan – Sep 2019		Jan – Sep 2020	
	Number of units	Percent	Number of units	Percent
Cost-Based	499	83%	547	91%
Price-Based	105	17%	55	9%
Total	604	100%	602	100%

Generators can have positive or negative markups in their no load and start costs under the price-based option. Generators cannot have positive markups in no load and start costs when they select the cost-based option. Table 3-101 shows the average markup in the no load and start costs in the first nine months of 2019 and 2020. Generators that selected the cost-based option, offer on average with a negative markup on the no load cost (9 percent) and a negative markup on the start costs (6 percent). This means that units tend to discount their price-based offers from their cost-based offers. Generators that selected the price-based option, offer on average with a negative markup on the no load cost (2 percent) and with a substantial positive markup on the start costs (677 percent).

Table 3-101 No load and start cost markup

Period	No Load and Start		Intermediate		
	Cost Option	No Load Cost	Cold Start Cost	Start Cost	Hot Start Cost
Jan - Sep 2019	Cost-Based	(9%)	(7%)	(6%)	(6%)
	Price-Based	(22%)	316%	369%	379%
Jan - Sep 2020	Cost-Based	(9%)	(7%)	(6%)	(6%)
	Price-Based	(2%)	570%	711%	750%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the day-ahead energy market and the real-time energy market helps ensure competitive market outcomes even in the presence of structural market power.

Cost-based offers in PJM affect all aspects of the PJM energy market. Cost-based offers affect prices when units are committed and dispatched on their cost-based offers. In the first nine months of 2020, 6.6 percent of the marginal units set prices based on cost-based offers, 2.7 percentage points less than the first nine months of 2019.

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

The efficacy of market power mitigation rules also depends on the accuracy of cost-based offers. Some unit owners use fuel cost policies that are not algorithmic, verifiable, and systematic. These inadequate fuel cost policies permit overstated fuel costs in cost-based offers. FERC's decision to permit maintenance costs in cost-based offers that are not short run marginal costs also results in overstated cost-based offers.

When market power mitigation is not effective due to inaccurate cost-based offers that exceed short run marginal costs, market power causes increases in market prices above the competitive level.

Short Run Marginal Costs

Short run marginal costs are the only costs relevant to competitive offers in the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. The current PJM market rules distinguish costs includable in cost-based energy offers from costs includable in cost-based capacity market offers based on whether costs are directly related to energy production. The rules do not provide a clear standard. Energy production is the sole purpose of a power plant. Therefore, all costs, including the sunk costs, are directly related to energy production. This current ambiguous criterion is incorrect and, in addition, allows for multiple interpretations, which could lead to tariff violations. The incorrect rules will lead to higher energy market prices and higher uplift.

There are three types of costs identified under PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer is that the cost is "directly related to electric production."¹²²

Variable costs are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are fuel costs, emission allowance costs, operating costs, and energy market opportunity costs.¹²³

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM

¹²² See 167 FERC ¶ 61,030 (2019).

¹²³ See OA Schedule 2(a).

includes overhaul and maintenance costs, replacement of obsolete equipment, and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, improvement of working equipment, maintenance expenses triggered by a time milestone (e.g. annual, weekly) and pipeline reservation charges in costs not related to electric production.

Fixed costs are costs associated with an investment in a facility including the return on and of capital.

The MMU recommends that PJM require that the level of costs includable in cost-based offers not exceed the unit's short run marginal cost.

Fuel Cost Policies

Fuel cost policies (FCP) document the process by which market sellers calculate the fuel cost component of their cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel.

Fuel Cost Policy Review

Table 3-102 shows the status of all Fuel Cost Policies as of September 30, 2020. As of September 30, 2020, 1,199 units (91 percent) had an FCP passed by the MMU, zero units had an FCP under the MMU review (submitted) and 113 units (9 percent) had an FCP failed by the MMU. The number of units with fuel cost policies failed by the MMU included units with 16,876 MW. All units had an FCP approved by PJM. The proportion of units with fuel cost policies passed by the MMU decreased by one percent compared as of September 30, 2020 compared to the 2019 Annual Fuel Cost Policy Review.

Table 3-102 FCP Status for PJM Generating Units: September 30, 2020

PJM Status	MMU Status			
	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	0	0	0	0
Customer Input Required	0	0	0	0
Approved	1,199	0	113	1,312
Revoked	0	0	0	0
Expired	0	0	0	0
Total	1,199	0	113	1,312

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:¹²⁴ Verifiable means that the FCP must provide that a market seller provide a fuel price that can be calculated by the MMU after the fact with the same data available to the market seller at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the FCP must document a standardized method or methods for calculating fuel costs including objective triggers for each method.¹²⁵ PJM and FERC did not agree that Fuel Cost Policies should be algorithmic:¹²⁶ Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').¹²⁷

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.

¹²⁴ Answer of PJM Interconnection, LLC. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) ("October 7th Filing") at P 11.

¹²⁵ Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) ("September 16th Filing") at P 8.

¹²⁶ October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).

¹²⁷ September 16th Filing at P 8.

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:¹²⁸ accuracy (reflect applicable costs accurately); procurement practices (provide information sufficient for the verification of the market seller's fuel procurement practices where relevant); fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts).

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 units.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were:

- 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, objective, 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

¹²⁸ See PJM Operating Agreement Schedule 2 § 2.3 (a).

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, often by a wide margin. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved 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.

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 15.¹²⁹ Penalties became effective May 15, 2017.

¹²⁹ 158 FERC ¶ 61,133 (2017).

In the first nine months of 2020, 106 penalty cases were identified, 97 resulted in assessed cost-based offer penalties, five resulted in disagreement between the MMU and PJM, and four remain pending PJM's determination. These cases were from 94 units owned by 20 different companies. Table 3-104 shows the penalties by the year in which participants were notified.

Table 3-103 Cost-based offer penalty cases by year notified: May 2017 through September 2020

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	187	161	26	0	138	35
2019	57	57	0	0	57	19
2020	106	97	5	4	94	20
Total	407	371	32	4	294	53

Since 2017, 407 penalty cases have been identified, 371 resulted in assessed cost-based offer penalties, 32 resulted in disagreement between the MMU and PJM, and four remain pending PJM's determination. The 371 cases were from 294 units owned by 53 different companies. The total penalties were \$2.6 million, charged to units that totaled 76,477 available MW. The average penalty was \$1.57 per available MW. This means that a 100 MW unit would have paid a penalty of \$3,772.¹³⁰ Table 3-104 shows the total cost-based offer penalties since 2017 by year.

Table 3-104 Cost-based offer penalties by year: May 2017 through September 2020

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty (\$/MW)
2017	92	20	\$556,826	16,930	\$1.56
2018	127	34	\$1,265,698	26,343	\$2.27
2019	79	20	\$490,926	19,798	\$1.10
2020	91	18	\$310,801	13,406	\$1.01
Total	389	55	\$2,624,251	76,477	\$1.57

¹³⁰ 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.

The incorrect cost-based offers resulted from incorrect application of fuel cost policies, lack of approved fuel cost policies, fuel cost policy violations, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

2020 Fuel Cost Policy Changes

On July 28, 2020, the Commission approved tariff revisions that modified the fuel cost policy process and the cost-based offer penalties.¹³¹ The revisions were:

- Replacement of the annual review process with a periodic review set by PJM. The revisions reinstated the periodic review process employed by the MMU prior to PJM's involvement in the review and approval of fuel cost policies. Monitoring participant behavior through the use of fuel cost policies is an ongoing process that necessitates frequent updates. Market sellers must revise their fuel cost policies whenever circumstances change that impact fuel pricing (e.g. different pricing points, dual fuel addition capability).
- Removal of the requirement for units with zero marginal cost to have an approved fuel cost policy. Previously, zero marginal costs units were required to submit fuel cost policies in which they stated that the units will be offered at zero. The revisions removed the requirement but also enforced a zero offer cap for units' cost-based offers that do not have an approved fuel cost policy.
- Allowance of a temporary cost offer method for units that do not have an approved fuel cost policy. The revisions allow units to submit nonzero cost-based offers without an approved fuel cost policy if they follow the temporary cost offer method. The use of the method results in cost-based offers that do not follow the fuel cost policy rules. The approach significantly weakens market power mitigation by allowing market sellers to make offers without an approved fuel cost policy. The proposed approach substitutes an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy. The approach undercuts a core

¹³¹ 172 FERC ¶ 61,094.

principle of PJM, that market sellers have sole and exclusive authority over their own offers.

The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy.

- Replacement of the fuel cost policy revocation provision with the ability for PJM to terminate fuel cost policies.
- Reduction of the penalties for noncompliant cost-based offers. The revisions reduced the penalties in two situations. When market sellers report their noncompliant cost-based offers, the penalty is reduced by 75 percent. When market sellers do not meet conditions defined to measure a potential market impact the penalty is reduced by 90 percent. The conditions include if the market seller failed the TPS test, if the unit was committed on its cost-based offer, if the unit was marginal or if the unit was paid uplift.

The revisions eliminate penalties entirely when units submit noncompliant cost-based offers if PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based offer. This new provision allows market sellers to not follow their fuel cost policy, submit cost-based offers that are not verifiable or systematic and not face any penalties for doing so.

The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced 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.

Variable Operating and Maintenance Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. On October 29, 2018, PJM filed tariff revisions changing the rules related to VOM costs.¹³² The changes proposed by PJM attempted but failed to clarify the rules. The proposed rules defined all costs directly related to electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

On April 15, 2019, FERC accepted PJM's filing order, subject to revisions requested by FERC.¹³³ On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.¹³⁴ Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory and effective market power mitigation and competitive market results.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start. The MMU converted all VOM costs into dollars per

¹³² See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.

¹³³ 167 FERC ¶ 61,030.

¹³⁴ 168 FERC ¶ 61,134.

MWh using the units' heat rates, the average economic maximum and average minimum run time of the units in 2018 and 2019.

The average variable operating and maintenance cost approved by PJM for combustion turbines and diesels for 2019 was 43 percent higher than the approved variable operating and maintenance cost approved by PJM in 2018. The increase reflects PJM's implementation of the new rules that allow major maintenance and overhauls.¹³⁵

The average variable operating and maintenance cost approved by PJM for combined cycles for 2019 was 19 percent higher than the approved variable operating and maintenance cost approved by PJM in 2018. The increase reflects PJM's implementation of the new rules that allow major maintenance and overhauls.

The average variable operating and maintenance cost approved by PJM for coal units for 2019 was 37 percent higher than the approved variable operating and maintenance cost approved by PJM in 2018. The increase reflects PJM's implementation of the new rules that allow major maintenance and overhauls and the inclusion of other fuel related costs such as fuel handling, chemicals and ash disposal that previously were not part of variable operating and maintenance costs and were part of total fuel related costs.

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.

MMU analysis shows that as a unit runs more, the VOM cost as approved by PJM, decreases. This is the result for CTs, CCs and coal plants. This is an indication that fixed costs are being included in VOM costs. By comparison,

¹³⁵ PJM reviews VOM once per year. The results reflect PJM's most recent review.

fuel costs per MWh remain constant or increase as run hours and the heat rate increase. Fixed costs should not be includable in cost-based energy offers.

The level of costs included in VOM is dependent on PJM's interpretation of the maintenance activities or expenses directly related to electricity production and the level of detailed support provided by market sellers to PJM.

PJM's VOM review is not adequate to determine whether all costs included in VOM are compliant. PJM's VOM review focuses only on the expenses submitted for the last year (of up to 20 years) and PJM's review is dependent on the level of detail provided by the market seller. Recent changes in PJM's review process, triggered by MMU questions, required more details from market sellers and have led to the appropriate exclusion of expenses that were previously included.¹³⁶

The flaws in PJM's review process for VOM are compounded by the ambiguity in the criteria used to determine if costs are includable. PJM's definition of allowable costs for cost-based offers, "costs resulting from electric production," is so broad as to be meaningless. Most costs incurred at a generating station result from electric production in one way or another. The generator itself would not exist but for the need for electric production. PJM's definition does not clearly define which costs associated with electric production are includable in cost-based offers. The lack of clarity leaves the definition of incremental costs to the discretion of PJM and generators.

While the MMU disagrees with the inclusion of maintenance costs in cost-based offers, there are several improvements that PJM could make to exclude costs that should not be included under PJM's criteria.

The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics.

¹³⁶ See "Maintenance Adder & Operating Cost Submission Process," 55-57 PJM presentation to the Tech Change Forum. (April 21, 2020) <<https://pjm.com/-/media/committees-groups/forums/tech-change/2020/20200421-special/20200421-item-01-maintenance-adder-and-operating-cost-submission-process.ashx>>.

The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced.

The MMU understands that companies have different document retention policies but in order to be allowed to include maintenance costs, such costs must be verified, and they cannot be verified without documentation. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts. Market participants should be required to provide the operational data (e.g. run hours, MWh, MMBtu) that supports the maintenance cycle of the equipment being serviced/replaced. For example, if equipment is serviced every 5,000 run hours, the market participant must include at least 5,000 run hours of historical operation in its maintenance cost history.

Failure to address these recommendations will continue to result in the inclusion of overstated maintenance adders.

FERC System of Accounts

PJM Manual 15 relies on the FERC System of Accounts, which predates markets and does not define costs consistent with market economics. Market sellers should not rely solely on the FERC System of Accounts for the calculation of their variable operating and maintenance costs. The FERC System of Accounts does not differentiate between short run marginal costs and avoidable costs. The FERC System of Accounts does not differentiate between costs directly related to energy production and costs not directly related to energy production. Reliance on the FERC System of Accounts for the calculation of variable operating and maintenance costs is likely to lead to incorrect, overstated costs.

The MMU recommends removal of all references to and reliance on the FERC System of Accounts in PJM Manual 15.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the incremental offer curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a \$300 per hour (EOH) VOM cost can add \$180 per MWh to a 5 MW peak segment.¹³⁷

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 unit is compensated in the energy market. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

¹³⁷ The peak adder is equal to \$300 times three divided by 5 MW.

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 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 Sections 12.3-12.6 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 fuel capability, multiple emissions limitations, and fuel usage limitations. The solution algorithm described in Sections 12.5-12.6

is flawed, most notably in its incomplete estimate of a generator's optimal revenue and the algorithm's inability to simultaneously impose multiple environmental or operational constraints typically associated with permits that have rolling limits.

The MMU Opportunity Cost Calculator, described in Manual 15, Section 12.7, is a constrained optimization software application that uses an integer programming solver to find the optimal commitment, dispatch, and lost opportunity cost for a generator based on forward power prices and fuel costs. The MMU calculator incorporates start up time, notification time, minimum down time, multiple fuel capability, multiple emissions limitations, and fuel usage limitations. The MMU recommends that the PJM Opportunity Cost Calculator, which adheres to the solution method described in Sections 12.5-12.6, be discontinued and that the MMU Opportunity Cost Calculator be used for all opportunity cost calculations.

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)

The rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero units eligible for an FMU or AU adder for the period between December 2014 and August 2019.¹³⁸ One unit qualified for an FMU adder for the months of September and October, 2019. In the first nine months of 2020, five units qualified for an FMU adder in at least one month.

¹³⁸ For a definition of FMUs and AUs, and for historical FMU/AU results, see the *2018 State of the Market Report for PJM*, Volume 2, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).

Table 3-105 shows, by month, the number of FMUs and AUs in 2019 and 2020. For example, in September 2020, there was one FMU and AU in Tier 1, zero FMUs and AUs in Tier 2, and two FMUs and AUs in Tier 3.

Table 3-105 Number of frequently mitigated units and associated units (By month): 2019 and 2020

Month	2019				2020			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	0	0	0	0	2	0	0	2
July	0	0	0	0	2	0	0	2
August	0	0	0	0	1	0	0	1
September	0	1	0	1	1	0	2	3
October	1	0	0	1				
November	0	0	0	0				
December	0	0	0	0				

Effective in the 2020/2021 planning year, 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.

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

Market Performance

Ownership of Marginal Resources

Table 3-106 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.¹³⁹ The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first nine months of 2020, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine months of 2020, the offers of one company resulted in 15.2 percent of the real-time, load-weighted PJM system LMP and the offers of the top four companies resulted in 43.7 percent of the real-time, load-weighted, average PJM system LMP. In the first nine months of 2020, the offers of one company resulted in 15.3 percent of the peak hour real-time, load-weighted PJM system LMP.

¹³⁹ See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-106 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through September, 2019 and 2020

2019 (Jan - Sep)						2020 (Jan - Sep)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	12.8%	12.8%	1	13.7%	13.7%	1	15.2%	15.2%	1	15.3%	15.3%
2	10.0%	22.8%	2	10.4%	24.1%	2	11.4%	26.6%	2	13.4%	28.7%
3	9.3%	32.1%	3	8.8%	32.9%	3	10.5%	37.0%	3	9.6%	38.2%
4	9.3%	41.5%	4	7.2%	40.1%	4	6.7%	43.7%	4	6.4%	44.7%
5	4.8%	46.3%	5	5.1%	45.2%	5	6.4%	50.1%	5	6.1%	50.8%
6	4.5%	50.8%	6	4.1%	49.3%	6	6.2%	56.3%	6	6.1%	56.9%
7	4.4%	55.3%	7	4.1%	53.4%	7	4.6%	60.9%	7	4.6%	61.5%
8	3.6%	58.9%	8	3.9%	57.2%	8	3.9%	64.8%	8	3.4%	64.8%
9	3.6%	62.5%	9	3.9%	61.1%	9	2.9%	67.7%	9	3.1%	68.0%
Other (74 companies)	37.5%	100.0%	Other (70 companies)	38.9%	100.0%	Other (71 companies)	32.3%	100.0%	Other (66 companies)	32.0%	100.0%

Figure 3-64 shows the first nine month marginal unit contribution to the real-time, load-weighted PJM system LMP summed by parent companies since 2012.

Figure 3-64 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through September, 2012 through 2020

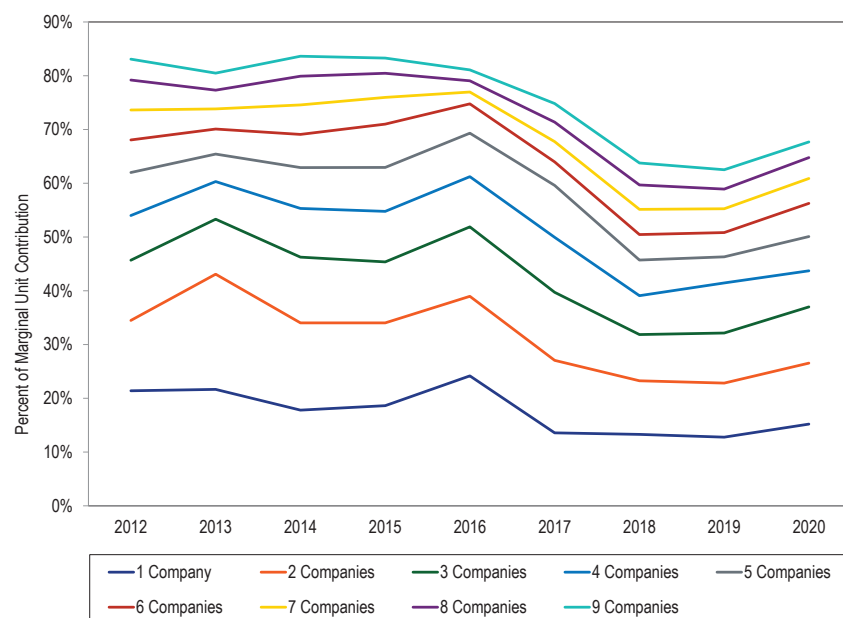


Table 3-107 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.¹⁴⁰ The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market. The results show that in the first nine months of 2020, the offers of one company contributed 10.6 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 33.5 percent of the day-ahead, load-weighted, average, PJM system LMP.

Table 3-107 Marginal resource contribution to day-ahead, load-weighted LMP (By parent company): January through September, 2019 and 2020

2019 (Jan - Sep)						2020 (Jan - Sep)					
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	10.0%	10.0%	1	12.1%	12.1%	1	10.6%	10.6%	1	11.3%	11.3%
2	7.8%	17.8%	2	6.1%	6.1%	2	10.5%	21.1%	2	11.2%	22.5%
3	6.2%	24.0%	3	5.8%	5.8%	3	7.1%	28.2%	3	10.3%	32.8%
4	6.1%	30.1%	4	5.3%	5.3%	4	5.2%	33.5%	4	6.3%	39.1%
5	5.2%	35.4%	5	5.1%	5.1%	5	4.9%	38.4%	5	4.6%	43.7%
6	4.6%	39.9%	6	3.6%	3.6%	6	4.1%	42.5%	6	4.4%	48.1%
7	3.4%	43.4%	7	3.4%	3.4%	7	3.8%	46.3%	7	4.2%	52.2%
8	2.9%	46.3%	8	3.2%	3.2%	8	3.7%	50.0%	8	3.4%	55.7%
9	2.9%	49.2%	9	3.1%	3.1%	9	3.7%	53.8%	9	3.0%	58.6%
Other (142 companies)	50.8%	100.0%	Other (133 companies)	52.2%	52.2%	Other (140 companies)	46.2%	100.0%	Other (138 companies)	41.4%	100.0%

Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. As an example, if unit A has a \$90 cost and a \$100 price, while unit B has a \$9 cost and a \$10 price, both would show a markup index of 10 percent, but the price impact of unit A's markup at the generator bus would be \$10 while the price impact of unit B's markup at the generator bus would be \$1. Depending on each unit's location on the transmission system, those bus level impacts could also have different impacts on total system price. Markup

¹⁴⁰ Id.

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.¹⁴¹ 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

¹⁴¹ 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.

actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-108 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time, load-weighted, average system LMP, using unadjusted and adjusted offers. The adjusted markup component of LMP decreased from \$3.90 per MWh in the first nine months of 2019 to \$2.25 per MWh in the first nine months of 2020. The adjusted markup contribution of coal units in the first nine months of 2020 was \$0.22 per MWh. The adjusted markup component of gas fired units in the first nine months of 2020 was \$2.06 per MWh, a decrease of \$0.95 per MWh from the first nine months of 2019. The markup component of wind units was less than \$0.0 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first nine months of 2020, among the wind units that were marginal, 93.6 percent had negative offer prices.

Table 3-108 Markup component of real-time, load-weighted, average LMP by primary fuel type and unit type: January through September, 2019 and 2020¹⁴²

Fuel	Technology	2019 (Jan - Sep)		2020 (Jan - Sep)	
		Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	\$0.05	\$0.91	(\$0.42)	\$0.22
Gas	CC	\$1.72	\$2.71	\$0.91	\$1.69
Gas	CT	\$0.19	\$0.38	\$0.25	\$0.40
Gas	RICE	\$0.02	\$0.03	\$0.03	\$0.04
Gas	Steam	(\$0.15)	(\$0.10)	(\$0.11)	(\$0.06)
Landfill Gas	CT	(\$0.00)	(\$0.00)	\$0.00	\$0.00
Municipal Waste	RICE	\$0.00	\$0.00	\$0.00	\$0.00
Oil	CC	(\$0.00)	\$0.00	\$0.00	\$0.00
Oil	CT	\$0.00	\$0.00	(\$0.00)	(\$0.00)
Oil	RICE	\$0.00	\$0.00	\$0.00	\$0.00
Oil	Steam	(\$0.03)	(\$0.03)	(\$0.04)	(\$0.04)
Other	Steam	(\$0.00)	(\$0.00)	(\$0.00)	(\$0.00)
Wind	Wind	(\$0.01)	(\$0.01)	(\$0.00)	(\$0.00)
Total		\$1.79	\$3.90	\$0.61	\$2.25

Markup Component of Real-Time Price

Table 3-109 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-110 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In the first nine months of 2020, when using unadjusted cost-based offers, \$0.61 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, \$2.25 per MWh of the PJM real-time load-weighted, average LMP was attributable to markup. In the first nine months of 2020, the peak markup component was highest in August, \$2.88 per MWh using unadjusted cost-based offers and peak markup component was highest in August, \$4.83 per MWh using adjusted cost-based offers. This corresponds to 9.7 percent and 16.3 percent of the real-time peak load-weighted average LMP in August.

¹⁴² The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-109 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 2019 through September, 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	\$1.89	\$2.43	\$1.33	\$0.49	\$0.94	\$0.03
Feb	\$2.15	\$2.85	\$1.46	(\$0.15)	(\$0.00)	(\$0.28)
Mar	\$2.11	\$2.57	\$1.67	(\$0.09)	\$0.46	(\$0.66)
Apr	\$1.38	\$2.01	\$0.67	(\$0.07)	\$0.17	(\$0.33)
May	\$1.27	\$2.02	\$0.45	\$0.54	\$1.03	\$0.10
Jun	\$1.36	\$1.74	\$0.98	\$1.24	\$2.02	\$0.30
Jul	\$3.25	\$4.40	\$1.99	\$0.83	\$1.75	(\$0.30)
Aug	\$0.86	\$0.78	\$0.95	\$1.80	\$2.88	\$0.70
Sep	\$1.57	\$2.58	\$0.55	\$0.47	\$0.97	(\$0.08)
Oct	\$1.39	\$2.01	\$0.64			
Nov	\$1.12	\$1.79	\$0.51			
Dec	\$0.19	\$0.29	\$0.08			
Total	\$1.58	\$2.16	\$0.97	\$0.61	\$1.23	(\$0.04)

Table 3-110 Monthly markup components of real-time load-weighted LMP (Adjusted): January through September, 2019 and 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	\$4.45	\$5.21	\$3.65	\$2.21	\$2.80	\$1.60
Feb	\$4.33	\$5.11	\$3.55	\$1.57	\$1.85	\$1.30
Mar	\$4.37	\$4.93	\$3.84	\$1.44	\$2.07	\$0.81
Apr	\$3.40	\$4.16	\$2.53	\$1.43	\$1.73	\$1.11
May	\$3.23	\$4.15	\$2.22	\$1.98	\$2.65	\$1.39
Jun	\$3.21	\$3.79	\$2.64	\$2.77	\$3.75	\$1.58
Jul	\$5.38	\$6.71	\$3.92	\$2.70	\$3.81	\$1.33
Aug	\$2.81	\$3.03	\$2.55	\$3.61	\$4.83	\$2.35
Sep	\$3.61	\$4.85	\$2.36	\$1.89	\$2.50	\$1.22
Oct	\$3.17	\$4.00	\$2.17			
Nov	\$3.18	\$3.95	\$2.49			
Dec	\$2.12	\$2.38	\$1.88			
Total	\$3.64	\$4.40	\$2.86	\$2.25	\$3.01	\$1.44

Hourly Markup Component of Real-Time Prices

Figure 3-65 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in 2019 and the first nine months of 2020. Figure 3-66 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in 2019 and the first nine months of 2020.

Figure 3-65 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2019 and 2020

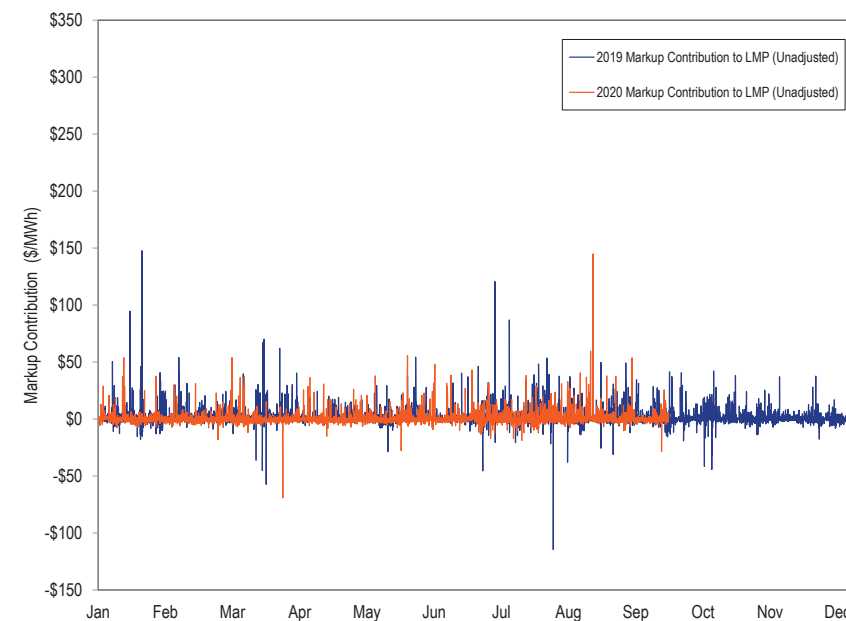
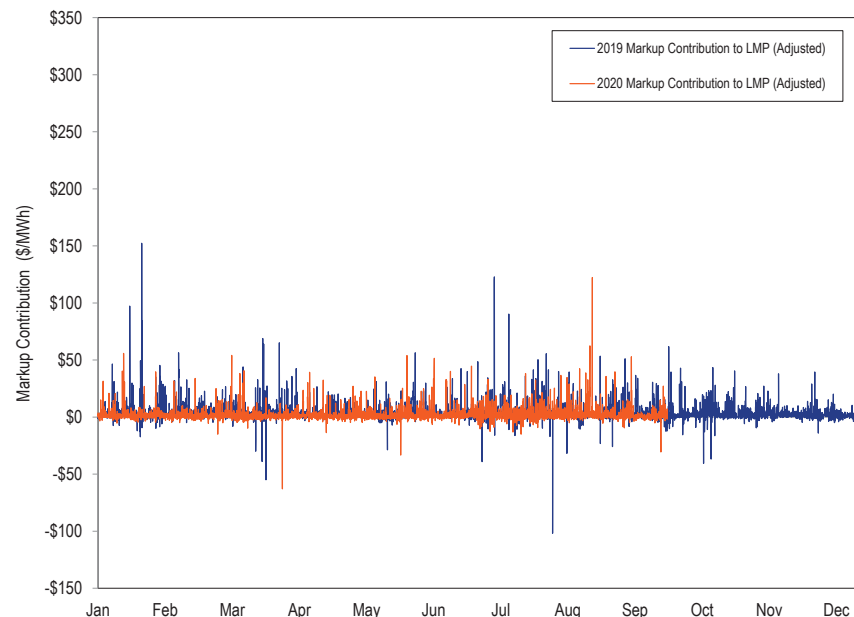


Figure 3-66 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2019 and 2020



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first nine months of 2019 and 2020 in Table 3-111 and for adjusted offers in Table 3-112¹⁴³. The smallest zonal all hours average markup component using unadjusted offers in the first nine months of 2020, was in the PPL Control Zone, \$0.26 per MWh, while the highest was in the BGE Control Zone, \$1.29 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first nine months of 2020, was in the PPL Control Zone, \$0.51 per MWh, while the highest was in the BGE Control Zone, \$2.24 per MWh.

Table 3-111 Average real-time zonal markup component (Unadjusted): January through September, 2019 and 2020

	2019 (Jan – Sep)			2020 (Jan – Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	\$2.18	\$2.64	\$1.71	\$0.31	\$0.75	(\$0.14)
AEP	\$1.74	\$2.41	\$1.04	\$0.64	\$1.27	(\$0.03)
APS	\$1.73	\$2.35	\$1.09	\$0.70	\$1.41	(\$0.05)
ATSI	\$1.81	\$2.46	\$1.13	\$0.75	\$1.44	\$0.00
BGE	\$1.92	\$2.76	\$1.05	\$1.29	\$2.24	\$0.29
ComEd	\$1.26	\$1.72	\$0.77	\$0.59	\$1.28	(\$0.16)
DAY	\$1.90	\$2.68	\$1.06	\$0.74	\$1.39	\$0.03
DEOK	\$1.80	\$2.55	\$1.01	\$0.66	\$1.29	(\$0.01)
DLCO	\$1.77	\$2.38	\$1.13	\$0.80	\$1.57	(\$0.02)
Dominion	\$1.77	\$2.44	\$1.07	\$0.76	\$1.50	(\$0.00)
DPL	\$2.31	\$2.69	\$1.91	\$0.29	\$0.74	(\$0.19)
EKPC	\$1.73	\$2.45	\$1.00	\$0.62	\$1.26	(\$0.04)
JCPL	\$2.08	\$2.59	\$1.52	\$0.31	\$0.70	(\$0.12)
Met-Ed	\$1.80	\$2.28	\$1.28	\$0.44	\$0.83	\$0.02
OVEC	\$1.47	\$2.17	\$0.84	\$0.33	\$0.92	(\$0.20)
PECO	\$2.24	\$2.57	\$1.89	\$0.28	\$0.74	(\$0.20)
PENELEC	\$1.70	\$2.21	\$1.14	\$0.40	\$0.85	(\$0.09)
Pepco	\$1.83	\$2.55	\$1.06	\$0.91	\$1.66	\$0.12
PPL	\$1.88	\$2.37	\$1.35	\$0.26	\$0.51	\$0.00
PSEG	\$2.08	\$2.65	\$1.48	\$0.27	\$0.67	(\$0.17)
RECO	\$1.86	\$2.37	\$1.28	\$0.33	\$0.74	(\$0.13)

¹⁴³ A marginal unit's offer price affects LMPs in the entire PJM market. The markup component of average zonal real-time price is based on offers of units located within the zone and units located outside the transmission zone.

Table 3-112 Average real-time zonal markup component (Adjusted): January through September, 2019 and 2020

	2019 (Jan - Sep)			2020 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	\$4.12	\$4.73	\$3.51	\$1.89	\$2.48	\$1.28
AEP	\$3.88	\$4.75	\$2.99	\$2.29	\$3.08	\$1.47
APS	\$3.89	\$4.70	\$3.06	\$2.36	\$3.23	\$1.44
ATSI	\$3.97	\$4.82	\$3.07	\$2.42	\$3.26	\$1.51
BGE	\$4.26	\$5.30	\$3.18	\$3.08	\$4.18	\$1.92
ComEd	\$3.27	\$3.94	\$2.55	\$2.15	\$3.00	\$1.23
DAY	\$4.13	\$5.10	\$3.07	\$2.47	\$3.27	\$1.59
DEOK	\$3.94	\$4.88	\$2.95	\$2.32	\$3.09	\$1.50
DLCO	\$3.89	\$4.70	\$3.05	\$2.47	\$3.41	\$1.46
Dominion	\$4.00	\$4.87	\$3.11	\$2.43	\$3.30	\$1.54
DPL	\$4.33	\$4.85	\$3.79	\$1.91	\$2.52	\$1.27
EKPC	\$3.88	\$4.77	\$2.98	\$2.27	\$3.05	\$1.49
JCPL	\$4.06	\$4.72	\$3.35	\$1.90	\$2.42	\$1.32
Met-Ed	\$3.84	\$4.49	\$3.13	\$2.03	\$2.56	\$1.45
OVEC	\$3.53	\$4.42	\$2.73	\$1.92	\$2.66	\$1.26
PECO	\$4.18	\$4.66	\$3.67	\$1.82	\$2.39	\$1.21
PENELEC	\$3.76	\$4.44	\$3.02	\$1.99	\$2.59	\$1.33
Pepco	\$4.11	\$5.04	\$3.13	\$2.62	\$3.50	\$1.69
PPL	\$3.84	\$4.50	\$3.14	\$1.79	\$2.16	\$1.39
PSEG	\$4.04	\$4.75	\$3.30	\$1.84	\$2.39	\$1.26
RECO	\$3.80	\$4.43	\$3.08	\$1.94	\$2.49	\$1.30

Markup by Real-Time Price Levels

Table 3-113 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 3-113 Real-time markup contribution (By PJM load-weighted LMP category, unadjusted): January through September, 2019 and 2020

LMP Category	2019 (Jan - Sep)		2020 (Jan - Sep)	
	Markup Component	Frequency	Markup Component	Frequency
< \$10	(\$2.63)	0.4%	(\$1.12)	2.8%
\$10 to \$15	(\$0.26)	5.1%	(\$0.61)	24.7%
\$15 to \$20	\$0.16	21.7%	(\$0.79)	39.6%
\$20 to \$25	(\$0.16)	33.9%	\$0.19	18.6%
\$25 to \$50	\$2.53	35.3%	\$4.42	11.8%
\$50 to \$75	\$15.15	2.5%	\$11.09	1.8%
\$75 to \$100	\$23.52	0.6%	\$15.30	0.5%
\$100 to \$125	\$20.88	0.2%	\$5.95	0.1%
\$125 to \$150	\$25.99	0.1%	\$7.89	0.0%
>= \$150	\$25.75	0.3%	\$5.71	0.0%

Table 3-114 Real-time markup contribution (By PJM load-weighted LMP category, adjusted): January through September, 2019 and 2020

LMP Category	2019 (Jan - Sep)		2020 (Jan - Sep)	
	Markup Component	Frequency	Markup Component	Frequency
< \$10	(\$1.74)	0.4%	(\$0.21)	2.8%
\$10 to \$15	\$1.03	5.1%	\$0.62	24.7%
\$15 to \$20	\$1.79	21.7%	\$0.83	39.6%
\$20 to \$25	\$1.89	33.8%	\$2.06	18.7%
\$25 to \$50	\$4.94	35.3%	\$6.39	11.8%
\$50 to \$75	\$18.00	2.5%	\$13.23	1.8%
\$75 to \$100	\$27.07	0.6%	\$17.45	0.5%
\$100 to \$125	\$24.86	0.2%	\$7.83	0.1%
\$125 to \$150	\$29.37	0.1%	\$10.61	0.0%
>= \$150	\$28.14	0.3%	\$7.23	0.0%

Markup by Company

Table 3-115 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time, load-weighted average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute

interval, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine months of 2020, when using unadjusted cost-based offers, the markup of one company accounted for 1.9 percent of the load-weighted, average LMP, the markup of the top five companies accounted for 4.1 percent of the load-weighted, average LMP and the markup of all companies accounted for 2.9 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 decreased in the first nine months of 2020. The markup contribution to the load-weighted, average LMP and share of the markup contribution to the load-weighted, average LMP also decreased in the first nine months of 2020. The markup contribution of a unit to the real-time, load-weighted, average LMP can be positive or negative.

Table 3-115 Markup component of real-time, load-weighted, average LMP by Company: January through September, 2019 and 2020

	2019 (Jan - Sep)				2020 (Jan - Sep)			
	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	\$0.39	1.4%	\$0.63	2.3%	\$0.41	1.9%	\$0.63	3.0%
Top 2 Companies	\$0.71	2.6%	\$1.15	4.2%	\$0.56	2.7%	\$0.88	4.2%
Top 3 Companies	\$0.97	3.5%	\$1.59	5.8%	\$0.68	3.2%	\$1.12	5.3%
Top 4 Companies	\$1.22	4.4%	\$2.00	7.2%	\$0.77	3.7%	\$1.27	6.0%
Top 5 Companies	\$1.42	5.2%	\$2.35	8.5%	\$0.86	4.1%	\$1.40	6.6%
All Companies	\$1.79	6.5%	\$3.90	14.1%	\$0.61	2.9%	\$2.25	10.6%

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 3-116. INC, DEC and up to congestion transactions (UTC) have zero markups. UTCs were 53.8 percent of marginal resources, INCs were 12.4 percent of marginal resources and DEC were 17.6 percent of marginal resources in the first nine months of 2020.

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 3-116 shows the markup component of LMP for marginal generating resources. Generating resources were only 16.1 percent of marginal resources in the first nine months of 2020. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources decreased for coal fired steam units from \$0.40 to \$0.08 per MWh and decreased for gas fired CC units from \$1.44 to \$0.89 per MWh.

Table 3-116 Markup component of day-ahead, load-weighted, average LMP by primary fuel type and technology type: January through September, 2019 and 2020

Fuel	Technology	2019 (Jan - Sep)			2020 (Jan - Sep)		
		Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	(\$0.32)	\$0.40	40.7%	(\$0.58)	\$0.08	34.6%
Gas	CC	\$0.92	\$1.44	50.7%	\$0.50	\$0.89	54.6%
Gas	CT	\$0.01	\$0.02	1.1%	\$0.03	\$0.05	1.8%
Gas	RICE	(\$0.00)	(\$0.00)	0.5%	(\$0.00)	(\$0.00)	0.4%
Gas	Steam	(\$0.06)	(\$0.02)	4.3%	(\$0.09)	(\$0.05)	3.3%
Municipal Waste	RICE	\$0.00	\$0.00	0.1%	\$0.00	\$0.00	0.1%
Oil	CT	\$0.00	\$0.00	0.5%	\$0.00	\$0.00	0.7%
Oil	Steam	(\$0.01)	(\$0.01)	0.1%	(\$0.01)	(\$0.01)	0.1%
Other	Solar	\$0.00	\$0.00	0.2%	\$0.00	\$0.00	0.1%
Other	Steam	(\$0.00)	(\$0.00)	0.1%	(\$0.00)	(\$0.00)	0.4%
Uranium	Steam	\$0.00	\$0.00	0.7%	\$0.00	\$0.00	1.9%
Wind	Wind	\$0.13	\$0.13	1.1%	\$0.00	\$0.00	1.9%
Total		\$0.67	\$1.96	100.0%	(\$0.15)	\$0.95	100.0%

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-117 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted cost-based offers. In the first nine months of 2020, when using unadjusted cost-based offers, -\$0.15 per MWh of the PJM day-ahead load-weighted, average LMP was attributable to markup. In the first nine months of 2020, the peak markup component was highest in August, \$0.70 per MWh using unadjusted cost-based offers.

Table 3-117 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January 2019 through September 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	\$0.78	\$1.68	(\$0.16)	(\$0.03)	\$0.29	(\$0.35)
Feb	\$0.60	\$0.80	\$0.41	(\$0.23)	(\$0.08)	(\$0.39)
Mar	\$0.65	\$0.99	\$0.32	(\$0.21)	(\$0.19)	(\$0.23)
Apr	\$0.15	\$0.30	(\$0.03)	(\$0.27)	(\$0.19)	(\$0.36)
May	\$0.11	\$0.13	\$0.09	(\$0.19)	\$0.17	(\$0.52)
Jun	\$0.45	\$0.38	\$0.53	\$0.07	\$0.39	(\$0.33)
Jul	\$2.50	\$4.14	\$0.66	(\$0.54)	(\$0.41)	(\$0.72)
Aug	\$0.39	\$0.44	\$0.34	\$0.07	\$0.70	(\$0.59)
Sep	(\$0.09)	(\$0.28)	\$0.09	(\$0.01)	\$0.55	(\$0.63)
Oct	\$1.11	\$1.82	\$0.25			
Nov	\$1.71	\$1.75	\$1.68			
Dec	(\$0.34)	\$0.21	(\$0.87)			
Annual	\$0.67	\$1.05	\$0.26	(\$0.15)	\$0.14	(\$0.47)

Table 3-118 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In the first nine months of 2020, when using adjusted cost-based offers, \$0.95 per MWh of the PJM day-ahead load-weighted, average LMP was attributable to markup. In the first nine months of 2020, the peak markup component was highest in August, \$1.77 per MWh using adjusted cost-based offers.

Table 3-118 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January 2019 through September 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	\$2.46	\$3.34	\$1.55	\$1.35	\$1.65	\$1.03
Feb	\$2.12	\$2.35	\$1.88	\$0.99	\$1.17	\$0.83
Mar	\$2.02	\$2.28	\$1.78	\$0.96	\$1.02	\$0.90
Apr	\$1.26	\$1.28	\$1.24	\$0.70	\$0.91	\$0.47
May	\$1.29	\$1.17	\$1.43	\$0.72	\$1.00	\$0.47
Jun	\$1.64	\$1.62	\$1.67	\$1.04	\$1.35	\$0.67
Jul	\$3.67	\$5.17	\$2.00	\$0.65	\$0.75	\$0.51
Aug	\$1.55	\$1.48	\$1.64	\$1.14	\$1.77	\$0.48
Sep	\$1.06	\$0.81	\$1.32	\$0.95	\$1.50	\$0.34
Oct	\$2.02	\$2.55	\$1.36			
Nov	\$2.92	\$3.01	\$2.84			
Dec	\$1.12	\$1.65	\$0.61			
Annual	\$1.96	\$2.27	\$1.63	\$0.95	\$1.24	\$0.64

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 3-119. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-120. The smallest zonal all hours average markup component using adjusted cost-based offers for the first nine months of 2020 was in the Pepco Zone, \$0.59 per MWh, while the highest was in the PPL Control Zone, \$1.54 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the Pepco Control Zone, \$0.73 per MWh, while the highest was in the OVEC Control Zone, \$1.91 per MWh.

Table 3-119 Day-ahead, average, zonal markup component (Unadjusted): January through September, 2019 and 2020

	2019 (Jan – Sep)			2020 (Jan – Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	\$1.81	\$2.82	\$0.76	\$0.16	\$0.48	(\$0.16)
AEP	\$0.48	\$0.73	\$0.21	(\$0.31)	(\$0.03)	(\$0.60)
APS	\$0.43	\$0.67	\$0.18	(\$0.33)	(\$0.08)	(\$0.60)
ATSI	\$0.94	\$1.61	\$0.21	(\$0.24)	\$0.05	(\$0.56)
BGE	\$0.90	\$1.86	(\$0.11)	(\$0.32)	(\$0.04)	(\$0.62)
ComEd	(\$0.05)	(\$0.24)	\$0.15	(\$0.23)	\$0.08	(\$0.58)
DAY	\$1.40	\$2.54	\$0.15	(\$0.08)	\$0.45	(\$0.67)
DEOK	\$1.10	\$2.01	\$0.12	(\$0.09)	\$0.51	(\$0.75)
DLCO	\$0.65	\$1.11	\$0.17	(\$0.40)	(\$0.18)	(\$0.63)
Dominion	\$0.38	\$0.72	\$0.02	(\$0.19)	\$0.23	(\$0.62)
DPL	\$1.23	\$1.68	\$0.74	\$0.08	\$0.27	(\$0.12)
EKPC	\$0.53	\$0.83	\$0.23	(\$0.22)	\$0.20	(\$0.65)
JCPL	\$1.40	\$2.04	\$0.69	\$0.07	\$0.31	(\$0.20)
Met-Ed	\$0.88	\$1.27	\$0.44	(\$0.08)	(\$0.12)	(\$0.04)
OVEC	(\$0.06)	\$0.41	(\$0.46)	\$0.32	\$0.69	(\$0.21)
PECO	\$1.37	\$1.99	\$0.70	\$0.09	\$0.31	(\$0.16)
PENELEC	\$0.42	\$0.42	\$0.43	(\$0.01)	\$0.19	(\$0.26)
Pepco	\$0.45	\$0.92	(\$0.06)	(\$0.49)	(\$0.31)	(\$0.70)
PPL	\$1.01	\$1.41	\$0.58	\$0.53	\$0.69	\$0.36
PSEG	\$1.26	\$1.81	\$0.68	\$0.06	\$0.25	(\$0.16)
RECO	\$1.02	\$1.45	\$0.53	\$0.11	\$0.39	(\$0.21)

Table 3-120 Day-ahead, average, zonal markup component (Adjusted): January through September, 2019 and 2020

	2019 (Jan – Sep)			2020 (Jan – Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	\$3.00	\$3.91	\$2.04	\$1.25	\$1.57	\$0.91
AEP	\$1.78	\$1.94	\$1.61	\$0.81	\$1.06	\$0.55
APS	\$1.74	\$1.91	\$1.57	\$0.74	\$0.97	\$0.50
ATSI	\$2.26	\$2.87	\$1.61	\$0.89	\$1.18	\$0.56
BGE	\$2.30	\$3.21	\$1.33	\$0.75	\$1.00	\$0.48
ComEd	\$1.21	\$0.99	\$1.45	\$0.87	\$1.21	\$0.51
DAY	\$2.80	\$3.90	\$1.60	\$1.10	\$1.62	\$0.53
DEOK	\$2.46	\$3.31	\$1.55	\$1.02	\$1.57	\$0.43
DLCO	\$1.92	\$2.26	\$1.55	\$0.66	\$0.83	\$0.47
Dominion	\$1.71	\$1.97	\$1.44	\$1.02	\$1.54	\$0.47
DPL	\$2.42	\$2.77	\$2.05	\$1.14	\$1.28	\$0.98
EKPC	\$1.83	\$2.05	\$1.60	\$0.88	\$1.23	\$0.51
JCPL	\$2.63	\$3.17	\$2.03	\$1.16	\$1.41	\$0.89
Met-Ed	\$2.12	\$2.44	\$1.78	\$0.93	\$0.86	\$1.01
OVEC	\$0.91	\$1.22	\$0.64	\$1.46	\$1.91	\$0.82
PECO	\$2.56	\$3.09	\$2.00	\$1.15	\$1.37	\$0.91
PENELEC	\$1.68	\$1.60	\$1.77	\$0.99	\$1.18	\$0.76
Pepco	\$1.84	\$2.27	\$1.37	\$0.59	\$0.73	\$0.43
PPL	\$2.23	\$2.55	\$1.89	\$1.54	\$1.69	\$1.37
PSEG	\$2.45	\$2.89	\$1.98	\$1.13	\$1.33	\$0.92
RECO	\$2.22	\$2.52	\$1.87	\$1.17	\$1.42	\$0.88

Markup by Day-Ahead Price Levels

Table 3-121 and Table 3-122 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 3-121 Average, day-ahead markup component (By LMP category, unadjusted): January through September, 2019 and 2020

LMP Category	2019 (Jan – Sep)		2020 (Jan – Sep)	
	Average Markup Component	Frequency	Average Markup Component	Frequency
< \$10	\$0.00	0.0%	(\$0.01)	1.4%
\$10 to \$15	\$0.01	3.9%	(\$0.08)	20.4%
\$15 to \$20	\$0.04	20.8%	(\$0.21)	41.8%
\$20 to \$25	(\$0.09)	29.0%	(\$0.00)	22.3%
\$25 to \$50	\$0.35	44.1%	\$0.15	13.5%
\$50 to \$75	\$0.28	1.5%	\$0.00	0.7%
\$75 to \$100	\$0.03	0.6%	\$0.00	0.0%
\$100 to \$125	\$0.02	0.1%	\$0.00	0.0%
\$125 to \$150	\$0.02	0.0%	\$0.00	0.0%
>= \$150	\$0.01	0.0%	\$0.00	0.0%

Table 3-122 Average, day-ahead markup component (By LMP category, adjusted): January through September, 2019 and 2020

LMP Category	2019 (Jan – Sep)		2020 (Jan – Sep)	
	Average Markup Component	Frequency	Average Markup Component	Frequency
< \$10	\$0.00	0.0%	\$0.00	1.4%
\$10 to \$15	\$0.04	3.9%	\$0.07	20.4%
\$15 to \$20	\$0.26	20.8%	\$0.28	41.8%
\$20 to \$25	\$0.32	29.0%	\$0.30	22.3%
\$25 to \$50	\$0.96	44.1%	\$0.29	13.5%
\$50 to \$75	\$0.29	1.5%	\$0.01	0.7%
\$75 to \$100	\$0.05	0.6%	\$0.00	0.0%
\$100 to \$125	\$0.03	0.1%	\$0.00	0.0%
\$125 to \$150	\$0.02	0.0%	\$0.00	0.0%
>= \$150	\$0.01	0.0%	\$0.00	0.0%

Market Structure, Participant Behavior, and Market Performance

The goal of regulation through competition is to achieve competitive market outcomes even in the presence of market power. Market structure in the PJM energy market is not competitive in local markets created by transmission constraints. At times, market structure is not competitive in the aggregate energy market. Market sellers pursuing their financial interests may choose behavior that benefits from structural market power in the absence of an effective market power mitigation program. The overall competitive

assessment determines the extent to which that participant behavior results in competitive or above competitive pricing. The competitive assessment brings together the structural measures of market power, HHI and pivotal suppliers, with participant behavior, specifically markup, and pricing outcomes.

HHI and Markup

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:¹⁴⁴

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

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

The PJM energy market HHIs and application of the FERC concentration categories 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 electricity demand

elasticity ranging from -0.2 to -0.4.¹⁴⁵ Using the Lerner Index, the elasticities imply, for example, an average markup ranging from 25 to 50 percent at the unconcentrated to moderately concentrated threshold HHI of 1000:¹⁴⁶

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

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of \$20.61 per MWh and an average HHI of 723 in the first nine months of 2020, average PJM prices would theoretically range from \$25 to \$32 per MWh using the elasticity range of -0.2 to -0.4.¹⁴⁷ The theoretical prices exceed marginal costs because the exercise of market power is profit maximizing in the absence of market power mitigation. Actual prices, averaging \$21.22 per MWh, and markups, at 2.9 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some market intervals, markup and prices reach levels that reflect the exercise of market power.

Market Power Mitigation and Markup

Fully effective market power mitigation would not allow a seller that fails the structural market power test (the TPS test) to set prices with a positive markup. With the flaws in PJM's implementation of the TPS test, resources can and do set prices with a positive markup while failing the TPS test.

Table 3-123 categorizes real-time marginal unit intervals by markup level and TPS test status. In the first nine months of 2020, 6.0 percent of marginal unit intervals included a positive markup even though the resource failed the TPS test for local market power. Unmitigated local market power affects PJM market prices. Zero markup with a TPS test failure indicates the mitigation

¹⁴⁵ 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>>.

¹⁴⁶ 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.

¹⁴⁷ The average HHI is found in Table 3-75. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3-62.

¹⁴⁴ See Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

of a marginal unit. The 6.0 percent of marginal unit intervals failing the TPS test with unmitigated positive markup exceeds the 3.7 percent of marginal unit intervals failing the TPS with zero markup. Marginal units with positive markup are mitigated less often than not.

Table 3-123 Percent of real-time marginal unit intervals with markup and local market power: January through September, 2020

Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	32.7%	6.4%	39.1%
Zero Markup	10.8%	3.7%	14.6%
\$0 to \$5	34.6%	5.3%	39.8%
\$5 to \$10	3.9%	0.4%	4.3%
\$10 to \$15	0.6%	0.1%	0.7%
\$15 to \$20	0.3%	0.0%	0.3%
\$20 to \$25	0.5%	0.0%	0.5%
\$25 to \$50	0.4%	0.0%	0.4%
\$50 to \$75	0.1%	0.0%	0.1%
\$75 to \$100	0.0%	0.0%	0.1%
Above \$100	0.1%	0.1%	0.1%
Total Positive Markup	40.3%	6.0%	46.3%
Total	83.8%	16.2%	100.0%

The markup of marginal units was zero or negative in only 53.7 percent of marginal unit intervals in the first nine months of 2020. Pivotal suppliers in the aggregate market also set prices with high markups in the summer of 2020. Allowing positive markups to affect prices in the presence of market power permits the exercise of market power and has a negative impact on the competitiveness of the PJM energy market. This problem can and should be addressed.

Energy Uplift (Operating Reserves)

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 operators. 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 the first nine months of 2020, energy uplift credits were \$58.6 million, including \$7.0 million in day-ahead generator credits, \$31.8 million in balancing generator credits, \$17.1 million in lost opportunity cost credits, and \$2.2 million in local constraint control credits.
- **Types of units.** In the first nine months of 2020, coal units received 89.5 percent of all day-ahead generator credits. During the same time period, combustion turbines received 88.0 percent of all balancing generator credits and 95.8 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In the first nine months of 2020, 86.9 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.2 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first nine months of 2020, less than 0.1 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 76.6 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 18.0 percent of all credits. The top 10 organizations received 73.3 percent of all credits. The HHI for day-ahead operating

⁴ Demand response payments are addressed in Section 6: Demand Response.

reserves was 8481, the HHI for balancing operating reserves was 3859 and the HHI for lost opportunity cost was 5325, all of which are classified as highly concentrated.

- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by \$4.6 million or 36.6 percent, in the first nine months of 2020 compared to the first nine months of 2019, from \$12.5 million to \$17.1 million. Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive lost opportunity cost credits as a result. The amount of day-ahead generation paid LOC credits for this reason increased by 637.1 GWh or 131.4 percent during the first nine months of 2020, compared to the first nine months of 2019, from 484.8 GWh to 1,121.9 GWh.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges decreased by \$11.8 million, or 16.8 percent, in the first nine months of 2020 compared to the first nine months of 2019, from \$70.5 million to \$58.6 million.
- **Energy Uplift Charges Categories.** The decrease of \$11.8 million in the first nine months of 2020 was comprised of a \$6.9 million decrease in day-ahead operating reserve charges, a \$4.9 million decrease in balancing operating reserve charges, and a \$0.1 million decrease in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid \$0.012 per MWh, real-time load paid \$0.024 per MWh, a DEC paid \$0.345 per MWh and an INC and any load, generation or interchange transaction deviation paid \$0.333 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid \$0.012 per MWh, real-time load paid \$0.017 per MWh, a DEC paid \$0.314 per MWh and an INC and any load, generation or interchange transaction deviation paid \$0.302 per MWh in the first nine months of 2020.
- **Reactive Services Rates.** JCPL, PPL, and EKPC control zones were the three zones with the highest local voltage support rates, excluding reactive

capability payments. JCPL had a rate of \$0.010 per MWh, PPL had a rate of \$0.006 per MWh, and EKPC had a rate of \$0.005.

Geography of Charges and Credits

- In the first nine months of 2020, 88.8 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 3.9 percent by transactions at hubs and aggregates, and 7.3 percent by transactions at interchange interfaces.
- In the first nine months of 2020, generators in the Eastern Region received 35.8 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2020, generators in the Western Region received 61.3 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2020, external generators received 2.9 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM 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: Partially adopted, 2019.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)

- The MMU recommends the elimination of day-ahead 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.)
- 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 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 clearly identify and classify all reasons for incurring operating reserves in the day-ahead and the real-time

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*, Volume 2, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

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.⁶)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends 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 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. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation. (Priority: Medium. New recommendation. Status: Not adopted.)

⁶ On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. PJM began posting unit specific uplift reports on May 1, 2019.

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 start up and no load 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 the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules.

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 will create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff will exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff will be created by PJM's fast start pricing proposal (limited convex hull pricing). This tradeoff would be created in more 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. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.⁷ However, Order No. 844 failed to require the

publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability in the day-ahead market.

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 continued to pay no energy uplift charges in the first nine months of 2020, which means that all others who pay these charges paid too much.⁸ On July 16, 2020, following its investigation of the issue, the Commission ordered PJM to revise its rules so that UTCs are required to pay uplift on the withdrawal side (DEC) only.⁹ 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.

⁷ On March 21, 2019 FERC accepted PJM's Order No. 844 compliance filing. The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates.

⁸ 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.

⁹ See 172 FERC ¶ 61,046.

Energy Uplift Credits 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 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.

Table 4-1 shows the totals for each credit category for the first nine months of 2019 and 2020.¹⁰ In the first nine months of 2020, energy uplift credits decreased by \$11.8 million or 16.8 percent compared to the first nine months of 2019.

Table 4-1 Energy uplift credits by category: January through September, 2019 and 2020¹¹

Category	Type	2019 Credits (Millions)	2020 Credits (Millions)	Change	Percent Change	2019 Share	2020 Share
Day-Ahead	Generators	\$13.9	\$7.0	(\$6.9)	(49.5%)	19.8%	12.0%
	Imports	\$0.0	\$0.0	(\$0.0)	(100.0%)	0.0%	0.0%
	Load Response	\$0.0	\$0.0	\$0.0	99.6%	0.0%	0.0%
Balancing	Canceled Resources	\$0.0	\$0.0	\$0.0	NA	0.0%	0.0%
	Generators	\$40.7	\$31.8	(\$8.9)	(21.9%)	57.7%	54.2%
	Imports	\$0.0	\$0.0	\$0.0	NA	0.0%	0.0%
	Load Response	\$0.0	\$0.0	\$0.0	NA	0.0%	0.0%
	Local Constraints Control	\$2.7	\$2.2	(\$0.5)	(18.8%)	3.8%	3.7%
	Lost Opportunity Cost	\$12.5	\$17.1	\$4.6	36.6%	17.8%	29.1%
	Day-Ahead	\$0.2	\$0.1	(\$0.1)	(65.6%)	0.3%	0.1%
Reactive Services	Local Constraints Control	\$0.0	\$0.0	\$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	\$0.0	\$0.0	(\$0.0)	(87.2%)	0.0%	0.0%
	Reactive Services	\$0.3	\$0.3	\$0.1	35.1%	0.4%	0.6%
	Synchronous Condensing	\$0.0	\$0.0	(\$0.0)	(100.0%)	0.0%	0.0%
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	\$0.0	\$0.0	NA	0.0%	0.0%
	Testing	\$0.2	\$0.2	(\$0.0)	(10.1%)	0.2%	0.3%
Total		\$70.5	\$58.6	(\$11.8)	(16.8%)	100.0%	100.0%

¹⁰ 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 October 9, 2020.

¹¹ Year to year change is rounded to one tenth of a million, and includes values less than \$0.05 million.

Characteristics of Credits

Types of Units

Table 4-2 shows the distribution of total energy uplift credits by unit type for the first nine months of 2019 and 2020. Uplift credits decreased for most unit types. A combination of factors led to decreased uplift payments in the first nine months of 2020. Milder winter weather in the first three months of 2020, measured by reduced heating degree days and cold weather alerts, contributed to low natural gas prices, reducing the costs of gas units and reducing the need for, and level of, make whole payments, and reducing uplift credits for combustion turbines. Similarly, reduced load beginning in March 2020 resulting from a combination of weather and COVID-19 caused sustained and significant decreases in generation and fuel prices. Coal units had the largest reduction in uplift credits, with a reduction of \$7.0 million or 45.7 percent in the first nine months of 2020 compared with the first nine months of 2019. Combustion turbines had the second largest reduction in uplift credits with a reduction of \$3.2 million or 6.4 percent. The largest decrease in uplift, 92.8 percent of the total reduction in day ahead operating reserves in the first nine months of 2020, was accounted for by a small number of coal units in the BGE and Pepco Zones.

Wind turbines are less common recipients of uplift, and in the first nine months of 2020 uplift credits to wind units were \$0.1 million, down by 25.3 percent compared to the first nine months of 2019.

Table 4-2 Energy uplift credits by unit type: January through September, 2019 and 2020^{12 13}

Unit Type	(Jan - Sep) 2019 Credits (Millions)	(Jan - Sep) 2020 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2019 Share	(Jan - Sep) 2020 Share
Combined Cycle	\$2.7	\$2.0	(\$0.7)	(24.6%)	3.8%	3.5%
Combustion Turbine	\$49.5	\$46.4	(\$3.2)	(6.4%)	70.3%	79.0%
Diesel	\$0.6	\$0.5	(\$0.1)	(13.2%)	0.8%	0.9%
Hydro	\$0.0	\$0.0	\$0.0	0.0%	0.0%	0.0%
Nuclear	\$0.0	\$0.0	\$0.0	0.0%	0.0%	0.0%
Solar	\$0.1	\$0.0	(\$0.1)	(98.6%)	0.1%	0.0%
Steam - Coal	\$15.4	\$8.4	(\$7.0)	(45.7%)	21.8%	14.3%
Steam - Other	\$2.0	\$1.2	(\$0.8)	(38.2%)	2.9%	2.1%
Wind	\$0.2	\$0.1	(\$0.0)	(25.3%)	0.2%	0.2%
Total	\$70.5	\$58.6	(\$11.8)	(16.8%)	100.0%	100.0%

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2020. 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, 95.1 percent, went 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. Combustion turbines, which, unlike other unit types, can be committed and decommitted in the real-time market, received 88.0 percent of balancing credits and 94.6 percent of lost opportunity credits. Combustion turbines committed in the real-time market tend to require balancing credits due to inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines with a day-ahead schedule and not committed in real time 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 pricing node and the unit's balancing charges are greater than its day-ahead revenues.

¹² Table 4-2 does not include balancing imports credits and load response credits in the total amounts.

¹³ Solar units should be ineligible for all uplift payments because they do not follow PJM's dispatch instructions. The MMU notified PJM of the discrepancy.

Table 4-3 Energy uplift credits by unit type: January through September, 2020

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	2.8%	2.2%	0.0%	16.9%	3.6%	33.8%	0.0%	13.5%
Combustion Turbine	2.0%	88.0%	0.0%	79.4%	94.6%	55.1%	0.0%	86.5%
Diesel	0.1%	0.8%	0.0%	2.5%	1.2%	0.0%	0.0%	0.1%
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%	0.0%	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	89.5%	6.2%	0.0%	0.0%	0.3%	11.0%	0.0%	0.0%
Steam – Other	5.6%	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	1.2%	0.3%	0.0%	0.0%	0.0%
Total (Millions)	\$7.0	\$31.8	\$0.0	\$2.2	\$17.1	\$0.4	\$0.0	\$0.2

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 market. Such reliability issues include black start service and reactive service or reactive transfer interface control needed to maintain system reliability in a zone.¹⁴ 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.¹⁵ 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 subset of that generation committed for reliability by PJM. In the first nine months of 2020, 0.1 percent of the total day-ahead generation was committed for reliability by PJM, 0.2 percentage points lower than in the first nine months of 2019. The decrease in day-ahead generation committed for reliability by PJM was due to a reduction of the need to commit uneconomic units in BGE and Pepco for reliability.

¹⁴ See OA Schedule 1 § 3.2.3(b).

¹⁵ See PJM, "PJM Markets Gateway User Guide," Section Managing Unit Data (version July 16, 2018) at 33, <<http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?a=en>>.

Table 4-4 Day-ahead generation committed for reliability (GWh): January 2019 through September 2020

	2019			2020		
	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share
Jan	77,616	81	0.1%	71,116	0	0.0%
Feb	66,102	91	0.1%	65,827	5	0.0%
Mar	68,331	305	0.4%	63,058	6	0.0%
Apr	57,926	0	0.0%	55,091	41	0.1%
May	63,432	131	0.2%	58,114	117	0.2%
Jun	67,899	301	0.4%	69,651	60	0.1%
Jul	83,474	327	0.4%	85,585	63	0.1%
Aug	77,632	367	0.5%	79,173	88	0.1%
Sep	69,009	357	0.5%	65,105	145	0.2%
Oct	60,594	112	0.2%			
Nov	63,347	8	0.0%			
Dec	69,808	61	0.1%			
Total (Jan – Sep)	631,423	1,960	0.3%	612,721	525	0.1%
Total	825,172	2,142	0.3%	612,721	525	0.1%

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 2020 were \$7.0 million. The top 10 units received \$6.1

million or 87.1 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 the first nine months of 2020, 76.6 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, of which 72.1 percent was paid as day-ahead operating reserve credits. The remaining 23.4 percent of the day-ahead generation committed for reliability by PJM was economic, meaning prices covered all resource operating costs.

Table 4-5 Day-ahead generation committed for reliability by category (GWh): January through September, 2020

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	0.0	0.0	0.0	0.0
Feb	0.0	4.6	0.0	4.6
Mar	6.0	0.1	0.0	6.1
Apr	0.0	33.7	7.3	41.0
May	14.9	82.0	20.6	117.4
Jun	0.5	59.4	0.0	59.8
Jul	0.0	33.3	29.4	62.7
Aug	2.5	24.2	61.3	88.0
Sep	0.0	141.1	4.1	145.2
Total (Jan - Sep)	23.8	378.3	122.8	524.9
Share	4.5%	72.1%	23.4%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2020 were \$7.0 million, of which \$4.6 million or 65.6 percent was paid to units committed for reliability by PJM, and not scheduled to provide black start or reactive services. An additional 0.9 percent, or \$0.1 million, was paid to units scheduled to provide black start or reactive services.¹⁶

¹⁶ The value for black start and reactive in the 2020 Quarterly State of the Market Report for PJM: January through June was incorrect.

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, reserve markets, reactive service credits, and day-ahead operating reserve credits) and its real-time costs (startup, no load, and energy offer). Combustion turbines (CTs) received \$27.9 million or 88.0 percent of all balancing operating reserve (BOR) credits in the first nine months of 2020. The majority of these credits, 97.1 percent, are paid to CTs that are committed in real time either without or outside of a day-ahead schedule.¹⁷ Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day.

Uplift is higher than necessary because settlement rules do not disqualify units from receiving uplift when they do not follow PJM's dispatch instructions, unless the PJM dispatcher changes the dispatch reason to self scheduled. PJM dispatchers should not decide which units qualify for uplift. The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits and for assessing generator deviations. The MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation.

Balancing operating reserve credits for generators decreased by 21.9 percent from the first nine months of 2019 to the first nine months of 2020. The decrease was a result of lower natural gas prices in the first nine months of 2020 compared to the first nine months of 2019. The decrease in credits in the Dominion, AEP, and ComEd Zones accounted for 70.9 percent of the total change in balancing operating reserve credits. While overall generation in the Dominion, AEP, and ComEd Zones increased by only 2.0 percent in the first

¹⁷ 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.

nine months of 2020 compared to the first nine months of 2019, generation by combustion turbines in the three regions increased by 21.7 percent.

The credits paid to combustion turbines committed in real time without a day-ahead commitment occurs despite the fact that total combustion turbines are committed in the day-ahead energy market at levels comparable to the totals in the real-time energy market. Table 4-6 shows the monthly day-ahead and real-time generation by combustion turbines. In the first nine months of 2020, generation by combustion turbines was 3.5 percent lower in the real-time energy market than in 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 10.6 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 24.3 percent of generation from combustion turbines in the real-time market was uneconomic and required \$27.9 million in BOR credits.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines: January through September, 2020

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	607	0.9%	\$0.0	549	15.1%	\$1.5	(10.4%)
Feb	399	0.2%	\$0.0	316	11.0%	\$0.6	(26.2%)
Mar	434	0.2%	\$0.0	457	11.9%	\$0.8	5.1%
Apr	379	0.6%	\$0.0	394	25.0%	\$0.8	3.9%
May	822	0.9%	\$0.0	825	24.2%	\$1.7	0.3%
Jun	1,908	1.4%	\$0.0	1,699	25.6%	\$4.5	(12.3%)
Jul	4,320	3.0%	\$0.1	4,216	23.1%	\$7.9	(2.5%)
Aug	2,410	2.2%	\$0.0	2,477	29.6%	\$7.4	2.7%
Sep	1,444	1.1%	\$0.0	1,359	27.5%	\$2.8	(6.2%)
Total (Jan - Sep)	12,722	10.6%	\$0.1	12,294	24.3%	\$27.9	(3.5%)

An analysis of real-time generation by combustion turbines shows that BOR credits are incurred primarily by combustion turbines operating without or outside a day-ahead schedule, which constitute 85.4 percent of total BOR credits.

Table 4-7 shows real-time generation by combustion turbines by day-ahead commitment status in the first nine months of 2020. CTs that operated on a day-ahead schedule constituted 73.1 percent of real-time generation by CTs, of which 19.7 percent was uneconomic in the real-time market and received \$0.8 million in BOR credits.

In the first nine months of 2020, 26.9 percent of real-time generation by CTs was from CTs that operated outside of a day-ahead schedule, of which 36.8 percent was uneconomic in the real-time market and received \$27.1 million in BOR credits.

Thus, while enough total generation from CTs may be committed economically in the day-ahead energy market, uplift can still be incurred because the committed units operate at different times than originally scheduled and when CTs operate in real time outside of a day-ahead schedule. For example, in January 2020, although total CT generation committed in the day-ahead market was greater than CT generation in real time, 33.9 percent of real-time generation by CTs operated outside of a day-ahead schedule.

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: January through September, 2020

Month	Real-Time Generation Operating on a Day-Ahead Schedule				Real-Time Generation Operating Outside of a Day-Ahead Schedule			
	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	363	66.1%	3.8%	\$0.0	186	33.9%	37.1%	\$1.5
Feb	241	76.1%	4.3%	\$0.0	76	23.9%	32.3%	\$0.6
Mar	316	69.1%	4.8%	\$0.0	141	30.9%	27.9%	\$0.8
Apr	257	65.2%	16.9%	\$0.0	137	34.8%	40.3%	\$0.8
May	579	70.2%	15.2%	\$0.1	246	29.8%	45.2%	\$1.7
Jun	1,210	71.2%	22.8%	\$0.1	489	28.8%	32.6%	\$4.4
Jul	3,255	77.2%	19.2%	\$0.2	962	22.8%	36.4%	\$7.7
Aug	1,750	70.6%	26.1%	\$0.3	727	29.4%	38.0%	\$7.1
Sep	1,015	74.6%	24.0%	\$0.1	345	25.4%	38.0%	\$2.7
Total (Jan - Sep)	8,985	73.1%	19.7%	\$0.8	3,309	26.9%	36.8%	\$27.1

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two 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 manually reduced or suspended by PJM due to a transmission constraint or other reliability issue. In this scenario the unit will receive a credit for LOC based on its desired output. 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 the first nine months of 2019 and 2020. In the first nine months of 2020, LOC credits increased by \$4.6 million or 36.6 percent compared to the first nine months of 2019. The increase of \$4.6 million is comprised of a \$4.2 million increase

in day-ahead LOC and a \$0.4 million increase in real-time LOC. The increase in day-ahead LOC credits was the result of increased day-ahead generation by combustion turbines and diesels not requested by PJM in real-time.

In the first nine months of 2020, wind units received \$0.5 million of real-time LOC, down by 71.2 percent compared to the first nine months of 2019. In the first nine months of 2020, real-time LOC credits to wind units accounted for 42.9 percent of the uplift payments to wind units. Wind units in the AEP and ComEd Zones received 99.1 percent of those real-time lost opportunity cost credits.

Table 4-9 shows day-ahead generation for combustion turbines and diesels, including scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and the subset of day-ahead generation receiving LOC credits. In the first nine months of 2020, 15.7 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 4.1 percentage points higher than in the first nine months of 2019. Generation by natural gas fired combustion turbines increased by 24.6 percent during the first nine months of 2020 compared to the first nine months of 2019, and coal generation decreased by 24.9 percent during the first nine of months of 2020 compared to the first nine months of 2019. During the first nine months of 2020 compared to 2019, day-ahead generation by combustion turbines increased 51.1 percent, day-ahead generation not requested in real time increased disproportionately by 104.4 percent, and day-ahead generation not requested in real time receiving lost opportunity costs increased disproportionately by 131.4 percent. Unlike coal units, combustion turbines that clear the day-ahead energy market still have to be instructed by PJM in real time to come online. The combination of increased combustion turbines scheduled in the day-ahead energy market and this different treatment was a key factor in increasing LOC credits to generation from.

Table 4-8 Monthly lost opportunity cost credits (Millions): January 2019 through September 2020

	2019			2020		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	\$0.4	\$0.0	\$0.5	\$0.5	\$0.0	\$0.5
Feb	\$0.1	\$0.0	\$0.2	\$0.4	\$0.0	\$0.4
Mar	\$0.4	\$0.0	\$0.5	\$0.6	\$0.1	\$0.6
Apr	\$0.5	\$0.0	\$0.5	\$0.3	\$0.5	\$0.9
May	\$1.6	\$0.1	\$1.6	\$0.8	\$0.0	\$0.8
Jun	\$0.6	\$0.0	\$0.7	\$3.3	\$0.1	\$3.4
Jul	\$1.9	\$0.0	\$2.0	\$4.2	\$0.1	\$4.2
Aug	\$1.7	\$0.0	\$1.7	\$4.5	\$0.1	\$4.5
Sep	\$4.7	\$0.2	\$4.9	\$1.6	\$0.0	\$1.7
Oct	\$2.2	\$0.1	\$2.3			
Nov	\$1.4	\$0.1	\$1.6			
Dec	\$0.8	\$0.0	\$0.8			
Total (Jan - Sep)	\$12.0	\$0.5	\$12.5	\$16.2	\$0.9	\$17.1
Share (Jan - Sep)	96.0%	4.0%	100.0%	94.6%	5.4%	100.0%
Total	\$16.4	\$0.8	\$17.1	\$16.2	\$0.9	\$17.1
Share	95.5%	4.5%	100.0%	94.6%	5.4%	100.0%

Table 4-9 Day-ahead generation from combustion turbines and diesels (GWh): January 2019 through September 2020

	2019			2020		
	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)
Jan	692	38	13	873	171	73
Feb	370	19	4	653	114	49
Mar	524	48	12	729	103	55
Apr	619	71	21	656	95	37
May	848	171	49	1,126	188	80
Jun	938	128	46	2,278	438	244
Jul	2,555	197	68	4,759	590	272
Aug	1,901	197	109	2,728	386	181
Sep	1,808	320	163	1,696	346	131
Oct	2,125	289	155			
Nov	1,212	183	61			
Dec	777	128	59			
Total (Jan - Sep)	10,255	1,189	485	15,498	2,431	1,122
Share (Jan - Sep)	100.0%	11.6%	4.7%	100.0%	15.7%	7.2%
Total	14,369	1,789	760	15,498	2,431	1,122

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 and real-time market clearing 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.¹⁸ In the day-ahead energy market only pool scheduled resources are eligible for day-ahead operating reserve credits. A unit may self schedule in day ahead to clear and then pool schedule in subsequent days to remain online, in which case they would be eligible for uplift for the subsequent days. In the real-time energy market only pool scheduled resources that follow PJM's dispatch are 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.¹⁹

Table 4-10 Dispatch status, commitment status and uplift eligibility²⁰

Dispatch Status	Dispatch Description	Eligible to Set LMP	Commitment Status	
			Self Scheduled (units committed by the generation owner)	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 the first nine months of 2020, 42.7 percent of generation in the day-ahead energy market was pool scheduled and 45.0 percent of generation in the real-time energy market was pool scheduled. Thus the majority of generation in both the day-ahead and real-time markets is not eligible to receive uplift credits. Most nuclear and coal resources, which make up 52.7 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): January through September, 2020

	Self Scheduled			Pool Scheduled			Total GWh	Total Pool Scheduled	Total Self Scheduled	Total Generation Eligible to Set Price
	Dispatchable	Economic Minimum	Block Loaded	Dispatchable	Economic Minimum	Block Loaded				
Day-Ahead Generation	59,999	137,625	153,234	114,770	130,743	16,351	612,721	261,864	350,857	174,768
Share of Day-Ahead	9.8%	22.5%	25.0%	18.7%	21.3%	2.7%	100.0%	42.7%	57.3%	28.5%
Real-Time Generation	52,586	131,055	153,117	114,035	141,601	19,587	611,980	275,222	336,757	166,620
Share of Real-Time	8.6%	21.4%	25.0%	18.6%	23.1%	3.2%	100.0%	45.0%	55.0%	27.2%

¹⁸ PJM has modified the basic rules of eligibility to set price using its CT price setting logic.

¹⁹ 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.

²⁰ PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.

Economic and Noneconomic Generation²¹

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 the first nine months of 2020, 86.9 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.2 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): January through September, 2020

Energy Market	Economic Generation	Noneconomic Generation	Total Eligible Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	227,517	34,347	261,864	86.9%	13.1%
Real-Time	156,818	76,659	233,477	67.2%	32.8%

²¹ 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 the first nine months of 2020, 0.6 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.2 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-13 Generation receiving operating reserve credits (GWh): January through September, 2020

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits
			Percent
Day-Ahead	261,864	1,631	0.6%
Real-Time	233,477	2,729	1.2%

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 a lack of transparency has made it almost impossible for competition to affect these payments.²²

Figure 4-1 shows the concentration of energy uplift credits. The top 10 units received 18.0 percent of total energy uplift credits in the first nine months of 2020, compared to 23.7 percent in the first nine months of 2019. In the first nine months of 2020, 239 units received 90 percent of all energy uplift credits, compared to 245 units in the first nine months of 2019.

²² As a result of FERC Order No. 844, PJM began publishing total uplift credits by unit by month for credits incurred on and after July 1, 2019 on September 10, 2019.

Figure 4-1 Cumulative share of energy uplift credits: January through September, 2019 and 2020 by unit

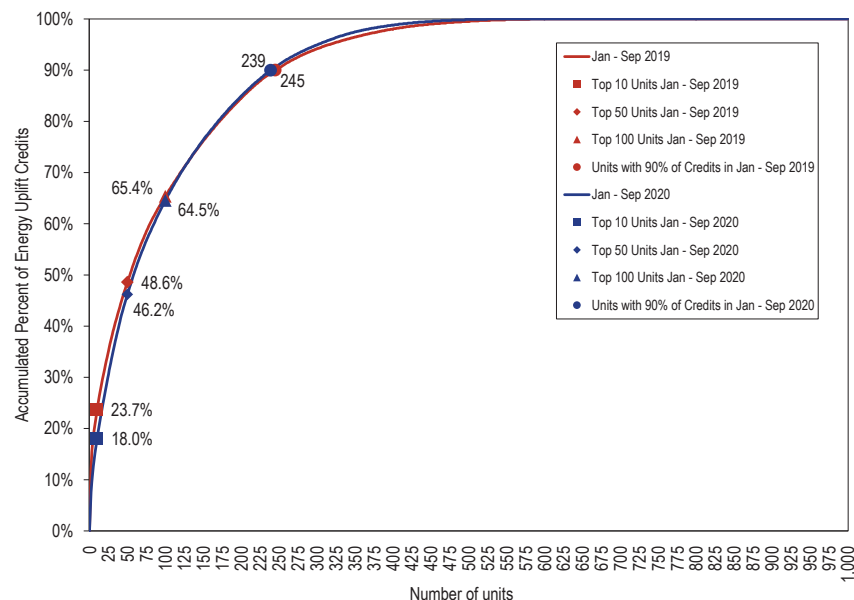


Table 4-14 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in the first nine months of 2020.

Table 4-14 Top 10 units and organizations energy uplift credits: January through September, 2020

Category	Type	Top 10 Units		Top 10 Organizations	
		Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	\$6.1	87.1%	\$6.9	97.7%
	Canceled Resources	\$0.0	0.0%	\$0.0	0.0%
Balancing	Generators	\$4.3	13.7%	\$23.8	74.9%
	Local Constraints Control	\$1.5	69.3%	\$2.2	99.7%
	Lost Opportunity Cost	\$4.2	24.7%	\$13.8	81.0%
Reactive Services		\$0.4	94.8%	\$0.4	100.0%
Synchronous Condensing		\$0.0	0.0%	\$0.0	0.0%
Black Start Services		\$0.1	43.7%	\$0.1	90.9%
Total		\$10.6	18.0%	\$43.0	73.3%

Table 4-15 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first nine months of 2020, 91.8 percent of all credits paid to these units were allocated to deviations while the remaining 8.2 percent were paid for reliability reasons.

Table 4-15 Balancing operating reserve credits to top 10 units by category and region: January through September, 2020

	Reliability			Deviations			Total
	RTO	East	West	RTO	East	West	
Credits (Millions)	\$0.3	\$0.0	\$0.0	\$3.4	\$0.6	\$0.0	\$4.3
Share	8.0%	0.1%	0.0%	77.2%	14.7%	0.0%	100.0%

In the first nine months of 2020, concentration in all energy uplift credit categories was high.^{23 24} 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 8481, for balancing operating reserve credits to generators was 3859, for lost opportunity cost credits was 5325 and for reactive services credits was 9562. All of these HHI values are characterized as highly concentrated.

Table 4-16 Daily energy uplift credits HHI: January through September, 2020

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	8481	3265	10000	100.0%	54.8%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	70.9%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	3859	778	10000	100.0%	27.3%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
	Lost Opportunity Cost	5325	1168	10000	100.0%	19.9%
Reactive Services		9562	5236	10000	100.0%	35.0%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9563	5045	10000	100.0%	19.3%
Total		3370	617	9864	99.3%	21.6%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-17 through Table 4-20 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits. The top 10 units receiving uplift credits received 18.0 percent of all credits, with the top recipient receiving 3.9 percent. The top 10 units receiving day-ahead operating reserves received 87.1 percent. The top 10 recipients of balancing operating reserves received 13.7 percent of balancing operating reserve credits. The top 10 recipients of lost opportunity cost credits received 24.7 percent of total lost opportunity cost credits.

Table 4-17 Top 10 recipients of total uplift: January through September, 2020

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 1 F	BGE	\$2,286,801	3.9%
2	BC BRANDON SHORES 2 F	BGE	\$2,165,940	3.7%
3	BC PERRYMAN 6 CT	BGE	\$1,199,938	2.0%
4	PEP MORGANTOWN 2 F	Pepco	\$926,841	1.6%
5	DPL INDIAN RIVER 4 F	DPL	\$868,608	1.5%
6	COM 900 ELWOOD 7 CT	ComEd	\$705,029	1.2%
7	COM 900 ELWOOD 5 CT	ComEd	\$694,385	1.2%
8	COM 900 ELWOOD 1 CT	ComEd	\$599,082	1.0%
9	PEP MORGANTOWN 1 F	Pepco	\$562,365	1.0%
10	COM 900 ELWOOD 2 CT	ComEd	\$561,257	1.0%
Total of Top 10			\$10,570,246	18.0%
Total Uplift Credits			\$58,648,284	100.0%

Table 4-18 Top 10 recipients of day-ahead generation credits: January through September, 2020

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 1 F	BGE	\$2,070,730	29.4%
2	BC BRANDON SHORES 2 F	BGE	\$1,525,928	21.7%
3	DPL INDIAN RIVER 4 F	DPL	\$739,881	10.5%
4	PEP MORGANTOWN 2 F	Pepco	\$671,158	9.5%
5	PEP MORGANTOWN 1 F	Pepco	\$516,264	7.3%
6	PEP CHALKPOINT 2 F	Pepco	\$145,113	2.1%
7	COM 3 POWERTON 5	ComEd	\$136,128	1.9%
8	PL BRUNNER ISLAND 3 F	PPL	\$128,535	1.8%
9	PEP CHALKPOINT 4 F	Pepco	\$117,987	1.7%
10	PEP CHALKPOINT 3 F	Pepco	\$79,282	1.1%
Total of Top 10			\$6,131,006	87.1%
Total day-ahead operating reserve credits			\$7,038,678	100.0%

Table 4-19 Top 10 recipients of balancing operating reserve credits: January through September, 2020

Rank	Unit Name	Zone	Balancing Operating Reserve Credit	Share of Balancing Operating Reserve Credits
1	BC BRANDON SHORES 2 F	BGE	\$640,012	2.0%
2	AEP FOOT HILLS 2 CT	AEP	\$434,970	1.4%
3	COM 951 AURORA 4 CT	ComEd	\$434,792	1.4%
4	VP MARSHRUN 1 CT	Dominion	\$431,958	1.4%
5	AEP RIVERSIDE ZELDA 3 CT	AEP	\$421,936	1.3%
6	AEP RIVERSIDE ZELDA 2 CT	AEP	\$417,630	1.3%
7	COM 951 AURORA 2 CT	ComEd	\$407,234	1.3%
8	VP MARSHRUN 3 CT	Dominion	\$402,652	1.3%
9	COM 951 AURORA 3 CT	ComEd	\$378,335	1.2%
10	COM 952 ROCKFORD 12 CT	ComEd	\$375,464	1.2%
Total of Top 10			\$4,344,983	13.7%
Total balancing operating reserve credits			\$31,770,587	100.0%

Table 4-20 Top 10 recipients of lost opportunity cost credits: January through September, 2020

Rank	Unit Name	Zone	Lost Opportunity Cost Credit	Share of Lost Opportunity Cost Credits
1	BC PERRYMAN 6 CT	BGE	\$817,676	4.8%
2	COM 900 ELWOOD 5 CT	ComEd	\$522,510	3.1%
3	COM 900 ELWOOD 7 CT	ComEd	\$507,000	3.0%
4	COM 900 ELWOOD 2 CT	ComEd	\$449,979	2.6%
5	COM 900 ELWOOD 1 CT	ComEd	\$411,750	2.4%
6	COM 900 ELWOOD 6 CT	ComEd	\$352,221	2.1%
7	COM 900 ELWOOD 4 CT	ComEd	\$346,925	2.0%
8	FE LEMOYNE 1 CT	ATSI	\$279,239	1.6%
9	FE RICHLAND 5 CT	ATSI	\$272,452	1.6%
10	COM 900 ELWOOD 3 CT	ComEd	\$267,099	1.6%
Total of Top 10			\$4,226,850	24.7%
Total lost opportunity cost credits			\$17,090,303	100.0%

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-21 and Table 4-22 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 4-21 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
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
Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits		Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids
Balancing			
Generation Resources	Balancing Operating Reserve Generator	Balancing Operating Reserve for Reliability Balancing Operating Reserve for Deviations Balancing Local Constraint	Real-Time Load plus Real-Time Export Transactions Deviations Applicable Requesting Party
Canceled Resources	Balancing Operating Reserve Startup Cancellation		
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC	Balancing Operating Reserve for Deviations	Deviations
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

Table 4-22 Reactive services, synchronous condensing and black start services credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:
		Reactive		
	Day-Ahead Operating Reserve			
	Reactive Services Generator		Reactive Services Charge	Zonal Real-Time Load
Resources Providing Reactive Service	Reactive Services LOC	→		
	Reactive Services Condensing			
	Reactive Services Synchronous Condensing LOC		Reactive Services Local Constraint	Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing	→	Synchronous Condensing	Real-Time Load
	Synchronous Condensing LOC			Real-Time Export Transactions
		Black Start		
	Day-Ahead Operating Reserve			
Resources Providing Black Start Service	Balancing Operating Reserve	→	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations
	Black Start Testing			

Uplift Resettlement

Some units have been incorrectly paid uplift despite not meeting uplift eligibility requirements, such as not following dispatch, not having the correct commitment status, or not operating with proper offer parameters. The MMU has requested that PJM correctly resettle the uplift payments in these cases. By the end of the first nine months of 2020, the cumulative resettlement requests totaled \$2.2 million. Of that amount, PJM has agreed and resettled 59.5 percent of the requests, 30.4 percent remains pending. The remaining 10.2 percent occurred prior to September 2018 and require a directive for FERC for them to be resettled. The MMU continues to bring new cases to the attention of PJM.

Energy Uplift Charges Results

Energy Uplift Charges

Total energy uplift charges decreased by \$11.8 million or 16.8 percent in the first nine months of 2020 compared to the first nine months of 2019. Energy uplift charges in the first nine months of 2020 were \$58.6 million.

Table 4-23 shows total energy uplift charges by category in the first nine months of 2019 and 2020.²⁵ The decrease of \$11.8 million is comprised of a decrease of \$6.9 million in day-ahead operating reserve charges, a decrease of \$4.9 million in balancing operating reserve charges and a decrease of \$0.1 million in reactive service charges.

Table 4-23 Total energy uplift charges by category: January through September, 2019 and 2020

Category	(Jan - Sep) 2019 Charges (Millions)	(Jan - Sep) 2020 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	\$14.0	\$7.0	(\$6.9)	(49.6%)
Balancing Operating Reserves	\$55.9	\$51.0	(\$4.9)	(8.7%)
Reactive Services	\$0.5	\$0.4	(\$0.1)	(11.5%)
Synchronous Condensing	\$0.0	\$0.0	\$0.0	0.0%
Black Start Services	\$0.2	\$0.2	(\$0.0)	(8.9%)
Total	\$70.5	\$58.6	(\$11.8)	(16.8%)
Energy Uplift as a Percent of Total PJM Billing	0.2%	0.2%	(0.0%)	(0.2%)

Table 4-24 compares monthly energy uplift charges by category for the first nine months of 2019 and 2020.

Table 4-24 Monthly energy uplift charges: January 2019 through September 2020

	2019 Charges (Millions)						2020 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	\$1.0	\$6.5	\$0.1	\$0.0	\$0.0	\$7.6	\$0.1	\$4.0	\$0.0	\$0.0	\$0.0	\$4.1
Feb	\$0.8	\$3.9	\$0.0	\$0.0	\$0.0	\$4.7	\$0.2	\$1.2	\$0.0	\$0.0	\$0.0	\$1.4
Mar	\$2.3	\$4.6	\$0.0	\$0.0	\$0.0	\$6.9	\$0.0	\$1.6	\$0.0	\$0.0	\$0.0	\$1.7
Apr	\$0.1	\$4.0	\$0.0	\$0.0	\$0.0	\$4.2	\$0.8	\$2.0	\$0.1	\$0.0	\$0.1	\$2.9
May	\$1.4	\$4.1	\$0.1	\$0.0	\$0.1	\$5.7	\$1.0	\$2.7	\$0.3	\$0.0	\$0.0	\$4.0
Jun	\$2.6	\$4.8	\$0.2	\$0.0	\$0.0	\$7.5	\$0.9	\$8.5	\$0.0	\$0.0	\$0.0	\$9.5
Jul	\$1.4	\$10.6	\$0.0	\$0.0	\$0.0	\$12.0	\$1.2	\$13.0	\$0.0	\$0.0	\$0.0	\$14.2
Aug	\$2.7	\$6.8	\$0.0	\$0.0	\$0.0	\$9.5	\$0.8	\$12.7	\$0.0	\$0.0	\$0.0	\$13.5
Sep	\$1.7	\$10.6	\$0.0	\$0.0	\$0.0	\$12.3	\$2.1	\$5.3	\$0.0	\$0.0	\$0.0	\$7.4
Oct	\$0.9	\$8.3	\$0.0	\$0.0	\$0.0	\$9.2						
Nov	\$0.2	\$5.6	\$0.0	\$0.0	\$0.0	\$5.8						
Dec	\$0.5	\$2.5	\$0.1	\$0.0	\$0.0	\$3.1						
Total (Jan - Sep)	\$14.0	\$55.9	\$0.5	\$0.0	\$0.2	\$70.5	\$7.0	\$51.0	\$0.4	\$0.0	\$0.2	\$58.6
Share (Jan - Sep)	19.8%	79.3%	0.7%	0.0%	0.2%	100.0%	12.0%	87.0%	0.7%	0.0%	0.3%	100.0%
Total	\$15.5	\$72.2	\$0.6	\$0.0	\$0.2	\$88.5	\$7.0	\$51.0	\$0.4	\$0.0	\$0.2	\$58.6
Share	17.5%	81.6%	0.6%	0.0%	0.3%	100.0%	12.0%	87.0%	0.7%	0.0%	0.3%	100.0%

²⁵ Table 4-27 includes all categories of charges as defined in Table 4-25 and Table 4-26 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 October 9, 2020. The 2020 uplift charges differ from the 2020 uplift credits by \$0.02 million in the PJM data although they should be equal.

Table 4-25 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.^{26 27} Day-ahead operating reserve charges decreased by \$6.9 million or 49.6 percent in the first nine months of 2020 compared to the first nine months of 2019. Day-ahead operating reserve charges decreased in 2020 as a result of a decrease in day-ahead unit commitments for reliability. The decrease in day-ahead operating reserve credits paid to units in Pepco and BGE accounted for 92.1 percent of the total decrease in day-ahead operating reserve charges during the first nine months of 2020 compared to the first nine months of 2019.

Table 4-25 Day-ahead operating reserve charges: January through September, 2019 and 2020

Type	(Jan - Sep) 2019 Charges (Millions)	(Jan - Sep) 2020 Charges (Millions)	Change (Millions)	(Jan - Sep) 2019 Share	(Jan - Sep) 2020 Share
Day-Ahead Operating Reserve Charges	\$14.0	\$7.0	(\$6.9)	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	\$14.0	\$7.0	(\$6.9)	100.0%	100.0%

Table 4-26 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by \$4.9 million or 8.7 percent in the first nine months of 2020 compared to 2019.

Table 4-26 Balancing operating reserve charges: January through September, 2019 and 2020

Type	(Jan - Sep) 2019 Charges (Millions)	(Jan - Sep) 2020 Charges (Millions)	Change (Millions)	(Jan - Sep) 2019 Share	(Jan - Sep) 2020 Share
Balancing Operating Reserve Reliability Charges	\$17.0	\$11.9	(\$5.1)	30.5%	23.4%
Balancing Operating Reserve Deviation Charges	\$36.2	\$36.9	\$0.8	64.7%	72.4%
Balancing Operating Reserve Charges for Load Response	\$0.0	\$0.0	(\$0.0)	0.0%	0.0%
Balancing Local Constraint Charges	\$2.7	\$2.2	(\$0.5)	4.8%	4.3%
Total	\$55.9	\$51.0	(\$4.8)	100.0%	100.0%

²⁶ See PJM Operating Agreement Schedule 1 § 3.2.3(c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves only 10 times since 1999, totaling \$26.9 million.

²⁷ See the 2020 Quarterly State of the Market Report for PJM: January through September, Section 13, Financial Transmission Rights and Auction Revenue Rights.

Table 4-27 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges are equal to the sum of the following three categories: make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators, and payments to resources scheduled by PJM but canceled by PJM before coming online. In the first nine months of 2020, energy lost opportunity cost deviation charges increased by \$4.6 million or 36.4 percent, and make whole deviation charges decreased by \$3.8 million or 16.1 percent compared to the first nine months of 2019. The decrease in charges was the result of the significant decrease in balancing credits to generators.

Table 4-27 Balancing operating reserve deviation charges: January through September, 2019 and 2020

Charge Attributable To	(Jan - Sep) 2019 Charges (Millions)	(Jan - Sep) 2020 Charges (Millions)	Change (Millions)	(Jan - Sep) 2019 Share	(Jan - Sep) 2020 Share
Make Whole Payments to Generators and Imports	\$23.7	\$19.9	(\$3.8)	65.4%	53.8%
Energy Lost Opportunity Cost	\$12.5	\$17.1	\$4.6	34.6%	46.2%
Canceled Resources	\$0.0	\$0.0	\$0.0	0.0%	0.0%
Total	\$36.2	\$36.9	\$0.8	100.0%	100.0%

Table 4-28 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by \$0.1 million or 11.5 percent in the first nine months of 2020, compared to the first nine months of 2019.

Table 4-28 Additional energy uplift charges: January through September, 2019 and 2020

Type	(Jan - Sep) 2019 Charges (Millions)	(Jan - Sep) 2020 Charges (Millions)	Change (Millions)	(Jan - Sep) 2019 Share	(Jan - Sep) 2020 Share
Reactive Services Charges	\$0.5	\$0.4	(\$0.1)	72.6%	72.1%
Synchronous Condensing Charges	\$0.0	\$0.0	\$0.0	0.0%	0.0%
Black Start Services Charges	\$0.2	\$0.2	(\$0.0)	27.4%	27.9%
Total	\$0.6	\$0.6	(\$0.1)	100.0%	100.0%

Table 4-29 and Table 4-30 show the amount and shares of regional balancing charges in the first nine months of 2019 and 2020. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. In the first nine months of 2020, the largest share of regional charges was paid by real-time load which paid 23.2 percent of all regional balancing charges. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In the first nine months of 2020, regional balancing operating reserve charges decreased by \$4.4 million compared to the first nine months of 2019. Balancing operating reserve reliability charges decreased by \$5.1 million or 29.9 percent, and balancing operating reserve deviation charges increased by \$0.7 million, or 1.9 percent.

Table 4-29 Regional balancing charges allocation (Millions): January through September, 2019

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	\$14.8	27.8%	\$1.1	2.1%	\$0.5	0.9%	\$16.4	30.8%
	Real-Time Exports	\$0.6	1.1%	\$0.0	0.1%	\$0.0	0.0%	\$0.6	1.2%
	Total	\$15.4	28.9%	\$1.1	2.1%	\$0.5	0.9%	\$17.0	31.9%
Deviation Charges	Demand	\$21.2	39.7%	\$0.8	1.6%	\$0.3	0.6%	\$22.3	41.9%
	Supply	\$5.6	10.5%	\$0.3	0.5%	\$0.1	0.2%	\$6.0	11.2%
	Generator	\$7.5	14.0%	\$0.4	0.7%	\$0.1	0.2%	\$7.9	14.9%
Total Regional Balancing Charges		\$49.6	93.2%	\$2.6	4.9%	\$1.0	2.0%	\$53.3	100%

Table 4-30 Regional balancing charges allocation (Millions): January through September, 2020

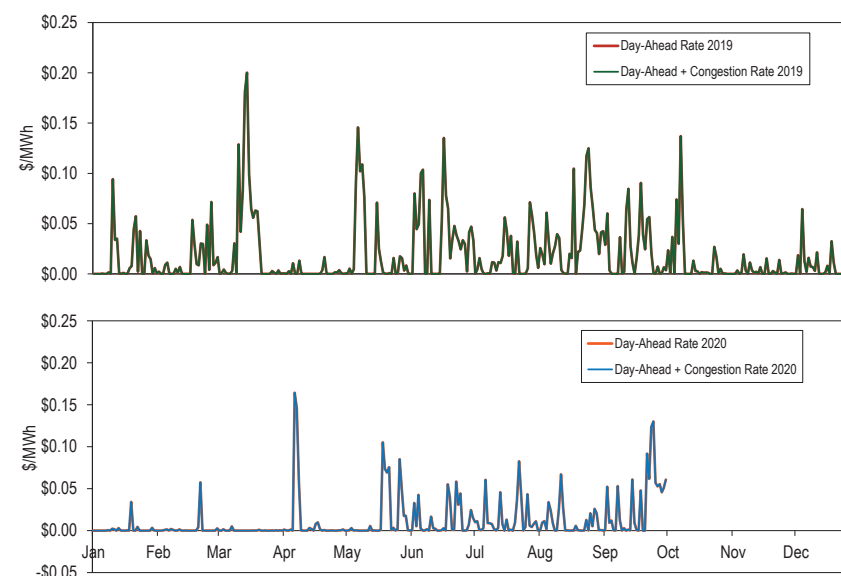
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	\$9.1	18.7%	\$2.0	4.1%	\$0.2	0.5%	\$11.4	23.2%
	Real-Time Exports	\$0.5	1.0%	\$0.1	0.1%	\$0.0	0.0%	\$0.6	1.2%
	Total	\$9.6	19.6%	\$2.1	4.2%	\$0.3	0.5%	\$11.9	24.4%
Deviation Charges	Demand	\$22.9	46.8%	\$1.4	2.8%	\$0.3	0.5%	\$24.5	50.2%
	Supply	\$4.3	8.8%	\$0.3	0.7%	\$0.0	0.1%	\$4.7	9.6%
	Generator	\$7.3	14.8%	\$0.4	0.8%	\$0.1	0.2%	\$7.8	15.9%
Total Regional Balancing Charges		\$44.0	90.1%	\$4.2	8.6%	\$0.6	1.3%	\$48.9	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 4-21 shows how these charges are allocated.²⁸

Figure 4-2 shows the daily day-ahead operating reserve rate for 2019 and 2020. The average rate in the first nine months of 2020 was \$0.012 per MWh, \$0.011 per MWh lower than the average in the first nine months of 2019. The highest rate in the first nine months of 2020 occurred on April 6, when units were called on by reliability engineers due to transmission constraints, and the rate reached \$0.164 per MWh, \$0.036 per MWh lower than the \$0.200 per

MWh reached in the first nine months of 2019, on March 15. Figure 4-2 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 2019 or 2020.

Figure 4-2 Daily day-ahead operating reserve rate (\$/MWh): 2019 through September 2020

²⁸ 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.

Figure 4-3 shows the RTO and the regional reliability rates for 2019 and the first nine months of 2020. The average RTO reliability rate in 2020 was \$0.016 per MWh. The highest RTO reliability rate in 2020 occurred on June 10, when the rate reached \$0.152 per MWh, \$0.216 per MWh lower than the \$0.368 per MWh rate reached in the first nine months of 2019, on January 22.

Figure 4-3 Daily balancing operating reserve reliability rates (\$/MWh): 2019 through September 2020

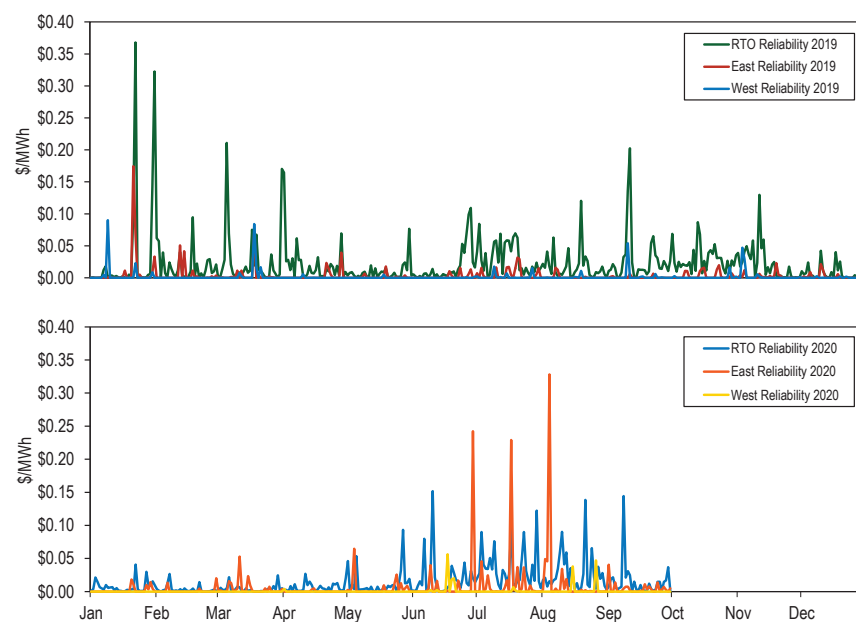


Figure 4-4 shows the RTO and regional deviation rates for 2019 and the first nine months of 2020. The average RTO deviation rate in 2020 was \$0.149 per MWh. The highest daily rate in the first nine months of 2020 occurred on August 21, when the RTO deviation rate reached \$1.224 per MWh, \$0.002 per MWh less than the \$1.226 per MWh rate reached in 2019, on July 9.

Figure 4-4 Daily balancing operating reserve deviation rates (\$/MWh): 2019 through September 2020

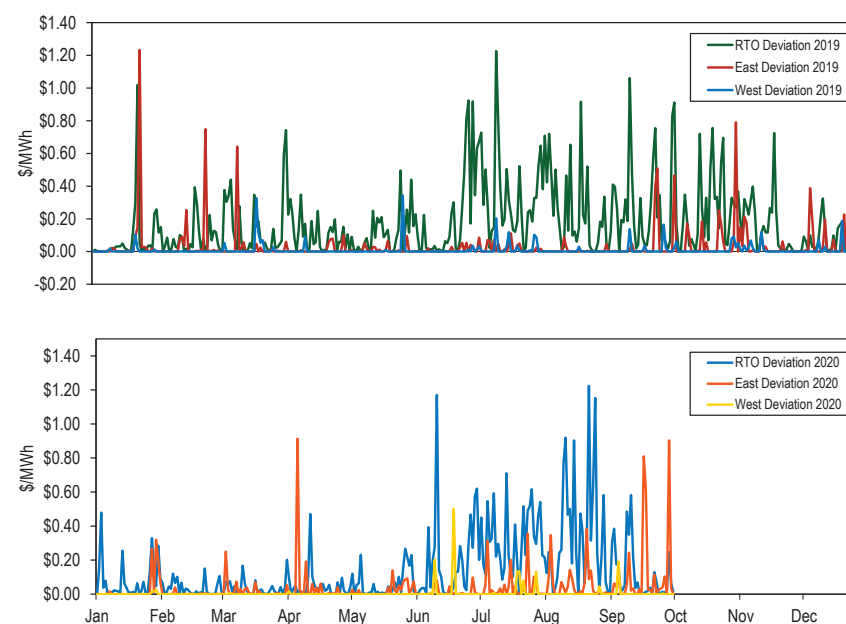


Figure 4-5 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2019 and the first nine months of 2020. The average lost opportunity cost rate in 2020 was \$0.147 per MWh. The highest lost opportunity cost rate in the first nine months of 2020 occurred on June 3, when it reached \$1.923 per MWh, \$0.125 per MWh lower than the \$2.049 per MWh rate reached in 2019, on May 22.

Figure 4-5 Daily lost opportunity cost and canceled resources rates (\$/MWh): 2019 through September 2020

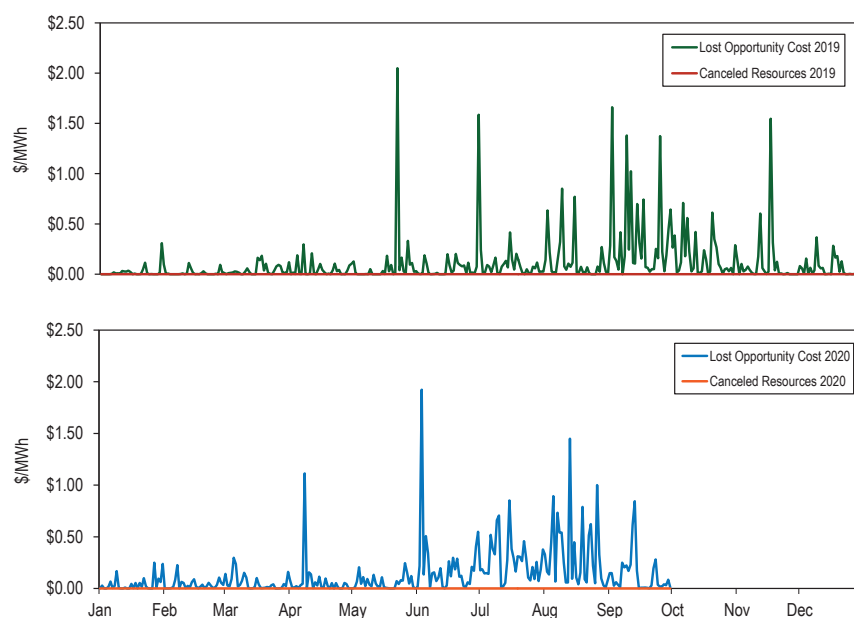


Table 4-31 shows the average rates for each region in each category for the first nine months of 2019 and 2020.

Table 4-31 Operating reserve rates (\$/MWh): January through September, 2019 and 2020

Rate	(Jan - Sep) 2019 (\$/MWh)	(Jan - Sep) 2020 (\$/MWh)	Difference (\$/MWh)	Percent Difference
Day-Ahead	0.022	0.012	(0.011)	(47.7%)
Day-Ahead with Unallocated Congestion	0.022	0.012	(0.011)	(47.7%)
RTO Reliability	0.025	0.016	(0.009)	(35.5%)
East Reliability	0.004	0.007	0.004	90.0%
West Reliability	0.002	0.001	(0.001)	(47.6%)
RTO Deviation	0.185	0.149	(0.036)	(19.5%)
East Deviation	0.025	0.038	0.013	50.9%
West Deviation	0.010	0.007	(0.003)	(31.6%)
Lost Opportunity Cost	0.107	0.147	0.040	37.3%
Canceled Resources	0.000	0.000	NA	NA

Table 4-32 shows the operating reserve cost of a one MW transaction in the first nine months of 2020. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of \$0.345 per MWh with a maximum rate of \$1.966 per MWh, a minimum rate of \$0.001 per MWh and a standard deviation of \$0.360 per MWh. The rates in Table 4-32 include all operating reserve charges including RTO deviation charges. Table 4-32 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 DECAs 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 4-32 Operating reserve rates statistics (\$/MWh): January through September, 2020

Rates Charged (\$/MWh)					
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	1.961	0.333	<0.001	0.358
	DEC	1.966	0.345	0.001	0.360
	DA Load	0.164	0.012	<0.001	0.025
	RT Load	0.344	0.024	<0.001	0.040
	Deviation	1.961	0.333	<0.001	0.358
West	INC	1.961	0.302	<0.001	0.338
	DEC	1.966	0.314	<0.001	0.340
	DA Load	0.164	0.012	<0.001	0.025
	RT Load	0.152	0.017	<0.001	0.024
	Deviation	1.961	0.302	<0.001	0.338

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.²⁹ 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 4-33 shows the reactive services rates associated with local voltage support in the first nine months of 2019 and 2020. Table 4-33 shows that in the first nine months of 2020 only five zones incurred reactive charges, in addition to reactive capability charges. Real-time load in the JCPL Zone, where reactive service charges were the highest, paid an average of \$0.010 per MWh for reactive

services, and real-time load in the PPL Control Zone, where charges were the second highest, paid an average of \$0.006 per MWh for reactive services.

Table 4-33 Local voltage support rates: January through September, 2019 and 2020

Control Zone	(Jan - Sep) 2019 (\$/MWh)	(Jan - Sep) 2020 (\$/MWh)	Difference (\$/MWh)	Percent Difference
AECO	0.000	0.000	0.000	0.0%
AEP	0.000	0.000	(0.000)	(100.0%)
APS	0.000	0.000	(0.000)	(100.0%)
ATSI	0.000	0.000	(0.000)	(100.0%)
BGE	0.000	0.000	0.000	0.0%
ComEd	0.000	0.000	0.000	0.0%
DAY	0.000	0.000	0.000	0.0%
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.002	0.000	(0.002)	(100.0%)
DPL	0.007	0.001	(0.007)	(92.6%)
EKPC	0.000	0.005	0.005	NA
JCPL	0.000	0.010	0.010	NA
Met-Ed	0.000	0.000	0.000	NA
OVEC	0.000	0.000	0.000	0.0%
PECO	0.000	0.000	0.000	0.0%
PENELEC	0.011	0.000	(0.011)	(100.0%)
Pepco	0.000	0.000	0.000	0.0%
PPL	0.000	0.006	0.006	NA
PSEG	0.000	0.000	0.000	0.0%
RECO	0.000	0.000	0.000	0.0%

²⁹ See 2019 State of the Market Report for PJM, Volume 2, Section 10: Ancillary Service Markets.

Balancing Operating Reserve Determinants

Table 4-34 shows the determinants used to allocate the regional balancing operating reserve charges in the first nine months of 2019 and 2020. Total real-time load and real-time exports were 594,486 GWh, 3.7 percent lower in 2020 compared to 2019. Total deviations summed across the demand, supply, and generator categories were 116,337 GWh, 1.0 percent lower in the first nine months of 2020 compared to the first nine months of 2019.

Table 4-34 Balancing operating reserve determinants (GWh): January through September, 2019 and 2020

		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
(Jan - Sep) 2019	RTO	590,833	26,274	617,108	71,103	20,835	25,548	117,487
	East	282,332	11,440	293,772	34,611	11,297	13,033	58,941
	West	308,502	14,834	323,335	35,909	9,077	12,516	57,501
(Jan - Sep) 2020	RTO	564,700	29,786	594,486	74,144	17,053	25,140	116,337
	East	270,505	9,646	280,152	35,611	9,586	11,454	56,651
	West	294,194	20,140	314,334	38,174	7,272	13,686	59,132
Difference	RTO	(26,134)	3,512	(22,622)	3,041	(3,782)	(408)	(1,149)
	East	(11,827)	(1,794)	(13,620)	1,001	(1,711)	(1,578)	(2,289)
	West	(14,307)	5,306	(9,001)	2,265	(1,805)	1,170	1,631

Under PJM's operating reserve rules, balancing operating reserve charges are allocated regionally. PJM defined the Eastern and Western regions, in addition to the RTO region to allocate the cost of balancing operating reserves. These regions consist of three location types: zones, hubs/aggregates, and interfaces. The deviations are aggregated regionally by location type, depending on where the charge occurs.

Credits paid to generators that are defined as operating for reliability purposes are charged to real-time load and exports. Credits paid to generators and credits paid to import transactions that are defined to be operating control deviations on the system, such as energy lost opportunity credits and cancellation credits, are charged to deviations.

Deviations fall into three categories, demand, supply and generator deviations. Table 4-35 shows the different categories by type of transactions that incurred deviations. In the first nine months of 2020, 31.8 percent of all RTO deviations were incurred by either virtual transactions, or by a combined transaction that includes virtuals, such as combinations with exports and load. The remaining 68.2 percent of all RTO deviations were incurred by transaction types not involving virtuals. Combined transactions with virtuals incur higher deviations than those without.

Table 4-35 Deviations by transaction type: January through September, 2020

Deviation Category	Transaction	Deviation (GWh)			Share		
		RTO	East	West	RTO	East	West
Demand	DECs Only	19,537	10,332	8,846	16.8%	18.2%	15.0%
	Exports Only	5,762	2,371	3,391	5.0%	4.2%	5.7%
	Load Only	46,324	22,736	23,587	39.8%	40.1%	39.9%
	Combination with DECs	2,511	161	2,350	2.2%	0.3%	4.0%
	Combination without DECs	11	11	0	0.0%	0.0%	0.0%
Supply	Imports Only	2,126	1,745	381	1.8%	3.1%	0.6%
	INCs Only	14,766	7,681	6,890	12.7%	13.6%	11.7%
	Combination with INCs	161	160	2	0.1%	0.3%	0.0%
	Combination without INCs	0	0	0	0.0%	0.0%	0.0%
Generators		25,140	11,454	13,686	21.6%	20.2%	23.1%
Total		116,337	56,651	59,132	100.0%	100.0%	100.0%

Geography of Charges and Credits

Table 4-36 shows the geography of charges and credits in the first nine months of 2020. Table 4-36 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 5.5 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 10.7 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 4.1 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 11.7 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 22.0 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-36 also shows that 88.8 percent of all charges were allocated in control zones, 3.9 percent in hubs and aggregates and 7.3 percent in interfaces.

Table 4-36 Geography of regional charges and credits: January through September, 2020

Location	Charges (Millions)	Credits (Millions)	Balance	Shares			
				Total Charges	Total Credits	Deficit	Surplus
Zones							
AECO	\$0.8	\$1.0	\$0.1	1.4%	1.7%	0.0%	0.7%
AEP	\$7.4	\$8.1	\$0.8	13.2%	14.6%	0.0%	4.0%
APS	\$2.8	\$1.2	(\$1.7)	5.1%	2.1%	8.7%	0.0%
ATSI	\$3.6	\$2.7	(\$0.9)	6.5%	4.9%	4.8%	0.0%
BGE	\$2.3	\$6.5	\$4.3	4.1%	11.7%	0.0%	22.0%
ComEd	\$6.0	\$14.6	\$8.7	10.7%	26.2%	0.0%	44.9%
DAY	\$0.8	\$1.2	\$0.4	1.4%	2.1%	0.0%	1.9%
DEOK	\$1.6	\$1.1	(\$0.5)	2.8%	2.0%	2.4%	0.0%
DLCO	\$0.9	\$0.1	(\$0.7)	1.5%	0.2%	3.9%	0.0%
Dominion	\$5.9	\$6.9	\$1.0	10.6%	12.3%	0.0%	5.1%
DPL	\$1.5	\$3.1	\$1.6	2.6%	5.5%	0.0%	8.5%
EKPC	\$0.6	\$1.4	\$0.8	1.1%	2.5%	0.0%	4.1%
External	\$0.0	\$1.4	\$1.4	0.0%	2.6%	0.0%	7.4%
JCPL	\$1.6	\$1.1	(\$0.5)	2.9%	2.0%	2.4%	0.0%
Met-Ed	\$1.2	\$0.5	(\$0.7)	2.1%	1.0%	3.4%	0.0%
OVEC	\$0.2	\$0.0	(\$0.2)	0.4%	0.0%	1.1%	0.0%
PECO	\$2.6	\$0.1	(\$2.5)	4.6%	0.1%	13.1%	0.0%
PENELEC	\$1.9	\$0.8	(\$1.1)	3.4%	1.5%	5.6%	0.0%
Pepco	\$2.2	\$2.4	\$0.2	3.9%	4.4%	0.0%	1.3%
PPL	\$3.0	\$1.0	(\$2.1)	5.5%	1.8%	10.7%	0.0%
PSEG	\$2.7	\$0.6	(\$2.1)	4.8%	1.1%	10.8%	0.0%
RECO	\$0.2	\$0.0	(\$0.2)	0.3%	0.0%	0.8%	0.0%
All Zones	\$49.6	\$55.9	\$6.3	88.8%	100.0%	67.6%	100.0%
Hubs and Aggregates							
AEP - Dayton	\$0.5	\$0.0	(\$0.5)	0.8%	0.0%	2.4%	0.0%
Dominion	\$0.2	\$0.0	(\$0.2)	0.3%	0.0%	0.9%	0.0%
Eastern	\$0.1	\$0.0	(\$0.1)	0.2%	0.0%	0.7%	0.0%
New Jersey	\$0.3	\$0.0	(\$0.3)	0.5%	0.0%	1.4%	0.0%
Ohio	\$0.1	\$0.0	(\$0.1)	0.2%	0.0%	0.5%	0.0%
Western Interface	\$0.0	\$0.0	\$0.0	0.0%	0.0%	0.0%	0.0%
Western	\$1.0	\$0.0	(\$1.0)	1.9%	0.0%	5.4%	0.0%
RTEP B0328 Source	\$0.0	\$0.0	\$0.0	0.0%	0.0%	0.0%	0.0%
All Hubs and Aggregates	\$2.2	\$0.0	(\$2.2)	3.9%	0.0%	11.4%	0.0%
Interfaces							
CPLE Exp	\$0.0	\$0.0	(\$0.0)	0.0%	0.0%	0.1%	0.0%
CPLE Imp	\$0.0	\$0.0	(\$0.0)	0.0%	0.0%	0.1%	0.0%
Duke Exp	\$0.0	\$0.0	(\$0.0)	0.0%	0.0%	0.0%	0.0%
Duke Imp	\$0.0	\$0.0	(\$0.0)	0.0%	0.0%	0.1%	0.0%
Hudson	\$0.2	\$0.0	(\$0.2)	0.4%	0.0%	1.2%	0.0%
IMO	\$0.0	\$0.0	(\$0.0)	0.1%	0.0%	0.2%	0.0%
Linden	\$0.3	\$0.0	(\$0.3)	0.5%	0.0%	1.5%	0.0%
MISO	\$2.0	\$0.0	(\$2.0)	3.5%	0.0%	10.2%	0.0%
NCMPA Imp	\$0.1	\$0.0	(\$0.1)	0.2%	0.0%	0.7%	0.0%
Neptune	\$0.2	\$0.0	(\$0.2)	0.3%	0.0%	1.0%	0.0%
NIPSCO	\$0.0	\$0.0	(\$0.0)	0.0%	0.0%	0.0%	0.0%
Northwest	\$0.2	\$0.0	(\$0.2)	0.4%	0.0%	1.1%	0.0%
NYIS	\$0.4	\$0.0	(\$0.4)	0.6%	0.0%	1.8%	0.0%
South Exp	\$0.3	\$0.0	(\$0.3)	0.6%	0.0%	1.6%	0.0%
South Imp	\$0.3	\$0.0	(\$0.3)	0.5%	0.0%	1.4%	0.0%
All Interfaces	\$4.1	\$0.0	(\$4.1)	7.3%	0.0%	21.0%	0.0%
Total	\$55.9	\$55.9	\$0.0	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).³⁰ 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 4-37 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In the first nine months of 2019, balancing operating reserve credits would have been \$10.0 million or 24.6 percent lower if they were calculated on a daily basis. In the first nine months of 2020, balancing operating reserve credits would have been \$8.1 million or 25.5 percent lower if they were calculated on a daily basis.

Table 4-37 Intraday segments and daily balancing operating reserve credits: January 2019 through September 2020

	2019 BOR Credits (Millions)			2020 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	\$5.4	\$4.6	(\$0.8)	\$1.6	\$1.3	(\$0.3)
Feb	\$2.5	\$2.3	(\$0.3)	\$0.7	\$0.5	(\$0.2)
Mar	\$3.6	\$2.9	(\$0.7)	\$0.9	\$0.7	(\$0.2)
Apr	\$3.5	\$2.9	(\$0.6)	\$1.1	\$0.9	(\$0.2)
May	\$2.3	\$1.7	(\$0.5)	\$1.9	\$1.6	(\$0.3)
Jun	\$4.1	\$3.3	(\$0.8)	\$5.1	\$4.1	(\$1.0)
Jul	\$8.7	\$6.0	(\$2.7)	\$8.8	\$5.7	(\$3.1)
Aug	\$5.1	\$3.0	(\$2.0)	\$8.1	\$6.1	(\$2.1)
Sep	\$5.7	\$4.0	(\$1.7)	\$3.6	\$2.8	(\$0.7)
Oct	\$5.9	\$4.5	(\$1.4)			
Nov	\$3.9	\$2.5	(\$1.4)			
Dec	\$1.7	\$1.2	(\$0.5)			
Total (Jan - Sep)	\$40.7	\$30.7	(\$10.0)	\$31.8	\$23.7	(\$8.1)
Total	\$52.1	\$38.9	(\$13.3)	\$31.8	\$23.7	(\$8.1)

30 See PJM "Manual 28: Operating Reserve Accounting," Rev. 83 (Dec. 3, 2019).

Prior to April 1, 2018, for purposes of calculating LOC credits, each hour was defined as a unique segment. Following the implementation of five minute settlements on April 1, 2018, LOC credits are calculated with each five minute interval defined as a unique segment. Thus a profit in one five minute segment, resulting from the real-time LMP being lower than the day-ahead LMP, is not used to offset a loss in any other five minute segment. This change in settlements causes an increase in LOC credits compared to hourly settlement as generators are made whole for any losses incurred in a five minute interval while previously gains and losses were netted within the hour. Table 4-38 compares the impact on day-ahead LOC credits of adopting five minute settlements over hourly settlements in April 2018 and the impact of having adopted the recommended daily settlements over five minute settlements. For the first nine months of 2020, LOC credits would have been 7.4 percent lower if they had been settled on an hourly basis rather than on a five minute basis. For the first nine months of 2020, LOC credits would have been \$3.0 million or 18.8 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute settlement.

Table 4-38 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: January through September, 2020

2020 Day Ahead LOC Credits (Millions)					
	Five Minute Settlement (Status Quo)	Hourly Settlement (Pre-April 2018)	Difference	Daily Settlement (Recommendation)	Difference
Jan	\$0.5	\$0.5	\$0.1	\$0.5	\$0.0
Feb	\$0.4	\$0.4	(\$0.0)	\$0.3	(\$0.1)
Mar	\$0.6	\$0.5	(\$0.1)	\$0.5	(\$0.1)
Apr	\$0.3	\$0.3	(\$0.0)	\$0.3	(\$0.1)
May	\$0.8	\$0.8	(\$0.0)	\$0.6	(\$0.2)
Jun	\$3.3	\$3.1	(\$0.2)	\$2.8	(\$0.4)
Jul	\$4.2	\$3.8	(\$0.4)	\$3.2	(\$1.0)
Aug	\$4.5	\$4.2	(\$0.3)	\$3.8	(\$0.7)
Sep	\$1.6	\$1.4	(\$0.2)	\$1.2	(\$0.5)
Total (Jan - Sep)	\$16.1	\$15.0	(\$1.2)	\$13.1	(\$3.0)

Uplift Credits and Offer Capping

Absent market power mitigation, unit owners that submit noncompetitive offers or offers with inflexible operating parameters, can exercise market power, resulting in noncompetitive and excessive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.³¹ If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners identified as having local market power. Offer capping is designed to set offers at competitive levels.

Table 4-39 shows that during the first nine months of 2020, 81.9 percent of uplift credits were paid to units that were committed and dispatched on price offers without parameter limits, 11.7 percent to units committed on cost-based offers, 5.7 percent were committed on price-based offers with limited parameters (PLS) and 0.7 percent to units committed on a combination of price-based and cost-based offers.

Table 4-39 Operating Reserve Credits by Offer Type: January through September, 2020

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Balancing Operating Reserve Credits (Millions)	Day Ahead Reactive Credits (Millions)	Real Time Reactive Credits (Millions)
Cost	\$0.5	\$3.8	\$0.0	\$0.3
Price	\$6.4	\$25.6	\$0.0	\$0.0
Price PLS	\$0.2	\$2.1	\$0.0	\$0.0
Cost & Price	\$0.0	\$0.2	\$0.0	\$0.0
Cost & PLS	\$0.0	\$0.1	\$0.0	\$0.0
Price & PLS	\$0.0	\$0.0	\$0.0	\$0.0
Total	\$7.0	\$31.7	\$0.1	\$0.3

³¹ 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>.

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, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.¹ The conclusions are a result of the MMU's evaluation of the last Base Residual Auction, for the 2021/2022 Delivery Year.

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

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. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test.

- Participant behavior was evaluated as not competitive in the 2021/2022 RPM Base Residual Auction. 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 30 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 nonperformance 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 based on the 2021/2022 RPM Base Residual Auction. 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.

- PJM did not run the 2022/2023 Base Residual Auction in May 2019, the 2023/2024 Base Residual Auction in May 2020, or the 2022/2023 First Incremental Auction in September 2020 because the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved.

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.⁵ Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.⁶ First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.⁷ 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.⁸

The 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted in the first nine months of 2020.

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.⁹ 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.** In the first nine months of 2020, RPM installed capacity decreased 788.7 MW or 0.4 percent, from 184,722.8 MW on January 1 to 183,934.17 MW on September 30. 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 September 30, 2020, 45.7 percent was gas; 27.0 percent was coal; 17.6 percent was nuclear; 4.8 percent was hydroelectric; 3.4 percent was oil; 0.7 percent was wind; 0.4 percent was solid waste; and 0.5 percent was solar.
- **Market Concentration.** In the 2021/2022 RPM Second Incremental Auction, two participants in the EMAAC LDA market passed the TPS test.¹⁰ 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,

⁴ The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.

⁵ Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either with commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.

⁶ See 126 FERC ¶ 61,275 at P 86 (2009).

⁷ See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).

⁸ See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.

⁹ 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.

¹⁰ 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)(iii).

the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.^{11 12 13}

- **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 10,586.0 MW for June 1, 2020, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2020/2021 delivery year (13,015.2 MW) less purchases of replacement capacity (2,429.2 MW).

Market Conduct

- **2021/2022 RPM Second Incremental Auction.** Of the 276 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for zero generation resources (0.0 percent).

Market Performance

- The 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted in the first nine months of 2020.¹⁴ The weighted average capacity price for the 2019/2020 Delivery Year is \$109.82 per MW-day, including all RPM auctions for the 2019/2020 Delivery Year. The weighted average capacity price for the 2020/2021 Delivery Year is \$111.05 per MW-day, including all RPM auctions for the 2020/2021 Delivery Year.
- For the 2020/2021 Delivery Year, RPM annual charges to load are \$7.0 billion.

- In the 2021/2022 RPM Base Residual Auction, the 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 in the first nine months of 2020 was 6.3 percent, an increase from 6.0 percent in the first nine months of 2019.¹⁵
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first nine months of 2020 was 86.8 percent, an increase from 85.2 percent in the first nine months of 2019.

Recommendations¹⁶

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

¹¹ See OATT Attachment DD § 6.5.

¹² 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).

¹³ 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).

¹⁴ FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

¹⁵ The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on October 23, 2020. 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.

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.

types, including planned generation, demand resources and imports.^{17 18} (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.^{19 20} 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.)

¹⁷ See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

¹⁸ See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

¹⁹ See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

²⁰ See the 2019 State of the Market Report for PJM, Volume 2, Section 7: Net Revenue.

- 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.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be reviewed. (Priority: Medium. First reported 2019. 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.²¹ (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.²² (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 the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate

²¹ Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

²² 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).

be left at its current level. 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 MSOC. 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 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 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit which is not capable of supplying energy consistent with its day-ahead offer which should equal its ICAP, reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance,

shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

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: Not 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 nonperformance 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 filed a complaint with the Commission asserting that the market seller offer cap is overstated.²³ The result of an overstated market seller offer cap is to permit the exercise of market power, as occurred in the 2021/2022 BRA. That complaint remains pending. The outcome of the complaint could have a significant and standalone impact on clearing prices in the 2022/2023 BRA.

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 the last BRA and in the first nine months of 2020. 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} In 2019 and 2020, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The capacity performance modifications to the RPM construct significantly improved the capacity market and addressed a number of issues that had been identified by the MMU. But significant issues remain in the PJM capacity market design.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 11,911.9 ICAP MW on June 1, 2020, and will have excess reserves of 18,401.8 ICAP MW on June 1, 2021, based on current positions.³⁰ A majority of capacity investments in PJM were financed by market sources.³¹ Of the 41,979.4 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2019/2020 delivery years, 32,333.9 MW (77.0 percent) were based on market funding. Of the 2,640.4 MW of additional capacity that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years, 2,553.6 MW (96.7 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

The issue of external subsidies, particularly for economic nuclear power plants, continued to evolve. The subsidies are not part of the PJM market

24 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).

25 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).

26 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).

27 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).

28 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).

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

30 The calculated reserve margin for June 1, 2021, does not account for cleared buy bids that have not been used in replacement capacity transactions.

31 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

23 In 2019, the MMU filed a complaint seeking an order directing PJM to update the assumptions regarding the expected number of performance assessment intervals (PAI) in calculating the default capacity market seller offer cap (MSOC). Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47-000 (February 21, 2019).

design but nonetheless threaten the foundations of the PJM Capacity Market as well as the competitiveness of PJM markets overall.

The Ohio subsidy legislation to subsidize both nuclear and coal plants and to eliminate the RPS, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant and the requests for additional subsidies, the request in Pennsylvania to subsidize nuclear power plants, 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, the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal and the specific FRR proposals for ComEd and for New Jersey, 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 and is now being 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. Competition to receive subsidies is now a reality and is accelerating in PJM.

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).³² The SMR is fully consistent with the renewables targets of many states in the PJM footprint. The SMR is also consistent with incorporating economic nuclear power plants in the capacity market.

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

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 states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. As made clear in recent analyses of FRR options in Illinois, Maryland, New Jersey and Ohio, the FRR approach is likely to lead to significant increases in payments by customers.³³ The existing FRR rules

³² The MMU filed several comments as well as a proposal summary in the Capacity Market Investigation focused on the Sustainable Market Rule (SMR) in Docket Nos. ER18-1314-000, -001, EL16-49-000, and EL18-178-000 (October 2, 2018; October 31, 2018; November 6, 2018). MMU filings are located at the Monitoring Analytics website at <http://www.monitoringanalytics.com/Filings/2018.shtml>.

³³ The MMU has posted several reports regarding the creation of FRRs. "Potential Impacts of the Creation of a ComEd FRR," (December 18, 2019). http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf. "Potential Impacts of the Creation of Maryland FRRs," (April 16, 2020). http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf. "Potential Impacts of the Creation

were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The FRR rules should be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market.

Recent FRR proposals in Illinois for the ComEd Zone and in New Jersey are primarily nuclear subsidy programs that would increase nuclear subsidies well beyond the ZECs rules currently in place in both states while also providing for payments to some renewable resources at above market prices.³⁴ The MMU has prepared reports with analysis on the potential impacts of states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey and Ohio, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.^{35 36 37 38} Additionally, the impact on the remaining PJM capacity market footprint is computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM capacity market would be significantly lower.

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. PJM is considering the application of the Effective Load Carrying Capability (ELCC) approach to defining a dynamic and market based method for determining the capacity contribution of intermittent resources. ELCC would be an advance over the current approach to discounting the reliability contribution of intermittent resources, if done correctly. But implementing ELCC incorrectly, based on average rather than marginal values and locking in values regardless of market realities, would be a significant mistake and create new issues for the PJM capacity markets. The results could be degraded reliability, favoring old technologies over new technologies, and the inefficient displacement of thermal resources. It is essential to not build in a bad market design from the beginning as such designs gain momentum and gain entrenched supporters among the beneficiaries.

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.

of New Jersey FRRs," (May 13, 2020). <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRs_20200513.pdf>. "Potential Impacts of the Creation of Ohio FRRs," (July 17, 2020). <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf>.

34 In the Matter of the Investigation of Resource Adequacy Alternatives, New Jersey Board of Public Utilities, Docket No. E020030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_E020030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_E020030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_E020030203_20200715.pdf> (July 15, 2020).

35 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).

36 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).

37 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRs_20200513.pdf> (May 13, 2020).

38 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).

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/ISO to help ensure reliability.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.³⁹

39 See Monitoring Analytics, LLC, "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, 2008).

The Commission issued its MOPR order on December 19, 2019 ("December 19th Order").⁴⁰ The December 19th Order defines a clear path for defending competitive wholesale power markets in PJM. The Order defines a clear, consistent and comprehensive approach to the PJM markets and to the role of subsidized resources in the markets. The 2022/2023 BRA is expected to be run by mid 2021.⁴¹

In another proceeding, the Commission has ordered PJM on compliance to propose revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.⁴² The MMU has recommended such an approach. The change in the offset will affect MOPR floor prices and the results of unit specific reviews under MOPR. PJM submitted its compliance filing on August 5, 2020, and the matter is now pending.

40 169 FERC ¶ 61,239.

41 Docket Nos. ER18-1314-000, -001, EL16-49-000, and EL18-178-000 (March 18, 2020 and June 1, 2020).

42 171 FERC ¶ 61,153 at PP 320-321 (2020).

Table 5-2 RPM related MMU reports: 2019 through 2020

Date	Name
February 21, 2019	IMM Complaint re CONE x B Offers Docket No. EL19-47-000 http://www.monitoringanalytics.com/Filings/2019/IMM_Complaint_Docket_No_EL19-XXX_20190221.pdf
February 22, 2019	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/RPM_Must_Offer_Obligation_20190222.pdf
April 2, 2019	IMM Comments re ACR Review Waiver Docket No. ER19-1404 http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER19-1404_20190402.pdf
April 10, 2019	IMM Answer and Motion for Leave to Answer re Cube Yarkin Complaint Docket No. EL19-51 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_EL19-51_20190410.pdf
April 11, 2019	IMM Answer re Brookfield Energy Complaint Docket No. EL19-34 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket%20No.%20EL19-34_20190411.pdf
April 30, 2019	IMM Answer Re CONE x B Offers Docket No. EL19-47 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_EL19-47_20190430.pdf
May 24, 2019	IMM Answer to PJM re MSOC Docket No. EL19-47, EL19-63 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_to_PJM_EL19-47_-63_20190524.pdf
June 28, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Must_Offer_Obligation_20190628.pdf
August 23, 2019	IMM Answer re Capacity Resources and Must Offer Exception Process Docket No. ER19-2417 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_ER19-2417_20190823.pdf
September 6, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Must_Offer_Obligations_20190906.pdf
September 12, 2019	PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Reports/2019/IMM_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_Delivery_Years_20190912.pdf
September 13, 2019	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019 http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf
September 17, 2019	IMM Response to Grid Strategies Report http://www.monitoringanalytics.com/reports/Market_Messages/IMM_Response_to_Grid_Strategies_Report_20190917.pdf
December 13, 2019	IMM Comments re Performance Assessment Intervals Docket No. EL19-47-000 http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER15-623_EL15-29_EL19-47_20191213.pdf
December 18, 2019	Potential Impacts of the Creation of a ComEd FRR http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf
December 26, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligations_20191226.pdf
January 16, 2020	Net Revenues for PJM RPM Base Residual Auctions in 2020 http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Net_Revenues_20232024_RPM_BRA_20200116.pdf
January 17, 2020	IMM Request for Clarification re MOPR Order Docket Nos. EL16-49 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Request_for_Clarification_Docket_Nos_EL16-49_EL18-178_20200117.pdf
January 21, 2020	CONE and ACR Values – Preliminary http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Session_CONE_and_ACR_Values_20200128.pdf
February 5, 2020	IMM Answer to Requests for Rehearing's Docket No. EL14-69 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_To_RFRS_Docket_Nos_EL14-69_EL18-178_20200205.pdf
February 17, 2020	IMM MOPR Gross CONE Template http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MOPR_Gross_CONE_Template_20200217.xlsx
February 18, 2020	IMM Second Request for Clarification re MOPR Docket No. EL18-178, EL16-49 http://www.monitoringanalytics.com/filings/2020/IMM_Second_Request_for_Clarification_Docket_No_EL18-178_%20EL16-49_20200218.pdf
February 18, 2020	Unit Specific Nuclear ACR Information http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_MOPR_Unit_Specific_Nuclear_ACR_Information_20200219.pdf
February 21, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20200221.pdf
February 28, 2020	Monitoring Analytics ACR Template http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Session_ACR_Template_20200228.pdf
March 20, 2020	Potential Impacts of the MOPR Order http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_MOPR_Order_20200320.pdf
April 16, 2020	Potential Impacts of the Creation of Maryland FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf
May 6, 2020	Potential Compliance with P386 of FERC Order on Rehearing http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Session_Potential_Compliance_with_P386_of_FERC_Order_on_Rehearing_20200506.pdf
May 13, 2020	Potential Impacts of the Creation of New Jersey FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRs_20200513.pdf
May 15, 2020	IMM Request for Clarification re MOPR Ex Investigation Docket Nos. EL18-178-002 and EL16-49-002 http://www.monitoringanalytics.com/filings/2020/IMM_Request_for_Clarification_Docket_No_EL18-178-002_EL16-49-002_20200515.pdf
May 15, 2020	IMM Comments re MOPR-Ex Docket Nos. ER18-1314-00, EL16-49-000, EL18-178-000 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER18-1314-003_EL16-49_EL18-178_20200515.pdf
May 20, 2020	IMM Comments re NJBPU Investigation of Resource Adequacy Alternatives Docket No. E020030203 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_E020030203_20200520.pdf
June 22, 2020	IMM Comments re MOPR-Ex Compliance Filing Docket Nos. ER18-1314, EL16-49 and ERL8-178 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER18-1314_EL16-49_ER18-178_20200622.pdf
June 24, 2020	IMM Reply Comments re NJ BPU Resource Adequacy Alternatives Docket No. E020030203 http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_E020030203_20200624.pdf
June 30, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20200630.pdf
July 15, 2020	IMM Answer to PSEG and Exelon Reply re New Jersey FRR Docket No. E020030203 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_E020030203_20200715.pdf
July 17, 2020	Potential Impacts of the Creation of Ohio FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf
July 20, 2020	IMM Comments re NJ BPU Nuclear Power Plant ZECs Docket No. E018080899 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_E018080899_20200720.pdf
July 23, 2020	IMM Answer re MOPR Ex Docket No. EL16-49, ER18-1314 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_Docket_No_EL16-49_ER18-1314_EL18-178_20200724.pdf
July 27, 2020	IMM Comments re ORDC Compliance Filing Docket No. EL19-58-002 and ER19-1486 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_EL19-58-002_ER19-1486-20200727.pdf
September 15, 2020	2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022 http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf

Installed Capacity

On January 1, 2020, RPM installed capacity was 184,722.8 MW (Table 5-3).⁴³ Over the next nine months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 183,934.1 MW on September 30, 2020, a decrease of 788.7 MW or 0.4 percent from the January 1 level.^{44 45} The 788.7 MW decrease was the result of a decrease in imports (582.9 MW), an increase in exports (328.9 MW), derates (81.4 MW), and deactivations (2,456.1 MW), offset by new or reactivated generation (2,233.1 MW) and uprates (427.5 MW).

At the beginning of the new delivery year on June 1, 2020, RPM installed capacity was 184,583.3 MW, a decrease of 1,069.2 MW or 0.6 percent from the May 31, 2020, level of 185,652.5 MW.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2020

	01-Jan-20		31-May-20		01-Jun-20		30-Sep-20	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	52,181.3	28.2%	51,281.6	27.6%	49,942.4	27.1%	49,649.9	27.0%
Gas	82,313.9	44.6%	84,195.7	45.4%	84,355.1	45.7%	83,971.4	45.7%
Hydroelectric	8,873.9	4.8%	8,862.2	4.8%	8,778.7	4.8%	8,779.3	4.8%
Nuclear	32,297.9	17.5%	32,285.4	17.4%	32,285.4	17.5%	32,285.4	17.6%
Oil	6,311.0	3.4%	6,282.8	3.4%	6,282.8	3.4%	6,282.8	3.4%
Solar	791.0	0.4%	791.0	0.4%	946.9	0.5%	960.3	0.5%
Solid waste	695.6	0.4%	695.6	0.4%	695.6	0.4%	695.6	0.4%
Wind	1,258.2	0.7%	1,258.2	0.7%	1,296.4	0.7%	1,309.4	0.7%
Total	184,722.8	100.0%	185,652.5	100.0%	184,583.3	100.0%	183,934.1	100.0%

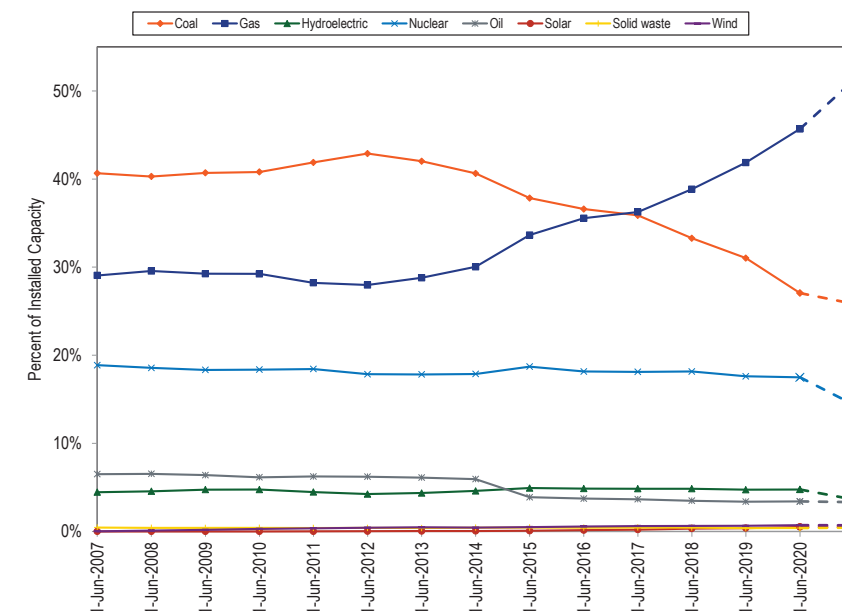
⁴³ Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

⁴⁴ Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.

⁴⁵ Wind resources accounted for 1,309.4 MW, and solar resources accounted for 960.3 MW of installed capacity in PJM on September 30, 2020. PJM administratively reduces the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind and solar resources will be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Appendix B.3 Calculation Procedure, Rev. 14 (Aug. 1, 2019).

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, 2020, as well as the expected installed capacity for the 2021/2022 delivery year, based on the results of all auctions held through September 30, 2020.⁴⁶ On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 27.1 percent on June 1, 2020, and is projected to decrease to 25.8 percent by June 1, 2021. The share of gas increased from 29.1 percent on June 1, 2007, to 45.7 percent on June 1, 2020, and is projected to increase to 51.3 percent on June 1, 2021.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2021



⁴⁶ Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Table 5-4 shows the RPM installed capacity on January 1, 2020, through September 30, 2020, 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 September 30, 2020

Parent Company	01-Jan-20			31-May-20			01-Jun-20			30-Sep-20		
	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	21,165.8	12.4%	1	21,041.9	12.3%	1	20,801.8	12.1%	1	20,788.8	12.2%	1
Dominion Resources, Inc.	20,198.5	11.8%	2	20,198.5	11.8%	2	20,549.9	12.0%	2	20,525.1	12.0%	2
FirstEnergy Corp.	11,609.3	6.8%	3	4,102.5	2.4%	12	4,100.6	2.4%	12	4,100.6	2.4%	12
Vistra Energy Corp.	11,451.0	6.7%	4	11,290.9	6.6%	3	11,319.0	6.6%	3	11,319.0	6.6%	3
Talen Energy Corporation	10,964.6	6.4%	5	10,964.6	6.4%	4	10,839.4	6.3%	4	10,839.4	6.4%	4
LS Power Group	7,839.5	4.6%	7	8,709.5	5.1%	5	8,862.5	5.2%	5	8,841.8	5.2%	5

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2020, to September 30, 2020, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and September 30, 2020

Funding Type	01-Jan-20		31-May-20		01-Jun-20		30-Sep-20	
	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	152,177.4	82.4%	153,111.1	82.5%	151,765.2	82.2%	151,140.8	82.2%
Nonmarket	32,545.4	17.6%	32,541.4	17.5%	32,818.1	17.8%	32,793.3	17.8%
Total	184,722.8	100.0%	185,652.5	100.0%	184,583.3	100.0%	183,934.1	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.⁴⁷ 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.⁴⁸ The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the ComEd, AEP, and Dayton Power & Light Control Zones.⁴⁹ The average FDI_c for the first nine months of 2020 decreased 1.4 percent compared to the first nine months of 2019. 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. A total of 9,543.0 MW of coal, diesel, and nuclear capacity were identified as being at risk of retirement.⁵⁰ Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance of the retirement.⁵¹ There are 4,556.0 MW of generation that have a requested retirement date

⁴⁷ 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.

⁴⁸ 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.

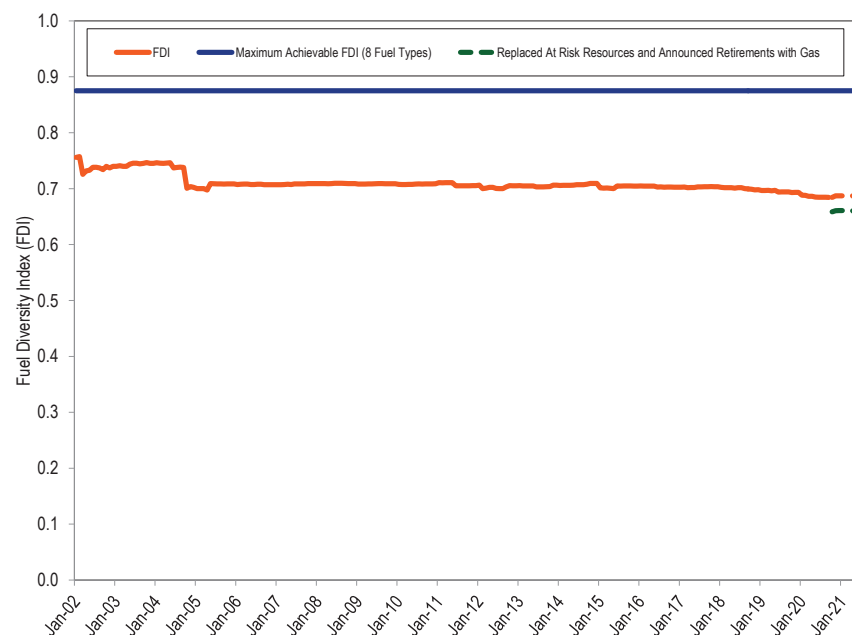
⁴⁹ See the 2019 *State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

⁵⁰ See the 2019 *State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.

⁵¹ See OATT Part V § 113.1.

after September 30, 2020.⁵² The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity that cleared in an RPM auction from the at risk resources and other resources with deactivation notices is replaced by gas generation.⁵³ The FDI_c under these assumptions would decrease by 3.9 percent on average from the expected FDI_c for the period October 1, 2020, through June 1, 2021.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2021



⁵² See 2020 Quarterly State of the Market Report for PJM: January through September, Section 12: Generation and Transmission Planning, Table 12-9.

⁵³ For this analysis resources for which PJM has received deactivation notifications were replaced with gas capacity beginning on the projected retirement date listed in the deactivation data. At risk resources that have not notified PJM regarding deactivation were replaced with gas capacity beginning on October 1, 2020.

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.⁵⁴ In the first nine months of 2020, the 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted.⁵⁵

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2019/2020 Delivery Year. The 21,993.1 MW increase was the result of new generation capacity resources (33,614.4 MW), reactivated generation capacity resources (1,362.8 MW), uprates (7,002.2 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (1,905.2 MW), offset by a net decrease in capacity imports (1,013.6 MW), deactivations (39,400.0 MW) and derates (3,445.4 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 most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction

⁵⁴ See Letter Order, Docket No. ER10-366-000 (January 22, 2010).

⁵⁵ FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

using the cleared buy bid capacity. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margins for June 1, 2021, does not account for cleared buy bids that have not been used in replacement capacity transactions. The projected reserve margin for June 1, 2021, accounts for projected replacement capacity using cleared buy bids by applying the rate at which historical buy bids have been used.

Future Changes in Generation Capacity⁵⁶

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 2019/2020 Delivery Year, internal installed capacity decreased by 866.0 MW after accounting for new capacity resources, reactivations, and uprates (41,979.4 MW) and capacity deactivations and derates (42,845.4 MW).

For the current and future delivery years (2020/2021 through 2021/2022), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified delivery year. Based on expected completion rates of cleared new generation capacity (2,640.4MW) and pending deactivations (3,464.7MW), PJM capacity is expected to decrease by 824.3 MW for the 2020/2021 through 2021/2022 Delivery Years.

Table 5-6 Generation capacity changes: 2007/2008 through 2019/2020^{57 58}

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
Total	33,614.4	1,362.8	7,002.2	21,967.5	(1,013.6)	(1,905.2)	39,400.0	3,445.4	21,993.1

⁵⁶ For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

⁵⁷ The capacity changes in this report are calculated based on June 1 through May 31.

⁵⁸ The calculated export MW for 2012/2013 were revised from the 2020 Quarterly State of the Market Report for PJM: January through March.

Table 5-7 RPM reserve margin: June 1, 2016, to June 1, 2021^{59 60}

	Generation and DR RPM Committed Less Deficiency UCAP (MW)	Forecast Peak Load	FRR Peak Load	PRD	RPM Peak Load	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%	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%	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%	171,662.5	22.9%	6.8%	9,499.8	0.0	22.9%
01-Jun-19	162,276.1	151,643.5	12,284.2	0.0	139,359.3	16.0%	172,781.2	24.0%	8.0%	11,124.4	0.0	24.0%
01-Jun-20	159,560.4	148,355.3	11,488.3	558.0	136,309.0	15.5%	169,348.8	24.2%	8.7%	11,911.9	0.0	24.2%
01-Jun-21	164,773.5	147,501.6	11,394.3	510.0	135,597.3	15.1%	174,474.3	28.7%	13.6%	18,401.8	7,325.0	23.0%

Sources of Funding⁶¹

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2019/2020 Delivery Year totaled 34,977.2 MW (83.3 percent of all additions), with 26,796.1 MW from market funding and 8,181.1 MW from nonmarket funding. Upgrades to existing generation capacity from the 2007/2008 Delivery Year through the 2019/2020 Delivery Year totaled 7,002.2 MW (16.7 percent of all additions), with 5,537.8 MW from market funding and 1,464.4 MW from nonmarket funding. In summary, of the 41,979.4 MW of additional capacity from new, reactivated, and upgraded generation that cleared in RPM auctions for the 2007/2008 through 2019/2020 Delivery Years, 32,333.9 MW (77.0 percent) were based on market funding.

Of the 2,640.4 MW of the additional generation capacity (new resources, reactivated resources, and upgrades) that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years, 2,214.9 MW are not yet in service. Of those 2,214.9 MW that have not yet gone into service, 2,195.9 MW

have market funding and 19.0 MW have nonmarket funding. Applying the historical completion rates, 73.1 percent of all the projects in development are expected to go into service (1,604.1 MW of the 2,195.9 MW of market funded projects; 13.9 MW of the 19.0 MW of nonmarket funded projects). Together, 1,618.0 MW of the 2,214.9 MW 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 425.5 MW of the additional generation capacity that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years and are already in service, 357.7 MW (84.1 percent) are based on market funding and 67.8 MW (15.9 percent) are based on nonmarket funding. In summary, 2,553.6 MW (96.7 percent) of the additional generation capacity (425.5 MW in service and 2,214.9 MW not yet in service) that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 86.8 MW (3.3 percent) of proposed generation that cleared at least one RPM auction for the 2020/2021 through 2021/2022 Delivery Years.

⁵⁹ 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.

⁶⁰ These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

⁶¹ For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

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:

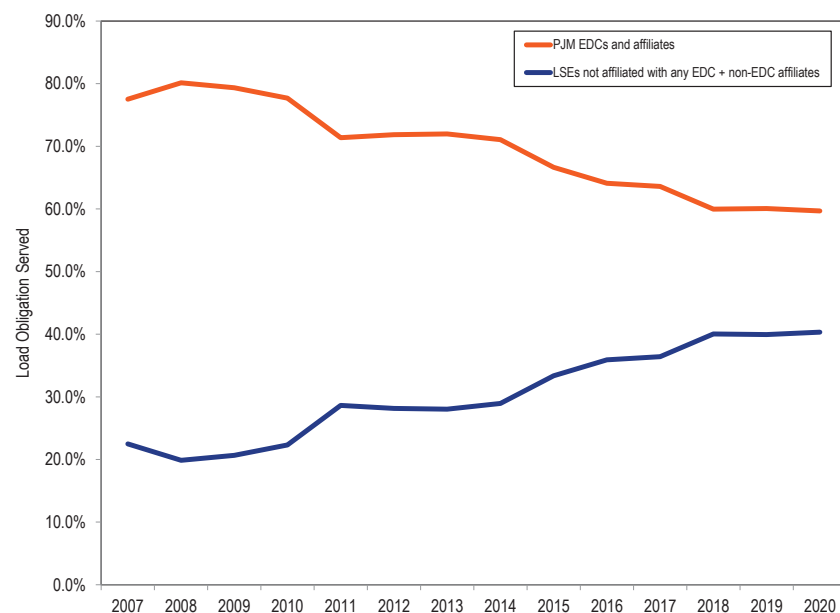
- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing 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, 2020, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 59.7 percent (Table 5-8), down from 60.1 percent on June 1, 2019. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 40.3 percent, up from 39.9 percent on June 1, 2019. 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, 2020, 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 59.7 percent on June 1, 2020. 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 40.3 percent on June 1, 2020. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-8 Capacity market load obligation served: June 1, 2019 and June 1, 2020

	1-Jun-19		1-Jun-20		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	113,416.3	60.1%	104,849.4	59.7%	(8,566.8)	(0.4%)
LSEs not affiliated with any EDC + non EDC Affiliates	75,445.0	39.9%	70,838.3	40.3%	(4,606.7)	0.4%
Total	188,861.3	100.0%	175,687.7	100.0%	(13,173.6)	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2020



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 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. CTRs permit customers to receive the benefit of importing cheaper capacity using transmission capability. The MW of CTRs available for allocation to LSEs in an LDA are 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 \$1,446,024,

and ComEd had 1,097.0 MW of customer funded ICTRs with a total value of \$22,242,498.

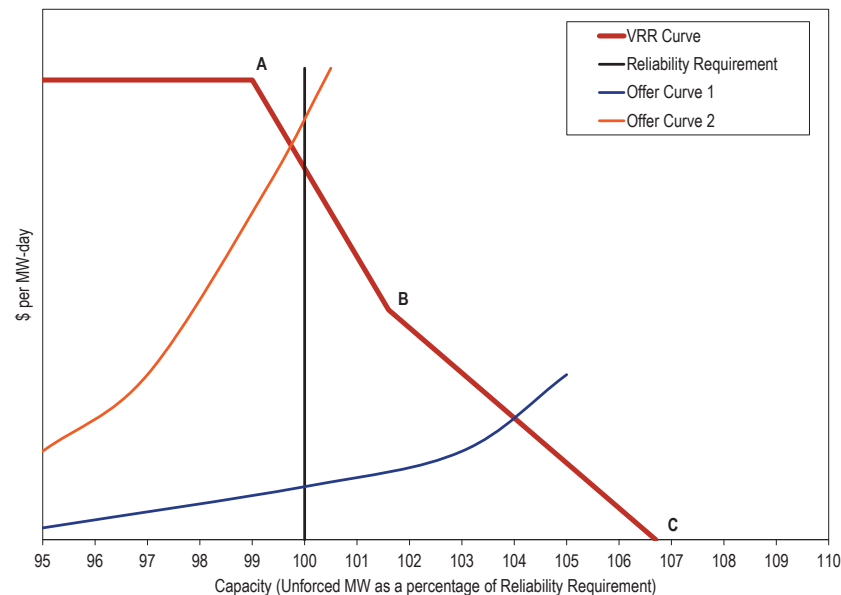
EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of \$8,903,095. PSEG had 499.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of \$7,028,755. BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of \$6,734,907.

Demand Curve

Effective for the 2018/2019 and subsequent Delivery Years, PJM revised the variable resource requirement (VRR) curve. The starting MW point of the downward sloping demand curve is set at 99.0 percent of the reliability requirement. The highest MW point is set at 106.7 percent of the reliability requirement. Almost all of the downward sloping part of the VRR curve lies to the right side of the reliability requirement.

The PJM definition of the VRR curve means the clearing price and cleared quantity will be higher, almost without exception, using the current VRR curve than using a vertical demand curve at the reliability requirement. As a result, payments for capacity will be higher. Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2022/2023 RPM BRA. The clearing price and cleared quantity would be lower if a vertical VRR curve set at the reliability requirement were used in place of the existing VRR curve. This is the case if the supply curve intersects the VRR curve to the right side of the reliability requirement (Offer Curve 1). The only exception would be if the supply curve intersects the VRR curve to the left of the reliability requirement (Offer Curve 2). In that case, the clearing price and cleared quantity would be higher with the vertical demand curve than with the existing VRR curve. In almost all RPM auctions, the offer curve intersected the VRR curve to the right side of the vertical demand curve.

Figure 5-4 VRR curve relative to the reliability requirement: 2022/2023 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2021/2022 RPM Second Incremental Auction two participants in the EMAAC LDA market passed the three pivotal supplier (TPS) test.⁶² 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.^{63 64 65}

⁶² 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.

⁶³ See OATT Attachment DD § 6.5.

⁶⁴ 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).

⁶⁵ 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).

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Table 5-9 RSI results: 2019/2020 through 2021/2022 RPM Auctions⁶⁶

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
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

⁶⁶ The RSI shown is the lowest RSI in the market.

Table 5-9 RSI results: 2019/2020 through 2021/2022 RPM Auctions (cont'd)

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2019/2020 Third Incremental Auction				
RTO	0.70	0.59	72	72
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
2020/2021 Second Incremental Auction				
RTO	0.40	0.56	34	34
2020/2021 Third Incremental Auction				
RTO	0.54	0.72	59	59
MAAC	0.25	0.18	14	14
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3
2021/2022 First Incremental Auction				
RTO	0.57	0.48	26	26
EMAAC	0.00	0.82	5	3
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
BGE	0.00	0.00	1	1
2021/2022 Second Incremental Auction				
RTO	0.19	0.12	19	19
EMAAC	0.05	0.23	7	5
PSEG	0.00	0.00	2	2
BGE	0.00	0.00	0	0

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.⁶⁷ 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.”⁶⁸ 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.⁶⁹ 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 5-5, Figure 5-6 and Figure 5-7.

Figure 5-5 Map of locational deliverability areas

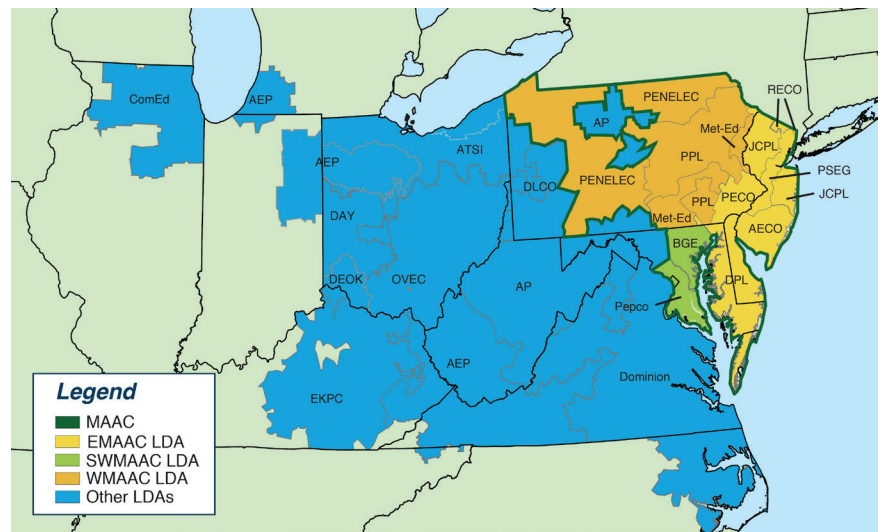
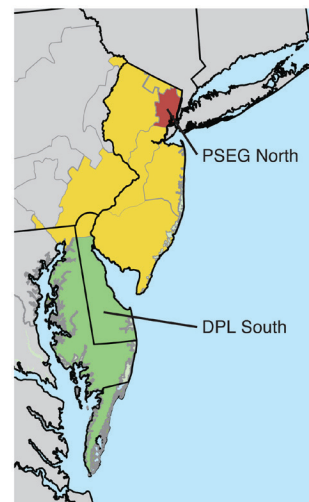


Figure 5-6 Map of RPM EMAAC subzonal LDAs

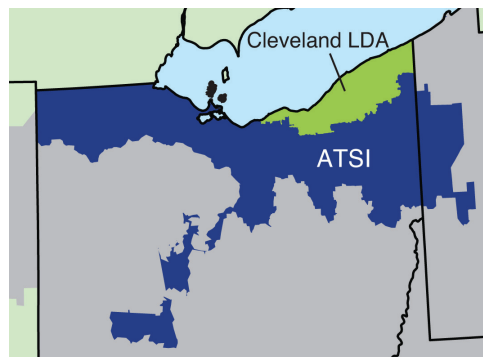


⁶⁷ Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.

⁶⁸ OATT Attachment DD § 5.10 (a) (ii).

⁶⁹ 146 FERC ¶ 61,052 (2014).

Figure 5-7 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.⁷⁰

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 of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of \$999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules

governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources.

For the 2017/2018 through the 2019/2020 Delivery Years, 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.⁷¹ 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.⁷²

Effective May 9, 2017, enhanced pseudo tie requirements for external generation capacity resources were implemented, including a transition period with deliverability requirements for existing pseudo tie resources that have previously cleared an RPM auction.⁷³ The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in

⁷⁰ OATT Attachment DD § 5.6.6(b).

⁷¹ 147 FERC ¶ 61,060 (2014).

⁷² 151 FERC ¶ 61,208 (2015).

⁷³ 161 FERC ¶ 61,197 (2017), *order denying reh'g*, 170 FERC ¶ 61,217 (2020).

effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

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.

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

Demand Resources

There are two basic demand products incorporated in the RPM market design:⁷⁴

- **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.
- **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.⁷⁵

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:^{76 77}

- **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.

⁷⁴ 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.

⁷⁵ Letter Order, Docket No. ER10-366-000 (January 22, 2010).

⁷⁶ 151 FERC ¶ 61,208.

⁷⁷ PJM Reliability Assurance Agreement Article 1.

- **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 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 10,586.0 MW for June 1, 2020, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2020/2021 Delivery Year (13,015.2 MW) less replacement capacity (2,429.2 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2018 to June 1, 2021^{78 79 80}

		UCAP (MW)													
								PSEG		ATSI					
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	North	Pepco	ATSI	Cleveland	ComEd	BGE	PPL	DAY
															DEOK
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	(3,182.4)	(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	
	RPM load management	10,798.1	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	10,703.1	3,878.9	1,659.2	817.0	91.3	381.2	176.5	554.6	1,047.0	333.9	1,759.9	262.4	741.4	
	EE cleared	2,528.5	821.4	395.3	301.7	7.8	134.5	52.8	170.0	204.8	41.7	792.9	131.7	72.7	
	DR net replacements	(2,138.8)	(1,004.2)	(468.8)	(129.0)	(40.9)	(141.5)	(86.6)	(74.8)	(130.3)	(123.1)	(143.0)	(54.2)	(208.9)	
	EE net replacements	(50.0)	(24.1)	4.7	3.3	(0.2)	2.7	9.1	2.2	3.4	0.0	0.0	1.1	(20.4)	
	RPM load management	11,042.8	3,672.0	1,590.4	993.0	58.0	376.9	151.8	652.0	1,124.9	252.5	2,409.8	341.0	584.8	
01-Jun-20	DR cleared	9,445.7	2,829.1	1,168.9	485.8	72.6	339.0	152.7	236.3	951.7	231.9	1,657.3	249.5	616.6	241.5
	EE cleared	3,569.5	1,288.8	700.3	394.5	28.8	246.1	111.3	196.2	356.0	72.9	852.0	198.3	111.4	79.5
	DR net replacements	(2,399.5)	(858.7)	(369.0)	(176.5)	(29.7)	(136.5)	(89.0)	(53.3)	(121.1)	(36.2)	(314.5)	(123.2)	(171.0)	(66.1)
	EE net replacements	(29.7)	(0.5)	(0.3)	5.9	0.0	(6.3)	12.0	(0.6)	(0.2)	0.0	(0.1)	6.5	(5.2)	0.0
	RPM load management	10,586.0	3,258.7	1,499.9	709.7	71.7	442.3	187.0	378.6	1,186.4	268.6	2,194.7	331.1	551.8	254.9
01-Jun-21	DR cleared	11,419.8	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7
	EE cleared	4,031.0	1,549.0	853.8	438.6	31.9	351.4	135.1	213.4	330.6	73.7	895.0	225.2	142.0	83.4
	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
	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
	RPM load management	15,450.8	5,003.1	2,235.3	1,063.5	98.2	761.9	323.7	559.3	1,527.4	346.5	2,968.7	504.2	839.7	311.1

78 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.

79 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.

80 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2021^{81 82 83}

	UCAP (MW)					Registered DR			
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,419.8	0.0	0.0	11,419.8	0.0	11,419.8	0.0	1.087	0.0

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2021^{84 85}

	UCAP (MW)					RPM Commitments	
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0	
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0	
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0	
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0	
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6	
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1	
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3	
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2	
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6	
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8	
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5	
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1	
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5	
01-Jun-20	3,569.5	0.0	(29.7)	3,539.8	(0.1)	3,539.7	
01-Jun-21	4,031.0	0.0	0.0	4,031.0	0.0	4,031.0	

81 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.

82 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.

83 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.

84 Pursuant to the OA § 15.1.6(c), PJM Settlement shall close out and liquidate all forward positions of PJM members that are declared in default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

85 Effective with the 2019/2020 Delivery Year, available capacity from an EE Resource can be used to replace only EE Resource commitments. This rule change and related EE add back rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

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.^{86 87 88} 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 exceed this level. 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.⁸⁹ 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/nonperformance charges.⁹⁰ 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.⁹¹

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).⁹² 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

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).

⁸⁹ OATT Attachment DD § 6.8 (b).

⁹⁰ 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).

⁹¹ OATT Attachment DD § 6.8(a).

⁹² 151 FERC ¶ 61,208.

performance during performance assessment intervals (A) in the delivery year.⁹³

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 intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The 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.⁹⁴

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:

$$ACR \leq \sum_{i=1}^H (CPBR_i \times A_i)$$

$$\text{or } ACR \leq \left(\frac{1}{12}\right) (CPBR \times H \times \bar{A})$$

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})

⁹³ 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.

⁹⁴ OATT Attachment DD § 10A (d).

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 nonperformance charge rate (PPR), the opportunity of earning bonuses as an energy only resource, as well as the net nonperformance charges incurred by taking on a capacity obligation are lower. Under such a scenario, the likelihood 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 nonperformance 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 nonperformance charge 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.⁹⁵ ⁹⁶ 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 nonperformance charge rate

⁹⁵ PJM experienced only one emergency event since April 2014 that triggered a PAI in an area that at least encompasses a PJM transmission zone. On October 2, 2019, PJM declared a pre-emergency load management action that triggered PAIs in four zones for a period of two hours or 24 five minute intervals.

⁹⁶ See Table 5-7.

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.⁹⁷ 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.⁹⁸ 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.⁹⁹

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.¹⁰⁰ 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

97 See Monitoring Analytics, LLC "Analysis of the 2021/2022 RPM Base Residual Auction—Revised," at Attachment B <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_2021/2022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

98 135 FERC ¶ 61,022 (2011).

99 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011).

100 143 FERC ¶ 61,090 (2013).

(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; decreasing the screen from 90 percent to 100 percent of the applicable net CONE values; 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.¹⁰¹

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.¹⁰² The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes include expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity

101 161 FERC ¶ 61,252 (2017).

102 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).

resources with state subsidies as 100 percent of the applicable net CONE or net ACR values.

2021/2022 RPM Second Incremental Auction

As shown in Table 5-14, 276 generation resources submitted Capacity Performance offers in the 2021/2022 RPM Third Incremental Auction. Unit specific offer caps were calculated for zero generation resources (0.0 percent). Of the 276 generation resources, 241 generation resources had the net CONE times B offer cap (87.3 percent), 20 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units (7.2 percent), 10 Planned Generation Capacity Resources had uncapped offers (3.6 percent), and the remaining five generation resources were price takers (1.8 percent). 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 5-15, of the 844.4 ICAP MW of MOPR Unit-Specific Exception requests for the 2021/2022 RPM Second Incremental Auction, requests for 844.4 MW were granted.

Table 5-14 ACR statistics: RPM auctions conducted in third quarter, 2020

Offer Cap/Mitigation Type	2021/2022 Second Incremental Auction	
	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA
Unit specific ACR (APIR)	0	0.0%
Unit specific ACR (APIR and CPQR)	0	0.0%
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	241	87.3%
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	20	7.2%
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	10	3.6%
Existing generation resources as price takers	5	1.8%
Total Generation Capacity Resources offered	276	100.0%

Table 5-15 MOPR statistics: RPM auctions conducted in third quarter, 2020¹⁰³

		Number of Requests (Company-Plant Level)	ICAP (MW)		UCAP (MW)		
			Requested	Granted	Offered	Offered	Cleared
2021/2022 Second Incremental Auction	Unit-Specific Exception	19	844.4	844.4	16.2	16.0	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	140.1	137.0	0.0
	Total	19	844.4	844.4	156.3	153.0	0.0

Replacement Capacity¹⁰⁴

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2021. The 2021 numbers are not final.

Table 5-16 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	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	169,478.0	0.0	(673.5)	168,804.5	0.0	168,804.5

¹⁰³ 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 are not reported as a result of PJM confidentiality rules.

¹⁰⁴ For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

Market Performance

Figure 5-8 shows cleared MW weighted average capacity market prices on a delivery year basis for the entire history of the PJM capacity markets.

Table 5-17 shows RPM clearing prices for all RPM auctions held through the first nine months of 2020, and Table 5-18 shows the RPM cleared MW for all RPM auctions held through the first nine months of 2020.

Figure 5-9 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 the first nine months of 2020. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by delivery year for all RPM auctions held through the first nine months of 2020 based on the unforced MW cleared and the resource clearing prices. In 2019/2020, RPM revenue was \$7.1 billion. In 2020/2021, RPM revenue was \$7.0 billion.

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through the first nine months of 2020. In 2018, RPM revenue was \$10.3 billion. In 2019, RPM revenue was \$8.7 billion.

Table 5-22 shows the RPM annual charges to load. For the 2018/2019 Delivery Year, RPM annual charges to load were \$11.0 billion. For the 2020/2021 Delivery Year, annual charges to load are \$7.0 billion.

Table 5-17 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
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
2019/2020 BRA	Capacity Performance	\$100.00	\$100.00	\$100.00	\$100.00	\$119.77	\$100.00	\$119.77	\$119.77	\$119.77	\$100.00	\$100.00	\$202.77	\$100.30
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
2019/2020 Third Incremental Auction	Base Capacity	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35
2019/2020 Third Incremental Auction	Base Capacity DR/EE	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$21.35	\$20.00	\$21.35	\$21.35	\$21.35
2019/2020 Third Incremental Auction	Capacity Performance	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35	\$28.35
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
2020/2021 Second Incremental Auction	Capacity Performance	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25	\$20.25
2020/2021 Third Incremental Auction	Capacity Performance	\$10.00	\$15.25	\$10.00	\$15.25	\$15.25	\$15.25	\$15.25	\$15.25	\$15.25	\$15.25	\$10.00	\$10.00	\$15.25
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
2021/2022 First Incremental Auction	Capacity Performance	\$23.00	\$23.00	\$23.00	\$23.00	\$25.00	\$23.00	\$25.00	\$45.00	\$219.00	\$23.00	\$23.00	\$23.00	\$60.00
2021/2022 Second Incremental Auction	Capacity Performance	\$10.26	\$10.26	\$10.26	\$10.26	\$15.37	\$10.26	\$15.37	\$125.00	\$125.00	\$10.26	\$10.26	\$10.26	\$70.00

Table 5-18 Capacity market cleared MW: 2007/2008 through 2021/2022 RPM Auctions¹⁰⁵

		UCAP (MW)												
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE	TOTAL
2019/2020	BASE	60,061.8	9,996.2	9,066.6	12,754.9	20,382.4	1,598.5	5,583.1	3,228.9	6,971.7	10,291.1	22,971.4	4,422.9	167,329.5
2019/2020	FIRST	784.5	249.4	39.3	157.7	78.7	11.7	10.6	28.8	43.6	147.5	711.4	31.9	2,295.1
2019/2020	SECOND	442.9	160.4	30.1	146.2	210.1	21.2	38.1	44.8	41.9	263.6	105.8	107.5	1,612.6
2019/2020	THIRD	1,608.0	440.9	429.4	1,216.6	265.7	2.4	180.4	23.2	83.6	454.2	867.4	255.2	5,827.0
2020/2021	BASE	56,012.4	11,413.2	8,990.6	14,398.2	19,978.5	1,647.2	5,041.2	2,975.4	6,410.0	9,925.9	23,960.3	4,021.1	164,773.9
2020/2021	FIRST	1,265.6	331.0	144.2	83.4	76.2	38.9	105.8	32.0	97.8	666.9	644.4	38.7	3,524.8
2020/2021	SECOND	447.2	206.9	53.0	30.7	302.9	28.4	29.5	48.8	35.4	366.2	194.6	160.3	1,903.8
2020/2021	THIRD	1,106.6	569.7	118.7	89.0	194.1	33.1	423.0	137.0	93.1	554.3	127.7	39.8	3,486.0
2021/2022	BASE	55,642.6	12,565.1	10,136.1	15,368.6	19,857.3	1,673.8	4,667.2	3,134.1	6,546.1	8,010.5	22,358.1	3,667.8	163,627.3
2021/2022	FIRST	281.7	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	2,143.2
2021/2022	SECOND	1,307.8	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	3,707.5

¹⁰⁵ The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-19 Weighted average clearing prices by zone: 2018/2019 through 2021/2022

	Weighted Average Clearing Price (\$ per MW-day)			
	2018/2019	2019/2020	2020/2021	2021/2022
LDA				
RTO				
AEP	\$158.20	\$93.63	\$74.42	\$137.02
APS	\$158.20	\$93.63	\$74.42	\$137.02
ATSI	\$148.42	\$92.97	\$69.75	\$149.70
Cleveland	\$158.68	\$89.17	\$68.93	\$106.96
ComEd	\$199.02	\$188.90	\$182.15	\$191.17
DAY	\$158.20	\$93.63	\$72.42	\$138.19
DEOK	\$158.20	\$93.63	\$121.24	\$133.54
DLCO	\$158.20	\$93.63	\$74.42	\$137.02
Dominion	\$158.20	\$93.63	\$74.42	\$137.02
EKPC	\$158.20	\$93.63	\$74.42	\$137.02
MAAC				
EMAAC				
AECO	\$214.31	\$112.48	\$182.04	\$164.07
DPL	\$214.31	\$112.48	\$182.04	\$164.07
DPL South	\$211.38	\$115.95	\$178.65	\$161.07
JCPL	\$214.31	\$112.48	\$182.04	\$164.07
PECO	\$214.31	\$112.48	\$182.04	\$164.07
PSEG	\$210.92	\$110.56	\$165.74	\$199.70
PSEG North	\$211.71	\$116.03	\$176.45	\$202.27
RECO	\$214.31	\$112.48	\$182.04	\$164.07
SWMAAC				
BGE	\$141.58	\$88.20	\$80.71	\$189.98
Pepco	\$144.90	\$90.59	\$84.24	\$134.58
WMAAC				
Met-Ed	\$152.65	\$93.81	\$81.85	\$136.11
PENELEC	\$152.65	\$93.81	\$81.85	\$136.11
PPL	\$147.90	\$88.53	\$85.07	\$139.16

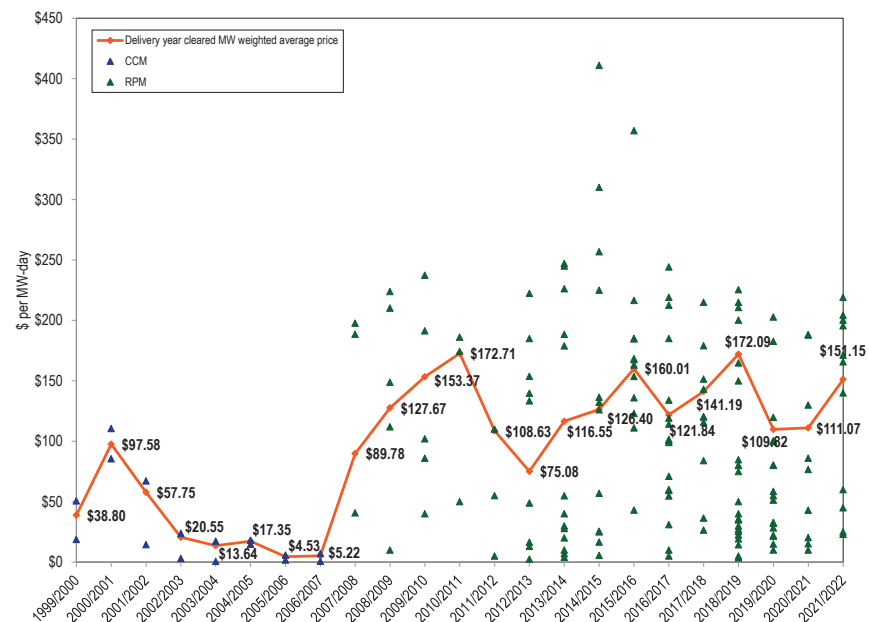
Table 5-20 RPM revenue by delivery year: 2007/2008 through 2021/2022¹⁰⁶

Delivery Year	Weighted Average RPM Price (\$ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	\$89.78	129,409.2	366	\$4,252,287,381
2008/2009	\$127.67	130,629.8	365	\$6,087,147,586
2009/2010	\$153.37	134,030.2	365	\$7,503,218,157
2010/2011	\$172.71	134,036.2	365	\$8,449,652,496
2011/2012	\$108.63	134,182.6	366	\$5,335,087,023
2012/2013	\$75.08	141,283.9	365	\$3,871,714,635
2013/2014	\$116.55	159,844.5	365	\$6,799,778,047
2014/2015	\$126.40	161,205.0	365	\$7,437,267,646
2015/2016	\$160.01	173,519.4	366	\$10,161,726,902
2016/2017	\$121.84	179,749.0	365	\$7,993,888,695
2017/2018	\$141.19	180,590.5	365	\$9,306,676,719
2018/2019	\$172.09	175,996.0	365	\$11,054,943,851
2019/2020	\$109.82	177,064.2	366	\$7,116,815,360
2020/2021	\$111.07	173,688.5	365	\$7,041,524,517
2021/2022	\$151.15	169,478.0	365	\$9,349,894,658

Table 5-21 RPM revenue by calendar year: 2007 through 2022¹⁰⁷

Year	Weighted Average RPM Price (\$ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	\$89.78	75,665.5	214	\$2,486,310,108
2008	\$111.93	130,332.1	366	\$5,334,880,241
2009	\$142.74	132,623.5	365	\$6,917,391,702
2010	\$164.71	134,033.7	365	\$8,058,113,907
2011	\$135.14	133,907.1	365	\$6,615,032,130
2012	\$89.01	138,561.1	366	\$4,485,656,150
2013	\$99.39	152,166.0	365	\$5,588,442,225
2014	\$122.32	160,642.2	365	\$7,173,539,072
2015	\$146.10	168,147.0	365	\$9,018,343,604
2016	\$137.69	177,449.8	366	\$8,906,998,628
2017	\$133.19	180,242.4	365	\$8,763,578,112
2018	\$159.31	177,896.7	365	\$10,331,688,133
2019	\$135.58	176,338.6	365	\$8,734,613,179
2020	\$110.55	175,368.7	366	\$7,084,072,778
2021	\$134.57	171,219.9	365	\$8,394,925,093
2022	\$151.15	70,112.8	151	\$3,868,038,612

¹⁰⁶ The results for the ATSI Integration Auctions are not included in this table.¹⁰⁷ The results for the ATSI Integration Auctions are not included in this table.

Figure 5-8 History of capacity prices: 1999/2000 through 2021/2022¹⁰⁸

¹⁰⁸ 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 5-9 Map of RPM capacity prices: 2018/2019 through 2021/2022

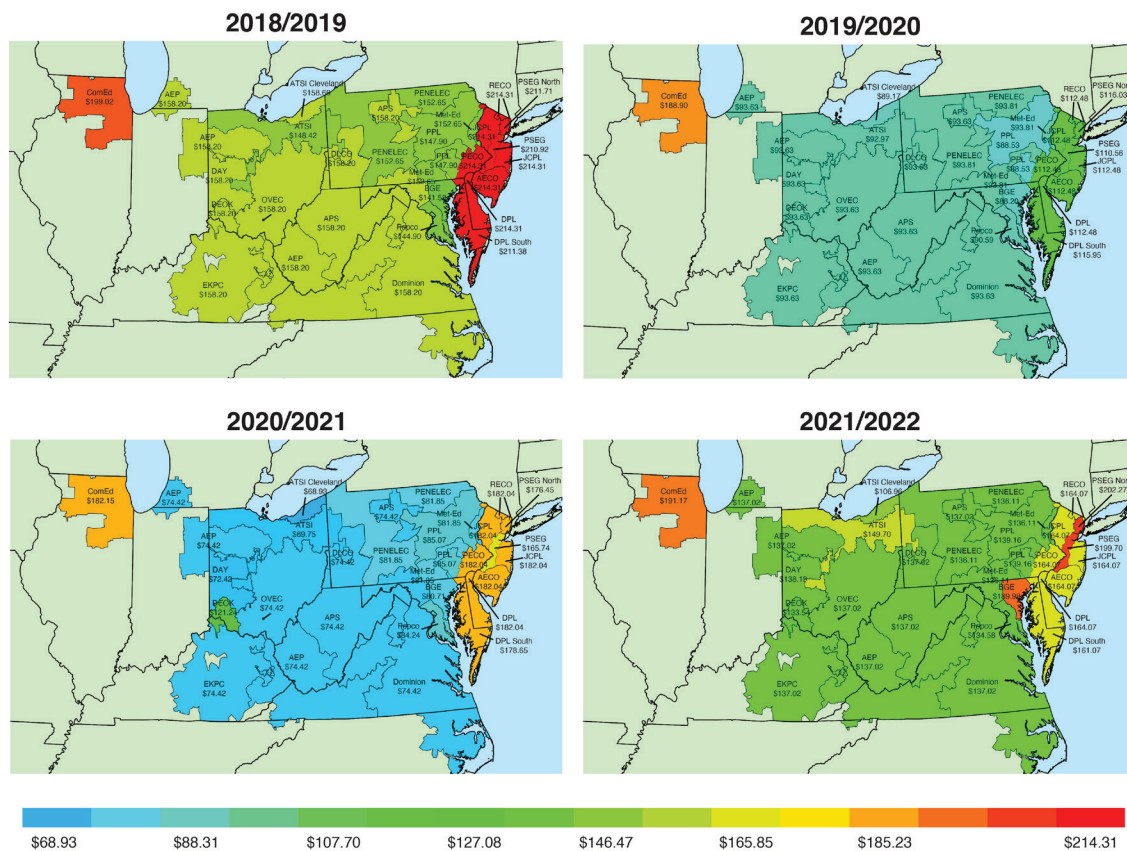


Table 5-22 RPM cost to load: 2019/2020 through 2021/2022 RPM Auctions^{109 110 111}

	Zonal Capacity Price (\$ per MW-Day)	Zonal CTR Credit Rate (\$ per MW-Day)	Net Load Price (\$ per MW-day)	UCAP Obligation (MW)	Days	Annual Charges	Charges per Day
2019/2020							
Rest of RTO	\$98.07	\$0.00	\$98.07	89,185.9	366	\$3,201,364,940	\$8,746,899
Rest of EMAAC	\$117.92	\$2.35	\$115.58	24,415.1	366	\$1,032,810,556	\$2,821,887
BGE	\$97.22	-\$0.56	\$97.79	7,595.2	366	\$271,828,430	\$742,701
ComEd	\$195.99	\$3.43	\$192.56	24,985.1	366	\$1,760,892,086	\$4,811,181
Pepco	\$92.90	\$0.00	\$92.90	7,330.3	366	\$249,230,694	\$680,958
PSEG	\$118.18	\$2.35	\$115.83	11,281.1	366	\$478,247,326	\$1,306,687
Total				164,792.8		\$6,994,374,033	
2020/2021							
Rest of RTO	\$77.31	\$0.00	\$77.31	69,073.7	365	\$1,949,098,489	\$5,339,996
Rest of MAAC	\$86.98	-\$0.08	\$87.06	29,555.9	365	\$939,246,366	\$2,573,278
EMAAC	\$187.13	\$12.80	\$174.32	35,740.4	365	\$2,274,098,760	\$6,230,408
ComEd	\$190.04	\$0.12	\$189.92	23,744.7	365	\$1,645,988,210	\$4,509,557
DEOK	\$128.73	\$24.23	\$104.50	5,072.0	365	\$193,459,838	\$530,027
Total				163,186.7		\$7,001,891,663	
2021/2022							
Rest of RTO	\$142.71	\$0.00	\$142.71	81,244.5	365	\$4,232,062,441	\$11,594,692
Rest of EMAAC	\$168.34	\$3.44	\$164.89	23,999.1	365	\$1,444,396,169	\$3,957,250
ATSI	\$168.49	\$7.71	\$160.78	13,978.7	365	\$820,348,098	\$2,247,529
BGE	\$205.09	\$40.51	\$164.58	7,316.9	365	\$439,530,736	\$1,204,194
ComEd	\$198.71	\$0.00	\$198.71	23,149.9	365	\$1,679,053,039	\$4,600,145
PSEG	\$210.74	\$22.72	\$188.02	11,275.2	365	\$773,794,246	\$2,119,984
Total				160,964.3		\$9,389,184,729	

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU at least 90 days prior to the proposed deactivation date. Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.¹¹² If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power

¹⁰⁹ The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.

¹¹⁰ There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.

¹¹¹ The net load prices and obligation MW for 2021/2022 are not finalized.

¹¹² OATT Attachment DD § 6.6(g).

issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.¹¹³

Table 5-23 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through September 2020. Of the 69 deactivation requests submitted, 17 units (24.6 percent) deactivated an average of 232 days earlier than their initially requested date; 11 units (15.9 percent) deactivated an average of 84 days later than the originally requested deactivation date; and 22 units (31.9 percent) deactivated on their initially requested date. Eleven (15.9 percent) of the unit deactivations were cancelled an average of 465 days before their scheduled deactivation date, and 8 (11.6 percent) of the unit deactivations have not yet reached their target retirement date.

Table 5-23 Timing of actual unit deactivations compared to initially requested deactivation date: Requests submitted January 2018 through September 2020

	Number of Units	Percent	Average Deviation from Originally Requested Date
Early	17	24.6%	(232)
Late	11	15.9%	84
On time	22	31.9%	0
Cancelled	11	15.9%	(465)
Pending	8	11.6%	-
Total	69	100.0%	-

¹¹³ OATT Part V §113

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.¹¹⁴ 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.¹¹⁵

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.¹¹⁶ PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.¹¹⁷ 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.¹¹⁸ 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.¹¹⁹ 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.¹²⁰ 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.¹²¹

¹¹⁴ OATT Part V §114.

¹¹⁵ 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.”).

¹¹⁶ OATT § 113.2; OATT Attachment M § IV.1.

¹¹⁷ OATT § 113.2.

¹¹⁸ *Id.*

¹¹⁹ OATT § 113.1.

¹²⁰ OATT Attachment DD § 6.6(g).

¹²¹ *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.¹²² Avoidable costs are defined to mean “incremental expenses directly required for the operation of a generating unit.”¹²³ The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).¹²⁴ 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.¹²⁵ Project investment is capped at \$2 million, above which FERC approval is required.¹²⁶ 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.¹²⁷

¹²² 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).

¹²³ OATT § 115.

¹²⁴ *Id.*

¹²⁵ OATT § 118.

¹²⁶ OATT §§ 115, 117.

¹²⁷ OATT § 119.

Table 5-24 shows units that have provided RMR service to PJM.

Table 5-24 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	30-Apr-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-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.

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 and costs associated with closing the unit that would have been incurred regardless of the RMR service period.¹²⁸ In one cost of service recovery rate, the filing included costs that already had been written off on the company's public books.¹²⁹ Unit owners have filed for revenues under the cost of service method that substantially exceed the actual incremental costs of providing RMR service.

Because an RMR unit is needed by PJM for reliability reasons, and the provision of RMR service is voluntary 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

¹²⁸ See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.

¹²⁹ See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16-21.

recovery of 100 percent of the actual incremental costs incurred to provide the service plus an incentive markup.

The cost of service recovery rates have been excessive compared to the actual incremental 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 incremental 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 5-25 shows the capacity factors by unit type in the first nine months of 2019 and 2020. In the first nine months of 2020, nuclear units had a capacity factor of 93.1 percent, compared to 92.7 percent in the first nine months of 2019; combined cycle units had a capacity factor of 55.2 percent in the first nine months of 2020, compared to a capacity factor of 55.0 percent in the first nine months of 2019; all steam units had a capacity factor of 23.3 percent in the first nine months of 2020, compared to 28.7 percent in the first nine months of 2019; coal units had a capacity factor of 25.4 percent in the first nine months of 2020, compared to 31.6 percent in the first nine months of 2019.

Table 5-25 Capacity factor (By unit type (GWh)): January through September, 2019 and 2020^{130 131}

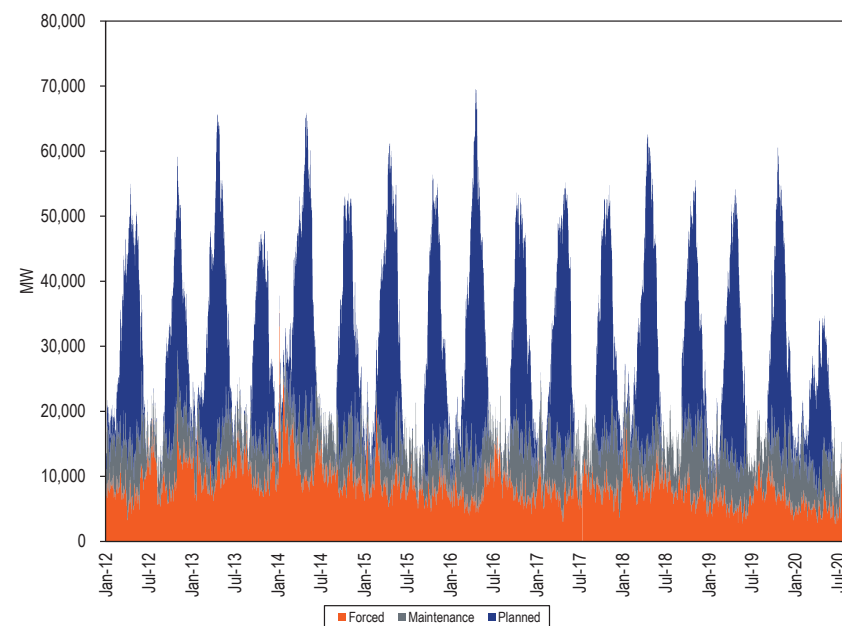
Unit Type	2019 (Jan-Sep)		2020 (Jan-Sep)		Change in 2020 from 2019
	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	
Battery	15.1	0.7%	27.0	1.2%	0.5%
Combined Cycle	211,909.2	55.0%	229,071.1	55.2%	0.1%
Single Fuel	180,345.5	57.4%	194,993.4	56.7%	(0.7%)
Dual Fuel	31,563.7	44.7%	34,077.7	48.1%	3.4%
Combustion Turbine	12,167.9	5.3%	15,069.9	6.7%	1.3%
Single Fuel	8,174.8	5.0%	10,573.3	6.5%	1.6%
Dual Fuel	3,993.1	6.4%	4,496.7	7.1%	0.8%
Diesel	200.3	6.2%	188.5	5.6%	(0.7%)
Single Fuel	196.3	7.4%	182.6	6.5%	(0.9%)
Dual Fuel	4.0	0.7%	5.9	1.0%	0.3%
Diesel (Landfill gas)	1,267.2	43.6%	1,182.9	42.6%	(0.9%)
Fuel Cell	163.1	77.9%	170.3	81.0%	3.1%
Nuclear	210,535.4	92.7%	207,426.7	93.1%	0.4%
Pumped Storage Hydro	4,597.2	10.6%	4,839.4	11.1%	0.5%
Run of River Hydro	8,818.5	33.8%	8,108.9	30.9%	(2.8%)
Solar	2,218.6	21.0%	2,977.8	20.7%	(0.3%)
Steam	166,172.0	28.7%	127,877.2	23.3%	(5.4%)
Biomass	4,563.1	55.2%	4,203.5	53.0%	(2.2%)
Coal	156,702.4	31.6%	118,216.2	25.4%	(6.2%)
Single Fuel	153,788.9	32.5%	116,152.6	26.2%	(6.3%)
Dual Fuel	2,913.5	13.1%	2,063.5	9.5%	(3.6%)
Natural Gas	4,807.9	35.5%	5,384.4	37.1%	1.6%
Single Fuel	354.1	41.2%	344.7	42.4%	1.2%
Dual Fuel	4,453.8	21.4%	5,039.7	23.3%	1.8%
Oil	98.6	0.4%	73.0	0.5%	0.1%
Wind	16,973.8	27.2%	17,986.2	25.8%	(1.4%)
Total	635,041.1	40.5%	614,930.3	39.1%	(1.4%)

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 5-10, 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 5-14.

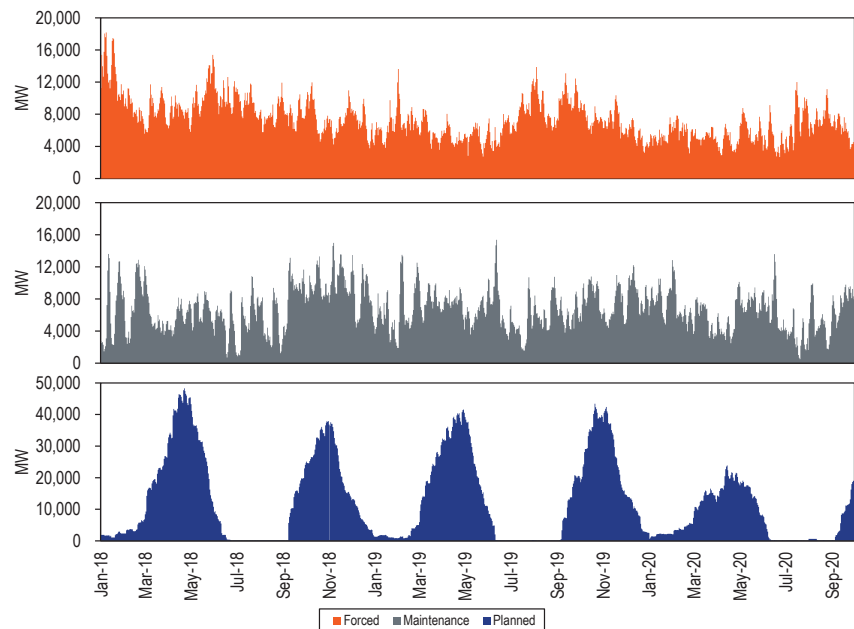
¹³⁰ The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

¹³¹ 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.

Figure 5-10 Outages (MW): 2012 through September 2020

In the first nine months of 2020, forced and planned outages were lower than in 2018 and 2019 (Figure 5-11). The MWh of planned outages in the first nine months of 2020 were 31 percent lower than in the first nine months of 2019 and the MWh of forced outages were 4 percent lower than in the first nine months of 2019. The MWh of maintenance outages were 1 percent higher than in the first nine months of 2019.

Figure 5-11 Outages (MW): Forced, maintenance and planned outages 2018 through September 2020



Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-12. Metrics by unit type are shown in Table 5-26.

Figure 5-12 Equivalent outage and availability factors: January through September, 2007 to 2020

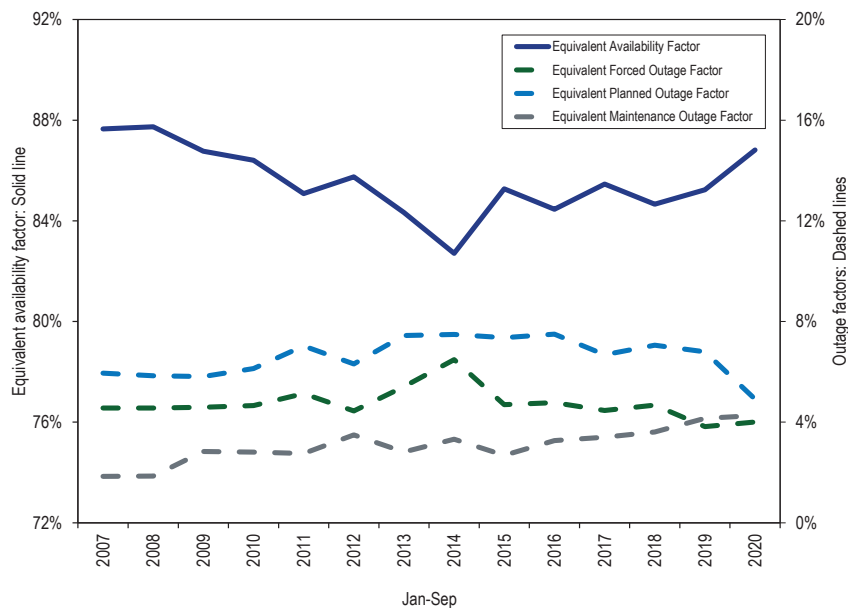


Table 5-26 EFOF, EPOF, EMOF and EAF by unit type: January through September, 2007 through 2020

	Coal				Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Other			
Jan-Sep	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7.0%	8.4%	2.5%	82.2%	2.2%	5.2%	1.3%	91.2%	4.6%	2.3%	2.1%	91.0%	10.8%	0.7%	1.8%	86.7%	1.3%	5.4%	1.6%	91.8%	1.1%	3.8%	0.3%	94.7%	6.0%	7.2%	2.8%	83.9%
2008	7.9%	6.3%	2.4%	83.3%	2.1%	5.0%	1.4%	91.5%	3.0%	3.9%	1.9%	91.2%	9.8%	1.2%	1.2%	87.9%	1.6%	6.8%	1.7%	89.9%	0.9%	5.2%	0.6%	93.3%	4.2%	8.7%	2.6%	84.4%
2009	6.7%	7.1%	3.6%	82.6%	3.4%	5.1%	3.5%	88.0%	1.5%	2.7%	2.1%	93.8%	6.7%	0.3%	1.2%	91.8%	2.1%	8.9%	2.3%	86.7%	4.2%	4.2%	0.7%	90.9%	3.4%	7.9%	5.0%	83.7%
2010	7.8%	7.8%	4.2%	80.2%	2.6%	6.0%	3.1%	88.3%	2.0%	2.0%	1.6%	94.4%	4.7%	0.6%	0.8%	93.9%	0.8%	8.4%	2.1%	88.8%	1.9%	4.4%	0.5%	93.1%	5.0%	8.3%	3.5%	83.3%
2011	8.7%	8.1%	4.0%	79.3%	2.4%	7.0%	2.1%	88.5%	2.0%	3.2%	1.5%	93.2%	3.8%	0.0%	1.9%	94.3%	1.6%	13.2%	2.0%	83.2%	2.2%	5.8%	1.5%	90.5%	5.1%	8.1%	3.0%	83.8%
2012	7.3%	7.5%	5.8%	79.3%	2.5%	6.4%	1.8%	89.3%	2.0%	2.4%	1.5%	94.1%	3.9%	0.1%	1.7%	94.4%	3.5%	4.9%	1.8%	89.8%	1.4%	6.1%	0.9%	91.6%	4.8%	8.3%	4.7%	82.2%
2013	8.5%	9.4%	4.4%	77.6%	1.9%	8.5%	2.6%	87.0%	5.3%	3.1%	1.3%	90.2%	5.5%	0.3%	1.4%	92.8%	2.1%	6.5%	1.6%	89.7%	1.2%	5.6%	0.8%	92.4%	7.5%	9.2%	3.7%	79.6%
2014	10.0%	8.2%	5.2%	76.5%	2.8%	8.7%	2.1%	86.4%	7.7%	3.3%	1.4%	87.5%	14.0%	0.5%	2.3%	83.2%	2.0%	8.9%	3.0%	86.1%	1.8%	5.9%	0.9%	91.5%	7.1%	12.9%	5.9%	74.1%
2015	8.1%	7.7%	4.0%	80.1%	2.1%	8.3%	1.7%	87.9%	2.9%	4.1%	1.7%	91.3%	8.4%	0.4%	2.3%	88.9%	2.3%	7.9%	1.5%	88.3%	1.2%	4.9%	1.3%	92.7%	6.6%	15.3%	4.2%	73.9%
2016	8.7%	7.9%	5.9%	77.5%	3.0%	8.6%	1.7%	86.7%	2.2%	4.3%	1.9%	91.6%	5.4%	0.2%	2.5%	91.9%	2.1%	6.7%	2.7%	88.4%	2.1%	4.6%	1.1%	92.2%	5.2%	16.5%	3.8%	74.5%
2017	10.1%	8.1%	6.6%	75.3%	1.9%	7.9%	1.6%	88.6%	1.2%	3.9%	1.7%	93.2%	5.8%	0.2%	1.7%	92.3%	2.2%	5.3%	2.9%	89.6%	0.6%	5.0%	0.6%	93.9%	4.3%	8.5%	5.0%	82.2%
2018	10.6%	9.6%	6.8%	73.0%	1.5%	7.9%	1.2%	89.4%	2.0%	4.2%	1.5%	92.4%	6.2%	0.9%	2.7%	90.2%	2.2%	5.3%	3.1%	89.4%	0.8%	4.5%	0.5%	94.2%	4.0%	8.2%	8.1%	79.8%
2019	8.4%	7.8%	8.4%	75.3%	1.6%	7.9%	1.7%	88.8%	1.5%	5.4%	1.6%	91.5%	7.3%	1.0%	2.3%	89.3%	1.4%	5.4%	3.6%	89.7%	0.9%	4.6%	0.9%	93.5%	3.8%	9.9%	6.5%	79.7%
2020	1.6%	7.9%	1.7%	88.8%	1.5%	5.4%	1.6%	91.5%	7.3%	1.0%	2.3%	89.3%	1.4%	5.4%	3.6%	89.7%	0.9%	4.6%	0.9%	93.5%	3.8%	9.9%	6.5%	79.7%	3.8%	6.8%	4.1%	85.2%

Generator Forced Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORD). EFORD is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORD measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORD calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.¹³² The EFORD metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORD in the first nine months of 2020 was 6.3 percent, an increase from 6.0 percent in the first nine months of 2019. Figure 5-13 shows the average EFORD since 1999 for all units in PJM.¹³³

¹³² 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.

¹³³ The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the 2019 State of the Market Report for PJM, Appendix A: "PJM Overview" for details.

Figure 5-13 Trends in the equivalent demand forced outage rate (EFORd): 1999 through 2020

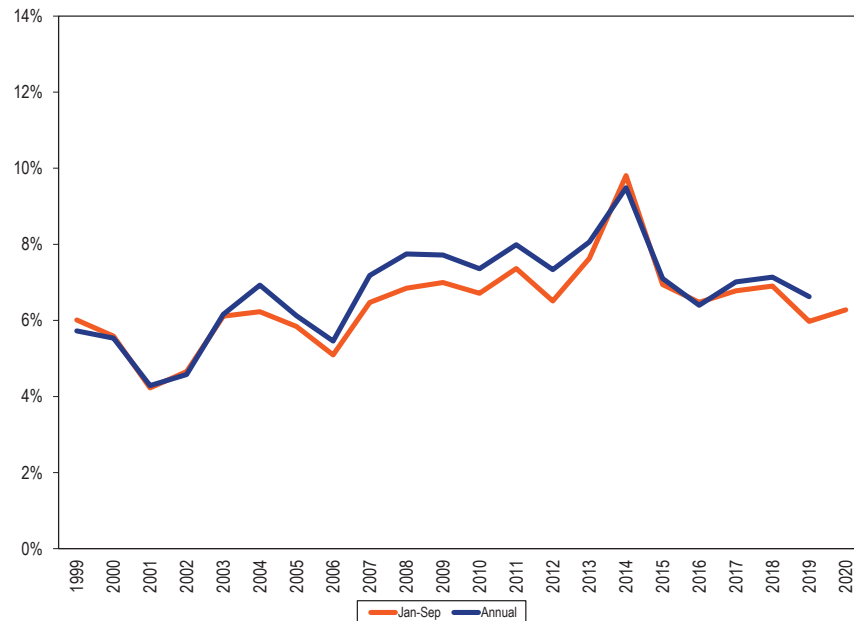


Table 5-27 shows the class average EFORd by unit type.

Table 5-27 EFORd by unit type: January through September, 2007 through 2020

	Jan-Sep													
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	7.9%	8.9%	8.2%	9.2%	10.8%	9.6%	10.8%	12.5%	9.5%	10.6%	12.7%	13.5%	11.8%	9.7%
Combined Cycle	3.7%	3.5%	4.8%	3.6%	3.1%	3.1%	2.6%	4.6%	2.8%	3.6%	2.4%	2.2%	2.0%	4.1%
Combustion Turbine	11.2%	11.3%	9.1%	9.1%	7.9%	6.5%	10.5%	17.7%	9.9%	5.3%	5.0%	6.4%	5.1%	4.1%
Diesel	12.3%	10.8%	8.8%	6.7%	9.8%	5.1%	6.1%	15.0%	9.7%	7.3%	7.1%	6.8%	8.0%	7.4%
Hydroelectric	1.9%	2.5%	2.7%	1.3%	2.2%	5.1%	3.2%	3.1%	3.1%	2.9%	3.1%	2.8%	1.7%	4.9%
Nuclear	1.2%	1.0%	4.3%	2.1%	2.4%	1.5%	1.3%	2.0%	1.2%	2.3%	0.6%	0.8%	1.0%	1.3%
Other	10.2%	9.6%	8.5%	7.9%	9.2%	8.3%	12.2%	13.6%	13.1%	9.8%	12.6%	9.5%	9.4%	16.7%
Total	6.5%	6.8%	7.0%	6.7%	7.4%	6.5%	7.6%	9.8%	6.9%	6.5%	6.8%	6.9%	6.0%	6.3%

Other Forced Outage Rate Metrics

Under the capacity performance modifications to RPM, effective with the 2018/2019 Delivery Year, neither XEFORd nor EFORp are relevant.

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.¹³⁴ On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).

PJM EFOF was 4.0 percent in the first nine months of 2020. This means there was 4.0 percent lost availability because of forced outages. Table 5-28 shows that forced outages for boiler tube leaks, at 13.6 percent of the systemwide EFOF, were the largest single contributor to EFOF.

¹³⁴ 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 systemwide basis.

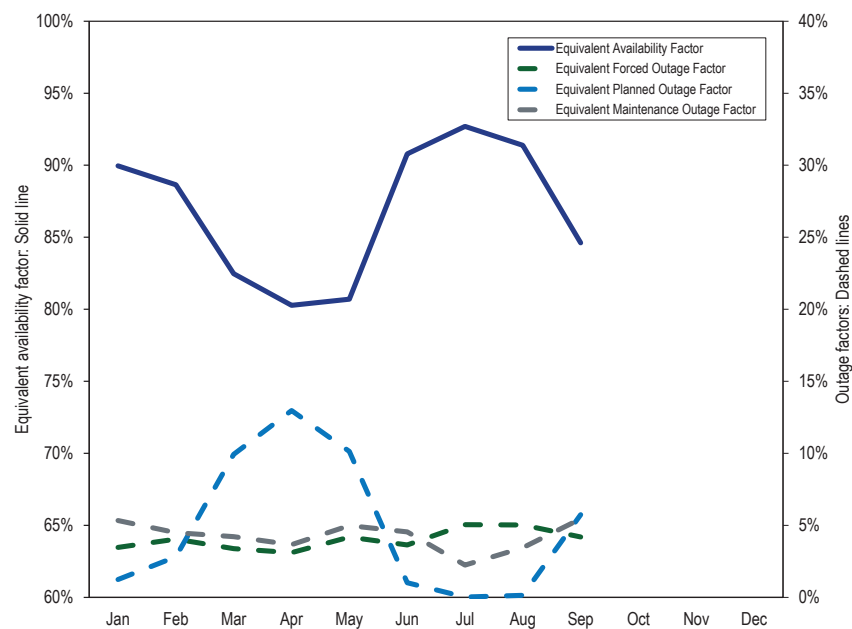
Table 5-28 Contribution to EFOF by unit type by cause: January through September, 2020

	Combined		Combustion		Hydroelectric	Nuclear	Other	System
	Coal	Cycle	Turbine	Diesel				
Boiler Tube Leaks	23.8%	1.8%	0.0%	0.0%	0.0%	0.0%	7.0%	13.6%
Electrical	2.6%	38.3%	14.0%	5.9%	6.2%	0.0%	1.9%	8.9%
Miscellaneous (Pollution Control Equipment)	12.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%	6.3%
High Pressure Turbine	10.9%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	5.7%
Catastrophe	1.8%	6.9%	1.7%	0.1%	54.4%	0.0%	6.5%	5.4%
Unit Testing	2.9%	3.9%	9.2%	25.9%	16.5%	0.5%	13.1%	5.4%
Generator	0.7%	18.6%	0.3%	5.1%	1.0%	4.9%	6.5%	4.7%
Controls	2.8%	0.8%	1.2%	9.7%	2.2%	0.0%	16.4%	4.0%
Feedwater System	6.5%	1.0%	0.0%	0.0%	0.0%	4.4%	1.0%	4.0%
Boiler Air and Gas Systems	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	16.2%	3.9%
Boiler Piping System	5.7%	2.2%	0.0%	0.0%	0.0%	0.0%	0.5%	3.4%
Miscellaneous (Steam Turbine)	0.8%	1.4%	0.0%	0.0%	0.0%	0.0%	16.2%	2.8%
Miscellaneous (Gas Turbine)	0.0%	4.8%	27.1%	0.0%	0.0%	0.0%	0.0%	2.5%
Boiler Fuel Supply from Bunkers to Boiler	4.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.5%	2.3%
Steam Generators and Steam System	0.0%	0.0%	0.0%	0.0%	0.0%	30.9%	0.0%	2.2%
Wet Scrubbers	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%
Economic	3.2%	0.1%	0.2%	3.0%	4.4%	0.0%	0.4%	2.0%
Auxiliary Systems	1.0%	1.8%	6.5%	0.0%	0.1%	0.0%	0.2%	1.3%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	0.0%	17.4%	0.0%	1.2%
All Other Causes	13.9%	18.2%	39.7%	50.4%	15.1%	41.9%	13.2%	18.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-14.

Figure 5-14 Monthly generator performance factors: January through September, 2020



Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation.

Overview

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.¹ Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

Total demand response revenue decreased by \$122.0 million, 31.0 percent, from \$393.7 million in the first nine months of 2019 to \$271.8 million in the first nine months of 2020. Emergency demand response revenue accounted for 99.1 percent of all demand response revenue, economic demand response for 0.1 percent, demand response in the synchronized reserve market for 0.4 percent and demand response in the regulation market for 0.4 percent.

Total emergency demand response revenue decreased by \$119.5 million, 30.7 percent, from \$389.0 million in the first nine months of 2019 to \$269.4 million in the first nine months of 2020. This decrease consisted entirely of capacity market revenue.²

Economic demand response revenue decreased by \$0.6 million, 69.8 percent, from \$0.9 million in the first nine months of 2019 to \$0.3 million in the first nine months of 2020.³ Demand response revenue in

the synchronized reserve market decreased by \$1.0 million, 46.4 percent, from \$2.1 million in the first nine months of 2019 to \$1.1 million in the first nine months of 2020. Demand response revenue in the regulation market decreased by \$0.9 million, 47.2 percent, from \$1.8 million in the first nine months of 2019 to \$1.0 million in the first nine months of 2020.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted, average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.⁴
- **Demand Response Market Concentration.** The ownership of economic load response resources was highly concentrated in the first nine months of 2019 and 2020. The HHI for economic resource reductions increased by 669 points from 8261 in the first nine months of 2019 to 8930 in the first nine months of 2020. The ownership of emergency load response resources was highly concentrated in the first nine months of 2020. The HHI for emergency load response committed MW was 1840 for the 2019/2020 Delivery Year. In the 2019/2020 Delivery Year, the four largest CSPs owned 79.1 percent of all committed demand response UCAP MW. The HHI for emergency demand response committed MW was 2171 for the 2020/2021 Delivery Year. In the 2020/2021 Delivery Year, the four largest CSPs owned 85.6 percent of all committed demand response UCAP MW.
- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. But PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can

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 October 16, 2020 and may change as a result of continued PJM billing updates.

³ Economic credits are synonymous with revenue received for reductions under the economic load response program.

⁴ "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 83 (Dec. 3, 2019).

be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

Recommendations

- 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 operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.⁶ (Priority: Medium. First reported 2013. Status: Not adopted.)

⁵ See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

⁶ See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends limited, extended summer and annual demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.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. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency 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. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported Q1 2020. Status: Not adopted.)

⁷ PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

Conclusion

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

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

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

demand resources are dispatched and demand resources do not have telemetry requirements similar to other Capacity Performance resources.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day-ahead energy market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that 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 (DR) 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 to being a substitute for generation in the capacity and energy markets, demand response resources should be on the demand side of the capacity market rather than on the supply side. Rather than detailed demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol.

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.⁸ The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.⁹ ¹⁰ Under the MMU proposal,

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).

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, accounting for market prices in any way they like, and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. 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 measurement and verification estimates are required. No promises of future reductions which can only be verified by inaccurate and biased measurement and verification methods are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, measurement and verification can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE.

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).

But the system would be paid for actual, metered usage, regardless of which contractual party takes that obligation.

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

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

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side. 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). Table 6-1 provides an overview of the key features of PJM demand response programs.

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.¹² Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

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.¹³ PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits end use customers' participation.¹⁴ 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.¹⁵ RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program.

¹² 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.

¹³ *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).

¹⁴ 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.

¹⁵ PJM Operating Agreement Schedule 1 § 1.5A.3.1.

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Load Response Program			Economic Load Response Program	Price Responsive Demand
	Load Management (LM)			Economic Demand Response	
Product Types	Limited, Annual, Base, Capacity Performance, Summer-Period Capacity Performance OATT Attachment DD § 5.5A	Limited, Annual, Base, Capacity Performance, Summer-Period Capacity Performance OATT Attachment DD § 5.5A		OATT Attachment K § 1.5A	
Market	Capacity Only OATT Attachment K § 8.1	Full Program Option (Capacity and Energy) OATT Attachment K § 8.1	Energy Only OATT Attachment K § 8.1	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	LSE PRD Credit RAA Schedule 6.1.G
Capacity Measurement and Verification	Firm Service Level Guaranteed Load Drop	Firm Service Level Guaranteed Load Drop	NA	NA	Firm Service Level
CBL	NA	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	NA
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment. OATT Attachment K § 3.3A	NA
Penalties	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	NA	NA	RPM event RAA Schedule 6.1.G Test compliance penalties RAA Schedule 6.1.L
Associate Manuals	Manual 18	Manual 11 Manual 18	Manual 11 Manual 18	Manual 11	Manual 18

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.

PJM Demand Response Programs

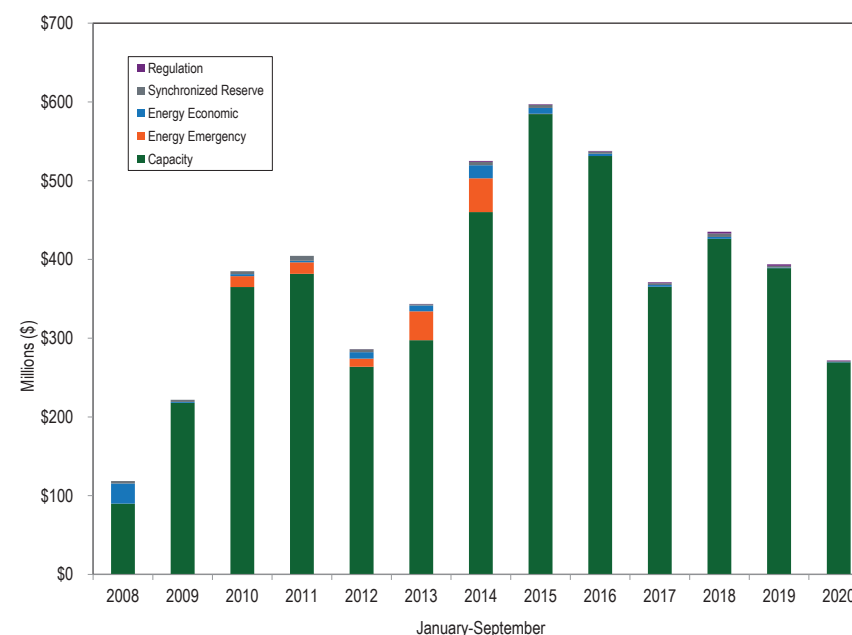
Figure 6-1 shows all revenue from PJM demand response programs by market for January through September, 2008 through 2020. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market (demand resources) has been the primary source of demand response revenue.¹⁶ In the first nine months of 2020, total demand response revenue decreased by \$122.0 million, 31.0 percent, from \$393.7 million in the first nine months of 2019 to \$271.8 million in the first nine months of 2020. Total emergency demand response revenue decreased by \$119.5 million, 30.7 percent, from \$389.0 million in the first nine months of 2019 to \$269.4 million in the first nine months of 2020. This decrease consisted of capacity market revenue and emergency energy revenue.¹⁷ In the first nine months of 2020, emergency demand response revenue, which includes capacity and emergency energy revenue, accounted for 99.1 percent of all revenue received by demand response providers, the economic program for 0.1 percent, synchronized reserve for 0.4 percent and the regulation market for 0.4 percent.

Economic demand response revenue decreased by \$0.6 million, 69.8 percent, from \$0.9 million in the first nine months of 2019 to \$0.3 million in the first nine months of 2020.¹⁸ Demand response revenue in the synchronized reserve market decreased by \$0.9 million, 47.2 percent, from \$2.1 million in the first nine months of 2019 to \$1.1 million in the first nine months of 2020. Demand response revenue in the regulation market decreased by \$0.9 million, 47.2

percent, from \$1.8 million in the first nine months of 2019 to \$1.0 million in the first nine months of 2020.

Lower demand resource revenues were in part a result of lower capacity market prices in the 2019/2020 RPM and 2020/2021 RPM auctions. The annual RTO capacity market prices decreased \$23.47 per MW-day from \$100.00 in the 2019/2020 Delivery Year to \$76.53 in the 2020/2021 Delivery Year, a 23.5 percent decrease.

Figure 6-1 Demand response revenue by market: January through September, 2008 through 2020



¹⁶ This includes both capacity market revenue and emergency energy revenue for capacity resources.

¹⁷ The total credits and MWh for demand resources were calculated as of October 16, 2020 and may change as a result of continued PJM billing updates.

¹⁸ Economic credits are synonymous with revenue received for reductions under the economic load response program.

Emergency and Pre-Emergency Load Response Programs

Demand resources participate in the capacity market within the Emergency and Pre-Emergency Load Response Programs.

All demand resources must register as pre-emergency unless the participant relies on behind the meter generation and the resource has environmental restrictions that limit the resource's ability to operate only in emergency conditions.¹⁹ Under current rules, PJM will declare an emergency if pre-emergency or emergency demand response is dispatched. In all demand response programs, CSPs are companies that sign up customers that have the ability to reduce load. CSPs satisfy cleared RPM commitments registering customers as Nominated MW. After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response programs, but a participant can register as a PJM special member and become a CSP without any additional cost.

The emergency and pre-emergency load response programs consist of the base and capacity performance demand response products. Full implementation of the Capacity Performance design in the 2020/2021 Delivery Year requires all emergency or pre-emergency demand resources to be registered as annual capacity resources. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement of the CP design.²⁰

All capacity resources must respond during a Performance Assessment Interval (PAI). Demand resources are the only capacity performance resource that create a PAI when dispatched by PJM. PJM eliminated any substantive difference between pre-emergency and emergency by making the dispatch of either type trigger a PAI.

¹⁹ OA Schedule 1 § 8.5.

²⁰ 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.

The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI unless the product type and lead time type are dispatched by PJM. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI if the area dispatched is not a defined subzone or control zone. Demand resources are not required to meet the same requirements as other capacity resources for the PAI.

Demand resources are also not required to meet the same must offer requirements as other capacity resources. All other capacity resources must offer daily into the day-ahead energy market.

The MMU recommends that if demand resources remain on the supply side of the capacity market, a daily must offer requirement in the day-ahead energy market apply to demand resources, comparable to the rule applicable to generation capacity resources. This will help to ensure comparability and consistency for demand resources.

The MMU recommends 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.²¹

Market Structure

The HHI for demand resources showed that ownership was highly concentrated for the 2019/2020 Delivery Year, with an HHI value of 1840. In the 2019/2020 Delivery Year, the four largest companies contributed 79.1 percent of all committed demand resources UCAP MW in the 2019/2020 Delivery Year. The HHI for demand resources showed that ownership was highly concentrated for the 2020/2021 Delivery Year, with an HHI value of 2171. In the 2020/2021

²¹ 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).

Delivery Year, the four largest companies owned 85.6 percent of all committed demand response UCAP MW.

Table 6-2 shows the HHI value for committed UCAP MW by LDA by delivery year. The HHI values are calculated by the committed UCAP MW in each delivery year for demand resources.

Table 6-2 HHI value for committed UCAP MW by LDA by delivery year: 2019/2020 and 2020/2021 delivery years²²

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
2019/2020	ATSI	713.1	2419	High
	ATSI-CLEVELAND	333.9	2760	High
	BGE	262.4	2181	High
	COMED	1,759.9	2669	High
	DPL-SOUTH	91.3	3037	High
	EMAAC	1,186.7	1949	High
	MAAC	661.3	2232	High
	PEPCO	554.6	4517	High
	PPL	741.4	2003	High
	PS-NORTH	176.5	2198	High
	PSEG	204.7	2163	High
	RTO	4,017.3	2112	High
2020/2021	ATSI	719.8	2247	High
	ATSI-CLEVELAND	231.9	3848	High
	BGE	249.5	2217	High
	COMED	1,657.3	2732	High
	DAY	241.5	3161	High
	DEOK	184.7	3664	High
	DPL-SOUTH	72.6	3010	High
	EMAAC	757.3	2291	High
	MAAC	557.8	2142	High
	PEPCO	236.3	2522	High
	PPL	616.6	2083	High
	PS-NORTH	152.7	2232	High
	PSEG	186.3	1747	Moderate
	RTO	3,581.4	2384	High

Market Performance

Table 6-3 shows the cleared Demand Resource UCAP MW by delivery year. Total cleared demand response UCAP MW in PJM decreased by 1,257.4 MW, or 11.7 percent, from 10,703.1 MW in the 2019/2020 Delivery Year to 9,445.7

²² The RTO LDA refers to the rest of RTO.

MW in the 2020/2021 Delivery Year. The DR percent of capacity decreased by 0.6 percentage points, from 6.0 percent in the 2019/2020 Delivery Year to 5.4 percent in the 2020/2021 Delivery Year.

Table 6-3 Cleared Demand Resource UCAP MW for PJM: 2007/2008 through 2020/2021 delivery year

	UCAP (MW)		
	DR RPM Cleared	Total RPM Cleared	DR Percent Cleared
2007/2008	127.6	129,409.2	0.1%
2008/2009	559.4	130,629.8	0.4%
2009/2010	892.9	134,030.2	0.7%
2010/2011	962.9	134,036.2	0.7%
2011/2012	1,826.6	134,139.6	1.4%
2012/2013	8,740.9	141,061.8	6.2%
2013/2014	10,779.6	159,830.5	6.7%
2014/2015	14,943.0	161,092.4	9.3%
2015/2016	15,453.7	173,487.4	8.9%
2016/2017	13,265.3	179,749.0	7.4%
2017/2018	11,870.5	180,590.3	6.6%
2018/2019	11,435.4	175,957.4	6.5%
2019/2020	10,703.1	177,040.6	6.0%
2020/2021	9,445.7	173,688.5	5.4%

Table 6-4 shows zonal monthly capacity market revenue to demand resources for the first nine months of 2020. Capacity market revenue decreased in the first nine months of 2020 by \$119.5 million, 30.7 percent, from \$389.0 million in the first nine months of 2019 to \$269.4 million in the first nine months of 2020. Lower demand resource revenues were a result of lower capacity market prices in the 2019/2020 and 2020/2021 RPM auctions. The capacity revenue in the first nine months of 2019 is from the 2018/2019 and 2019/2020 RPM auction clearing prices and the capacity revenue in the first nine months of 2020 is from the 2019/2020 and 2020/2021 RPM auction clearing prices. The annual capacity market prices decreased \$23.47 per MW-day from \$100.00 in the 2019/2020 Delivery Year to \$76.53 in the 2020/2021 Delivery Year, a 23.5 percent decrease.

Table 6-4 Zonal monthly capacity revenue: January through September, 2020

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	\$451,066	\$421,965	\$451,066	\$436,515	\$451,066	\$353,042	\$364,810	\$364,810	\$353,042	\$3,647,381
AEP, EKPC	\$3,996,832	\$3,738,972	\$3,996,832	\$3,867,902	\$3,996,832	\$3,202,784	\$3,309,544	\$3,309,544	\$3,202,784	\$32,622,027
APS	\$2,361,289	\$2,208,948	\$2,361,289	\$2,285,119	\$2,361,289	\$1,732,456	\$1,790,204	\$1,790,204	\$1,732,456	\$18,623,254
ATSI	\$2,422,538	\$2,266,246	\$2,422,538	\$2,344,392	\$2,422,538	\$1,821,792	\$1,882,518	\$1,882,518	\$1,821,792	\$19,286,872
BGE	\$651,153	\$609,143	\$651,153	\$630,148	\$651,153	\$453,083	\$468,186	\$468,186	\$453,083	\$5,035,285
ComEd	\$9,961,211	\$9,318,552	\$9,961,211	\$9,639,882	\$9,961,211	\$8,192,692	\$8,465,782	\$8,465,782	\$8,192,693	\$82,159,017
DAY	\$551,678	\$516,086	\$551,678	\$533,882	\$551,678	\$450,951	\$465,983	\$465,983	\$450,951	\$4,538,873
DEOK	\$628,567	\$588,015	\$628,567	\$608,291	\$628,567	\$567,208	\$586,115	\$586,115	\$567,208	\$5,388,652
DLCO	\$1,818,792	\$1,701,451	\$1,818,792	\$1,760,122	\$1,818,792	\$1,733,857	\$1,791,652	\$1,791,652	\$1,733,857	\$15,968,968
Dominion	\$1,171,216	\$1,095,654	\$1,171,216	\$1,133,435	\$1,171,216	\$940,665	\$972,021	\$972,021	\$940,665	\$9,568,110
DPL	\$619,442	\$579,478	\$619,442	\$599,460	\$619,442	\$370,874	\$383,237	\$383,237	\$370,874	\$4,545,487
JCPL	\$626,062	\$585,671	\$626,062	\$605,867	\$626,062	\$791,309	\$817,686	\$817,686	\$791,309	\$6,287,714
Met-Ed	\$801,598	\$749,882	\$801,598	\$775,740	\$801,598	\$624,134	\$644,939	\$644,939	\$624,134	\$6,468,563
OVEC	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
PECO	\$1,635,718	\$1,530,188	\$1,635,718	\$1,582,953	\$1,635,718	\$2,064,206	\$2,133,013	\$2,133,013	\$2,064,206	\$16,414,735
PENLEEC	\$857,760	\$802,420	\$857,760	\$830,090	\$857,760	\$800,092	\$826,762	\$826,762	\$800,092	\$7,459,498
Pepco	\$147,322	\$137,817	\$147,322	\$142,570	\$147,322	\$418,494	\$432,443	\$432,443	\$418,494	\$2,424,227
PPL	\$1,862,026	\$1,741,895	\$1,862,026	\$1,801,961	\$1,862,026	\$1,542,983	\$1,594,416	\$1,594,416	\$1,542,983	\$15,404,734
PSEG	\$1,196,021	\$1,118,858	\$1,196,021	\$1,157,439	\$1,196,021	\$1,840,639	\$1,901,994	\$1,901,994	\$1,840,639	\$13,349,626
RECO	\$31,919	\$29,860	\$31,919	\$30,889	\$31,919	\$21,883	\$22,613	\$22,613	\$21,883	\$245,497
Total	\$31,792,211	\$29,741,101	\$31,792,211	\$30,766,656	\$31,792,211	\$27,923,146	\$28,853,918	\$28,853,918	\$27,923,146	\$269,438,518

Pre-Emergency and Emergency Load Response resources must register all resources to respond within 30, 60 or 120 minutes of a PJM dispatched event. The quick lead time, or 30 minute lead time, is the default lead time, unless a CSP submits an exception request for 60 or 120 minute notification time based on a physical constraint.²³ 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 18.²⁴ 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 6-5 shows the amount of nominated MW and locations by product type and lead time for the 2019/2020 Delivery Year. Nominated MW are Pre-Emergency or Emergency Load Response registrations used to satisfy a CSP's committed MW position for a delivery year. PJM approved 3,114 locations, or 20.9 percent of all locations, which have 3,908.0 nominated MW, or 40.6 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2019/2020 Delivery Year.

²³ See "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 45 (May 28, 2020).

²⁴ See "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 45 (May 28, 2020).

Table 6-5 Nominated MW and locations by product type and lead time: 2019/2020 Delivery Year

Pre-Emergency MW				Emergency MW			
Lead Type	Base	Capacity	Pre-Emergency	Base	Capacity	Emergency	Total
		Performance	Total		Performance	Total	
Quick Lead (30 Minutes)	5,292.4	159.1	5,451.5	238.4	17.7	256.1	5,707.6
Short Lead (60 Minutes)	326.7	36.3	363.0	27.2	0.0	27.2	390.3
Long Lead (120 Minutes)	2,939.8	428.2	3,368.0	148.3	1.4	149.8	3,517.8
Total	8,558.9	623.6	9,182.6	414.0	19.1	433.1	9,615.7

Pre-Emergency Locations				Emergency Locations			
Lead Type	Base	Capacity	Pre-Emergency	Base	Capacity	Emergency	Total
		Performance	Total		Performance	Total	
Quick Lead (30 Minutes)	10,887	356	11,243	513	26	539	11,782
Short Lead (60 Minutes)	289	8	297	52	0	52	349
Long Lead (120 Minutes)	2,052	425	2,477	285	3	288	2,765
Total	13,228	789	14,017	850	29	879	14,896

Table 6-6 shows the amount of nominated MW and locations by product type and lead time for the 2020/2021 Delivery Year. PJM approved 3,105 locations, or 21.3 percent of all locations, which have 3,548.6 nominated MW, or 45.0 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2020/2021 Delivery Year.

Table 6-6 Nominated MW and locations by product type and lead time: 2020/2021 Delivery Year

Pre-Emergency MW				Emergency MW			
Lead Type	Capacity	Pre-Emergency	Capacity	Emergency		Emergency	
	Performance	Total	Performance	Total	Total	Total	Total
Quick Lead (30 Minutes)	4,097.2	4,097.2	240.6	240.6	4,337.9	256.1	5,707.6
Short Lead (60 Minutes)	326.9	326.9	28.8	28.8	355.7	27.2	390.3
Long Lead (120 Minutes)	3,043.0	3,043.0	150.0	150.0	3,192.9	149.8	3,517.8
Total	7,467.1	7,467.1	419.4	419.4	7,886.5	433.1	9,615.7

Pre-Emergency Locations				Emergency Locations			
Lead Type	Capacity	Pre-Emergency	Capacity	Emergency		Emergency	
	Performance	Total	Performance	Total	Total	Total	Total
Quick Lead (30 Minutes)	10,995	10,995	472	472	11,467	539	11,782
Short Lead (60 Minutes)	315	315	39	39	354	52	349
Long Lead (120 Minutes)	2,476	2,476	275	275	2,751	288	2,765
Total	13,786	13,786	786	786	14,572	879	14,896

There are two ways to measure load reductions of demand resources. The Firm Service Level (FSL) method, applied to the summer, measures the difference between a customer's peak load contribution (PLC) and its real-time load, multiplied by the loss factor (LF).²⁵ 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

²⁵ Real-time load is hourly metered load.

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.²⁶ With the introduction of the Winter Peak Load (WPL) concept, effective for the 2017/2018 Delivery Year, both the FSL and GLD methods are modified for the non-summer period. The FSL method measures compliance during the non-summer period as the difference between a customer's WPL multiplied by the Zonal Winter Weather Adjustment Factor (ZWWAF) and the LF, rather than the PLC, and real-time load, multiplied by the LF. PJM calculates and posts on the PJM website the ZWWAF as the zonal winter weather normalized peak divided by the zonal average of the five coincident peak loads in December through February.²⁷ The Winter Peak Load is adjusted up for transmission and distribution line loss factors because one MW of load would be served by more than one MW of generation to account for transmission losses. The Winter Peak Load is normalized based on the winter conditions during the five coincident peak loads in winter using the ZWWAF to account for an extreme temperatures or a mild winter. The GLD method measures compliance during the non-summer period as the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the WPL multiplied by the ZWWAF and the LF, rather than the PLC, minus the real-time load multiplied by the LF.²⁸

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.²⁹ LSEs generally allocate capacity costs to customers based on the five coincident peak method.³⁰ The allocation of capacity costs to customers uses each customer's PLC. Customers pay for capacity based

on the PLC, not the WPL. If an end customer has 3 MW of load during the coincidental peak load hour, but only 1 MW during the coincidental winter peak load hour, the end use customer must pay for 3 MW of capacity for the entire delivery year, but can only participate as a 1 MW demand response resource. Using PLC to measure compliance the entire delivery year would allow the customer to fully participate as a 3 MW demand response resource. FERC allowed the use of the WPL for calculating compliance for non-summer months effective June 1, 2017.³¹ The MMU recommends setting the baseline for measuring capacity compliance under summer and winter compliance at the customer's PLC, similar to GLD, to avoid double counting, to avoid under counting and to ensure that a customer's purchase of capacity is calculated correctly. The FSL and GLD equations for calculating load reductions are:

$$FSL\ Compliance_{Summer} = PLC - (Load \cdot LF)$$

$$FSL\ Compliance_{Non-Summer} = (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)$$

$$GLD\ Compliance_{Summer} = \text{Minimum}\{(comparison\ load - Load) \cdot LF; PLC - (Load \cdot LF)\}$$

$$GLD\ Compliance_{Non-Summer} = \text{Minimum}\{(comparison\ load - Load) \cdot LF; (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)\}$$

Table 6-7 shows the MW registered by measurement and verification method and by technology type for the 2019/2020 Delivery Year. For the 2019/2020 Delivery Year, 99.7 percent use the FSL method and 0.3 percent use the GLD measurement and verification method.

²⁶ 135 FERC ¶ 61,212.

²⁷ "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 45 (May 28, 2020).

²⁸ "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev.45 (May 28, 2020).

²⁹ OATT Attachment DD.5.11.

³⁰ OATT Attachment M-2.

³¹ 162 FERC ¶ 61,159 (2018).

Table 6-7 Reduction MW by each demand response method: 2019/2020 Delivery Year

Measurement and Verification Method	Technology Type							Total	Percent by type
	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Batteries and Plug Load MW		
Firm Service Level	1,202.7	3,108.6	215.4	861.2	3,963.5	125.5	49.0	9,525.8	99.7%
Guaranteed Load Drop	0.4	12.3	0.0	1.4	15.1	0.1	0.3	29.5	0.3%
Total	1,203.1	3,120.8	215.4	862.6	3,978.5	125.6	49.3	9,555.3	100.0%
Percent by method	12.6%	32.7%	2.3%	9.0%	41.6%	1.3%	0.5%	100.0%	

Table 6-8 shows the MW registered by measurement and verification method and by technology type for the 2020/2021 Delivery Year. For the 2020/2021 Delivery Year, 99.9 percent use the FSL method and 0.1 percent use the GLD measurement and verification method.

Table 6-8 Reduction MW by each demand response method: 2020/2021 Delivery Year

Measurement and Verification Method	Technology Type							Total	Percent by type
	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW		
Firm Service Level	1,225.3	1,842.9	196.0	694.5	3,729.2	61.3	46.0	7,795.1	99.9%
Guaranteed Load Drop	0.3	1.1	0.0	0.0	4.4	0.0	0.3	6.1	0.1%
Total	1,225.5	1,844.0	196.0	694.5	3,733.6	61.3	46.2	7,801.2	100.0%
Percent by method	15.7%	23.6%	2.5%	8.9%	47.9%	0.8%	0.6%	100.0%	

Table 6-9 shows the fuel type used in the onsite generators for the 2019/2020 Delivery Year in the emergency and pre-emergency programs. During the 2019/2020 Delivery Year, 1,203.1 MW of the 9,555.31 nominated MW, 12.6 percent, used onsite generation. Of the 1,203.1 MW, 85.2 percent used diesel and 14.8 percent used natural gas, gasoline, oil, propane or waste products.

Table 6-9 Onsite generation fuel type (MW): 2019/2020 Delivery Year

Fuel Type	2019/2020	
	MW	Percent
Diesel	1,024.5	85.2%
Natural Gas, Gasoline, Oil, Propane, Waste Products	178.7	14.8%
Total	1,203.1	100.0%

Table 6-10 shows the fuel type used in the onsite generators for the 2020/2021 Delivery Year in the emergency and pre-emergency programs. During the 2020/2021 Delivery Year, 1,225.5 MW of the 7,801.2 nominated MW, 15.7 percent, used onsite generation. Of the 1,225.5 MW, 87.1 percent used diesel and 12.9 percent used natural gas, gasoline, oil, propane or waste products.

Table 6-10 Onsite generation fuel type (MW): 2020/2021 Delivery Year

Fuel Type	2020/2021	
	MW	Percent
Diesel	1,066.9	87.1%
Natural Gas, Gasoline, Oil, Propane, Waste Products	158.7	12.9%
Total	1,225.5	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Capacity Performance resources measure performance nodally, except for demand resources. PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

Subzonal dispatch became mandatory for emergency demand resources in the 2014/2015 Delivery Year, if the subzone was defined by PJM no later than the day before the dispatch.³² A subzone is defined by zip code, not by nodal location. If a registration has any location in the dispatched subzone, the entire registration must respond. PJM does not measure compliance when demand response is dispatched in a subzone created on the same day as the dispatch. Subzonal dispatch creates a PAI for the subzone, even if PJM does not measure compliance for demand resources.

There are 13 dispatchable subzones in PJM last updated September 21, 2018: AEP_CANTON, ATSI_CLE, DPL_SOUTH, PS_NORTH, ATSI_NEWCASOE, PPL_WESCO, ATSI_BLKRIIVER, PENELEC_ERIC, APS_EAST, DOM_CHES, DOM_

YORKTOWN, AECO_ENGLAND, and JCPL_REDBANK.³³ 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.³⁴

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.³⁵ PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR would not otherwise set price under the fundamental LMP logic. Of the 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of allowing emergency DR to set price.³⁶ 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.

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

³³ See "Load Management Subzones," <<http://www.pjm.com/~media/markets-ops/demand-response/subzone-definition-workbook.ashx>> (Accessed January 21, 2020).

³⁴ OATT Attachment DD, Section 10A.

³⁵ See PJM/Alstom, "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software, Docket No. AD10-12-006 (June 23, 2015) <<http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf>>.

³⁶ 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.

³² OATT Attachment DD, Section 11.

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 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.³⁷

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).³⁸ 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 6-11 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin as of June 1, for 2017, 2018, 2019 and 2020. There are 7,801.2 nominated MW of demand response for the 2020/2021 Delivery Year, 36.9 percent of the required reserve margin and 20.0 percent of the actual reserve margin on June 1, 2020.³⁹

Table 6-11 Demand response nominated MW compared to reserve margin: June 1, 2017 through 2020

	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%
01-Jun-19	9,547.1	22,297.5	42.8%	33,421.9	28.6%
01-Jun-20	7,801.2	21,127.9	36.9%	33,039.8	23.6%

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 Action Area (EAA).^{40 41} 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

³⁷ "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 45 (May 28, 2020).

³⁸ OATT § 1 (Performance Assessment Hour).

³⁹ 2018 State of the Market Report for PJM, Volume 2, Section 5: Capacity, Table 5-7.

⁴⁰ 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.

⁴¹ PJM, "Manual 18: Capacity Market," § 8.7.2, Rev. 45 (May 28, 2020).

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.⁴²

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 not limit the compliance calculation value to a zero MW reduction value.⁴³ 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.

⁴² OA Schedule 1 § 8.9.

⁴³ OA Schedule 1 § 8.9.

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.⁴⁴ 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.

The CBL for a customer is an estimate of what load would have been if the customer had not responded to LMP and reduced load. The difference between the CBL and real-time load is the energy reduction. When load responds to LMP by using a behind the meter generator, the energy reduction should be capped at the generation output. Any additional energy reduction is a result of inaccuracy in the CBL estimate rather than an actual reduction. The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to

⁴⁴ 157 FERC ¶ 61,067 (2016).

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.”⁴⁵ Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as emergency or pre-emergency load response customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events. Three proposals that included language to remove bankrupt customers from a CSP’s portfolio failed at the June 7, 2017, Market Implementation Committee.⁴⁶ The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

The metering requirement for demand resources is outdated, and has not kept up with the changes to PJM’s market design. PJM moved to five minute settlements, but the metering requirement for demand resources remained at an hourly interval meter. It is impossible to measure energy usage on a five minute basis using an hourly interval meter. PJM will estimate real-time usage by prorating the hourly interval meter and assume if load is less than the CBL, that the reduction occurred during the required dispatch window. The meter reading is not telemetered to PJM in real time. The resource is allowed up to 60 days to report the data to PJM. The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that

⁴⁵ OA Schedule 1 § 8.2.

⁴⁶ 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>>.

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.⁴⁷

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment.⁴⁸ 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 6-12 shows the test penalties by delivery year by product type for the 2015/2016 Delivery Year through the 2019/2020 Delivery Year.⁴⁹ 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 6-12 Test penalties by delivery year by product type: 2015/2016 through 2019/2020

Product Type	2015/2016			2016/2017			2017/2018			2018/2019			2019/2020		
	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty
Limited	96.4	\$165.35	\$5,836,255	48.9	\$166.41	\$2,967,158	13.9	\$124.08	\$631,665	0.0	\$179.80	\$2,100			
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 DR and EE										16.3	\$186.80	\$1,110,134	30.2	\$154.69	\$1,712,177
Capacity Performance				2.1	\$160.80	\$124,310	0.6	\$181.80	\$40,146	2.6	\$188.55	\$178,795			
Total	102.0	\$166.02	\$6,200,711	63.1	\$160.72	\$3,703,163	41.3	\$137.54	\$2,075,678	18.9	\$187.03	\$1,291,030	30.2	\$154.69	\$1,712,177

Emergency and Pre-Emergency Load Response Energy Payments

Emergency and pre-emergency demand response dispatched during a load management event by PJM are eligible to receive emergency energy payments if registered under the full program option. The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments.⁵⁰ There were 98.2 percent of nominated MW for the 2019/2020 Delivery Year registered under the full program option. There were 1.8 percent of nominated MW for the 2019/2020 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

⁴⁷ 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.

⁴⁸ 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: PJM Capacity Market," Rev. 45 (May 28, 2020).

⁴⁹ Not all products received penalties or existed in every delivery year. For example, the Base and Capacity Performance products were not an option for the 2015/2016 Delivery Year.

⁵⁰ *Id.*

before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. Demand resources should not be permitted to offer above \$1,000 per MWh without cost justification or to include a shortage penalty in the offer. FERC has stated clearly that demand resources in the capacity market must verify costs above \$1,000 per MWh, unless they are capacity only: “We clarify, however, that reforms adopted in this Final Rule, which provide that resources are eligible to submit cost-based incremental energy offers in excess of \$1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit incremental energy offers in energy markets.”⁵¹ PJM interprets the scarcity pricing rules to allow a maximum DR energy price of \$1,849 per MWh for the 2019/2020 Delivery Year.^{52 53} 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.⁵⁴ 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.⁵⁵

Table 6-13 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2019/2020 Delivery Year. The majority of participants, 75.2 percent of locations and 56.6 percent of nominated MW, have a minimum dispatch price between \$1,550 and \$1,849 per MWh, the maximum price allowed for the 2019/2020 Delivery Year, 3.6 percent of locations and 3.6 percent of

nominated MW have a dispatch price between \$0 and \$1,000 per MWh, and 96.4 percent of locations and 96.4 percent of nominated MW have a dispatch price above \$1,000 per MWh. The shutdown cost of resources with \$1,000 to \$1,275 per MWh strike prices had the highest average at \$181.18 per location and \$142.07 per nominated MW.

Table 6-13 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2019/2020 Delivery Year

Ranges of Strike Prices (\$/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
\$0-\$1,000	530	3.6%	339.5	3.6%	\$46.98	\$86.48
\$1,000-\$1,275	2,766	18.8%	3,385.2	36.0%	\$181.18	\$142.07
\$1,275-\$1,550	350	2.4%	364.9	3.9%	\$57.49	\$55.14
\$1,550-\$1,849	11,069	75.2%	5,323.3	56.6%	\$49.79	\$103.53
Total	14,715	100.0%	9,412.8	100.0%	\$74.57	\$116.57

Table 6-14 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2020/2021 Delivery Year. The majority of participants, 76.7 percent of locations and 52.9 percent of nominated MW, have a minimum dispatch price between \$1,550 and \$1,849 per MWh, the maximum price allowed for the 2020/2021 Delivery Year, 1.7 percent of locations and 2.9 percent of nominated MW have a dispatch price between \$0 and \$1,000 per MWh, and 98.3 percent of locations and 97.1 percent of nominated MW have a dispatch price above \$1,000 per MWh. The shutdown cost of resources with \$1,000 to \$1,275 per MWh strike prices had the highest average at \$154.45 per location and \$136.42 per nominated MW.

Table 6-14 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2020/2021 Delivery Year

Ranges of Strike Prices (\$/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
\$0-\$1,000	243	1.7%	222.4	2.9%	\$68.14	\$30.96
\$1,000-\$1,275	2,771	19.2%	3,102.7	39.8%	\$154.45	\$136.42
\$1,275-\$1,550	355	2.5%	345.0	4.4%	\$53.93	\$55.49
\$1,550-\$1,849	11,077	76.7%	4,118.9	52.9%	\$54.39	\$146.27
Total	14,446	100.0%	7,788.9	100.0%	\$73.80	\$136.88

51 161 FERC ¶ 61,153 at P 8 (2017).

52 139 FERC ¶ 61,057 (2012).

53 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.

54 OATT Attachment K Appendix Section 1.10.1A Day-ahead Energy Market Scheduling (d) (x).

55 “PJM Manual 15: Cost Development Guidelines,” § 8.1, Rev. 35 (Apr. 24, 2020).

PRD

The PRD rules are more aligned with the Capacity Performance construct effective December 30, 2019, although the rules still fall short.⁵⁶ PJM's initial filing was rejected by the Commission based on the MMU's comments and PJM's modified filing was accepted.⁵⁷ PJM's final filing adopted the MMU's recommendation to exclude the use of Winter Peak Load (WPL) when calculating the nominated MW for PRD resources used to satisfy RPM commitments. Load is allocated capacity obligations based on the annual peak load within PJM. The amount of capacity allocated to load is a function solely of summer coincident peak demand and is unaffected by winter demand. Use of the WPL to calculate the nominated MW for PRD resources to satisfy RPM commitments, would incorrectly restrict PRD to less than the total capacity the customer is required to buy. PJM's adoption of the MMU recommendation will correctly value PRD nominated MW. FERC required and PJM's filing also adopted the MMU's recommendation that PRD should be eligible for bonus performance payments during Performance Assessment Intervals (PAI) only when PRD resources respond above their nominated MW value. Allowing PRD resources to collect bonus payments at times when they are not even required to meet their basic obligation would be inconsistent with the basic CP construct as it applies to all other CP resources.⁵⁸

PJM's filing still fell short of completely aligning PRD with the Capacity Performance product. PRD resources will not have to respond during a PAI if the PAI's trigger price is above LMP during the PAI. All other CP resources have the obligation to perform during a PAI, regardless of the real-time LMP, subject to instructions from PJM. PRD should be held to the same standard during a PAI event.

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.⁵⁹ 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 resources. PRD first cleared the capacity market in the BRA for the 2020/2021 Delivery Year, and cleared for the 2021/2022 Delivery Year.⁶⁰

Economic Load Response Program

The Economic Load Response Program is for demand response customers that offer into the day-ahead or real-time energy market. The estimated load reduction is paid the zonal LMP, as long as the zonal LMP is greater than the monthly Net Benefits Test threshold.

Market Structure

The ownership of economic demand response resources was highly concentrated in 2019 and the first nine months of 2020.⁶¹ Table 6-15 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2019, through September 30, 2020. Table 6-15 lists the share of reported reductions provided by, and the share of credits claimed by the four largest CSPs in each year. In the first nine months of 2020, 82.1 percent of all economic DR reported reductions and 87.5 percent of economic DR revenue were attributable to the four largest CSPs. The HHI for economic demand response was highly concentrated for the first nine months of 2020. The HHI for economic demand response increased by 669 from 8261 for 2019 to 8930 for the first nine months of 2020.

⁵⁶ See "Compliance Filing Regarding Price Responsive Demand Rules," Docket No. ER20-271-001 (February 28, 2020).

⁵⁷ See "Order Rejecting Tariff Revisions," Docket No. ER19-1012-000 (June 27, 2019).

⁵⁸ October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).

⁵⁹ The Demand Response Subcommittee (DRS) is currently working to align PRD with the CP designed products.

⁶⁰ 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>>.

⁶¹ All HHI calculations in this section are at the parent company level.

Table 6-15 Average hourly MWh HHI and market concentration in the economic program: January 2019 through September 2020⁶²

Month	Average Hourly MWh HHI			Top Four CSPs Share of Reduction			Top Four CSPs Share of Credit		
	2019	2020	Percent Change	2019	2020	Change in Percent	2019	2020	Change in Percent
Jan	6884	8983	30.5%	82.1%	98.1%	16.0%	78.1%	98.3%	20.3%
Feb	9382	9652	2.9%	94.7%	100.0%	5.3%	90.7%	100.0%	9.3%
Mar	7758	9857	27.1%	99.3%	100.0%	0.7%	99.1%	100.0%	0.9%
Apr	7457	10000	34.1%	99.4%			99.8%		
May	7875	9926	26.0%	99.9%			99.9%		
Jun	9623	8976	(6.7%)	99.9%	100.0%	0.0%	100.0%	99.9%	(0.1%)
Jul	8035	8442	5.1%	88.8%	88.8%	(0.0%)	86.1%	89.1%	3.0%
Aug	9390	8357	(11.0%)	99.9%	93.6%	(6.4%)	100.0%	92.8%	(7.2%)
Sep	9513	10000	5.1%	99.5%			99.6%		
Oct	9400			99.9%			99.6%		
Nov	8121			96.3%			95.4%		
Dec	7745			93.8%			90.9%		
Total	8261	8930	8.1%	81.5%	82.1%	0.5%	74.0%	87.5%	13.5%

Market Performance

Table 6-16 shows the total MW reported reductions made by participants in the economic program and the total credits paid for these reported reductions in the first nine months of 2010 through 2020. The average credits per MWh paid decreased by \$7.66 per MWh, 18.6 percent, from \$41.21 per MWh in the first nine months of 2019 to \$33.55 per MWh in the first nine months of 2020. The PJM real-time, load-weighted, average LMP was 23.1 percent lower in the first nine months of 2020 than in the first nine months of 2019, \$27.60 per MWh versus \$21.22 per MWh. Curtailed energy for the economic program decreased by 13,117 MWh, 62.9 percent, from 20,867 MWh in the first nine months of 2019 to 7,750 MWh in the first nine months of 2020. Total credits paid for the economic load response program in the first nine months of 2020 decreased by \$0.6 million, 69.8 percent, from \$0.9 million in the first nine months of 2019 to \$0.3 million in the first nine months of 2020.

Low energy prices decreased the incentive for economic load response to participate in the energy market. Lockdown orders for areas within PJM restricted normal activity for many economic participants which decreased

⁶² April, May and June 2020 reduction and credit share percent are redacted based on confidentiality rules.

the opportunity for economic load response. The first nine months of 2020 had the least amount of economic load response since 2010.

Table 6-16 Credits paid to the PJM economic program participants: January through September, 2010 through 2020

(Jan-Sep)	Total MWh	Total Credits	\$/MWh
2010	58,280	\$2,677,937	\$45.95
2011	15,376	\$1,943,507	\$126.40
2012	121,381	\$8,172,654	\$67.33
2013	105,299	\$7,387,658	\$70.16
2014	118,007	\$16,510,733	\$139.91
2015	103,721	\$7,355,263	\$70.91
2016	67,516	\$3,032,039	\$44.91
2017	49,331	\$2,167,590	\$43.94
2018	44,735	\$2,360,007	\$52.76
2019	20,867	\$860,018	\$41.21
2020	7,750	\$260,034	\$33.55

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.⁶³ 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.⁶⁴ 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.

⁶³ PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 109 (Oct. 15, 2020).

⁶⁴ FERC Order No. 831.

Figure 6-2 shows monthly economic demand response credits and MWh, from January 1, 2010, through September 30, 2020.

Figure 6-2 Economic program credits and MWh by month: 2010 through September 2020

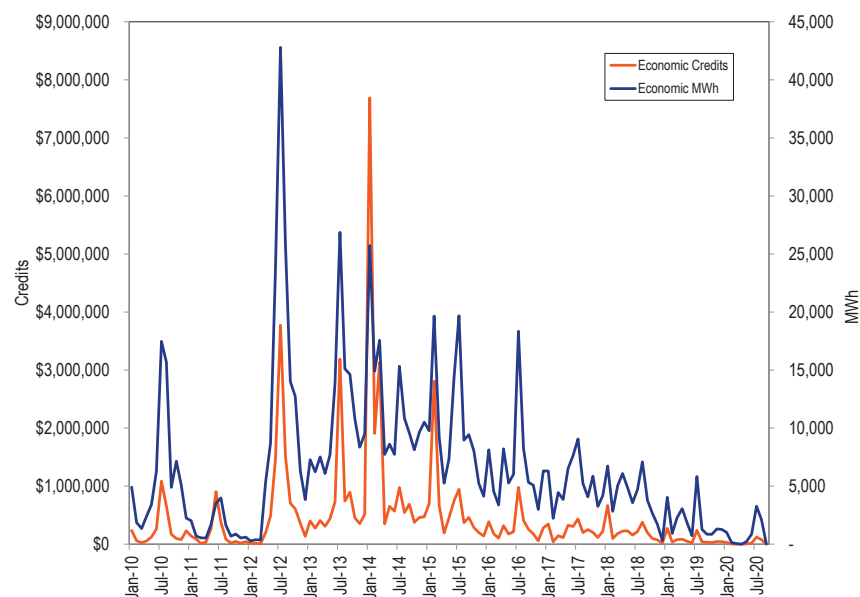


Table 6-17 shows performance for the first nine months of 2019 and 2020 in the economic program by control zone. Total reported reductions under the economic program decreased by 13,015 MWh, 62.4 percent, from 20,867 MWh in the first nine months of 2019 to 7,852 MWh in the first nine months of 2020. Total revenue under the economic program decreased by \$0.6 million, 69.8 percent, from \$0.9 million in the first nine months of 2019 to \$0.3 million in the first nine months of 2020.⁶⁵

⁶⁵ Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in . Payments for Economic demand response reductions are settled monthly.

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.⁶⁶ The zonal allocation is shown in Table 6-17.

⁶⁶ "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 83 (Dec. 3, 2019).

Table 6-17 PJM economic program participation by zone: January through September, 2019 and 2020

Zones	Credits			MWh Reductions			Credits per MWh Reduction		
	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change
AECO	\$1,353.78	\$0.00	NA	41	0	NA	\$33.27	NA	NA
AEP	\$4,777.47	\$880.95	(81.6%)	107	18	(83.2%)	\$44.59	\$48.95	9.8%
APS	\$140.53	\$12,356.22	8,692.6%	2	210	12,599.7%	\$84.84	\$58.74	(30.8%)
ATSI	\$9,355.23	\$26,170.70	179.7%	157	302	92.5%	\$59.71	\$86.77	45.3%
BGE	\$96,681.98	\$0.00	NA	2,352	0	NA	\$41.11	NA	NA
ComEd	\$5,938.46	\$118,682.91	1,898.5%	205	3,690	1,699.6%	\$28.96	\$32.16	11.1%
DAY	\$0.00	\$0.00	NA	0	0	NA	NA	NA	NA
DEOK	\$6,696.16	\$0.00	NA	100	0	NA	\$67.19	NA	NA
DLCO	\$0.00	\$0.00	NA	0	0	NA	NA	NA	NA
Dominion	\$267.33	\$505.67	89.2%	4	42	1,028.8%	\$71.78	\$12.03	(83.2%)
DPL	\$4,916.92	\$10,800.39	119.7%	150	138	(8.2%)	\$32.74	\$78.37	139.3%
JCPL	\$16,793.13	\$577.40	(96.6%)	338	305	(9.7%)	\$49.66	\$1.89	(96.2%)
Met-Ed	\$29,124.44	\$11,263.79	(61.3%)	666	300	(54.9%)	\$43.76	\$37.51	(14.3%)
OVEC	\$0.00	\$0.00	NA	0	0	NA	NA	NA	NA
PECO	\$126,377.00	\$10,021.03	(92.1%)	2,133	242	(88.6%)	\$59.25	\$41.40	(30.1%)
PENELEC	\$137,404.51	\$28,704.94	(79.1%)	4,176	1,020	(75.6%)	\$32.90	\$28.14	(14.5%)
Pepco	\$10,239.62	\$40.33	(99.6%)	314	1	(99.7%)	\$32.60	\$50.56	55.1%
PPL	\$150,797.21	\$136.91	(99.9%)	2,417	76	(96.9%)	\$62.38	\$1.81	(97.1%)
PSEG	\$259,154.45	\$39,893.19	(84.6%)	7,706	1,508	(80.4%)	\$33.63	\$26.46	(21.3%)
RECO	\$0.00	\$0.00	NA	0	0	NA	NA	NA	NA
Total	\$860,018.22	\$260,034.43	(69.8%)	20,867	7,852	(62.4%)	\$41.21	\$33.12	(19.6%)

Table 6-18 shows average reported MWh reductions and credits by hour for the first nine months of 2019 and 2020. The average LMP during Load Response is the reduction weighted average hourly DA or RT load weighted LMP during the economic load response hour. In the first nine months of 2019, 89.8 percent of the reported reductions and 86.2 percent of credits occurred in hours ending 0900 to 2100, and in the first nine months of 2020, 98.2 percent of the reported reductions and 98.0 percent of credits occurred in hours ending 0900 to 2100.

Table 6-18 Hourly frequency distribution of economic program reported MWh reductions and credits: January through September, 2019 and 2020

Hour Ending (EPT)	MWh Reductions			Program Credits			Average LMP during Load Response		
	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change
1 through 6	522	(1)	(100%)	\$31,808	(\$12)	(100%)	\$57.11	\$23.90	(58%)
7	264	12	(96%)	\$17,158	\$451	(97%)	\$60.97	\$35.32	(42%)
8	471	84	(82%)	\$29,217	\$3,642	(88%)	\$61.32	\$39.65	(35%)
9	786	119	(85%)	\$32,979	\$3,482	(89%)	\$42.79	\$27.03	(37%)
10	917	142	(84%)	\$33,749	\$3,847	(89%)	\$36.63	\$25.10	(31%)
11	1,063	166	(84%)	\$40,020	\$4,229	(89%)	\$36.13	\$26.72	(26%)
12	1,126	479	(57%)	\$35,890	\$12,446	(65%)	\$35.42	\$27.22	(23%)
13	1,169	676	(42%)	\$40,189	\$18,621	(54%)	\$34.54	\$29.88	(13%)
14	1,515	805	(47%)	\$53,294	\$25,407	(52%)	\$34.52	\$33.85	(2%)
15	1,572	991	(37%)	\$54,176	\$30,099	(44%)	\$33.80	\$37.49	11%
16	1,785	1,013	(43%)	\$64,069	\$32,614	(49%)	\$35.02	\$38.84	11%
17	2,125	1,100	(48%)	\$84,164	\$42,699	(49%)	\$40.76	\$43.83	8%
18	2,151	1,063	(51%)	\$110,783	\$44,661	(60%)	\$44.28	\$43.88	(1%)
19	1,836	826	(55%)	\$77,967	\$28,384	(64%)	\$41.46	\$35.85	(14%)
20	1,381	225	(84%)	\$56,429	\$5,646	(90%)	\$37.64	\$27.55	(27%)
21	1,313	104	(92%)	\$57,380	\$2,587	(95%)	\$38.51	\$26.75	(31%)
22	562	34	(94%)	\$25,789	\$988	(96%)	\$39.04	\$25.82	(34%)
23 through 24	309	13	(96%)	\$14,956	\$246	(98%)	\$37.39	\$37.33	(0%)
Total	20,867	7,852	(62%)	\$860,018	\$260,034	(70%)	\$41.52	\$32.56	(19%)

Table 6-19 shows the distribution of economic program reported MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in the first nine months of 2019 and 2020. In the first nine months of 2020, 0.8 percent of reported MWh reductions and 4.7 percent of program credits occurred during hours when the applicable zonal LMP was higher than \$175 per MWh.

Table 6-19 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): January through September, 2019 and 2020

LMP	MWh Reductions			Program Credits		
	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change	2019 (Jan-Sep)	2020 (Jan-Sep)	Percent Change
\$0 to \$25	4,705	3,120	(34%)	\$119,387	\$78,066	(35%)
\$25 to \$50	12,317	3,563	(71%)	\$451,029	\$115,635	(74%)
\$50 to \$75	2,155	682	(68%)	\$130,962	\$30,641	(77%)
\$75 to \$100	759	177	(77%)	\$57,811	\$4,892	(92%)
\$100 to \$125	456	137	(70%)	\$42,373	\$6,378	(85%)
\$125 to \$150	145	68	(53%)	\$12,448	\$8,792	(29%)
\$150 to \$175	124	46	(63%)	\$14,682	\$3,368	(77%)
> \$175	207	59	(71%)	\$31,327	\$12,263	(61%)
Total	20,867	7,852	(62%)	\$860,018	\$260,034	(70%)

Economic Load Response revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-20 shows the sum of real-time Economic Load Response charges and day-ahead DR charges paid in each zone and paid by exports. Real-time loads in AEP paid the highest Economic Load Response charges in the first nine months of 2020.

Table 6-20 Zonal Economic Load Response charge: January through September, 2020

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	\$307	\$22	\$12	\$2	\$53	\$228	\$1,818	\$1,074	\$17	\$3,534
AEP	\$4,802	\$459	\$191	\$31	\$1,004	\$2,311	\$17,307	\$11,729	\$155	\$37,987
APS	\$1,908	\$180	\$74	\$13	\$386	\$917	\$6,843	\$4,593	\$58	\$14,970
ATSI	\$2,392	\$229	\$103	\$16	\$547	\$1,219	\$9,511	\$6,312	\$84	\$20,415
BGE	\$1,244	\$110	\$40	\$8	\$236	\$745	\$4,986	\$3,212	\$43	\$10,624
ComEd	\$3,134	\$256	\$141	\$24	\$654	\$1,852	\$14,783	\$9,107	\$92	\$30,042
DAY	\$725	\$64	\$26	\$4	\$141	\$350	\$2,518	\$1,656	\$24	\$5,508
DEOK	\$945	\$94	\$39	\$6	\$224	\$542	\$3,958	\$2,585	\$37	\$8,430
DLCO	\$468	\$45	\$20	\$3	\$118	\$276	\$2,134	\$1,416	\$18	\$4,498
Dominion	\$3,927	\$364	\$133	\$25	\$792	\$2,134	\$15,660	\$10,201	\$141	\$33,377
DPL	\$698	\$50	\$24	\$3	\$97	\$386	\$2,990	\$1,718	\$27	\$5,994
EKPC	\$526	\$53	\$18	\$3	\$98	\$236	\$1,735	\$1,165	\$16	\$3,851
JCPL	\$762	\$61	\$30	\$4	\$170	\$544	\$4,162	\$2,501	\$36	\$8,269
Met-Ed	\$587	\$46	\$22	\$4	\$115	\$344	\$2,267	\$1,550	\$19	\$4,956
OVEC	\$4	\$0	\$0	\$0	\$1	\$2	\$11	\$8	\$0	\$26
PECO	\$1,374	\$93	\$53	\$7	\$230	\$804	\$6,078	\$3,593	\$54	\$12,285
PENELEC	\$574	\$56	\$25	\$5	\$134	\$306	\$2,291	\$1,522	\$19	\$4,931
Pepco	\$1,146	\$102	\$39	\$7	\$210	\$646	\$4,466	\$2,926	\$40	\$9,581
PPL	\$1,319	\$113	\$59	\$11	\$296	\$825	\$5,608	\$3,773	\$47	\$12,052
PSEG	\$1,456	\$123	\$59	\$8	\$318	\$927	\$7,053	\$4,343	\$62	\$14,349
RECO	\$47	\$4	\$2	\$0	\$12	\$35	\$282	\$169	\$2	\$553
Exports	\$1,955	\$127	\$62	\$11	\$325	\$967	\$6,114	\$4,187	\$54	\$13,803
Total	\$30,300	\$2,651	\$1,173	\$197	\$6,161	\$16,596	\$122,573	\$79,339	\$1,045	\$260,034

Table 6-21 shows the total zonal Economic Load Response charge per GWh of real-time load and exports in the first nine months of 2020.

Table 6-21 Zonal Economic Load Response charge per GWh of load and exports: January through September, 2020

Zone	January	February	March	April	May	June	July	August	September	Zonal Average
AECO	\$0.401	\$0.033	\$0.018	\$0.134	\$0.086	\$0.263	\$0.134	\$0.000	\$0.000	\$0.119
AEP	\$0.430	\$0.044	\$0.019	\$0.141	\$0.113	\$0.234	\$0.141	\$0.000	\$0.000	\$0.125
APS	\$0.431	\$0.044	\$0.019	\$0.142	\$0.112	\$0.243	\$0.142	\$0.000	\$0.000	\$0.126
ATSI	\$0.426	\$0.044	\$0.020	\$0.141	\$0.120	\$0.229	\$0.141	\$0.000	\$0.000	\$0.124
BGE	\$0.464	\$0.045	\$0.018	\$0.155	\$0.113	\$0.287	\$0.155	\$0.000	\$0.000	\$0.138
ComEd	\$0.392	\$0.034	\$0.020	\$0.130	\$0.100	\$0.227	\$0.130	\$0.000	\$0.000	\$0.115
DAY	\$0.490	\$0.045	\$0.020	\$0.154	\$0.121	\$0.245	\$0.154	\$0.000	\$0.000	\$0.137
DEOK	\$0.421	\$0.044	\$0.020	\$0.142	\$0.120	\$0.241	\$0.142	\$0.000	\$0.000	\$0.125
DLCO	\$0.424	\$0.044	\$0.020	\$0.143	\$0.125	\$0.244	\$0.143	\$0.000	\$0.000	\$0.127
Dominion	\$0.447	\$0.046	\$0.018	\$0.146	\$0.111	\$0.251	\$0.146	\$0.000	\$0.000	\$0.129
DPL	\$0.437	\$0.035	\$0.018	\$0.137	\$0.080	\$0.248	\$0.137	\$0.000	\$0.000	\$0.121
EKPC	\$0.437	\$0.045	\$0.019	\$0.143	\$0.112	\$0.241	\$0.143	\$0.000	\$0.000	\$0.127
JCPL	\$0.424	\$0.038	\$0.019	\$0.146	\$0.116	\$0.275	\$0.146	\$0.000	\$0.000	\$0.129
Met-Ed	\$0.427	\$0.037	\$0.019	\$0.145	\$0.109	\$0.274	\$0.145	\$0.000	\$0.000	\$0.128
OVEC	\$0.372	\$0.033	\$0.018	\$0.119	\$0.090	\$0.198	\$0.119	\$0.000	\$0.000	\$0.105
PECO	\$0.413	\$0.031	\$0.018	\$0.133	\$0.088	\$0.246	\$0.133	\$0.000	\$0.000	\$0.118
PENELEC	\$0.376	\$0.039	\$0.019	\$0.130	\$0.109	\$0.233	\$0.130	\$0.000	\$0.000	\$0.115
Pepco	\$0.461	\$0.046	\$0.019	\$0.152	\$0.111	\$0.273	\$0.152	\$0.000	\$0.000	\$0.135
PPL	\$0.354	\$0.033	\$0.019	\$0.129	\$0.105	\$0.259	\$0.129	\$0.000	\$0.000	\$0.114
PSEG	\$0.418	\$0.039	\$0.019	\$0.140	\$0.111	\$0.248	\$0.140	\$0.000	\$0.000	\$0.124
RECO	\$0.419	\$0.041	\$0.020	\$0.144	\$0.120	\$0.262	\$0.144	\$0.000	\$0.000	\$0.128
Exports	\$0.616	\$0.044	\$0.017	\$0.161	\$0.080	\$0.206	\$0.161	\$0.000	\$0.000	\$0.143
Monthly Average	\$0.431	\$0.040	\$0.019	\$0.141	\$0.107	\$0.247	\$0.141	\$0.000	\$0.000	\$0.125

Table 6-22 shows the monthly day-ahead and real-time Economic Load Response charges for 2019 through September 2020. The day-ahead Economic Load Response charges decreased by \$0.3 million, 63.7 percent, from \$0.5 million in the first nine months of 2019 to \$0.2 million in the first nine months of 2020. The real-time Economic Load Response charges decreased \$0.3 million, 79.6 percent, from \$0.3 million in the first nine months of 2019 to \$0.1 million in the first nine months of 2020.⁶⁷

Table 6-22 Monthly day-ahead and real-time Economic Load Response charge: 2019 through September 2020

Month	Day-ahead Economic Load Response Charge			Real-time Economic Load Response Charge		
	2019	2020	Percent Change	2019	2020	Percent Change
Jan	\$150,139	\$28,908	(80.7%)	\$122,303	\$1,391	(98.9%)
Feb	\$22,811	\$2,317	(89.8%)	\$15,850	\$335	(97.9%)
Mar	\$71,143	\$936	(98.7%)	\$8,462	\$237	(97.2%)
Apr	\$84,808			\$1,310	\$197	(85.0%)
May	\$47,488	\$4,315	(90.9%)	\$3,463	\$1,846	(46.7%)
Jun	\$18,261	\$11,138	(39.0%)	\$2,891	\$5,458	88.8%
Jul	\$77,468	\$74,206	(4.2%)	\$160,398	\$48,367	(69.8%)
Aug	\$34,048	\$69,849	105.1%	\$5,473	\$9,490	73.4%
Sep	\$24,599	\$1,045	(95.8%)	\$9,105		
Oct	\$25,008			\$5,206		
Nov	\$43,272			\$1,405		
Dec	\$34,892			\$9,547		
Total	\$633,937	\$192,714	(69.6%)	\$345,412	\$67,320	(80.5%)

Table 6-23 shows registered sites and MW for the last day of each month for the period January 1, 2015, through September 30, 2020. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations decreased by 44, 11.7 percent, from 373 in the first nine months of 2019 to 329 in the first nine months of 2020. Average monthly registered MW decreased by 580 MW, 20.3 percent, from 2,855 MW in the first nine months of 2019 to 2,275 MW in the first nine months of 2020.

Most economic demand response resources are registered in the emergency demand response program. Resources registered in both programs do not need to register for the same amount of MW. There are 102 economic registrations and 110 capacity registrations in the emergency program that share the same location ids in both programs. There are 819 nominated economic MW and 525 nominated capacity MW in the emergency program that share the same location ids in both programs.

⁶⁷ There was no DA Economic Load Response in April 2020 and no RT Economic Load Response in September 2020 as of October 16, 2020.

Table 6-23 Economic program registrations on the last day of the month: 2015 through September 2020⁶⁸

	2015		2016		2017		2018		2019		2020	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,078	2,960	838	2,557	871	2,603	537	2,570	374	2,651	377	2,909
Feb	1,076	2,956	835	2,557	842	2,578	537	2,628	370	2,640	382	2,912
Mar	1,075	2,949	834	2,556	850	2,576	519	2,641	378	2,648	380	2,941
Apr	1,076	2,938	832	2,556	897	2,574	501	2,624	366	2,594	350	2,917
May	980	2,846	829	2,545	977	2,626	471	2,615	372	3,193	308	2,824
Jun	871	2,614	518	2,500	577	1,305	397	2,576	370	2,768	286	1,432
Jul	870	2,609	519	2,421	589	1,548	374	2,591	376	2,899	284	1,466
Aug	869	2,609	805	2,569	590	1,541	382	2,609	360	2,885	293	1,496
Sep	867	2,608	831	2,608	588	1,663	378	2,580	368	2,954	300	1,582
Oct	858	2,568	822	2,564	574	1,660	382	2,584	375	2,909		
Nov	851	2,566	820	2,564	559	1,662	381	2,581	379	3,051		
Dec	850	2,566	807	2,561	556	1,659	392	2,671	383	3,070		
Avg	974	2,788	774	2,547	706	2,000	438	2,606	373	2,855	329	2,275

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 6-24 shows the sum of peak economic MW dispatched by registration each month from January 1, 2010, through September 30, 2020. 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 625.5 MW, 76.3 percent, from 820 MW in the first nine months of 2019 to 194 MW in the first nine months of 2020.⁶⁹ The peak dispatched MW in the first nine months of 2020, 135 MW, were 2,140 MW less than the average MW registered in the first nine months of 2020, 2,275 MW.

Table 6-24 Sum of peak MW reported reductions for all registrations per month: 2010 through September 2020

Sum of Peak MW Reductions for all Registrations per Month											
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Jan	183	132	110	193	446	169	139	123	142	88	28
Feb	121	89	101	119	307	336	128	83	70	58	11
Mar	115	81	72	127	369	198	120	111	71	38	12
Apr	111	80	108	133	146	143	118	54	71	41	3
May	172	98	143	192	151	161	131	169	70	22	12
Jun	209	561	954	433	483	833	121	240	105	26	38
Jul	999	561	1,631	1,088	665	1,362	1,316	936	518	770	135
Aug	794	161	952	497	358	272	249	141	581	33	99
Sep	276	84	451	530	795	816	263	140	112	76	6
Oct	118	81	242	168	214	136	150	88	69	29	
Nov	111	86	165	155	166	127	116	81	54	35	
Dec	114	88	98	168	155	122	147	83	11	31	
Annual	1,202	840	1,942	1,486	1,739	1,858	1,451	1,217	758	830	194

⁶⁸ Data for years 2010 through 2014 are available in the 2018 State of the Market Report for PJM.

⁶⁹ The total credits and MWh numbers for demand resources were calculated as of October 16, 2020 and may change as a result of continued PJM billing updates.

Table 6-25 shows total settlements submitted for the first nine months of 2010 through 2020. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-25 Settlements submitted in the economic program: January through September, 2010 through 2020

(Jan-Sep)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Number of Settlements	3,367	703	5,334	2,358	2,425	1,851	1,524	1,417	1,263	875	458

Table 6-26 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for the first nine months of 2010 through 2020. The number of active participants decreased by 22, 43.1 percent, from 51 in the first nine months of 2019 to 29 in the first nine months of 2020. All participants must be registered through a CSP.

Table 6-26 Participants and CSPs submitting settlements in the economic program by year: January through September, 2010 through 2020

(Jan-Sep)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Active CSPs	16	15	22	20	16	18	12	13	13	12	11
Active Participants	257	203	428	273	154	114	58	72	58	51	29

Issues

FERC Order No. 831 requires that each RTO/ISO market monitoring unit verify all energy offers above \$1,000 per MWh.⁷⁰ 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.”⁷¹ 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 No. 831. Demand resources should not be permitted to make offers above \$1,000 per MWh without the same verification requirements applied to economic resources or generation resources. The

⁷⁰ 157 FERC ¶ 61,115 at P 139 (2016).

⁷¹ *Id.* at 8.

MMU recommends that the rules for maximum offer for the emergency and pre-emergency program match the maximum offer for generation resources.

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefits test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission included in customers’ tariff rates. Following 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.⁷² The price at this point is the NBT threshold price.

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.

⁷² “PJM Manual 11: Energy & Ancillary Services Market Operations,” §10.3.1, Rev. 109 (Oct. 15, 2020).

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 reported reductions.

Table 6-27 shows the NBT threshold price for the historical test from August 2010 through July 2011, and April 2012, when Order No. 745 was implemented in PJM, through June 2020. The historical test was used as justification for the method of calculating the NBT for future months. The NBT threshold price has never exceeded the lowest historical test result of \$34.07 per MWh.

Table 6-27 Net benefits test threshold prices: August 2010 through September 2020

Historical Test (\$/MWh)											
	Net Benefits Test Threshold Price (\$/MWh)										
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Jan		\$40.27		\$25.72	\$29.51	\$29.63	\$23.67	\$32.60	\$26.27	\$29.44	\$20.04
Feb		\$40.49		\$26.27	\$30.44	\$26.52	\$26.71	\$31.57	\$24.65	\$23.49	\$19.29
Mar		\$38.48		\$25.60	\$34.93	\$24.99	\$22.10	\$30.56	\$25.50	\$22.15	\$17.44
Apr		\$36.76	\$25.89	\$26.96	\$32.59	\$24.92	\$19.93	\$30.45	\$25.56	\$22.36	\$15.91
May		\$34.68	\$23.46	\$27.73	\$32.08	\$23.79	\$20.69	\$29.77	\$25.52	\$21.01	\$14.69
Jun		\$35.09	\$23.86	\$28.44	\$31.62	\$23.80	\$20.62	\$27.14	\$23.59	\$20.20	\$15.56
Jul		\$36.78	\$22.99	\$29.42	\$31.62	\$23.03	\$20.73	\$24.42	\$23.57	\$19.76	\$14.66
Aug	\$35.57		\$24.47	\$28.58	\$29.85	\$23.17	\$23.24	\$22.75	\$23.53	\$19.57	\$14.58
Sep	\$34.07		\$24.93	\$28.80	\$29.83	\$21.69	\$24.70	\$21.51	\$22.23	\$18.19	\$15.16
Oct	\$38.10		\$25.96	\$29.13	\$30.20	\$21.48	\$26.50	\$21.70	\$23.84	\$20.20	
Nov	\$36.83		\$25.63	\$31.63	\$29.17	\$22.28	\$29.27	\$26.41	\$23.89	\$21.11	
Dec	\$37.04		\$25.97	\$28.82	\$29.01	\$22.31	\$29.71	\$29.16	\$26.35	\$22.24	
Average	\$36.32	\$37.51	\$24.80	\$28.09	\$30.91	\$23.97	\$23.99	\$27.34	\$24.54	\$21.64	\$16.37

Table 6-28 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 the first nine months of 2020, the highest zonal LMP in PJM was higher than the NBT threshold price 5,394 hours out of 6,575 hours, or 82.0 percent of all hours. Reductions occurred in 1,176 hours, 21.8 percent, of those 5,394 hours in the first nine months of 2020. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2019 through September 30, 2020. There are no economic payments when demand response occurs and zonal LMP is

below the NBT threshold. Demand response reported reductions occurred in 0.1 percent (1 hour) of the hours in which LMP was below the NBT threshold price in the first nine months of 2020, and 0.1 percent (1 hour) of the hours in which LMP was below the NBT threshold price in the first nine months of 2019.

Table 6-28 Hours with price higher than NBT and Economic Load Response occurrences in those hours: 2019 through September 2020

Month	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with Economic Load Response		
	2019	2020	2019	2020	Percent Change	2019	2020	Percent Change
Jan	744	744	503	569	13.1%	51.9%	38.1%	(13.8%)
Feb	672	696	582	513	(11.9%)	22.9%	15.0%	(7.8%)
Mar	743	743	711	558	(21.5%)	40.5%	9.0%	(31.5%)
Apr	720	720	559	606	8.4%	55.1%	2.0%	(53.1%)
May	744	744	579	635	9.7%	45.1%	19.5%	(25.6%)
Jun	720	720	488	495	1.4%	25.2%	36.4%	11.2%
Jul	744	744	627	675	7.7%	55.7%	50.1%	(5.6%)
Aug	744	744	569	695	22.1%	40.8%	24.9%	(15.9%)
Sep	720	720	665	648	(2.6%)	32.2%	0.8%	(31.4%)
Oct	744		637			29.5%		
Nov	721		664			31.8%		
Dec	744		506			37.5%		
Total	8,760	6,575	7,090	5,394		38.9%	21.8%	

Energy Efficiency

Calculating the Nominated MW value for Energy Efficiency (EE) resources is different than calculating the Nominated MW value for other capacity resources. The maximum amount of Nominated MW a generator can offer into the capacity market is based on the maximum output of a generator. EE resources do not produce power, but reduce power consumption. The Nominated MW for EE resources are not measured, although they could be, but a calculated value based on a set of largely unverified and unverifiable assumptions.

Figure 6-3 shows the installed EE MW in PJM by technology for the 2019/2020 and 2020/2021 Delivery Years. An installed EE resource may participate as a capacity resource for up to four consecutive delivery years.⁷³

Prescriptive energy efficiency MW have an assumed savings calculated based on an assumed installation rate and the difference between the assumed electricity usage of what is being replaced and the assumed electricity usage of the new product. All lighting EE is prescriptive. Prescriptive energy

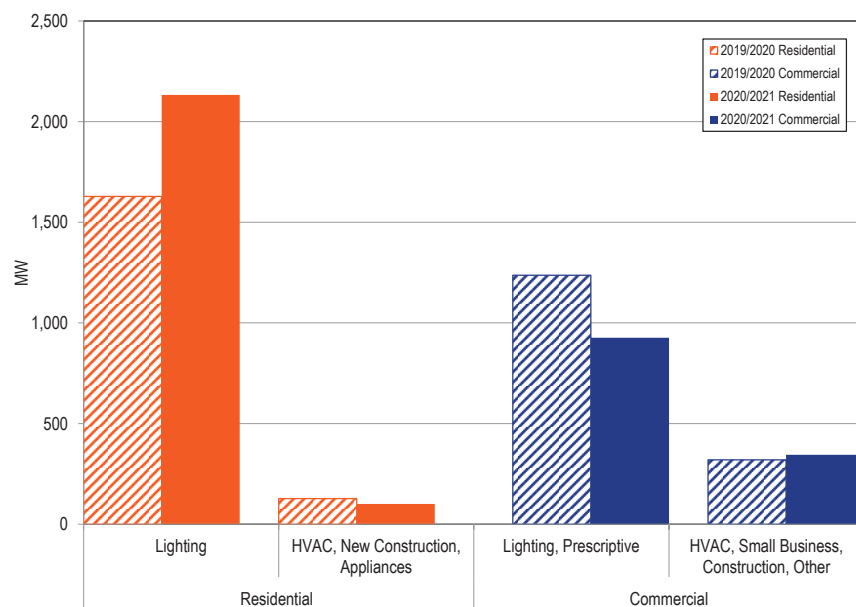
⁷³ PJM. "Manual 18: PJM Capacity Market," § 4.4, Rev. 45 (May 28, 2020).

efficiency MW were 86.5 percent of all energy efficiency MW and HVAC, new construction and appliances were 13.5 percent in the 2019/2020 Delivery Year. Prescriptive energy efficiency MW were 85.1 percent and HVAC, new construction and appliances were 14.9 percent in the 2020/2021 Delivery Year. The measurement and verification method for prescriptive energy efficiency projects relies on neither measurement or verification but instead relies on unverified assumptions and is too imprecise to rely on as a source of capacity comparable to capacity from a power plant. The nonprescriptive measurement and verification methods are also inadequate and rely on samples and assumptions for limited periods.⁷⁴

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. Effective energy efficiency measures reduce energy usage and capacity usage directly. The reduced market payments are the appropriate compensation.

⁷⁴ PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 4 (August 22, 2019).

Figure 6-3 Installed energy efficiency MW by type: 2019/2020 and 2020/2021 delivery years



Energy efficiency resources are included in the PJM Capacity Market. Table 6-29 shows the amount of energy efficiency (EE) resources in PJM on June 1 for the 2012/2013 through 2019/2020 Delivery Years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.⁷⁵ Only Kentucky has been authorized by the Commission.⁷⁶ The total MW of energy efficiency resources committed increased by 10.1 percent from 2,296.3 MW in the 2019/2020 Delivery Year to 2,528.5 MW in the 2020/2021 Delivery Year.⁷⁷

⁷⁵ See 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).

⁷⁶ 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.

⁷⁷ See the 2019 State of the Market Report for PJM, Vol. 2, Section 5: Capacity Market, Table 5-13.

Table 6-29 Energy efficiency resources (MW): June 1, 2012 to June 1, 2020

	UCAP (MW)		
	EE RPM Cleared	Total RPM Cleared	EE Percent Cleared
2012/2013	76.4	134,139.6	0.1%
2013/2014	666.1	141,061.8	0.5%
2014/2015	904.2	159,830.5	0.6%
2015/2016	1,077.7	161,092.4	0.7%
2016/2017	1,189.6	173,487.4	0.7%
2017/2018	1,723.2	179,749.0	1.0%
2018/2019	1,922.3	180,590.3	1.1%
2019/2020	2,296.3	175,957.4	1.3%
2020/2021	2,528.5	177,040.6	1.4%

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.⁷⁸ For example, Table 6-9 shows the fuel mix of behind the meter generation participating as emergency demand response in the 2019/2020 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.⁷⁹ 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.⁸¹

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 load response payments when economic load response resources injects power into the grid. PJM's test compares the total benefits of running the generator

⁷⁸ Some energy storage facilities may be DERs. 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).

⁷⁹ 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>>.

⁸⁰ 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).

⁸¹ 162 FERC ¶ 32,718 at P 139 (2016).

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 load response 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.

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear, solar, and wind generating units.

Overview

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and gas prices were lower in the first nine months of 2020 than in the first nine months of 2019.
- In the first nine months of 2020, average energy market net revenues decreased by 17 percent for a new combustion turbine (CT), 23 percent for a new combined cycle (CC), 67 percent for a new coal plant (CP), 25 percent for a new nuclear plant, 33 percent for a new diesel (DS), 33 percent for a new onshore wind installation, 27 percent for a new offshore wind installation and 27 percent for a new solar installation compared to the first nine months of 2019. Average energy market net revenues were higher in the third quarter than in either of the first two quarters of 2020 for all unit types.
- The prices of natural gas and oil fell in the first nine months of 2020. The marginal costs of a new CC and a new CT were less than the marginal cost of a new CP in the first nine months of 2020.
- Based on Western Hub prices, the spark spread in the first nine months of 2020 decreased by 4 percent while the spark spread standard deviation decreased by 51 percent. The dark spread decreased by 21 percent while the dark spread standard deviation decreased by 50 percent, and the quark spread decreased by 30 percent while the quark spread standard deviation decreased by 50 percent.
- The impact of lower energy prices on the net revenues of a new coal plant in the first nine months of 2020 was significant. New coal plant run hours

were down 54 percent. New coal plant net revenues were reduced by a zonal average of 67 percent.

- Negative prices do not have a significant impact on total nuclear unit market revenue. Since 2014, negative prices have affected nuclear plants' annual gross revenues by an average of 0.1 percent.¹

Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Adopted 2020.)

Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have not covered 100 percent of their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE and PSEG Zones, but have not covered 100 percent of total costs in the ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

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

¹ Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for the comparison.

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 not covered 100 percent of their total costs, including the return on and of capital, on a cumulative basis. CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE and PSEG Zones, but have not covered 100 percent of their total costs in the ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

Net Revenue

When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and to maintain existing generation 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 revenue is the contribution to fixed costs, which include a

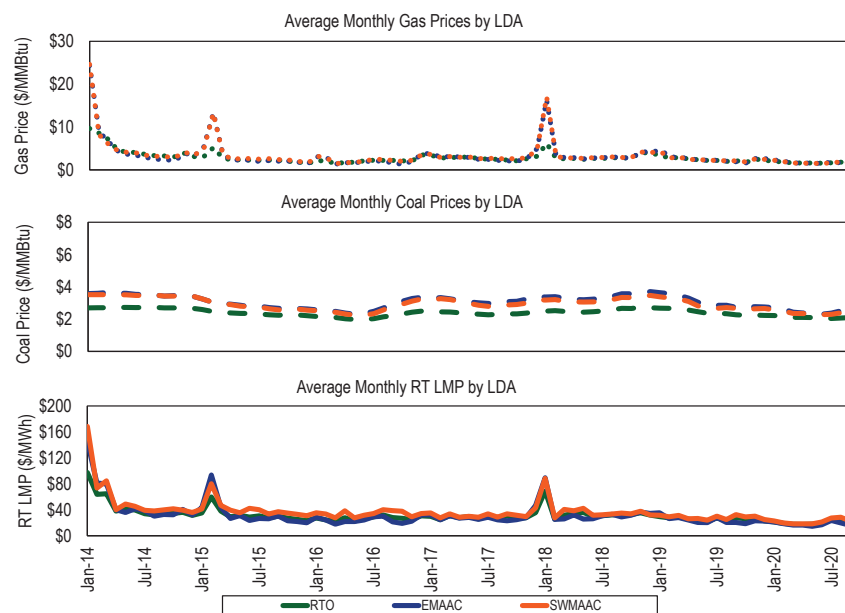
return on investment, depreciation and income taxes, and to avoidable costs, which include long term and intermediate term operation and maintenance expenses.² Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the annualized fixed and avoidable costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets that contribute to the payment of fixed and avoidable costs. In PJM, the energy, capacity and ancillary service markets are all significant sources of revenue to cover the fixed and avoidable costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long run equilibrium, with energy, capacity and ancillary service revenues, net revenue from all sources would be expected to equal the annualized fixed and avoidable costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity and to encourage maintaining existing capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. PJM real-time energy market prices decreased in the first nine months of 2020. The load-weighted, average real-time LMP was 23.1 percent lower in the first nine months of 2020 than in the first nine months of 2019, \$21.22 per MWh versus \$27.60 per MWh. Gas prices and coal prices decreased in the first nine months of 2020. The price of Northern Appalachian coal was 21.7 percent lower; the price of Central Appalachian coal was 31.5 percent lower; the price of Powder River Basin coal was 1.8 percent lower; the price of eastern natural gas was 36.5 percent lower; and the price of western natural gas was 31.7 percent lower (Figure 7-1).

² Avoidable costs are sometimes referred to as going forward costs.

Figure 7-1 Energy market net revenue factor trends: 2014 through September 2020



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 fuel. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability.

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative. Spreads are generally lower in 2020 than in 2019.

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 2020: January through September

	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
2019	\$16.48	\$16.01	\$28.30	\$11.02	\$21.01	\$22.60	\$9.18	\$4.54	\$22.20	\$13.26	\$12.72	\$25.01
2020	\$16.02	\$13.56	\$21.06	\$9.95	\$15.41	\$16.06	\$9.03	\$4.03	\$14.15	\$12.73	\$10.06	\$17.56

Table 7-2 Peak hour spread standard deviation (\$/MWh): 2014 through 2020: January through September

	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
2019	\$35.7	\$35.8	\$35.8	\$24.8	\$24.8	\$24.8	\$20.1	\$22.6	\$23.0	\$28.7	\$28.5	\$28.5
2020	\$21.8	\$21.8	\$21.7	\$11.7	\$11.8	\$11.8	\$9.9	\$10.3	\$10.2	\$14.1	\$14.2	\$14.2

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): 2018 through September 2020

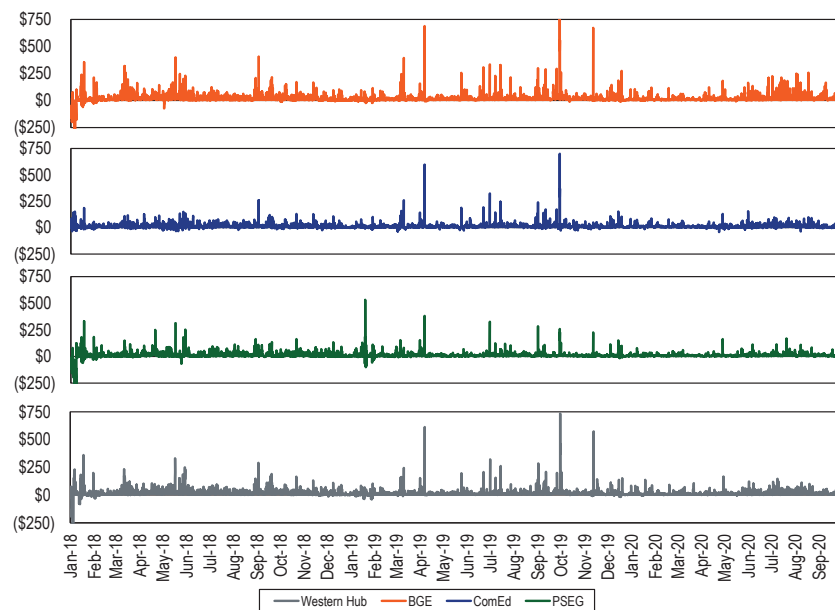
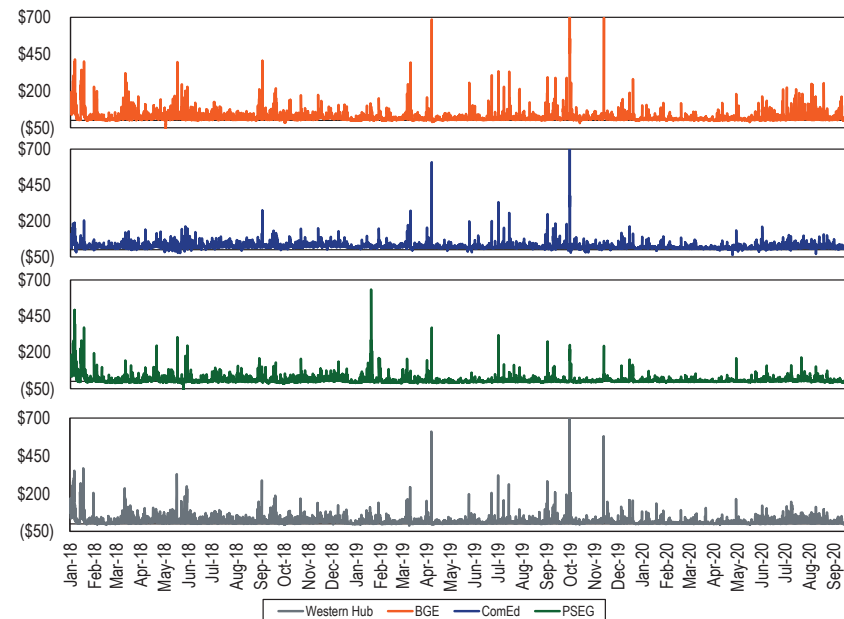
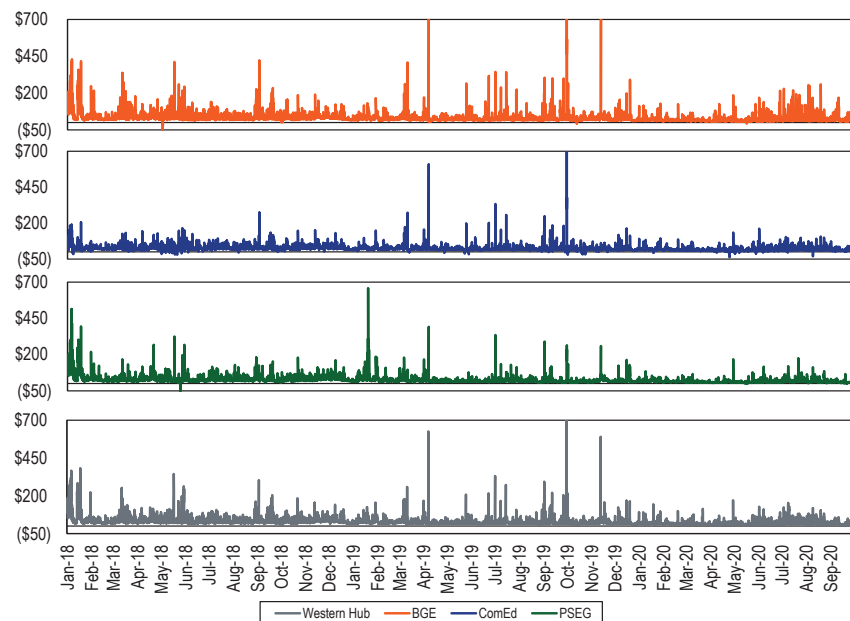


Figure 7-3 Hourly dark spread (coal) for peak hours (\$/MWh): 2018 through September 2020³



³ 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.

Figure 7-4 Hourly quark spread (uranium) for selected zones (\$/MWh): 2018 through September 2020⁴



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.

Analysis of energy market net revenues for a new entrant includes seven power plant configurations:

- The CT plant is a single GE Frame 7HA.02 CT with an installed capacity of 360.1 MW, equipped with evaporative coolers, and selective catalytic reduction (SCR) for NO_x reduction.

⁴ Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium (U₃O₈) prices.

- The CC plant includes two GE Frame 7HA.02 CTs and a single steam turbine generator with an installed capacity of 1,137.2 MW, equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT, with steam reheat, and SCR for NO_x reduction.
- The CP is a subcritical steam unit with an installed capacity of 600.0 MW, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant is a single oil fired CAT 2 MW unit with an installed capacity of 2.0 MW using New York Harbor ultra low sulfur diesel.
- The nuclear plant includes two units and related facilities using the Westinghouse AP1000 technology with an installed capacity of 2,200 MW.
- The onshore wind installation includes 37 Siemens 2.7 MW wind turbines with an installed capacity of 99.9 MW.
- The offshore wind installation includes of 43 Siemens 7.0 MW wind turbines with an installed capacity of 301.0 MW.
- The solar installation is a 35.5 acre ground mounted fixed tilt solar farm with an installed AC capacity of 10 MW.

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.^{5 6} Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

CO₂, NO_x and SO₂ emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost.⁷ CO₂, NO_x and SO₂ emission allowance costs were obtained from daily spot cash prices.⁸

⁵ Hourly ambient conditions supplied by DTN.

⁶ 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.

⁷ CO₂ emission allowance costs only included for states participating in RGGI, including New Jersey.

⁸ CO₂, NO_x and SO₂ emission daily prompt prices obtained from Evolution Markets, Inc.

The class average equivalent availability factor for each type of plant was calculated from PJM data and incorporated into all revenue calculations.⁹ In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day annual planned outage in the fall season.

Zonal net revenues reflect average zonal LMP and fuel costs based on locational fuel indices and zone specific delivery charges.¹⁰ The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas from a specific pipeline and is from published commodity daily cash prices, with a basis adjustment for transportation costs.¹¹ 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.¹² Net revenues are calculated for all zones except OVEC.¹³

Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.¹⁴ ¹⁵ Average short run marginal costs are shown, including all components, in Table 7-3 and the short run marginal component of VOM is also shown separately.

Table 7-3 Average short run marginal costs: January through September, 2020

Unit Type	Short Run Marginal Costs (\$/MWh)	Heat Rate (Btu/kWh)	VOM (\$/MWh)
CT	\$18.50	9,241	\$0.38
CC	\$12.82	6,296	\$1.39
CP	\$27.20	9,250	\$4.16
DS	\$89.31	9,660	\$0.25
Nuclear	\$0.00	NA	\$0.00
Wind	\$0.00	NA	\$0.00
Wind (off shore)	\$0.00	NA	\$0.00
Solar	\$0.00	NA	\$0.00

⁹ Outage figures obtained from the PJM eGADS database.

¹⁰ 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.

¹¹ Gas daily cash prices obtained from Platts.

¹² Coal prompt month prices obtained from Platts.

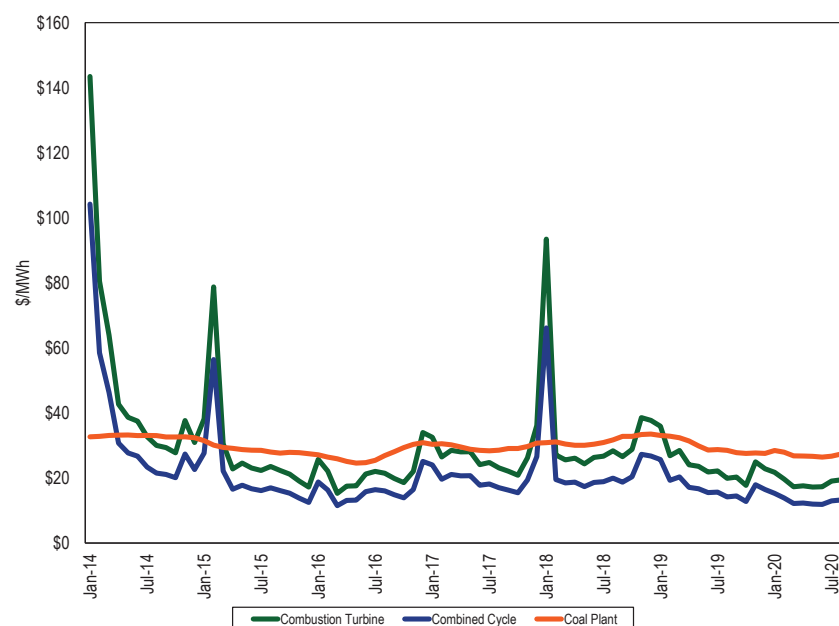
¹³ The Ohio Valley Electric Corporation (OVEC) includes a generating plant in Ohio and a generating plant in Indiana, and high voltage transmission lines, but does not occupy a single geographic footprint like the other control zones.

¹⁴ Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid.

¹⁵ VOM rates provided by Pasteris Energy, Inc.

A comparison of the monthly average short run marginal cost of the theoretical CT, CC and CP plants since 2014 shows that, on average, the short run marginal costs of the CC plant have been less than those of the CP plant but the costs of the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-5). The marginal costs of a new CC and a new CT were less than the marginal cost of a new CP in the first nine months of 2020.

Figure 7-5 Average short run marginal costs: 2014 through September 2020



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 7-4 shows the average run hours by a new entrant unit.

Table 7-4 Average run hours: January through September, 2014 through 2020

Jan-Sep	CT	CC	CP	DS	Nuclear
2014	3,550	6,076	5,364	149	6,576
2015	4,664	6,277	4,744	128	6,576
2016	5,208	6,446	4,082	39	6,600
2017	3,790	6,394	3,538	25	6,576
2018	4,176	6,346	3,822	111	6,576
2019	3,714	6,330	2,117	22	6,576
2020	3,744	6,319	967	33	6,600

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 lower in all but four zones in the first nine months of 2020 (Table 7-5).

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January through September, 2014 through 2020 (Dollars per installed MW-year)¹⁶

Zone	Jan-Sep							Change in 2020 from 2019
	2014	2015	2016	2017	2018	2019	2020	
AECO	\$73,405	\$41,708	\$46,249	\$22,093	\$26,654	\$20,547	\$6,069	(70%)
AEP	\$67,449	\$54,923	\$47,821	\$26,232	\$66,440	\$32,619	\$29,135	(11%)
APS	\$90,853	\$86,337	\$51,965	\$31,277	\$67,802	\$17,863	\$14,909	(17%)
ATSI	\$49,411	\$47,866	\$46,175	\$27,588	\$78,519	\$33,933	\$29,507	(13%)
BGE	\$88,636	\$60,519	\$79,045	\$32,085	\$47,455	\$25,748	\$24,059	(7%)
ComEd	\$31,315	\$25,079	\$29,620	\$17,939	\$29,727	\$18,371	\$16,343	(11%)
DAY	\$44,343	\$44,007	\$44,581	\$26,759	\$74,664	\$37,463	\$33,742	(10%)
DEOK	\$40,531	\$41,305	\$42,521	\$25,534	\$82,843	\$33,962	\$30,016	(12%)
DLCO	\$39,013	\$62,838	\$61,651	\$34,218	\$50,815	\$22,957	\$24,844	8%
Dominion	\$59,304	\$51,218	\$55,122	\$27,695	\$51,983	\$27,191	\$24,362	(10%)
DPL	\$58,747	\$27,998	\$24,357	\$10,733	\$21,770	\$13,405	\$8,491	(37%)
EKPC	\$59,896	\$43,174	\$41,526	\$21,852	\$50,179	\$26,697	\$25,653	(4%)
JCPL	\$74,696	\$40,861	\$41,674	\$25,592	\$27,533	\$19,586	\$6,625	(66%)
Met-Ed	\$72,367	\$72,623	\$61,579	\$42,471	\$38,978	\$23,145	\$26,345	14%
PECO	\$74,378	\$71,310	\$58,363	\$33,913	\$35,130	\$18,652	\$19,020	2%
PENELEC	\$121,487	\$120,357	\$76,585	\$41,150	\$75,603	\$29,818	\$32,133	8%
Pepco	\$64,618	\$39,478	\$40,681	\$20,329	\$38,778	\$15,797	\$11,518	(27%)
PPL	\$190,484	\$139,459	\$62,799	\$38,323	\$77,618	\$21,159	\$20,504	(3%)
PSEG	\$90,869	\$83,039	\$62,484	\$39,212	\$39,815	\$20,785	\$6,625	(68%)
RECO	\$66,401	\$46,358	\$45,660	\$26,864	\$29,648	\$20,669	\$7,498	(64%)
PJM	\$58,381	\$60,023	\$51,023	\$28,593	\$50,598	\$24,018	\$19,870	(17%)

¹⁶ The energy net revenues presented for the PJM area in this section are calculated using the zonal average LMP.

New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM. It was assumed that the CC plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs.¹⁷ 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 lower in all zones in the first nine months of 2020 as a result of lower energy prices (Table 7-6).

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through September, 2014 through 2020 (Dollars per installed MW-year)¹⁸

Zone	Jan-Sep							Change in 2020 from 2019
	2014	2015	2016	2017	2018	2019	2020	
AECO	\$107,700	\$62,168	\$56,886	\$39,174	\$50,966	\$42,173	\$23,571	(44%)
AEP	\$92,815	\$77,655	\$62,247	\$44,434	\$92,617	\$57,228	\$44,950	(21%)
APS	\$131,582	\$118,635	\$80,327	\$54,564	\$102,536	\$48,713	\$40,533	(17%)
ATSI	\$69,129	\$71,026	\$61,144	\$45,061	\$102,961	\$58,284	\$45,196	(22%)
BGE	\$133,084	\$95,354	\$106,523	\$57,009	\$83,020	\$58,457	\$51,395	(12%)
ComEd	\$40,701	\$41,928	\$43,638	\$30,194	\$47,185	\$36,356	\$29,238	(20%)
DAY	\$62,981	\$68,115	\$60,283	\$45,341	\$100,422	\$62,307	\$49,813	(20%)
DEOK	\$55,669	\$63,890	\$57,594	\$42,793	\$106,861	\$58,359	\$45,898	(21%)
DLCO	\$62,643	\$74,406	\$71,816	\$49,873	\$77,284	\$44,990	\$41,393	(8%)
Dominion	\$89,684	\$76,237	\$71,013	\$46,788	\$76,716	\$52,192	\$41,109	(21%)
DPL	\$89,342	\$43,314	\$38,818	\$18,293	\$35,953	\$19,622	\$11,844	(40%)
EKPC	\$81,876	\$66,320	\$55,747	\$39,454	\$76,898	\$50,642	\$41,584	(18%)
JCPL	\$110,897	\$61,681	\$52,688	\$42,416	\$51,793	\$41,791	\$24,112	(42%)
Met-Ed	\$103,311	\$87,534	\$68,353	\$55,898	\$64,015	\$45,628	\$40,894	(10%)
PECO	\$107,953	\$88,284	\$65,466	\$48,832	\$62,412	\$40,020	\$33,727	(16%)
PENELEC	\$151,728	\$125,644	\$81,939	\$55,665	\$99,692	\$53,876	\$46,280	(14%)
Pepco	\$100,641	\$73,941	\$70,434	\$42,566	\$71,155	\$45,137	\$32,748	(27%)
PPL	\$204,901	\$137,227	\$69,121	\$52,350	\$96,714	\$42,293	\$35,084	(17%)
PSEG	\$131,707	\$100,778	\$69,820	\$53,889	\$67,714	\$43,886	\$25,333	(42%)
RECO	\$103,106	\$65,662	\$56,066	\$43,741	\$53,424	\$43,555	\$26,458	(39%)
PJM	\$100,026	\$79,990	\$64,996	\$45,417	\$76,017	\$47,275	\$36,558	(23%)

¹⁷ All starts associated with combined cycle units are assumed to be warm starts.

¹⁸ 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 lower in all zones as a result of lower energy prices (Table 7-7).

Table 7-7 Energy net revenue for a new entrant CP: January through September, 2014 through 2020 (Dollars per installed MW-year)¹⁹

Zone	Jan-Sep							Change in 2020 from 2019
	2014	2015	2016	2017	2018	2019	2020	
AECO	\$113,398	\$47,038	\$10,176	\$3,349	\$29,209	\$3,777	\$175	(95%)
AEP	\$101,550	\$45,447	\$30,837	\$26,666	\$52,483	\$12,589	\$3,916	(69%)
APS	\$100,484	\$40,923	\$12,174	\$12,323	\$39,063	\$4,619	\$1,919	(58%)
ATSI	\$112,630	\$47,555	\$27,077	\$26,988	\$54,086	\$10,452	\$2,689	(74%)
BGE	\$160,039	\$77,070	\$42,308	\$12,521	\$47,574	\$7,999	\$3,992	(50%)
ComEd	\$100,594	\$35,744	\$21,329	\$21,413	\$26,138	\$11,102	\$1,444	(87%)
DAY	\$104,755	\$45,052	\$25,760	\$25,482	\$52,339	\$12,280	\$5,081	(59%)
DEOK	\$95,430	\$40,930	\$23,588	\$23,118	\$58,203	\$10,811	\$4,081	(62%)
DLCO	\$87,779	\$36,917	\$23,686	\$24,275	\$53,955	\$9,411	\$3,720	(60%)
Dominion	\$143,983	\$81,869	\$39,342	\$18,318	\$56,706	\$12,827	\$5,159	(60%)
DPL	\$153,229	\$67,849	\$20,071	\$8,560	\$43,215	\$9,115	\$3,943	(57%)
EKPC	\$92,397	\$34,808	\$19,867	\$18,722	\$34,975	\$7,634	\$3,388	(56%)
JCPL	\$117,588	\$46,725	\$7,563	\$4,344	\$29,942	\$3,387	\$731	(78%)
Met-Ed	\$144,624	\$64,207	\$17,424	\$14,224	\$42,829	\$7,414	\$4,569	(38%)
PECO	\$109,397	\$44,739	\$8,406	\$3,368	\$28,841	\$3,625	\$246	(93%)
PENELEC	\$119,745	\$57,345	\$21,026	\$10,659	\$37,959	\$7,005	\$3,042	(57%)
Pepco	\$112,907	\$39,127	\$9,917	\$2,959	\$29,204	\$3,734	\$497	(87%)
PPL	\$108,732	\$43,645	\$6,736	\$3,547	\$28,349	\$2,338	\$349	(85%)
PSEG	\$163,677	\$72,280	\$12,359	\$7,058	\$35,278	\$5,064	\$250	(95%)
RECO	\$158,832	\$72,446	\$11,758	\$6,912	\$34,502	\$5,981	\$658	(89%)
PJM	\$120,089	\$52,086	\$19,570	\$13,740	\$40,742	\$7,558	\$2,492	(67%)

¹⁹ The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Nuclear Plant

Energy market net revenue was calculated assuming that the nuclear plant was dispatched day ahead by PJM for all available plant hours. The unit runs for all hours and output reflects the class average equivalent availability factor.²⁰

New entrant nuclear plant energy market net revenues were lower in all zones as a result of lower energy prices (Table 7-8).

Table 7-8 Energy net revenue for a new entrant nuclear plant: January through September, 2014 through 2020 (Dollars per installed MW-year)^{21 22}

Jan-Sep								Change in 2020 from 2019
Zone	2014	2015	2016	2017	2018	2019	2020	
AECO	\$360,915	\$229,102	\$152,141	\$165,191	\$213,169	\$148,853	\$106,547	(28%)
AEP	\$286,963	\$204,221	\$167,316	\$178,362	\$218,529	\$163,269	\$123,808	(24%)
APS	\$311,630	\$225,877	\$172,174	\$179,527	\$230,145	\$163,243	\$123,888	(24%)
ATSI	\$299,869	\$208,113	\$169,248	\$181,909	\$229,744	\$165,213	\$124,387	(25%)
BGE	\$400,502	\$278,999	\$222,930	\$196,171	\$255,697	\$178,806	\$138,493	(23%)
ComEd	\$258,226	\$175,674	\$156,006	\$166,122	\$172,584	\$147,141	\$113,009	(23%)
DAY	\$289,914	\$204,805	\$168,415	\$182,281	\$226,966	\$169,847	\$129,624	(24%)
DEOK	\$278,699	\$199,944	\$165,436	\$179,053	\$234,243	\$165,438	\$125,195	(24%)
DLCO	\$270,088	\$195,317	\$164,951	\$178,387	\$229,363	\$162,886	\$125,980	(23%)
Dominion	\$353,605	\$251,055	\$185,648	\$188,523	\$247,128	\$170,020	\$126,248	(26%)
DPL	\$384,366	\$248,859	\$174,096	\$174,105	\$232,687	\$158,433	\$114,210	(28%)
EKPC	\$274,997	\$192,691	\$160,945	\$173,419	\$203,840	\$160,268	\$122,779	(23%)
JCPL	\$364,815	\$227,874	\$146,982	\$169,405	\$213,944	\$148,377	\$107,284	(28%)
Met-Ed	\$349,545	\$221,331	\$148,453	\$173,836	\$213,225	\$152,073	\$113,248	(26%)
PECO	\$353,646	\$223,312	\$145,566	\$164,881	\$211,302	\$145,791	\$105,149	(28%)
PENELEC	\$323,485	\$220,294	\$160,794	\$172,815	\$217,995	\$157,504	\$117,983	(25%)
Pepco	\$388,376	\$262,198	\$198,294	\$191,299	\$248,756	\$173,483	\$128,952	(26%)
PPL	\$350,494	\$221,731	\$145,926	\$167,451	\$206,624	\$144,711	\$106,177	(27%)
PSEG	\$385,152	\$237,992	\$150,318	\$171,295	\$218,177	\$150,459	\$107,906	(28%)
RECO	\$379,412	\$239,194	\$150,110	\$172,155	\$218,908	\$153,663	\$110,613	(28%)
PJM	\$333,235	\$223,429	\$165,287	\$176,309	\$222,151	\$158,974	\$118,574	(25%)

20 The annual class average equivalent availability factor was used in the calculation of energy market net revenues.

21 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues because fuel costs for nuclear units are included in the NEI nuclear costs.

22 The net revenues have changed since the 2018 State of the Market Report for PJM. The marginal cost of the nuclear plant has been reduced from \$8.50/MWh to \$0/MWh. Unit fuel costs have been moved to ACR.

New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were lower in all but five zones in the first nine months of 2020 (Table 7-9).

Table 7-9 Energy market net revenue for a new entrant DS: January through September, 2014 through 2020 (Dollars per installed MW-year)

Jan-Sep								Change in 2020 from 2019
Zone	2014	2015	2016	2017	2018	2019	2020	
AECO	\$32,623	\$12,075	\$2,405	\$800	\$9,969	\$1,849	\$451	(76%)
AEP	\$14,425	\$3,691	\$831	\$1,334	\$4,113	\$2,109	\$644	(69%)
APS	\$17,985	\$7,169	\$910	\$1,194	\$6,619	\$1,864	\$1,625	(13%)
ATSI	\$14,091	\$3,468	\$1,973	\$1,660	\$6,951	\$1,862	\$2,064	11%
BGE	\$49,568	\$15,595	\$7,196	\$2,314	\$12,647	\$3,220	\$3,535	10%
ComEd	\$11,311	\$2,151	\$638	\$1,267	\$702	\$1,623	\$337	(79%)
DAY	\$14,235	\$3,444	\$905	\$1,569	\$3,809	\$2,201	\$546	(75%)
DEOK	\$13,404	\$2,885	\$1,291	\$2,991	\$6,473	\$2,092	\$418	(80%)
DLCO	\$12,963	\$2,951	\$2,279	\$1,403	\$7,949	\$1,767	\$3,445	95%
Dominion	\$42,535	\$11,136	\$2,193	\$1,798	\$14,452	\$2,567	\$1,131	(56%)
DPL	\$37,438	\$16,044	\$3,417	\$1,966	\$13,916	\$6,074	\$7,619	25%
EKPC	\$14,441	\$2,730	\$851	\$896	\$1,892	\$1,964	\$452	(77%)
JCPL	\$32,717	\$13,021	\$870	\$1,103	\$11,091	\$1,774	\$1,255	(29%)
Met-Ed	\$31,781	\$12,875	\$886	\$2,585	\$10,938	\$1,458	\$1,730	19%
PECO	\$32,130	\$12,366	\$862	\$1,047	\$9,804	\$1,852	\$516	(72%)
PENELEC	\$15,964	\$6,410	\$876	\$1,247	\$5,438	\$1,213	\$910	(25%)
Pepco	\$51,173	\$11,388	\$2,939	\$1,757	\$12,291	\$2,777	\$1,125	(59%)
PPL	\$32,719	\$13,011	\$773	\$1,643	\$8,764	\$893	\$402	(55%)
PSEG	\$32,303	\$12,629	\$930	\$1,103	\$10,277	\$2,120	\$298	(86%)
RECO	\$29,837	\$13,705	\$973	\$1,113	\$9,530	\$2,084	\$612	(71%)
PJM	\$29,787	\$8,937	\$1,700	\$1,539	\$8,381	\$2,168	\$1,456	(33%)

New Entrant Onshore Wind Installation

Energy market net revenues for an onshore wind installation were calculated hourly assuming the unit generated at the average capacity factor of all operating wind units in the zone with an installed capacity greater than 3 MW. 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).²³

Onshore wind energy market net revenues were lower as a result of lower energy prices.

Table 7-10 Energy market net revenue for an onshore wind installation (Dollars per installed MW-year): January through September, 2014 through 2020

Zone	Jan-Sep							Change in 2020 from 2019
	2014	2015	2016	2017	2018	2019	2020	
AEP	\$80,488	\$54,850	\$45,842	\$48,743	\$69,611	\$49,912	\$30,754	(38%)
APS	\$83,957	\$55,410	\$40,843	\$51,330	\$69,984	\$42,199	\$32,374	(23%)
ComEd	\$72,887	\$46,732	\$39,315	\$48,121	\$46,613	\$44,297	\$26,061	(41%)
PENELEC	\$101,629	\$67,821	\$42,369	\$50,687	\$69,843	\$41,131	\$28,813	(30%)

²³ The 1603 payment is a direct payment of 30 percent of the project cost. The use of the 1603 option is based on observed behavior in the PJM markets.

New Entrant Offshore Wind Installation

Energy market net revenues for an offshore wind installation were calculated hourly assuming the unit generated 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).

Offshore wind energy market net revenues were lower as a result of lower energy prices.

Table 7-11 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): January through September, 2014 through 2020

Zone	Jan-Sep							Change in 2020 from 2019
	2014	2015	2016	2017	2018	2019	2020	
AECO	\$168,494	\$108,246	\$72,635	\$78,368	\$102,218	\$72,559	\$52,652	(27%)

New Entrant Solar Installation

Energy market net revenues for a solar installation were calculated hourly assuming the unit was generating at the average hourly capacity factor of operating solar units in the zone with an installed capacity greater than 3 MW. 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).²⁴

Solar energy market net revenues were lower as a result of lower energy prices.

Table 7-12 Energy market net revenue for a solar installation (Dollars per installed MW-year): January through September, 2014 through 2020

Zone	Jan-Sep							Change in 2020 from 2019
	2014	2015	2016	2017	2018	2019	2020	
AECO	\$60,221	\$43,274	\$32,609	\$31,056	\$35,469	\$27,917	\$19,596	(30%)
Dominion	-	-	\$58,175	\$57,902	\$65,866	\$49,013	\$36,735	(25%)
DPL	-	-	\$37,917	\$42,030	\$51,312	\$39,029	\$27,848	(29%)
JCPL	\$56,051	\$36,464	\$28,520	\$30,176	\$33,486	\$25,962	\$19,723	(24%)
PSEG	\$54,074	\$42,695	\$32,929	\$33,321	\$36,560	\$29,236	\$21,338	(27%)

Historical New Entrant CC Revenue Adequacy

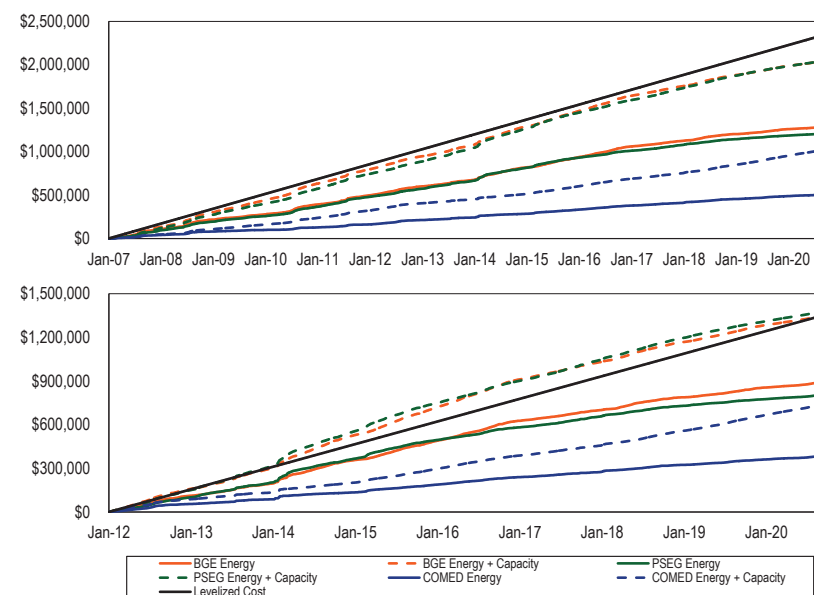
Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have covered 87 percent of their total costs in the BGE and PSEG Zones and 44 percent of total costs in the ComEd Zone, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE and PSEG Zones and 55 percent of total costs in the ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

²⁴ The 1603 payment is a direct payment of 30 percent of the project cost.

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.

Figure 7-6 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new entrant CC that began operation on January 1, 2007, and a new entrant CC that began operation on January 1, 2012. The solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

Figure 7-6 Historical new entrant CC revenue adequacy: January 2007 through September 2020 and January 2012 through September 2020²⁵



²⁵ The gas pipeline pricing points used in this analysis are Zone 6 non-NY for BGE, Chicago City Gate for ComEd, and Texas Eastern M3 for PSEG.

Table 7-13 shows the percent of levelized total costs recovered.

Table 7-13 Percent of levelized total costs recovered

	2007 CC	2012 CC
BGE	87%	100%
ComEd	44%	55%
PSEG	87%	102%

Assumptions used for this analysis are shown in Table 7-14.

Table 7-14 Assumptions for analysis of new entry in 2007 and 2012

	2007 CC	2012 CC
Project Cost	\$658,598,000	\$665,995,000
Fixed O&M (\$/MW-Year)	\$20,016	\$20,126
End of Life Value	\$0	\$0
Loan Term	20 years	20 years
Percent Equity (%)	50%	50%
Percent Debt (%)	50%	50%
Loan Interest Rate (%)	7%	7%
Cost of Equity (%)	12.0%	12.0%
Federal Income Tax Rate (%)	35%	35%
State Income Tax Rate (%)	9%	9%
General Escalation (%)	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	601	655
Depreciation MACRS 150% declining balance	20 years	20 years
IRR (%)	12.0%	12.0%

Nuclear Net Revenue Analysis

The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations of average costs for all U.S. nuclear plants.^{26 27} The analysis includes the most recent operating cost data and incremental

capital expenditure data published by NEI, for 2019. 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 (11.5 percent decrease from 2012 through 2019 for all plants including single and multiple unit plants).²⁸ NEI average incremental capital expenditures have decreased since their peak in 2012 (45.6 percent decrease from 2012 through 2019 for all plants including single and multiple unit plants).²⁹ NEI's incremental capital expenditures peaked in 2012 as a result of regulatory requirements following the 2011 accident at the Fukushima nuclear plant in Japan.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.³⁰ When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. In 2016, PJM energy prices were then at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs.³¹ In 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. Energy prices in 2018 were significantly higher than in 2017. Although energy prices in 2019 were lower than in 2016, higher capacity market revenues more than offset the difference. Realized and forward energy prices for 2020 are lower than 2019 prices. The result is that nuclear plant net revenues based on the two year forward period prices are lower than 2019 net revenues. 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.

²⁶ Operating costs from: Nuclear Energy Institute (October, 2020). "Nuclear Costs in Context," <<https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

²⁷ 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.

²⁸ Operating costs in this paragraph are operating costs as specified by NEI and do not include fuel costs or capital expenditures. Operating costs for single unit plants decreased by \$3.22/MWh, or 11.6 percent, from 2018 to 2019, a likely result of both cost reductions and the exclusion of recently retired single unit plants. Operating costs for single unit plants decreased by \$2.01/MWh or 7.6 percent from 2012 to 2019. Operating costs for multiple unit plants decreased by \$0.44/MWh, or 2.5 percent, from 2018 to 2019, and decreased by \$2.21/MWh, or 11.5 percent, from 2012 to 2019.

²⁹ Capital expenditures have decreased 46.0 percent since 2012 for single unit plants and 44.5 percent for multiple unit plants.

³⁰ A change in the capacity market price of \$24 per MW-day translates into a change in capacity revenue of \$1.00 per MWh for a nuclear power plant operating at a capacity factor of 100 percent. A change in the capacity market price of \$24 per MW-day translates into a change in capacity revenue of \$1.07 per MWh for a nuclear power plant operating at a capacity factor of 0.933 percent.

³¹ The MMU submitted testimony in New Jersey on the same issues of nuclear economics. *Establishing Nuclear Diversity Certificate Program*. Bill No. S-877 New Jersey Senate Environment and Energy Committee. (2018). *Revised Statement of Joseph Bowring*.

Table 7-15 includes the publicly available data on energy market prices, Table 7-16 and Table 7-17 show capacity market prices and Table 7-18 shows nuclear cost data for the 16 nuclear plants in PJM in addition to Oyster Creek, which retired September 17, 2018, and Three Mile Island, which retired September 20, 2019.³² The analysis excludes the Cook nuclear units and the Catawba 1 nuclear unit. The Cook nuclear units are designated FRR and receive cost of service revenues and are not subject to PJM market revenues.³³ Catawba 1 is not in PJM but is pseudo tied to PJM.

For nuclear plants, all calculations are based on publicly available data in order to avoid revealing confidential information. 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.

Table 7-15 Nuclear unit day ahead LMP: 2008 through 2019

	ICAP (MW)	Average DA LMP (\$/MWh)											
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Beaver Valley	1,808	\$49.46	\$31.51	\$35.59	\$37.43	\$30.34	\$34.24	\$41.86	\$30.35	\$27.07	\$29.11	\$36.35	\$26.22
Braidwood	2,337	\$48.10	\$27.76	\$31.48	\$32.02	\$27.51	\$30.26	\$37.34	\$25.97	\$24.30	\$24.99	\$27.11	\$22.88
Byron	2,300	\$47.61	\$23.98	\$28.49	\$28.09	\$24.25	\$29.22	\$35.05	\$21.00	\$17.94	\$23.79	\$26.96	\$22.19
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	\$28.00
Davis Besse	894	-	-	-	\$39.68	\$31.68	\$36.10	\$47.21	\$31.94	\$27.80	\$28.85	\$34.44	\$26.33
Dresden	1,797	\$48.76	\$28.27	\$32.73	\$33.07	\$28.42	\$31.82	\$39.22	\$27.45	\$25.89	\$26.35	\$28.25	\$23.41
Hope Creek	1,172	\$73.34	\$39.43	\$48.03	\$45.52	\$33.07	\$37.43	\$51.99	\$32.41	\$23.20	\$26.78	\$32.93	\$22.45
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	\$22.75
Limerick	2,242	\$73.49	\$39.49	\$48.23	\$45.27	\$33.09	\$37.28	\$51.71	\$32.65	\$23.37	\$26.99	\$33.08	\$22.68
North Anna	1,892	\$75.14	\$39.89	\$50.59	\$45.47	\$33.87	\$38.55	\$53.37	\$38.05	\$30.50	\$31.27	\$38.44	\$27.39
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	\$23.68
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	\$21.58
Perry	1,240	-	-	\$36.99	\$38.76	\$31.68	\$36.69	\$46.14	\$32.77	\$27.84	\$29.91	\$37.24	\$26.76
Quad Cities	1,819	\$47.28	\$24.81	\$27.53	\$26.79	\$20.43	\$25.94	\$30.71	\$19.47	\$18.04	\$23.09	\$25.54	\$21.13
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	\$22.43
Surry	1,676	\$71.96	\$39.02	\$49.30	\$45.01	\$33.62	\$37.98	\$51.75	\$37.91	\$30.08	\$31.08	\$38.50	\$26.65
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	\$21.08
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	\$23.47

³² Installed capacity is from NEI, "Map of U.S. Nuclear Plants," <<https://www.nei.org/resources/map-of-us-nuclear-plants>>.

³³ See "Resources Designated in 2021/2022 FRR Capacity Plans as of May 1, 2018," <<https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-resources-designated-in-frr-plans.ashx?a=en>>.

Table 7-16 BRA capacity market clearing prices (\$/MW-Day): 2008 through 2021³⁴

	ICAP (MW)	BRA Capacity Price (\$/MW-Day)														
		07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
Beaver Valley	1,808	\$41	\$112	\$102	\$174	\$110	\$16	\$28	\$126	\$136	\$59	\$120	\$165	\$100	\$77	\$140
Braidwood	2,337	\$41	\$112	\$102	\$174	\$110	\$16	\$28	\$126	\$136	\$59	\$120	\$215	\$203	\$188	\$196
Byron	2,300	\$41	\$112	\$102	\$174	\$110	\$16	\$28	\$126	\$136	\$59	\$120	\$215	\$203	\$188	\$196
Calvert Cliffs	1,708	\$189	\$210	\$237	\$174	\$110	\$133	\$226	\$137	\$167	\$119	\$120	\$165	\$100	\$86	\$140
Davis Besse	894	-	-	-	-	\$109	\$20	\$28	\$126	\$357	\$114	\$120	\$165	\$100	\$77	\$171
Dresden	1,797	\$41	\$112	\$102	\$174	\$110	\$16	\$28	\$126	\$136	\$59	\$120	\$215	\$203	\$188	\$196
Hope Creek	1,172	\$198	\$149	\$191	\$174	\$110	\$140	\$245	\$137	\$167	\$119	\$120	\$225	\$120	\$188	\$166
LaSalle	2,271	\$41	\$112	\$102	\$174	\$110	\$16	\$28	\$126	\$136	\$59	\$120	\$215	\$203	\$188	\$196
Limerick	2,242	\$198	\$149	\$191	\$174	\$110	\$140	\$245	\$137	\$167	\$119	\$120	\$225	\$120	\$188	\$166
North Anna	1,892	\$41	\$112	\$102	\$174	\$110	\$16	\$28	\$126	\$136	\$59	\$120	\$165	\$100	\$77	\$140
Oyster Creek	608	\$198	\$149	\$191	\$174	\$110	\$140	\$245	\$137	\$167	\$119	\$120	\$225	\$120	\$188	-
Peach Bottom	2,347	\$198	\$149	\$191	\$174	\$110	\$140	\$245	\$137	\$167	\$119	\$120	\$225	\$120	\$188	\$166
Perry	1,240	-	-	-	-	\$109	\$20	\$28	\$126	\$357	\$114	\$120	\$165	\$100	\$77	\$171
Quad Cities	1,819	\$41	\$112	\$102	\$174	\$110	\$16	\$28	\$126	\$136	\$59	\$120	\$215	\$203	\$188	\$196
Salem	2,328	\$198	\$149	\$191	\$174	\$110	\$140	\$245	\$137	\$167	\$119	\$120	\$225	\$120	\$188	\$166
Surry	1,676	\$41	\$112	\$102	\$174	\$110	\$16	\$28	\$126	\$136	\$59	\$120	\$165	\$100	\$77	\$140
Susquehanna	2,520	\$41	\$112	\$191	\$174	\$110	\$133	\$226	\$137	\$167	\$119	\$120	\$165	\$100	\$86	\$140
Three Mile Island	803	\$41	\$112	\$191	\$174	\$110	\$133	\$226	\$137	\$167	\$119	\$120	\$165	\$100	\$86	\$140

³⁴ Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <<http://www.exeloncorp.com/newsroom/oyster-creek-retires>>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <<https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>>.

Capacity revenues are not presented for calendar year 2022 because the 2022/2023 BRA has not been run.

Table 7-17 Nuclear unit capacity market revenue (\$/MWh): 2008 through 2021^{35 36}

	ICAP (MW)	Capacity Revenue (\$/MWh)													
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	\$3.57	\$4.50	\$6.23	\$5.87	\$2.41	\$1.01	\$3.70	\$5.75	\$3.96	\$4.17	\$6.42	\$5.61	\$3.82	\$5.03
Braidwood	2,337	\$3.57	\$4.50	\$6.23	\$5.87	\$2.41	\$1.01	\$3.70	\$5.75	\$3.96	\$4.17	\$7.71	\$9.20	\$8.60	\$8.52
Byron	2,300	\$3.57	\$4.50	\$6.23	\$5.87	\$2.41	\$1.01	\$3.70	\$5.75	\$3.96	\$4.17	\$7.71	\$9.20	\$8.60	\$8.52
Calvert Cliffs	1,708	\$8.73	\$9.59	\$8.64	\$5.87	\$5.38	\$8.21	\$7.53	\$6.74	\$6.04	\$5.26	\$6.42	\$5.62	\$4.07	\$5.21
Davis Besse	894	NA	NA	NA	NA	\$2.49	\$1.08	\$3.70	\$11.40	\$9.33	\$5.17	\$6.42	\$5.61	\$3.82	\$5.85
Dresden	1,797	\$3.57	\$4.50	\$6.23	\$5.87	\$2.41	\$1.01	\$3.70	\$5.75	\$3.96	\$4.17	\$7.71	\$9.20	\$8.60	\$8.52
Hope Creek	1,172	\$7.33	\$7.37	\$7.82	\$5.87	\$5.54	\$8.81	\$7.87	\$6.74	\$6.04	\$5.26	\$7.98	\$7.24	\$7.06	\$7.74
LaSalle	2,271	\$3.57	\$4.50	\$6.23	\$5.87	\$2.41	\$1.01	\$3.70	\$5.75	\$3.96	\$4.17	\$7.71	\$9.20	\$8.60	\$8.52
Limerick	2,242	\$7.33	\$7.37	\$7.82	\$5.87	\$5.54	\$8.81	\$7.87	\$6.74	\$6.04	\$5.26	\$7.98	\$7.24	\$7.06	\$7.74
North Anna	1,892	\$3.57	\$4.50	\$6.23	\$5.87	\$2.41	\$1.01	\$3.70	\$5.75	\$3.96	\$4.17	\$6.42	\$5.61	\$3.82	\$5.03
Oyster Creek	608	\$7.33	\$7.37	\$7.82	\$5.87	\$5.54	\$8.81	\$7.87	\$6.74	\$6.04	\$5.26	NA	NA	NA	NA
Peach Bottom	2,347	\$7.33	\$7.37	\$7.82	\$5.87	\$5.54	\$8.81	\$7.87	\$6.74	\$6.04	\$5.26	\$7.98	\$7.24	\$7.06	\$7.74
Perry	1,240	NA	NA	NA	NA	\$2.49	\$1.08	\$3.70	\$11.40	\$9.33	\$5.17	\$6.42	\$5.61	\$3.82	\$5.85
Quad Cities	1,819	\$3.57	\$4.50	\$6.23	\$5.87	\$2.41	\$1.01	\$3.70	\$5.75	\$3.96	\$4.17	\$7.71	\$9.20	\$8.60	\$8.52
Salem	2,328	\$7.33	\$7.37	\$7.82	\$5.87	\$5.54	\$8.81	\$7.87	\$6.74	\$6.04	\$5.26	\$7.98	\$7.24	\$7.06	\$7.74
Surry	1,676	\$3.57	\$4.50	\$6.23	\$5.87	\$2.41	\$1.01	\$3.70	\$5.75	\$3.96	\$4.17	\$6.42	\$5.61	\$3.82	\$5.03
Susquehanna	2,520	\$3.57	\$6.72	\$7.82	\$5.87	\$5.38	\$8.21	\$7.53	\$6.74	\$6.04	\$5.26	\$6.42	\$5.61	\$4.07	\$5.21
Three Mile Island	803	\$3.57	\$6.72	\$7.82	\$5.87	\$5.38	\$8.21	\$7.53	\$6.74	\$6.04	\$5.26	\$6.42	\$5.61	\$4.07	\$5.21

³⁵ Capacity revenue calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the 2019 class average capacity factor of 0.933 percent. Class average capacity factor is from 2019 State of the Market Report for PJM, Volume 2, Section 5: Capacity Market.

³⁶ Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <<http://www.exeloncorp.com/newsroom/oyster-creek-retires>>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <<https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>>.

Table 7-18 Nuclear unit costs: 2008 through 2019^{37 38}

	ICAP (MW)	NEI Costs (\$/MWh)											
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Beaver Valley	1,808	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Braidwood	2,337	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Byron	2,300	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Calvert Cliffs	1,708	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Davis Besse	894	\$35.31	\$39.36	\$41.23	\$45.45	\$47.41	\$44.16	\$44.32	\$44.51	\$41.39	\$42.66	\$42.00	\$38.40
Dresden	1,797	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Hope Creek	1,172	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
LaSalle	2,271	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Limerick	2,242	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
North Anna	1,892	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Oyster Creek	608	\$35.31	\$39.36	\$41.23	\$45.45	\$47.41	\$44.16	\$44.32	\$44.51	\$41.39	\$42.66	NA	NA
Peach Bottom	2,347	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Perry	1,240	\$35.31	\$39.36	\$41.23	\$45.45	\$47.41	\$44.16	\$44.32	\$44.51	\$41.39	\$42.66	\$42.00	\$38.40
Quad Cities	1,819	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Salem	2,328	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Surry	1,676	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Susquehanna	2,520	\$26.73	\$29.76	\$31.34	\$34.51	\$36.06	\$33.84	\$33.84	\$32.90	\$31.63	\$30.89	\$29.07	\$28.38
Three Mile Island	803	\$35.31	\$39.36	\$41.23	\$45.45	\$47.41	\$44.16	\$44.32	\$44.51	\$41.39	\$42.66	\$42.00	NA

Table 7-19 shows the surplus or shortfall in \$/MWh for the 16 nuclear plants in PJM and Oyster Creek and Three Mile Island calculated using historic LMP and cost data. In 2016, 13 nuclear plants, with a total capacity of 25,075 MW, in addition to Oyster Creek and Three Mile Island, did not recover all their fuel costs, operating costs, and capital expenditures. In 2017, seven nuclear plants with a total capacity of 12,658 MW, in addition to Oyster Creek and Three Mile Island, did not recover all their fuel costs, operating costs, and capital expenditures. In 2018, one nuclear plant, with a total capacity of 894 MW, in addition to Oyster Creek and Three Mile Island, did not recover all its fuel costs, operating costs, and capital expenditures. In 2019, two nuclear plants, with a total capacity of 4,654 MW, in addition to Three Mile Island, did not recover all their fuel costs, operating costs, and capital expenditures. Although Susquehanna shows a shortfall in 2019, cost reductions mean that Susquehanna did cover their fuel costs, operating costs, and capital expenditures.³⁹ The

37 Operating costs from: Nuclear Energy Institute (October, 2020). "Nuclear Costs in Context," <<https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>>.

38 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <<http://www.exeloncorp.com/newsroom/oyster-creek-retires>>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <<https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>>.

39 Talen Energy Investor Day, February 12, 2019.

surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.⁴⁰ Unforced capacity is determined using the annual class average EFORD rate.

The market revenues are based in part on the sale of capacity. Some nuclear plants did not clear the capacity market as a result of decisions by plant owners about how to offer the plants. When nuclear plants do not clear in the capacity market, it is a result of the offer behavior of the plants and does not reflect the economic viability of the plants unless the plants offer accurate net avoidable costs and fail to clear. This analysis is intended to define whether the

plants are receiving a retirement signal from the PJM markets. If the plants are viable including both energy and capacity market revenues based on actual clearing prices, then the PJM markets indicate that the plant is economically viable. If plant owners decide to offer so as to not clear in the capacity market, that does not change the market signals to the plants. Such decisions may reflect a variety of considerations. Three Mile Island did not clear in the 2018/2019 Auction⁴¹ and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear in the 2019/2020 Auction.⁴² Three Mile Island and Quad Cities did not clear in the 2020/2021 Auction.⁴³ Three Mile Island, Dresden, and most of Byron did not clear in the 2021/2022 Auction.⁴⁴ Beaver Valley, Davis Besse, and Perry did not clear in the 2021/2022 Auction.⁴⁵

40 Installed capacity is from NEI. "Maps of U.S. Nuclear Plants," <<https://www.nei.org/resources/map-of-us-nuclear-plants>>.

41 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <<http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>>.

42 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <<http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>>.

43 Exelon. "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <<http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>>.

44 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>>.

45 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>>.

Nuclear unit revenue is a combination of energy market revenue, ancillary market revenue and capacity market revenue. Negative prices do not have a significant impact on nuclear unit revenue. Since 2014, negative prices have affected nuclear plants' annual total revenues by an average of 0.1 percent. Negative LMPs reduced nuclear plant total revenues by an average of 0.0 percent and a maximum of 0.6 percent in 2014, an average of 0.2 percent and a maximum of 1.2 percent in 2015, an average of 0.1 percent and a maximum of 0.7 percent in 2016, an average of 0.0 percent and a maximum of 0.6 percent in 2017, an average of 0.0 percent and a maximum of 0.0 percent in 2018, an average of 0.0 percent and a maximum of 0.2 percent in 2019, and an average of 0.1 percent and a maximum of 1.0 percent in 2020.⁴⁶

Table 7-19 Nuclear unit surplus (shortfall) based on public data: 2008 through 2019⁴⁷

	ICAP (MW)	Surplus (Shortfall) (\$/MWh)											
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Beaver Valley	1,808	\$26.3	\$6.3	\$10.5	\$8.8	(\$3.3)	\$1.4	\$11.7	\$3.2	(\$0.4)	\$2.6	\$13.9	\$3.7
Braidwood	2,337	\$24.9	\$2.5	\$6.4	\$3.4	(\$6.1)	(\$2.6)	\$7.2	(\$1.2)	(\$3.1)	(\$1.5)	\$6.0	\$3.9
Byron	2,300	\$24.5	(\$1.3)	\$3.4	(\$0.6)	(\$9.4)	(\$3.6)	\$4.9	(\$6.1)	(\$9.5)	(\$2.7)	\$5.8	\$3.2
Calvert Cliffs	1,708	\$60.6	\$20.9	\$28.6	\$17.9	\$4.5	\$14.6	\$31.6	\$14.1	\$7.2	\$6.1	\$16.3	\$5.4
Davis Besse	894	NA	NA	NA	NA	(\$13.2)	(\$7.0)	\$6.6	(\$1.2)	(\$4.0)	(\$8.4)	(\$0.9)	(\$6.2)
Dresden	1,797	\$25.6	\$3.0	\$7.6	\$4.4	(\$5.2)	(\$1.0)	\$9.1	\$0.3	(\$1.5)	(\$0.0)	\$7.2	\$4.6
Hope Creek	1,172	\$54.0	\$17.0	\$24.5	\$16.9	\$2.6	\$12.4	\$26.0	\$6.3	(\$2.0)	\$1.6	\$12.3	\$1.7
LaSalle	2,271	\$24.8	\$2.5	\$6.4	\$3.3	(\$6.1)	(\$1.9)	\$7.7	(\$0.9)	(\$3.5)	(\$1.8)	\$6.0	\$3.7
Limerick	2,242	\$54.1	\$17.1	\$24.7	\$16.6	\$2.6	\$12.2	\$25.7	\$6.5	(\$2.1)	\$1.5	\$12.1	\$1.7
North Anna	1,892	\$52.0	\$14.6	\$25.5	\$16.8	\$0.2	\$5.7	\$23.2	\$10.9	\$3.0	\$4.7	\$16.0	\$4.8
Oyster Creek	608	\$47.5	\$8.4	\$15.9	\$7.2	(\$8.2)	\$3.3	\$16.4	(\$4.7)	(\$11.6)	(\$9.9)	NA	NA
Peach Bottom	2,347	\$53.7	\$16.9	\$24.2	\$16.1	\$2.3	\$12.3	\$25.5	\$5.8	(\$2.2)	\$1.4	\$11.8	\$0.7
Perry	1,240	NA	NA	NA	NA	(\$13.2)	(\$6.4)	\$5.5	(\$0.3)	(\$4.0)	(\$7.3)	\$1.9	(\$5.8)
Quad Cities	1,819	\$24.1	(\$0.4)	\$2.4	(\$1.8)	(\$13.2)	(\$6.9)	\$0.6	(\$7.7)	(\$9.5)	(\$3.5)	\$4.4	\$2.1
Salem	2,328	\$54.0	\$17.1	\$24.5	\$16.9	\$2.6	\$12.4	\$26.0	\$6.2	(\$2.3)	\$1.3	\$11.9	\$1.4
Surry	1,676	\$48.8	\$13.8	\$24.2	\$16.4	(\$0.0)	\$5.1	\$21.6	\$10.8	\$2.6	\$4.5	\$16.0	\$4.1
Susquehanna	2,520	\$46.8	\$15.2	\$22.4	\$16.1	\$1.4	\$11.1	\$24.6	\$6.3	(\$1.6)	\$1.8	\$10.0	(\$1.4)
Three Mile Island	803	\$40.7	\$6.5	\$13.3	\$4.6	(\$9.6)	\$0.9	\$13.7	(\$6.8)	(\$12.4)	(\$10.3)	(\$3.8)	NA

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2020, 2021 and 2022 and known capacity market prices for 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 7-20 shows PJM energy prices (LMP), annual fuel, operating and capital expenditures, and the required capacity revenue for total revenues to equal total costs for the 2020 through 2022 period. Capacity revenues are not presented for calendar year 2022 because the 2022/2023 BRA has not been run. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.⁴⁸ Forward prices are as of October 1, 2020. The 2020 energy prices include

⁴⁶ Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for comparison. Results round to 0.0 percent.

⁴⁷ The values for 2016 through 2019 have changed slightly from previous values to account for reactive supply and voltage control revenues.

⁴⁸ Forward prices on October 1, 2020. 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 2019 data.

actual day-ahead market prices through September 30, 2020, and forward prices for October through December 2020. The capacity prices are known based on PJM capacity auction results.

Table 7-20 Forward prices in PJM energy markets, capacity revenue, and annual costs⁴⁹

	ICAP (MW)	Average Forward LMP (\$/MWh)			Ancillary Revenue (\$/MWh) Reactive	Capacity Revenue (\$/MWh)		2019 NEI Costs (\$/MWh)		
		2020	2021	2022		2020	2021	Fuel	Operating	Capital
Beaver Valley	1,808	\$21.21	\$28.44	\$27.29	\$0.24	\$3.82	\$5.03	\$6.06	\$17.00	\$5.32
Braidwood	2,337	\$18.85	\$25.50	\$24.46	\$0.24	\$8.60	\$8.52	\$6.06	\$17.00	\$5.32
Byron	2,300	\$18.09	\$24.42	\$23.44	\$0.21	\$8.60	\$8.52	\$6.06	\$17.00	\$5.32
Calvert Cliffs	1,708	\$22.21	\$29.72	\$28.51	\$0.20	\$4.07	\$5.21	\$6.06	\$17.00	\$5.32
Davis Besse	894	\$21.31	\$28.37	\$27.21	\$0.24	\$3.82	\$5.85	\$6.50	\$24.60	\$7.30
Dresden	1,797	\$19.35	\$26.02	\$24.97	\$0.32	\$8.60	\$8.52	\$6.06	\$17.00	\$5.32
Hope Creek	1,172	\$18.00	\$25.49	\$24.53	\$0.43	\$7.06	\$7.74	\$6.06	\$17.00	\$5.32
LaSalle	2,271	\$18.76	\$25.35	\$24.33	\$0.18	\$8.60	\$8.52	\$6.06	\$17.00	\$5.32
Limerick	2,242	\$18.06	\$25.56	\$24.60	\$0.14	\$7.06	\$7.74	\$6.06	\$17.00	\$5.32
North Anna	1,892	\$21.61	\$29.28	\$28.09	\$0.17	\$3.82	\$5.03	\$6.06	\$17.00	\$5.32
Peach Bottom	2,347	\$17.59	\$24.70	\$23.77	\$0.28	\$7.06	\$7.74	\$6.06	\$17.00	\$5.32
Perry	1,240	\$21.34	\$29.04	\$27.87	\$0.24	\$3.82	\$5.85	\$6.50	\$24.60	\$7.30
Quad Cities	1,819	\$16.37	\$23.15	\$22.23	\$0.18	\$8.60	\$8.52	\$6.06	\$17.00	\$5.32
Salem	2,328	\$17.99	\$25.51	\$24.55	\$0.12	\$7.06	\$7.74	\$6.06	\$17.00	\$5.32
Surry	1,676	\$20.82	\$28.42	\$27.28	\$0.17	\$3.82	\$5.03	\$6.06	\$17.00	\$5.32
Susquehanna	2,520	\$16.36	\$23.51	\$22.57	\$0.28	\$4.07	\$5.21	\$6.06	\$17.00	\$5.32

The MMU also calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant. Under the Commission's December 19, 2019, MOPR Order, a competitive offer in the capacity market for a subsidized nuclear plant is defined to be net avoidable costs.⁵⁰ As a result, subsidized nuclear plants could make offers in the capacity market as low as but no lower than net avoidable costs. The capacity price required to cover net avoidable costs, when compared to recent capacity market prices, is an indicator of whether nuclear plants subject to the MOPR rules would clear in a capacity auction.

⁴⁹ Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <<http://www.exeloncorp.com/newsroom/oyster-creek-retires>>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <<https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>>.

⁵⁰ See 169 FERC ¶ 61,239 at P 148.

Based on the FERC order about inclusion of maintenance expense in energy offers, major maintenance costs can no longer be included in gross ACR values.⁵¹ The MMU calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant with major maintenance included in avoidable costs and with major maintenance excluded from

avoidable costs. For the case including major maintenance, gross ACR is NEI total cost including fuel; operating cost; and capital expenditures. For the case excluding major maintenance, gross ACR is NEI total cost including fuel and operating cost, excluding capital expenditures as a proxy for fixed VOM given that NEI does not provide a breakout of major maintenance. NEI capital expenditures are likely to be a conservatively low estimate of major maintenance expense.

While the FERC order on major maintenance defines a competitive offer under the MOPR order, all generating plants including nuclear plants must cover their gross avoidable costs, including major maintenance, to remain economically viable. All of the MMU analysis of nuclear plant economics includes gross avoidable costs as reported by NEI unless explicitly stated otherwise.

The capacity price required to cover avoidable costs in \$ per MWh is calculated by taking the total NEI costs in \$ per MWh and subtracting the total expected energy and ancillary services revenues in \$ per MWh. Total expected energy revenue is the average forward LMP. Total expected ancillary services revenue is reactive capability revenue.⁵² The capacity price required to cover avoidable costs in \$ per MW-day is calculated by multiplying the required price in \$ per MWh by 24. Plants may have actual operating costs higher or lower than the NEI average.

⁵¹ See 167 FERC ¶ 61,030 at P 41.

⁵² Reactive Supply & Voltage Control Revenue Requirements available from PJM <<https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx>>.

For 2022, using forward prices as of October 1, 2020, the capacity price required to cover avoidable costs ranges from \$0/MW-day for a multiple unit plant to \$245.04/MW-day for a single unit plant for NEI data as reported including major maintenance, and from \$0/MW-day for multiple unit plants to \$81.58/MW-day for a single unit plant, excluding capital expenditures as a proxy for major maintenance.

Table 7-21 Implied Net ACR

	ICAP (MW)	Net ACR (\$/MWh)			Net ACR (\$/MW-Day)			Net ACR Excluding Capital (\$/MW-Day)		
		2020	2021	2022	2020	2021	2022	2020	2021	2022
Beaver Valley	1,808	\$6.92	(\$0.30)	\$0.85	\$155.06	\$0.00	\$19.09	\$35.93	\$0.00	\$0.00
Braidwood	2,337	\$9.29	\$2.64	\$3.68	\$207.98	\$59.16	\$82.36	\$88.86	\$0.00	\$0.00
Byron	2,300	\$10.07	\$3.75	\$4.73	\$225.59	\$83.93	\$105.91	\$106.47	\$0.00	\$0.00
Calvert Cliffs	1,708	\$5.98	(\$1.54)	(\$0.33)	\$133.86	\$0.00	\$0.00	\$14.74	\$0.00	\$0.00
Davis Besse	894	\$16.85	\$9.79	\$10.94	\$377.20	\$219.23	\$245.04	\$213.73	\$55.77	\$81.58
Dresden	1,797	\$8.71	\$2.03	\$3.09	\$195.08	\$45.54	\$69.08	\$75.95	\$0.00	\$0.00
Hope Creek	1,172	\$9.95	\$2.46	\$3.42	\$222.85	\$55.18	\$76.65	\$103.73	\$0.00	\$0.00
LaSalle	2,271	\$9.44	\$2.84	\$3.87	\$211.29	\$63.69	\$86.71	\$92.16	\$0.00	\$0.00
Limerick	2,242	\$10.18	\$2.68	\$3.64	\$228.04	\$59.97	\$81.54	\$108.92	\$0.00	\$0.00
North Anna	1,892	\$6.60	(\$1.07)	\$0.13	\$147.78	\$0.00	\$2.82	\$28.66	\$0.00	\$0.00
Peach Bottom	2,347	\$10.50	\$3.39	\$4.33	\$235.17	\$75.97	\$96.88	\$116.04	\$0.00	\$0.00
Perry	1,240	\$16.81	\$9.12	\$10.29	\$376.50	\$204.26	\$230.47	\$213.04	\$40.80	\$67.01
Quad Cities	1,819	\$11.84	\$5.05	\$5.97	\$265.04	\$113.07	\$133.66	\$145.92	\$0.00	\$14.54
Salem	2,328	\$10.27	\$2.74	\$3.70	\$229.93	\$61.45	\$82.89	\$110.80	\$0.00	\$0.00
Surry	1,676	\$7.39	(\$0.21)	\$0.94	\$165.45	\$0.00	\$20.98	\$46.33	\$0.00	\$0.00
Susquehanna	2,520	\$11.74	\$4.59	\$5.53	\$262.87	\$102.81	\$123.82	\$143.74	\$0.00	\$4.69

Table 7-22 shows the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, on a per MWh basis. The fuel and operating costs are the 2019 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-22 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor.

Changes in forward energy market prices can significantly affect expected profitability of nuclear plants in PJM. The current analysis, based on forward prices for energy and known forward prices for capacity, shows that no plants would cover their annual avoidable costs in 2020 but that only two plants, Davis Besse and Perry would not cover their annual avoidable costs in 2021. These two plants are single unit sites which have higher operating costs per MWh than multiple unit plants and show an annual shortfall of \$3.94 and \$3.27 per MWh in 2021. In March 2018, Davis Besse and Perry requested deactivation in 2021 but reversed the decision based on new subsidies in Ohio.

Table 7-22 Nuclear unit forward annual surplus (shortfall)⁵³

	ICAP (MW)	Surplus (Shortfall) (\$/MWh)		Surplus (Shortfall) (\$ in millions)	
		2020	2021	2020	2021
Beaver Valley	1,808	(\$3.11)	\$5.34	(\$46.0)	\$78.9
Braidwood	2,337	(\$0.69)	\$5.88	(\$13.3)	\$112.3
Byron	2,300	(\$1.48)	\$4.77	(\$27.9)	\$89.7
Calvert Cliffs	1,708	(\$1.91)	\$6.75	(\$26.7)	\$94.2
Davis Besse	894	(\$13.03)	(\$3.94)	(\$95.4)	(\$28.8)
Dresden	1,797	(\$0.12)	\$6.49	(\$1.7)	\$95.3
Hope Creek	1,172	(\$2.89)	\$5.28	(\$27.8)	\$50.6
LaSalle	2,271	(\$0.84)	\$5.68	(\$15.6)	\$105.3
Limerick	2,242	(\$3.12)	\$5.06	(\$57.3)	\$92.8
North Anna	1,892	(\$2.78)	\$6.10	(\$43.1)	\$94.4
Peach Bottom	2,347	(\$3.44)	\$4.35	(\$66.1)	\$83.4
Perry	1,240	(\$12.99)	(\$3.27)	(\$132.1)	(\$33.2)
Quad Cities	1,819	(\$3.24)	\$3.47	(\$48.3)	\$51.6
Salem	2,328	(\$3.20)	\$5.00	(\$61.1)	\$95.1
Surry	1,676	(\$3.57)	\$5.24	(\$49.0)	\$71.8
Susquehanna	2,520	(\$7.67)	\$0.62	(\$158.5)	\$12.7

⁵³ Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <<http://www.exeloncorp.com/newsroom/oyster-creek-retires>>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <<https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>>.

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 affected offer behavior in the capacity market. Expectations about the cost and life of such investments and about future capacity and energy prices have affected retirement decisions. The markets have also provided incentives for new, lower emissions units to enter.

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 if they increased transparency. States could evaluate the impacts of a range of carbon prices if PJM would provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. A single carbon price across PJM, established by the states, would be the most efficient way to reduce carbon output, if that is the goal.

Overview

Federal Environmental Regulation

- **MATS.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.¹ On May 22, 2020, the EPA published its determination that MATS is not appropriate and necessary based on a cost-benefit analysis.² The list of coal steam units subject to MATS, however, remains in place.³ All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.
- **Air Quality Standards (NO_x and SO₂ 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.⁴
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.⁵ NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits. Recent EPA proposals would reduce the number of projects that require permits.
- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.⁶ RICE do not have to meet the same emissions standards if they are emergency stationary RICE. Environmental regulations allow emergency stationary RICE participating in demand response programs to operate for up to

¹ *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).

² *See National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, Docket No. EPA-HQ-OAR-2018-0794, 85 Fed. Reg. 31286.

³ *Id.* at 31291.

⁴ CAA § 110(a)(2)(D)(i)(I).

⁵ *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).

⁶ See 40 CFR § 63.6640(f).

100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

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

- **Greenhouse Gas Emissions.** On June 19, 2019, the EPA repealed the Clean Power Plan⁷ and replaced it with the Affordable Clean Energy (ACE) rule, which establishes guidelines for states to develop plans to address greenhouse gas emissions from existing coal fired power plants.⁸ Under the ACE Rule states may permit more CO₂ emissions than under the Clean Power Plan.
- **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.⁹
- **Waters of the United States.** The EPA finalized a rule that significantly narrows the definition of the Waters of the United States. In contrast, the Supreme Court expanded the scope of the CWA when it held that discharge of pollutants from a point source into non jurisdictional groundwater “is the functional equivalent of a direct discharge” when pollutants are conveyed by groundwater into jurisdictional waters.¹⁰

⁷ Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (Aug. 3, 2015) (Clean Power Plan). The Clean Power Plan never took effect because it was subject to a stay issued by the U.S. Supreme Court.

⁸ See *Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*, EPA Docket No. EPA-HQ-OAR-2017-0355, et al., 84 Fed. Reg. 32520 (July 8, 2019).

⁹ 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).

¹⁰ *County of Maui v. Hawaii Wildlife Fund*, Slip. Op. No. 18–260 (April 23, 2020).

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.¹¹ The EPA has proposed significant changes to the implementing regulations.

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO₂ 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 rejoined on January 1, 2020.¹² Virginia and Pennsylvania are preparing to join.^{13 14} The auction price in the September 2, 2020, auction for the 2018/2020 compliance period was \$6.82 per ton, or \$7.52 per metric tonne.
- **Carbon Price.** If the price of carbon were \$50.00 per metric tonne, short run marginal costs would increase by \$24.52 per MWh or 132.5 percent for a new combustion turbine (CT) unit, \$16.71 per MWh or 130.3 percent for a new combined cycle (CC) unit and \$43.15 per MWh or 158.6 percent for a new coal plant (CP) in 2020.

State Renewable Portfolio Standards

- **RPS.** In PJM, nine of 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers’ load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of September 30, 2020, 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, Tennessee and West Virginia did not have renewable portfolio standards.

¹¹ 42 U.S.C. §§ 6901 *et seq.*

¹² “Statement on New Jersey Greenhouse Gas Rule,” RGGI Inc., (June 17, 2019), <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.

¹³ See Regulation for Emissions Trading, 9 VAC 5–140. The Virginia Air Pollution Control Board is developing the regulation and considering public comments.

¹⁴ Executive Order – 2019-07– Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <<https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>>.

- **RPS Cost.** The cost of complying with RPS, as reported by the states, is \$4.5 billion over the five year period from 2014 through 2018, an average annual RPS compliance cost of \$893.1 million. The compliance cost for 2018, the most recent year with complete data, was \$986.9 million.

Emissions Controls in PJM Markets

- **Regulations.** Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology.
- **Emissions Controls.** In PJM, as of September 30, 2020, 93.9 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO₂ emissions, while 99.9 percent of coal steam MW had some type of particulate control, and 94.8 percent of fossil fuel fired capacity had NO_x emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 4.3 percent of total generation in PJM in the first nine months of 2020. RPS Tier I generation was 5.0 percent of total generation in PJM and RPS Tier II generation was 1.9 percent of total generation in PJM in the first nine months of 2020. Only Tier I generation is defined to be renewable but Tier I includes some carbon emitting generation.

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 REC markets because, given market changes since

that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. First reported 2018. Status: Not adopted.)

- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. 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.¹⁵ The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over REC markets

¹⁵ 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.”).

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. FERC's recent MOPR order addressed these impacts.

RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO on behalf of the states that would meet the standards and requirements of all states in the PJM footprint 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 provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to states in order to permit states to 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.

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 \$6.33 per tonne in Washington, DC to \$18.22 per tonne in New Jersey. The price of carbon implied by SREC prices ranges from \$62.89 per tonne in Pennsylvania to \$878.57 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in September 2020 of \$7.52 per tonne and to the social cost of carbon which is estimated in the range of \$50 per tonne.¹⁶ The impact on the cost of generation from a new combined cycle unit of a \$50 per tonne carbon price would be \$16.71 per MWh.¹⁷ The impact of an \$800 per tonne carbon price would be \$267.30 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

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

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

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

¹⁶ "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>.

¹⁷ The cost impact calculation assumes a heat rate of 6,296 MMBtu per MWh and a carbon emissions rate of 0.053070 tonne per MMBtu. The \$800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2019 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-18.

to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. A mechanism like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide modeling information to the states adequate to inform such a decision making process. Such modeling information would include the impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state. This would permit states to make critical decisions about carbon pricing. For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

The annual average cost of complying with RPS over the five year period from 2014 through 2018 for the nine jurisdictions that had RPS was \$893.1 million, or a total of \$4.5 billion over five years. The RPS compliance cost for 2018, the most recent year for which there is complete data, was \$986.9 million. RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately \$2.5 billion per year if the carbon price were \$6.82 per short

ton and emissions levels were five percent below 2019 emission levels. If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately \$18.0 billion if the carbon price were \$50 per short ton and emission levels were five percent below 2019 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at \$6.82 per short ton would be about \$1.4 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), the Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA), all of which address pollution created by electric power production. The administration of these statutes is relevant to the operation of PJM markets.¹⁸

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.^{19 20}

The CWA regulates discharges from point sources that affect water quality and temperature.

The Resource Conservation and Recovery Act (RCRA) regulates the disposal of solid and hazardous waste.²¹ Regulation of coal ash or coal combustion residuals affects coal fired power plants.

The EPA's actions have affected and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

¹⁸ For more details, see the *2019 State of the Market Report for PJM*, Vol. 2, Appendix H: "Environmental and Renewable Energy Regulations."

¹⁹ 42 U.S.C. § 7401 et seq. (2000).

²⁰ 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.

²¹ 42 U.S.C. §§ 6901 et seq.

CAA: NESHAP/MATS

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the 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.

On May 22, 2020, the EPA published a rule finalizing its Supplemental Cost Finding for the MATS, and the risk and technology review required by the CAA.²² The EPA determined that the estimated cost to coal and oil fired power plants of complying with the MATS rule in 2015 outweighed the estimated quantifiable benefits attributable to regulating hazardous air pollutant (HAP) emissions in 2015.²³ The EPA determined that based on analysis of costs versus benefits it is not “appropriate and necessary” to regulate HAP emissions from power plants under Section 112 of the Clean Air Act.²⁴ ²⁵ The immediate practical effect is limited because the emission standards and other requirements of the 2012 MATS rule remain in place and the list of coal and oil fired power plants regulated under Section 112 of the Act remains in place.²⁶ Removal of the appropriate and necessary finding creates the possibility of a challenge to the MATS rule if applied to the proposed construction or upgrade of a power plant.

On April 9, 2020, the EPA finalized a rule establishing a new sub category in the MATS with less stringent requirements for units fueled by eastern bituminous refuse coal, waste coal.²⁷ The rule allows four refuse coal plants,

²² See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, Docket No. EPA-HQ-OAR-2018-0794, 85 Fed. Reg. 31286.

²³ *Id.* at 31299.

²⁴ *Michigan v. EPA*, 135 S.Ct. 2699 (2015) (reversed EPA determination that cost does not have to be read into the definition of “appropriate”).

²⁵ 85 Fed. Reg. at 31288.

²⁶ *Id.* at 31291. The EPA explains (*id.*): “The Court’s holding in *New Jersey* [517 F.3d 574 (D.C. Cir. 2008)] plainly states that CAA section 112(c) (9) ‘unambiguously limit[s] EPA’s discretion to remove sources, including EGUs, from the section 112(c)(1) list once they have been added to it.’ 517 F.3d 574, 583 (D.C. Cir. 2008).”

²⁷ See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Subcategory of Certain Existing Electric Utility Steam Generating Units Firing Eastern Bituminous Coal Refuse for Emissions of Acid Gas Hazardous Air Pollutants*, Docket No. EPA-HQ-OAR-2018-0794, 85 Fed. Reg. 20838 (April 15, 2020).

Grant Town Power Plant (Unit 1A and 1 B (40 MW each)) in West Virginia; and Colver Power Project (110 MW), Ebensburg Power Plant (50 MW), and Scrubgrass Generating Co. (Units 1 and 2 (42 MW each)) in Pennsylvania; to emit higher levels of acid gases and SO₂.²⁸ The EPA stated that it was concerned that units would close and leave coal refuse piles, which are prone to smoldering and emit uncontrolled acid gases and other HAP.²⁹

CAA: NAAQS/CSAPR

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, SO₂, O₃ 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. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO₂ and NO_x that cross state lines and contribute to ozone and fine particle pollution in other states. CSAPR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS. CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.³⁰

Figure 8-1 shows average, monthly settled prices for NO_x, CO₂ and SO₂ emissions allowances including CSAPR related allowances for January 1, 2019, through September 30, 2020. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO₂ allowances.

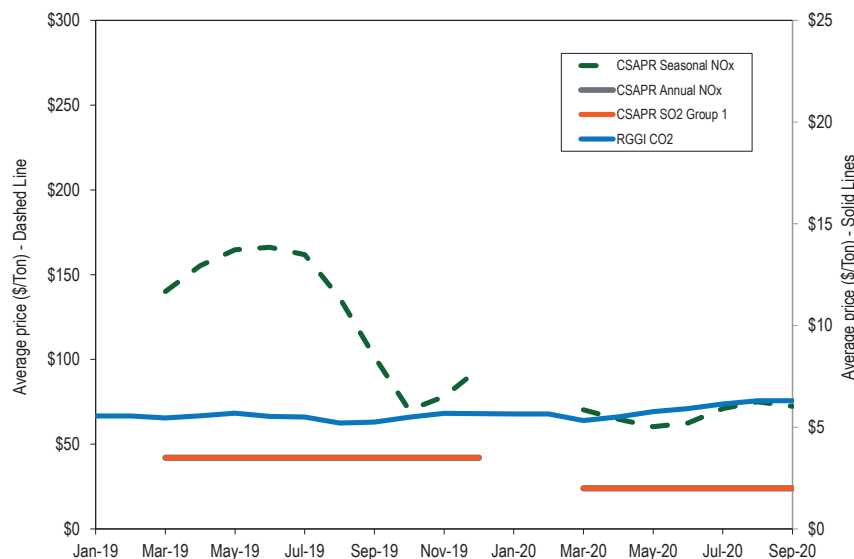
²⁸ *Id.* at 20841.

²⁹ *Id.* at 20847.

³⁰ 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. 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. U.S. Court of Appeals for the D.C. Circuit Case No. 18-1285. On May 15, 2020, the Court denied an appeal of the EPA decision filed by Maryland, except that the Court agreed that EPA did not sufficiently support its rejection based on the cost effectiveness of Maryland’s request that two waste coal plants, Cambria Cogeneration (Pa.) and Grant Town Cogen (W.Va.), be required to operate selective noncatalytic reduction (SNCR) controls, and remanded the decision. *Maryland v. Wheeler*, Case No. 18-1285 (D.C. Cir. May 19, 2020).

In the first nine months of 2020, CSAPR annual NO_x prices were 42.9 percent lower than in the first nine months of 2019. In the first nine months of 2020, CSAPR Seasonal NO_x prices were 53.6 percent lower than in the first nine months of 2019.

Figure 8-1 Spot monthly average emission price comparison: January 2019 through September 2020



CAA: NSR

Parts C and D of Title I of the CAA provide for New Source Review (NSR) in order to prevent new projects and projects receiving major modifications from increasing emissions in areas currently meeting NAAQS or from inhibiting progress in areas that do not.³¹ NSR requires permits before construction commences. In PJM, permits are issued by state environmental regulators, or in a process involving state and regional EPA regulators.³²

³¹ 42 U.S.C § 7470 et seq.

³² CAA permitting in EPA Region 2 (New Jersey) is the responsibility of the state's environmental regulatory authority; CAA permitting in Region 3 (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia) is the shared responsibility of each state's environmental regulatory authority and EPA Region 3; CAA permitting in Region 4 (Kentucky and North Carolina) is the shared responsibility of each state's environmental regulatory authority and EPA Region 4; CAA permitting in EPA Region 5 (Illinois, Indiana, Michigan and Ohio) is the responsibility of each state's environmental regulatory authority.

NSR review applies a two part analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and existing units. The first part considers whether a modification would cause a “significant emission increase” of a regulated NSR pollutant. The second part considers whether any identified increase is also a “significant net emission increase.”

On August 1, 2019, the EPA proposed revisions to the NSR permitting program under which, both emissions increases and decreases from a major modification would be considered in the first part of the NSR applicability test.³³ Under the revised rule the need for a permit and associated investments in pollution controls would be more frequently avoided than under the current rule.

The ACE rule as proposed on August 21, 2018, also included changes to NSR regulations.³⁴ These proposed NSR changes have been deferred to a separate future action.³⁵ As proposed, these NSR changes would apply to new units or existing units receiving major modifications. Under these proposed NSR changes, only modifications that increase a plant's hourly rate of emissions would be deemed major and require a two part 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. If accepted, fewer projects would be evaluated under the NSR analysis to determine whether an NSR permit is needed.

On March 25, 2020, the EPA released a memorandum changing the EPA's longstanding interpretation of “begin actual construction” under the NSR preconstruction permitting regulations.³⁶ EPA policy has been to preclude almost every physical onsite construction activity that is of a permanent nature prior to issuance of a permit. Under the new interpretation, which focuses on the statutory meaning of “emissions unit,”³⁸ the policy precludes

³³ *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).

³⁴ 82 Fed. Reg. 48035.

³⁵ 84 Fed. Reg. 32520, 32521.

³⁶ See Anne L. Idsal, Principal Deputy Assistant Administrator, Memorandum re Interpretation of “Begin Actual Construction” Under the New Source Review Preconstruction Permitting Regulations” (“March 25th Memo”).

³⁷ See 40 CFR § 52.21(b)(11); 40 CFR § 52.21(a)(2)(iii).

³⁸ 40 CFR § 52.21(b)(7) (“any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit...”).

only the construction of the emissions unit. The EPA clarified that the costs and consequences of pre permit construction are risks born by the owner/operators if no permit issues, or issues without the expected terms or conditions. The new interpretation significantly expands the scope of activity that an owner/operator willing to assume the risks may undertake prior to receiving an NSR permit when constructing a project that will include an emissions unit.

CAA: RICE

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules). The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_x, volatile organic compounds (VOCs) and PM.

EPA regulations require that RICE that do not meet EPA emissions standards (emergency stationary RICE) may operate for only 100 hours per year and only to provide emergency DR during an Energy Emergency Alert 2 (EEA2), or if there are five percent voltage/frequency deviations.³⁹ Under PJM rules, an EEA2 is automatically triggered when PJM initiates an emergency load response event. Demand resources that rely on RICE to provide load reductions are constrained to a maximum of 100 hours.

PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet emissions standards are now included in DR portfolios. There are 785.9 MW of diesel RICE, 86.8 percent of registered diesel generators in demand response, that do not meet EPA

³⁹ Emergency Operations, EOP-011-1, North American Electric Reliability Corporation, <<https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf>> (Accessed March 2, 2020).

emissions standards that are included in PJM DR portfolios but should not be. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it does not meet emissions standards. Emergency RICE with a limit of 100 hours per year cannot comply with the requirement to be available during the entire delivery year to be a capacity resource. PJM should not allow locations that rely upon emergency stationary RICE to register individually or in portfolios. Registration of DR should be based on a finding that registered locations are capable of providing load reductions without an hourly limit. Reliance on the prospect of penalties to deter registration of ineligible resources as DR in lieu of a substantive ex ante review is not appropriate.

CAA: Greenhouse Gas Emissions

The EPA regulates CO₂ as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.^{40 41}

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.”⁴² 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.⁴³ 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.

Effective October 23, 2015, the EPA placed national limits on the amount of CO₂ that new, modified or reconstructed fossil fuel fired steam power plants

⁴⁰ See CAA § 111.

⁴¹ 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.

⁴² 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).

⁴³ *Id.*

would be allowed to emit based on the best system of emission reductions (BSER) determined by the EPA (2015 GHG NSR Rule).⁴⁴ On December 12, 2018, the EPA proposed to revise the 2015 GHG NSR Rule by increasing the allowable emissions and eliminating the requirement for carbon capture for new coal units.⁴⁵

On June 19, 2019, the EPA repealed the Clean Power Plan⁴⁶ and replaced it with the Affordable Clean Energy (ACE) rule.⁴⁷

The ACE rule establishes emission guidelines pursuant to which states must develop plans to address greenhouse gas emissions from existing coal fired power plants.

The ACE Rule allows states to establish standards of performance based on a proposed list of candidate technologies to achieve the BSER standard.⁴⁸ As a result, the impact on coal fired generation depends upon actions taken in their host state. Under the ACE Rule states may permit more CO₂ emissions than under the Clean Power Plan.

CWA: WOTUS Definition and Effluents

WOTUS

The Clean Water Act (CWA) applies to the navigable waters, which are defined as waters of the United States (WOTUS).^{49 50}

On October 22, 2019, the EPA issued a final rulemaking to rescind the definition of WOTUS proposed in the 2015 Clean Water Rule. The rule prevents 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.⁵¹ 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, 2020.⁵²

On April 21, 2020, the EPA and the Department of the Army published a final rule to define WOTUS, the Navigable Waters Protection Rule (“NWPR”).⁵³ The NWPR became effective in PJM states on June 22, 2020. The replacement rule significantly narrows the scope of federal jurisdiction. The replacement rule does not include coal ash ponds in the definition of WOTUS.⁵⁴ Environmental groups have filed complaints seeking to overturn the NWPR, including in federal district court in Maryland.⁵⁵

The scope of the CWA has expanded and the precise definition of WOTUS has become less important as a result of a decision of the U.S. Supreme Court in *County of Maui v. Hawaii Wildlife Fund*, which held that the discharge of pollutants via groundwater requires a CWA permit.⁵⁶ Groundwater is not itself WOTUS. However, if pollutants pass through groundwater from a point source to WOTUS, a permit may be required.⁵⁷ This holding invalidates the EPA’s recent interpretive statement intended to establish a bright line rule excluding all releases of pollutants to groundwater from the permitting program.⁵⁸ The EPA may not interpret the CWA to require a direct discharge.⁵⁹ The Court held that discharge into groundwater “is the functional equivalent of a direct discharge.”⁶⁰ The existence of a functional discharge will depend on an

44 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 90 Fed. Reg. 205 (October 23, 2015) (“2015 GHG NSR Rule”); 40 CFR Part 60, subpart TTTT.

45 *Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0495; FRL-9987-85–OAR, 83 Fed. Reg. 65424, 65427 (Dec. 20, 2018) (“2018 Proposed Rev. GHG NSR”).

46 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (Aug. 3, 2015) (Clean Power Plan). The Clean Power Plan never took effect because it was subject to a stay issued by the U.S. Supreme Court.

47 *See Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*, EPA Docket No. EPA-HQ-OAR-2017-0355, et al., 84 Fed. Reg. 32520 (July 8, 2019) (“ACE Rule”).

48 Candidate technologies include: Neural network/intelligent sootblowers, boiler feed pumps, air heater and duct leakage control, variable frequency drives, blade path upgrade (steam turbine), redesign/replace economizer, and improved operating and maintenance practices.

49 33 U.S.C. 1251 et seq.; 33 U.S.C. § 1362(7) (“The term “navigable waters” means the waters of the United States, including the territorial seas.”).

50 For more details, see the 2019 *State of the Market Report for PJM*, Volume II, Appendix I: “Environmental and Renewable Energy Regulations.”

51 The stay was issued by the U.S. Court of Appeals for the Sixth Circuit on October 9, 2015.

52 *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).

53 *See The Navigable Waters Protection Rule: Definition of “Waters of the United States,”* EPA Docket No. EPA-HQ-OW-2018-0149, 85 Fed. Reg. 22250.

54 *Id.* at 22251–22252.

55 *See Chesapeake Bay Foundation et al. v. Wheeler et al.*, Case 1:20-cv-01064-GLR (USDC Dist. of Md.).

56 *Slip. Op. No. 18–260* (April 23, 2020).

57 *Id.*

58 *See Interpretive Statement on Application of the Clean Water Act National Pollutant Discharge Elimination System Program to Releases of Pollutants From a Point Source to Groundwater*, 84 Fed. Reg. 16810 (April 23, 2019).

59 *Slip. Op. No. 18–260* at 5.

60 *Id.* at 1.

analysis including time and distance, and other factors.⁶¹ Additional litigation or administrative action may clarify the functional discharge analysis.⁶² *County of Maui* reduces the importance of the precise definition of WOTUS because WOTUS is generally part of the watershed.⁶³

Discharges and Intakes

The EPA regulates discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations, under the CWA.⁶⁴

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.⁶⁵ Solid waste is regulated under subtitle D. Subtitle D criteria are not directly enforced by the EPA. Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

In April 2015, the EPA issued a rule under RCRA, the Coal Combustion Residuals rule (2015 CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.⁶⁶ 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.

⁶¹ *Id.* at 16 (“The difficulty with this approach, we recognize, is that it does not, on its own, clearly explain how to deal with middle instances. But there are too many potentially relevant factors applicable to factually different cases for this Court now to use more specific language. Consider, for example, just some of the factors that may prove relevant (depending upon the circumstances of a particular case): (1) transit time, (2) distance traveled, (3) the nature of the material through which the pollutant travels, (4) the extent to which the pollutant is diluted or chemically changed as it travels, (5) the amount of pollutant entering the navigable waters relative to the amount of the pollutant that leaves the point source, (6) the manner by or area in which the pollutant enters the navigable waters, (7) the degree to which the pollution (at that point) has maintained its specific identity. Time and distance will be the most important factors in most cases, but not necessarily every case.”).

⁶² *Id.*

⁶³ See *id.* at 5 (“Virtually all water, polluted or not, eventually makes its way to navigable water. This is just as true for groundwater.”).

⁶⁴ For more details, see the 2019 *State of the Market Report for PJM*, Volume 2, Appendix I: “Environmental and Renewable Energy Regulations.”

⁶⁵ 42 U.S.C. §§ 6901 *et seq.*

⁶⁶ See *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

In 2016, RCRA was amended to establish a permitting scheme allowing states to apply to the EPA for approval to operate a permit program that implements the CCR rule. Such state programs could include alternative state standards, provided that EPA determines that they are “at least as protective as” the EPA CCR regulations.⁶⁷

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR (“2018 CCRR Revisions”) partly in response to the 2016 amendments.⁶⁸

The 2018 CCRR Revisions provide for two types of alternative performance standards. The first type of standards allows a state director (if a state has EPA approved CCR permit program) or the EPA (if no state program) to suspend groundwater monitoring requirements if there is evidence that there is no potential for migration of hazardous constituents to the uppermost aquifer during the active life of the unit and during post closure care. The second type allows issuance of technical certifications by a state director in lieu of a professional engineer.

The 2018 CCRR Revisions revised the groundwater protection standards for health-based levels for four contaminants: cobalt at 6 mg/L; lithium at 40 mg/L; molybdenum at 100 mg/L and lead at 15 mg/L. Standards for other monitored contaminants follow the Maximum Contaminant Level (MCL) established under the Safe Water Drinking Act.

The 2018 CCRR Revisions extended the deadline for closing coal ash units in two situations: (i) detection of a statistically significant increase above a groundwater protection standard from an unlined surface impoundment; or (ii) inability to comply with the location restriction regarding placement above the uppermost aquifer. The exceptions in the 2018 CCRR to the standards in the 2015 CCRR and relaxation of the deadlines create a less stringent federal rule.

⁶⁷ The Water Infrastructure Improvements for the Nation Act (WIIN Act).

⁶⁸ 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).

The U.S. Court of Appeals for the D.C. Circuit invalidated certain provisions of the 2015 CCRR and remanded it to the EPA.⁶⁹ On July 29, 2020, the EPA finalized revisions to CCRR in compliance with the court orders (“Revised CCRR”).⁷⁰ The Revised CCRR requires (i) unlined surface impoundments (ponds) and ponds failing restrictions on the minimum depth to or interaction with an aquifer to cease receiving waste as soon as technically feasible and no later than April 11, 2021; and (ii) removal of compacted soil lined and clay lined ponds from classification as lined and exempt from CCRR.⁷¹ Impoundment facilities unable to meet the earliest deadline would be able to obtain extensions until an alternative can be “technically feasibly implemented.” Utilities may obtain an automatic extension to November 30, 2020, upon certification of need for additional time. Upon receipt of required documentation satisfying certain criteria, the EPA may grant certain extensions, including to as late as October 17, 2028, for a facility with a surface impoundment of 40 acres or greater that commits to a deadline for ending operations of its boiler.⁷²

In response to the RCRA amendments, the EPA proposed a new rule to implement a federal CCR permit program in non participating states, noticed February 20, 2020.⁷³ This proposal includes requirements for federal CCR permit applications, content and modification, as well as procedural requirements. The EPA would implement this permit program at CCR units located in states that have not submitted their own CCR permit program for approval. No PJM state has yet applied for EPA approval of a coal ash permitting program.

In Virginia, the Waste Management Board amended the Virginia Solid Waste Management Regulations in December 2015, to incorporate the EPA’s 2015 CCRR, and did not adopt the less stringent 2018 CCRR Revisions.⁷⁴ In 2019, Virginia enacted legislation directing the closure of coal ash ponds located in the Chesapeake Bay Watershed and owned by Dominion Energy.⁷⁵ Effective

July 1, 2019, coal ash ponds at power stations in the Chesapeake Bay Watershed had to be closed by removal of coal ash. The removed coal ash either had to be recycled (at least 6.8 million cubic yards) or disposed of in a modern, lined landfill. The Virginia DEQ is addressing closing ash ponds under two types of environmental permits: wastewater discharge permits covering the removal of treated water from the ponds; or solid waste permits covering the permanent closure of the ponds.

On March 30, 2020, in response to a statutory mandate,⁷⁶ the Illinois Environmental Protection Agency (Illinois EPA) proposed rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.⁷⁷ The proposed rules contain standards for the storage and disposal of coal combustion residuals in surface impoundments. The proposed rules include a permitting program and are intended to meet federal standards.⁷⁸ Presumably the rules, once finalized, would be the basis for an application under RCRA allowing the Illinois EPA to also administer the federal regulatory program. The Illinois EPA has identified 73 coal combustion residuals surface impoundments at power stations, some lined with impermeable materials and some not.⁷⁹ The Illinois EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.⁸⁰

The North Carolina Department of Environmental Quality (NCDEQ) has initiated a rule making on rules for the disposal or recycling of coal combustion residuals. None of the affected power stations or power station impoundments are located in the PJM Dominion Zone (which includes a portion of northeast coastal North Carolina).

The Maryland Department of Environment (MDE) indicated in April 2020, that it would require GenOn Holdings Inc. to meet a November 1, 2020, deadline for compliance with effluents guidelines at Chalk Point Generating Station, Dickerson Generating Station and Morgantown Generating Station.⁸¹ On May

69 Utility Solid Waste Activities Group, et al. v. EPA, No. 15-1219 (D.C. Cir. August 21, 2018); Waterkeeper Alliance Inc. et al. v. EPA, No. 18-1289 (D.C. Cir. March 13, 2019).

70 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure*, EPA-HQ-OLEM-2019-0172; FRL-10002-02-OLEM, 85 Fed. Reg. 53516 (August 28, 2020).

71 *Id.* at 53516-53517, 53536.

72 *Id.*

73 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Federal CCR Permit Program*, 85 Fed. Reg. 9940 (Feb. 20, 2020).

74 The following Virginia power stations host coal ash ponds: Bremono Power Station, Chesapeake Energy Center, Chesterfield Power Station, Clinch River Plant and Possum Point Power Station, owned by Dominion Energy; and Glen Lyn Plant, owned by Appalachian Power.

75 Va. Code § 10.1-1402.03.

76 Ill. Public Act 101-171 (a.k.a. SB 09).

77 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.

78 See *In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments*, No. R 2020-019 (March 30, 2020) at 1 (Proposed New 35 Ill. Adm. Code 845) (“Proposed Illinois CCR Rules”).

79 Proposed Illinois Rules at 3.

80 *Id.* at 3.

81 See Potomac Riverkeeper Network, Press Release, “Maryland Proposes to Reject Effort to Delay Pollution Reductions” (Posted April 4, 2020), <<https://www.potomacriverkeepernetwork.org/maryland-proposes-to-reject-effort-to-delay-pollution-reductions/>>.

15, 2020, GenOn announced its decision to start the retirement process for the Dickerson Generating Station, citing “unfavorable economic conditions and increased costs associated with environmental compliance.”⁸² On July 28, 2020, the MDE extended the permit to November 23, 2023.⁸³

State Environmental Regulation

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:⁸⁴

- **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, SO₂ and Hg).** The State of Illinois has promulgated its own standards for NO_x, SO₂ 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.

⁸² See “GenOn Holdings, Inc. Announces Retirement of Dickerson Coal Plant,” (May 15, 2020) <<https://www.genon.com/genon-news/genon-holdings-inc-announces-retirement-of-dickerson-coal-plant>>.

⁸³ MDE, Final Determination for GenOn Dickerson Generating Station State Discharge Permit Application 14DP0048A, NPDES Permit MD0002640 Montgomery County.

⁸⁴ For more details, see the 2019 *State of the Market Report for PJM*, Volume 2, Appendix I: “Environmental and Renewable Energy Regulations.”

State Regulation of Greenhouse Gas Emissions

Clean Energy Standards

In April 2020, Virginia enacted the Virginia Clean Economy Act, which orders the closure of most coal generation in state by 2024, most fossil fuel generation by 2045, and adopts a 100 percent clean energy standard by 2045.⁸⁵ The legislation mandates Chesterfield Power Station Units 5 & 6 and Yorktown Power Station Unit 3 to be retired by the end of 2024, Altavista, Southampton and Hopewell to be retired by the end of 2028 and Virginia Power’s remaining fossil fuel units to be retired by the end of 2045, unless the retirement of such generating units will compromise grid reliability or security.⁸⁶ The legislation also imposes a temporary moratorium on Certificates of Public Convenience and Necessity for fossil fuel generation, unless the resources are needed for grid reliability.⁸⁷

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (as of January 1, 2020), New York, Rhode Island, and Vermont to cap CO₂ emissions from power generation facilities.⁸⁸

Delaware and Maryland are the only PJM states that were members of RGGI in 2019. New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.⁸⁹ Other PJM states have expressed interest in joining RGGI. The Virginia Air Pollution Control Board approved a regulation that would allow Virginia to join RGGI on January 1, 2021.⁹⁰ Virginia’s RGGI rules were finalized in July 2020 and Virginia will begin participating in RGGI on January 1, 2021.⁹¹ Pennsylvania Governor Tom Wolf issued an executive order on October 3, 2019, directing the Pennsylvania Department of Environmental

⁸⁵ Va. HB 1526/SB 851.

⁸⁶ See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).

⁸⁷ *Id.*

⁸⁸ 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>>.

⁸⁹ “Statement on New Jersey Greenhouse Gas Rule,” RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.

⁹⁰ See 9VAC5-140-6010-6430.

⁹¹ “RGGI States Welcome Virginia as Its CO₂ Regulation is Finalized,” RGGI Inc., (July 8, 2020) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2020_07_08_VA_Announcement_Release.pdf>.

Protection (DEP) to develop a proposal to limit carbon emissions from fossil fuel generators that is consistent with RGGI.⁹² The Pennsylvania Environmental Quality Board (EQB), on September 15, 2020, approved a draft regulation developed by the Pennsylvania Department of Environmental Protection (DEP) that governs Pennsylvania's entry into RGGI in 2022. The draft regulation will be subject to public comment and then the DEP will hold a series of hearings prior to submitting a final regulation to the EQB.⁹³ The order also directs DEP to "engage with PJM Interconnection to promote the integration of this program in a manner that preserves orderly and competitive economic dispatch within PJM and minimizes emissions leakage."

Table 8-1 shows the RGGI CO₂ auction clearing prices and quantities for the 2015/2018 compliance period and the 2018/2020 compliance period auctions held as of September 2, 2020, in short tons and metric tonnes.⁹⁴ Prices for auctions held September 2, 2020, were \$6.82 per allowance (equal to one short ton of CO₂), above the current price floor of \$2.21 for RGGI auctions.⁹⁵ The RGGI base budget for CO₂ 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 \$5.75 in June 2020.

Table 8-1 RGGI CO₂ allowance auction prices and quantities in short tons and metric tonnes: 2015/2018 and 2018/2020 Compliance Periods⁹⁶

Auction Date	Short Tons			Metric Tonnes		
	Clearing Price	Quantity Offered	Quantity Sold	Clearing Price	Quantity Offered	Quantity Sold
March 11, 2015	\$5.41	15,272,670	15,272,670	\$5.96	13,855,137	13,855,137
June 3, 2015	\$5.50	15,507,571	15,507,571	\$6.06	14,068,236	14,068,236
September 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	\$5.35	13,360,649	13,360,649	\$5.90	12,120,580	12,120,580
March 13, 2019	\$5.27	12,883,436	12,883,436	\$5.81	11,687,660	11,687,660
June 5, 2019	\$5.62	13,221,453	13,221,453	\$6.19	11,994,304	11,994,304
September 4, 2019	\$5.20	13,116,447	13,116,447	\$5.73	11,899,044	11,899,044
December 4, 2019	\$5.61	13,116,444	13,116,444	\$6.18	11,899,041	11,899,041
March 11, 2020	\$5.65	16,208,347	16,208,347	\$6.23	14,703,969	14,703,969
June 3, 2020	\$5.75	16,336,298	16,336,298	\$6.34	14,820,045	14,820,045
September 2, 2020	\$6.82	16,192,785	16,192,785	\$7.52	14,689,852	14,689,852

RGGI auctions generated \$259.9 million in auction revenue in the first nine months of 2020 and have generated \$3.7 billion in auction revenue since 2008.⁹⁷ RGGI auction revenue is returned to the states. RGGI reported that the RGGI states, cumulative through the 2017 reporting year, have spent approximately 58 percent of the revenue on energy efficiency, 14 percent on clean and renewable energy, 8 percent on greenhouse gas abatement and 14 percent on direct bill assistance.⁹⁸

If all PJM states joined RGGI, the total RGGI revenue to the PJM states would be significant. The estimated allowance revenue for PJM states based on

⁹² Executive Order No. 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor (Oct. 3, 2019), <<https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>>.

⁹³ "Environmental Quality Board Approves Proposed Climate Change Regulation," DEP Newsroom, (September 15, 2020) <<https://www.ahs.dep.pa.gov/NewsRoomPublic/articleviewer.aspx?id=21865&typeid=1>>.

⁹⁴ 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 CCRs.

⁹⁵ 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).

⁹⁶ See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 23, 2020).

⁹⁷ See Auction Results at <<https://www.rggi.org/>>.

⁹⁸ *The Investment of RGGI Proceeds in 2017*, The Regional Greenhouse Gas Initiative (RGGI), October 2019, <<https://www.rggi.org/investments/proceeds-investments>>.

2019 CO₂ emission levels and the RGGI clearing price for the September 2020 auction ranges from \$1.3 billion per year to \$2.5 billion per year depending on associated reductions in carbon emission levels (Table 8-2).⁹⁹ Table 8-2 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2019 CO₂ emission levels ranging from five to 50 percent. A power plant owner must acquire an allowance for each ton of CO₂ emissions and the revenue values in Table 8-2 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2019 actual emissions level. States that participate in RGGI choose their emission cap. For example, New Jersey chose an emission cap of 18,000,000 short tons for reentry into RGGI in 2020, 5.3 percent below New Jersey's 2018 CO₂ emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.¹⁰⁰

Table 8-2 Estimated CO₂ allowance revenue at September 2020 RGGI price level^{101 102}

Jurisdiction	Estimated CO ₂ allowance revenue (\$ millions), carbon price \$6.82 per short ton						
	2019 power generation CO ₂ emissions (short tons)	5 percent reduction below 2019 emission levels	10 percent reduction below 2019 emission levels	15 percent reduction below 2019 emission levels	20 percent reduction below 2019 emission levels	25 percent reduction below 2019 emission levels	50 percent reduction below 2019 emission levels
Delaware	2,007,608.3	\$13.0	\$12.3	\$11.6	\$11.0	\$10.3	\$6.8
Illinois	27,218,451.4	\$176.3	\$167.1	\$157.8	\$148.5	\$139.2	\$92.8
Indiana	39,583,687.7	\$256.5	\$243.0	\$229.5	\$216.0	\$202.5	\$135.0
Kentucky	27,571,710.2	\$178.6	\$169.2	\$159.8	\$150.4	\$141.0	\$94.0
Maryland	13,176,745.0	\$85.4	\$80.9	\$76.4	\$71.9	\$67.4	\$44.9
Michigan	0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
New Jersey	15,820,055.8	\$102.5	\$97.1	\$91.7	\$86.3	\$80.9	\$53.9
North Carolina	114,473.8	\$0.7	\$0.7	\$0.7	\$0.6	\$0.6	\$0.4
Ohio	79,400,173.0	\$514.4	\$487.4	\$460.3	\$433.2	\$406.1	\$270.8
Pennsylvania	82,719,699.4	\$535.9	\$507.7	\$479.5	\$451.3	\$423.1	\$282.1
Tennessee	0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Virginia	31,030,859.6	\$201.0	\$190.5	\$179.9	\$169.3	\$158.7	\$105.8
Washington, D.C.	0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
West Virginia	61,130,636.7	\$396.1	\$375.2	\$354.4	\$333.5	\$312.7	\$208.5
Total	379,774,100.9	\$2,460.6	\$2,331.1	\$2,201.6	\$2,072.0	\$1,942.5	\$1,295.0

⁹⁹ This assumes that the PJM states would implement their RGGI rules consistent with the current RGGI states where owners of fossil fuel generators are required to purchase emission allowances in a regional centralized auction or purchase allowances in a secondary market.

¹⁰⁰ "Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative," State of New Jersey, Governor Phil Murphy Press Release, June 17, 2019 <<https://nj.gov/governor/news/news/562019/approved/20190617a.shtml>>.

¹⁰¹ The 2019 CO₂ emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from generators located within the PJM footprint.

¹⁰² Power generation companies subject to a RGGI emission cap can offset up to 3.3 percent of their allowance obligation by undertaking certain greenhouse gas emission reduction projects. The allowance revenue values in Table 8-2 do not reflect offset allowances.

The RGGI emissions cap is the sum of CO₂ allowances issued by each state. Table 8-3 shows the RGGI emission cap history. Compliance with the RGGI allowance obligation is evaluated at the end of each three year period which is called the control period. The first control period began in 2009. The 2020 compliance year is the third year of the fourth control period.

In 2014, RGGI began adjusting the emission cap to account for banked allowances from previous control periods.¹⁰³ At the end of the first control period, 57,449,495 banked allowances were held by market participants.¹⁰⁴ The cap adjustment for banked allowances was spread over a seven year period beginning in 2014 with the RGGI cap being reduced each year by one-seventh of the banked allowances. An additional reduction of 593 allowances per year, applying only to the Connecticut allowance budget, brings the overall cap adjustment to 8,207,664 allowances per year.¹⁰⁵ A second cap adjustment,

¹⁰³ A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.

¹⁰⁴ "First Control Period Interim Adjustment for Banked Allowances Announcements," Regional Greenhouse Gas Initiative (Jan. 13, 2014), <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_01_13_FCP_Adjustment.pdf>.

¹⁰⁵ *Id.* at 2. Due to rounding, the adjustment is 8,207,664 allowances for years 2014 through 2018, and 8,207,663 allowances for the remaining two years.

corresponding to banked allowances for 2012 and 2013, began in 2015 with an adjustment of 13,683,744 allowances per year and will be in place through 2020.¹⁰⁶ The RGGI clearing price since 2014 has been on average 104.5 percent higher than the prices prior to the emission cap adjustments.

Table 8-3 RGGI emissions cap history^{107 108}

Control Period	RGGI Average Clearing Price (\$ per short ton)	RGGI Cap (short tons)	Percent Change	RGGI Adjusted Cap (short tons)	Percent Change
2009	\$2.77	188,000,000		188,000,000	
2010	\$1.93	188,000,000	0.0%	188,000,000	0.0%
2011	\$1.89	188,000,000	0.0%	188,000,000	0.0%
2012	\$1.93	165,000,000	(12.2%)	165,000,000	(12.2%)
2013	\$2.92	165,000,000	0.0%	165,000,000	0.0%
2014	\$4.72	91,000,000	(44.8%)	82,792,336	(49.8%)
2015	\$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016	\$4.47	86,506,875	(2.5%)	64,615,467	(3.3%)
2017	\$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018	\$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019	\$5.43	80,179,708	(2.5%)	58,288,301	(3.4%)
2020	\$6.07	96,175,215	19.9%	74,283,807	27.4%

If higher carbon prices were implemented in PJM, the associated revenues flowing to states would also increase. Table 8-4 shows the estimated allowance revenue for PJM states for carbon prices ranging from \$10 per short ton to \$50 per short ton and for emissions reductions ranging from five percent to 50 percent. Allowance revenues to states would be \$18.0 billion if the carbon price were \$50 per short ton and emission levels were five percent below 2019 levels. Allowance revenues to states would be \$1.9 billion if the carbon price were \$10 per short ton and emission levels were 50 percent below 2019.

¹⁰⁶ "Second Control Period Interim Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 17, 2014), <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_03_17_SCP_Adjustment.pdf>.

¹⁰⁷ See Regional Greenhouse Gas Initiative, "Elements of RGGI" and "Auction Results," <<https://www.rggi.org/>> (Accessed June 25, 2019).

¹⁰⁸ The increase in the RGGI Cap and the RGGI Adjusted Cap in 2020 is due to the reentry of New Jersey. The new cap is 18 million short tons higher than the previously published 2020 caps.

Table 8-4 Estimated CO₂ allowance revenue at various carbon prices

Jurisdiction	Estimated CO ₂ allowance revenue (\$ millions)					
	5 percent reduction below 2019 emission levels	10 percent reduction below 2019 emission levels	15 percent reduction below 2019 emission levels	20 percent reduction below 2019 emission levels	25 percent reduction below 2019 emission levels	50 percent reduction below 2019 emission levels
	Carbon Price (\$ per short ton)					
Delaware	\$19.1	\$18.1	\$17.1	\$16.1	\$15.1	\$10.0
Illinois	\$258.6	\$245.0	\$231.4	\$217.7	\$204.1	\$136.1
Indiana	\$376.0	\$356.3	\$336.5	\$316.7	\$296.9	\$197.9
Kentucky	\$261.9	\$248.1	\$234.4	\$220.6	\$206.8	\$137.9
Maryland	\$125.2	\$118.6	\$112.0	\$105.4	\$98.8	\$65.9
Michigan	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
New Jersey	\$150.3	\$142.4	\$134.5	\$126.6	\$118.7	\$79.1
North Carolina	\$1.1	\$1.0	\$1.0	\$0.9	\$0.9	\$0.6
Ohio	\$754.3	\$714.6	\$674.9	\$635.2	\$595.5	\$397.0
Pennsylvania	\$785.8	\$744.5	\$703.1	\$661.8	\$620.4	\$413.6
Tennessee	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Virginia	\$294.8	\$279.3	\$263.8	\$248.2	\$232.7	\$155.2
Washington, D.C.	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
West Virginia	\$580.7	\$550.2	\$519.6	\$489.0	\$458.5	\$305.7
Total	\$3,607.9	\$3,418.0	\$3,228.1	\$3,038.2	\$2,848.3	\$1,898.9
	Carbon Price (\$ per short ton)					\$25.00
Delaware	\$47.7	\$45.2	\$42.7	\$40.2	\$37.6	\$25.1
Illinois	\$646.4	\$612.4	\$578.4	\$544.4	\$510.3	\$340.2
Indiana	\$940.1	\$890.6	\$841.2	\$791.7	\$742.2	\$494.8
Kentucky	\$654.8	\$620.4	\$585.9	\$551.4	\$517.0	\$344.6
Maryland	\$312.9	\$296.5	\$280.0	\$263.5	\$247.1	\$164.7
Michigan	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
New Jersey	\$375.7	\$356.0	\$336.2	\$316.4	\$296.6	\$197.8
North Carolina	\$2.7	\$2.6	\$2.4	\$2.3	\$2.1	\$1.4
Ohio	\$1,885.8	\$1,786.5	\$1,687.3	\$1,588.0	\$1,488.8	\$992.5
Pennsylvania	\$1,964.6	\$1,861.2	\$1,757.8	\$1,654.4	\$1,551.0	\$1,034.0
Tennessee	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Virginia	\$737.0	\$698.2	\$659.4	\$620.6	\$581.8	\$387.9
Washington, D.C.	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
West Virginia	\$1,451.9	\$1,375.4	\$1,299.0	\$1,222.6	\$1,146.2	\$764.1
Total	\$9,019.6	\$8,544.9	\$8,070.2	\$7,595.5	\$7,120.8	\$4,747.2
	Carbon Price (\$ per short ton)					\$50.00
Delaware	\$95.4	\$90.3	\$85.3	\$80.3	\$75.3	\$50.2
Illinois	\$1,292.9	\$1,224.8	\$1,156.8	\$1,088.7	\$1,020.7	\$680.5
Indiana	\$1,880.2	\$1,781.3	\$1,682.3	\$1,583.3	\$1,484.4	\$989.6
Kentucky	\$1,309.7	\$1,240.7	\$1,171.8	\$1,102.9	\$1,033.9	\$689.3
Maryland	\$625.9	\$593.0	\$560.0	\$527.1	\$494.1	\$329.4
Michigan	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
New Jersey	\$751.5	\$711.9	\$672.4	\$632.8	\$593.3	\$395.5
North Carolina	\$5.4	\$5.2	\$4.9	\$4.6	\$4.3	\$2.9

Table 8-4 Estimated CO₂ allowance revenue at various carbon prices (cont'd)

Jurisdiction	Estimated CO ₂ allowance revenue (\$ millions)					
	5 percent reduction below 2019 emission levels	10 percent reduction below 2019 emission levels	15 percent reduction below 2019 emission levels	20 percent reduction below 2019 emission levels	25 percent reduction below 2019 emission levels	50 percent reduction below 2019 emission levels
	Carbon Price (\$ per short ton)					
Ohio	\$3,771.5	\$3,573.0	\$3,374.5	\$3,176.0	\$2,977.5	\$1,985.0
Pennsylvania	\$3,929.2	\$3,722.4	\$3,515.6	\$3,308.8	\$3,102.0	\$2,068.0
Tennessee	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Virginia	\$1,474.0	\$1,396.4	\$1,318.8	\$1,241.2	\$1,163.7	\$775.8
Washington, D.C.	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
West Virginia	\$2,903.7	\$2,750.9	\$2,598.1	\$2,445.2	\$2,292.4	\$1,528.3
Total	\$18,039.3	\$17,089.8	\$16,140.4	\$15,191.0	\$14,241.5	\$9,494.4

Table 8-5 shows the estimated impact of five different carbon prices on PJM load-weighted LMP. For example, if the carbon price were \$5.00 per tonne, the PJM load-weighted average LMP in the first nine months of 2020 would have increased by 7.6 percent.¹⁰⁹

Table 8-5 Estimated impact of Carbon price on LMP: January through September, 2019 and 2020

Scenario	2019 (Jan - Sep)				2020 (Jan - Sep)		
	Carbon Price (\$/Metric Ton)	Actual LMP (\$/MWh)	Estimated LMP (\$/MWh)	Percent Change	Actual LMP (\$/MWh)	Estimated LMP (\$/MWh)	Percent Change
Scenario 1	\$5.00	\$27.60	\$28.22	2.3%	\$21.23	\$22.85	7.6%
Scenario 2	\$10.00	\$27.60	\$28.91	4.8%	\$21.23	\$24.67	16.2%
Scenario 3	\$15.00	\$27.60	\$29.60	7.3%	\$21.23	\$26.49	24.8%
Scenario 4	\$25.00	\$27.60	\$30.55	10.7%	\$21.23	\$30.13	41.9%
Scenario 5	\$50.00	\$27.60	\$33.56	21.6%	\$21.23	\$39.23	84.8%

¹⁰⁹ LMPs are recalculated to account for the defined cost of carbon emissions on marginal units' offer prices. The LMP calculation is not based on a counterfactual redispatch of the system to determine the marginal units and the marginal costs that would have occurred if all units had made all offers at short run marginal cost. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 8-6 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.^{110 111} For example, if the price of carbon were \$50.00 per tonne, the short run marginal costs would increase by \$24.52 per MWh for a new combustion turbine (CT) unit, \$16.71 per MWh for a new combined cycle (CC) unit and \$43.15 per MWh for a new coal plant (CP).

Table 8-6 Carbon price per MWh by unit type

Unit Type	Carbon Price per MWh						
	Carbon \$5/tonne	Carbon \$10/tonne	Carbon \$15/tonne	Carbon \$50/tonne	Carbon \$100/tonne	Carbon \$200/tonne	Carbon \$400/tonne
CT	\$2.45	\$4.90	\$7.36	\$24.52	\$49.04	\$98.08	\$196.17
CC	\$1.67	\$3.34	\$5.01	\$16.71	\$33.41	\$66.83	\$133.65
CP	\$4.32	\$8.63	\$12.95	\$43.15	\$86.30	\$172.60	\$345.21

Table 8-7 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 \$183.47 per MWh for the first nine months of 2020. 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 slightly less than \$400 per tonne. This result also assumes that the entire value of the SREC was based on reduced carbon emissions. The SREC price consistent with a carbon price of \$50.00 per tonne, assuming that a MWh from a CT is avoided, is \$24.52 per MWh.

Applying this method to tier I and class I REC and SREC price histories yields the implied carbon prices in Table 8-7. The carbon price implied by the average REC price for the first nine months of 2020 in Washington, DC is \$6.33 per tonne which is consistent with the average 2020 RGGI clearing price of \$6.69 per tonne. All other carbon prices implied by renewable RECs are well above the RGGI clearing price, and well below the social cost of carbon which is estimated to be in the range of \$50 per tonne.¹¹² The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. The carbon prices implied by the SREC prices all exceed the carbon prices implied by the corresponding REC prices, and all exceed the social cost of carbon.

¹¹⁰ Heat rates from: *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Table 7-4.

¹¹¹ 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 March 9, 2020).

¹¹² "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

Table 8-7 Implied carbon price based on REC and SREC prices: 2009 through 2020¹¹³

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Jurisdiction with Tier I or Class I REC												
	Carbon Price (\$ per tonne) Implied by REC Prices											
Delaware					\$34.15	\$35.17	\$31.91	\$32.91	\$10.26	\$11.57	\$16.05	
Maryland	\$2.07	\$1.92	\$3.06	\$6.34	\$17.46	\$28.45	\$29.18	\$26.09	\$23.12	\$21.28	\$17.73	\$17.56
New Jersey	\$13.34	\$17.74	\$8.58	\$4.74	\$13.09	\$21.04	\$25.29	\$26.93	\$24.01	\$22.01	\$19.18	\$18.22
Ohio						\$10.16	\$8.52	\$5.29	\$6.27	\$11.17	\$13.79	\$13.94
Pennsylvania	\$6.82	\$8.13	\$3.33	\$4.29	\$15.87	\$26.66	\$28.88	\$26.35	\$23.35	\$21.47	\$17.88	\$17.71
Washington, D.C.							\$3.19	\$4.04	\$4.88	\$4.68	\$5.50	\$6.33
Jurisdiction with Solar REC												
	Carbon Price (\$ per tonne) Implied by Solar REC Prices											
Delaware						\$117.25	\$85.40	\$86.48	\$35.70	\$17.33		
Maryland		\$546.11	\$494.54	\$382.57	\$304.54	\$292.70	\$251.23	\$183.09	\$127.67	\$87.00	\$82.77	\$79.36
New Jersey	\$1,372.37	\$1,352.15	\$1,309.00	\$537.08	\$345.94	\$326.21	\$388.73	\$424.21	\$459.21	\$445.00	\$409.08	\$374.10
Ohio						\$82.32	\$45.12	\$36.15	\$31.82			
Pennsylvania	\$610.05	\$590.57	\$378.67	\$101.80	\$68.34	\$75.90	\$66.89	\$55.06	\$43.84	\$28.07	\$49.52	\$62.89
Washington, D.C.	\$712.98	\$436.28	\$501.62	\$655.52	\$956.55	\$957.46	\$994.05	\$993.49	\$866.17	\$840.35	\$848.82	\$878.57
Regional Greenhouse Gas Initiative												
	CO ₂ Allowance Price (\$ per tonne)											
RGGI clearing price	\$3.06	\$2.12	\$2.08	\$2.13	\$3.22	\$5.21	\$6.72	\$4.93	\$3.77	\$4.86	\$5.98	\$6.69

State Renewable Portfolio Standards

Nine of 14 PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These requirements are known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called eligible technologies. Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS must pay penalties (alternative compliance payments).

Renewable energy sources replenish naturally in a short period of time but are flow limited and include solar, geothermal, wind, biomass and hydropower from flowing water. Renewable energy sources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Nonrenewable energy sources do not replenish in a short period of time and include crude oil, natural gas, coal and uranium (nuclear energy).¹¹⁴ Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of September 30, 2020, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of September 30, 2020, Virginia and Indiana had voluntary renewable portfolio standards that do not require participation and do not include noncompliance penalties.¹¹⁵ Incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. The voluntary standard

¹¹³ There were no trades in 2018 and 2019 for Ohio SRECs available in the Evomarkets data.

¹¹⁴ *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 23, 2019).

¹¹⁵ Effective January 1, 2021 the Virginia voluntary RPS is being replaced with a mandatory RPS.

was enacted by the Indiana legislature in 2011, but no load serving entities have volunteered to participate in the program.¹¹⁶

As of September 30, 2020, Kentucky, Tennessee and West Virginia have no renewable portfolio standards.

How each state satisfies its renewable portfolio standard requirements should be more transparent. While some jurisdictions publish transparent information regarding total REC generation, how the standard is fulfilled and the total cost to the state, some jurisdictions do not provide the same level of detail and there can be a significant lag from the end of the compliance year to the publication of the information. Some states provide adequate information with respect to the total cost for the RPS, where the RECs originated that fulfill the RPS requirements, and if the state fulfilled the RPS goals. Pennsylvania and Maryland both provide more information than other states and serve as a model for other states. The MMU recommends that jurisdictions with a renewable portfolio standard make the compliance data and cost data available in a more complete and transparent manner.

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year for use toward satisfying their REC obligation in either of the two subsequent reporting years.¹¹⁷

Table 8-8 shows the percent of retail electric load that must be served by renewable and/or alternative energy resources under each PJM jurisdictions' RPS by year.

Table 8-8 Renewable and alternative energy standards of PJM jurisdictions: 2020 to 2030^{118 119}

Jurisdiction with RPS	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	20.00%	21.00%	22.00%	23.00%	24.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Illinois	17.50%	19.00%	20.50%	22.00%	23.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Maryland	30.50%	30.80%	33.10%	35.40%	37.70%	40.00%	42.50%	45.50%	47.50%	49.50%	50.00%
Michigan	12.50%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	23.50%	23.50%	24.50%	29.50%	37.50%	40.50%	43.50%	46.50%	49.50%	52.50%	52.50%
North Carolina	10.00%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	5.50%	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Virginia (Phase I utilities)		6.00%	7.00%	8.00%	10.00%	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%
Virginia (Phase II utilities)		14.00%	17.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%
Washington, D.C.	20.00%	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%
Jurisdiction with Voluntary Standard											
Indiana	7.00%	7.00%	7.00%	7.00%	7.00%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Virginia	7.00%										
Jurisdiction with No Standard											
Kentucky	No Renewable Portfolio Standard										
Tennessee	No Renewable Portfolio Standard										
West Virginia	No Renewable Portfolio Standard										

On April 11, 2020, the Virginia legislature passed a new law that replaces Virginia's current voluntary renewable portfolio standard (RPS) with a mandatory RPS.¹²⁰ The new law requires by 2050 that 100 percent of energy sold by phase I utilities must come from RPS eligible resources; and 100 percent of energy sold by phase II utilities must come from RPS eligible resources by 2045.^{121 122} Intermediate RPS targets begin in 2021 with a 6.0 percent standard for phase I utilities and a 14.0 percent standard for phase II

¹¹⁸ This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.

¹¹⁹ The table reflects calendar year standards for Maryland, Washington, DC, Ohio, and North Carolina. The standards for the remaining jurisdictions are for compliance years that begin on June 1, CCYY and end on May 31 of the following year.

¹²⁰ See "Virginia Clean Economy Act," (April 12, 2020) <<https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>>.

¹²¹ A phase I utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a phase II utility is an investor-owned incumbent electric utility that was bound by such a settlement (§ 56-585.1 of the Virginia Code).

¹²² APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS

¹¹⁶ See the Indiana Utility Regulatory Commission's "2020 Annual Report," at 41 (Oct. 2020) <<https://www.in.gov/iurc/2981.htm>>.

¹¹⁷ Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).

utilities. Eligible RPS resources include wind, solar, hydroelectric, landfill gas and biomass resources.

In 2018, New Jersey passed legislation that included provisions promoting the development of solar power in the state.¹²³ 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. Table 8-9 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington DC.

New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.¹²⁸ 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).¹²⁹ The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issued Executive Order No. 8, which calls for full implementation of the statute. The offshore wind target 3,500 MW by 2030 has since been replaced by a target of 7,500 MW by 2035.¹³⁰ The BPU opened a 100 day application window for qualified offshore wind projects on September 20, 2018, and on June, 21, 2019, the first award for a 1,100 MW offshore wind project was granted to Orsted.^{131 132}

Table 8-9 Recent changes in RPS rules^{124 125 126 127}

Jurisdiction	Legislation	Effective Date	Summary of changes
Virginia	Virginia Clean Economy Act	April 11, 2020	Replaces the voluntary RPS with a mandatory RPS beginning in January 2021. The legislation requires 100 percent clean energy by 2050 for phase I utilities and 100 percent clean energy by 2045 for phase II utilities. Intermediate target levels begin in 2021 with 6 percent for phase I utilities and 14 percent for phase II utilities.
Ohio	House Bill 6	October 22, 2019	Reduced the RPS percent for each year beginning in 2020. The 2020 standard was reduced from 6.5 percent to 5.5 percent; the 2026 standard was reduced from 12.5 percent to 8.5 percent. The legislation also removed language that had previously indicated that the standard would remain at the 2026 level for each year after 2026. The solar carve out was removed for compliance year 2020 and beyond. Prior to the recent legislation, the solar carve out was 0.26 percent for 2020, increased to 0.50 percent for 2026, and remained at 0.50 percent for subsequent years.
Maryland	Clean Energy Jobs Act	May 25, 2019	Established a new Tier I target of 50.0 percent in 2030; previously the 2030 Tier I standard was 25.0 percent. The 2019 Tier I standard increased from 20.4 percent to 20.7. The solar carve out percent for 2019 increased from 1.95 percent to 5.50 percent. The solar carve out percent for 2030 increased from 2.5 percent to 14.5 percent. The 2.5 percent Tier II standard, scheduled to end in 2018, was extended through 2020.
Washington, D.C.	CleanEnergy DC Omnibus Amendment Act of 2018	March 22, 2019	Established a 100 percent Tier I renewable standard by 2032. Previously, the 2032 target was 50.0 percent. Tier I increases start in 2020, going from 20.0 percent to 26.25 percent. The 2020 solar carve out will increase from 1.58 percent to 2.175 percent. The 2041 target for the solar carve out is 10.0 percent.

¹²³ N.J. S. 2314/A. 3723.

¹²⁴ See “Virginia Clean Economy Act,” (April 12, 2020) <<https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>>.

¹²⁵ See Ohio Legislature House, 133rd Assembly, Bill No. 6, “Ohio Clean Air Program,” effective Date October 22, 2019, <<https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>>.

¹²⁶ See Maryland State Legislature, Senate Bill No. 516, “Clean Energy Jobs,” Passed May 25, 2019, <<https://legiscan.com/md/text/sb516/2019>>.

¹²⁷ D.C. Law 22-257 “CleanEnergy DC Omnibus Amendment Act of 2018,” Effective March 22, 2019, <<https://code.dccouncil.us/dc/council/laws/22-257.html>>.

¹²⁸ 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.

¹²⁹ N.J. S. 2314/A. 3723.

¹³⁰ Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/co_archive.html>.

¹³¹ BPU Docket No. Q018080851.

¹³² “New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Orsted’s Ocean Wind Project,” New Jersey BPU Press Release (June 21, 2019) <<https://nj.gov/bpu/newsroom/2019/approved/20190621.html>>.

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. Deepwater Wind has since been acquired by Orsted.¹³³ These project awards are the first under Maryland's 2010 OREC program.

On July 1, 2019, Dominion Energy announced the beginning of construction on an offshore wind demonstration project. The project consists of two 6 MW offshore wind turbines.¹³⁴ In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.¹³⁵

Each PJM jurisdiction with an RPS identifies the type of generation resources that may be used for compliance. These resources are often called eligible technologies. Some PJM jurisdictions with RPS group different eligible technologies into tiers based on the magnitude of their environmental impact. Of the nine PJM jurisdictions with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources.¹³⁶ Although there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources. Table 8-10 shows the Tier I standards for PJM states.¹³⁷ All eligible technologies for the RPS standards in Table 8-10 satisfy the EIA definition of renewable energy.¹³⁸

Table 8-10 Tier I / Class I renewable standards of PJM jurisdictions: 2020 to 2030

Jurisdiction with RPS	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	28.00%	30.80%	33.10%	35.40%	37.70%	40.00%	42.50%	45.50%	47.50%	49.50%	50.00%
New Jersey	21.00%	21.00%	22.00%	27.00%	35.00%	38.00%	41.00%	44.00%	47.00%	50.00%	50.00%
Pennsylvania	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Washington, D.C.	20.00%	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%

Delaware, Illinois, Michigan, North Carolina, and Ohio do not classify the resources eligible for their RPS standards by tiers. In these states eligible technologies are largely but not completely renewable resources.¹³⁹

RECs do not need to be used during the year in which they are generated. The result is that there may be multiple prices for a REC based on the year in which it was generated. RECs typically have a shelf life of five years during which they can be used to satisfy a state's RPS requirement. For example if a load serving entity (LSE) owns renewable generation and the renewable generation exceeds the LSE's RECs purchase obligation for the current year, the LSE can either sell the REC to another LSE or hold the REC for use in a subsequent year.

PJM GATS makes data available for the amount of eligible RECs by jurisdiction. Eligible RECs are not the amount of actual RECs generated for that timeframe. A REC that is created may be eligible in multiple jurisdictions resulting in an over representation of generated RECs. This means if one REC is retired in Pennsylvania, the total amount of eligible RECs will reduce by more than one REC.

The REC prices are the average price for each vintage of REC, defined by the year in which the associated power was generated, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and Washington, DC, but in the other states REC prices are not publicly available.

¹³³ "Orsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ORSTED Press Release (August 10, 2018).

¹³⁴ "Construction Begins on Dominion Energy Offshore Wind Project," Dominion Energy News Release (July 1, 2019) <<https://news.dominionenergy.com/2019-07-01-Construction-Begins-on-Dominion-Energy-Offshore-Wind-Project>>.

¹³⁵ "Dominion Energy Announces Largest Offshore Wind Project in US," Dominion Energy News Release (September 19, 2019) <<https://news.dominionenergy.com/2019-09-19-Dominion-Energy-Announces-Largest-Offshore-Wind-Project-in-US>>.

¹³⁶ New Jersey separates technologies into Class I/Class II resources in a manner that is consistent with the other jurisdictions' Tier I/Tier II categorizations.

¹³⁷ This includes New Jersey's Class I renewable standard.

¹³⁸ *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 17, 2019).

¹³⁹ Michigan's Public Act 342, effective April 20, 2017, removed nonrenewable technologies (e.g. coal gasification, industrial cogeneration, and coal with carbon capture) from the list of RPS eligible technologies.

Figure 8-2 shows the average Tier I REC price by jurisdiction from January 1, 2009, through September 30, 2020. Tier I REC prices are lower than SREC prices. For example, the average SREC price in Washington, DC in the first nine months of 2020 was \$430.87 and the average Tier I price in Washington, DC in the first nine months of 2020 was \$3.10.

Figure 8-2 Average Tier I REC price by jurisdiction: January 2009 through September 2020

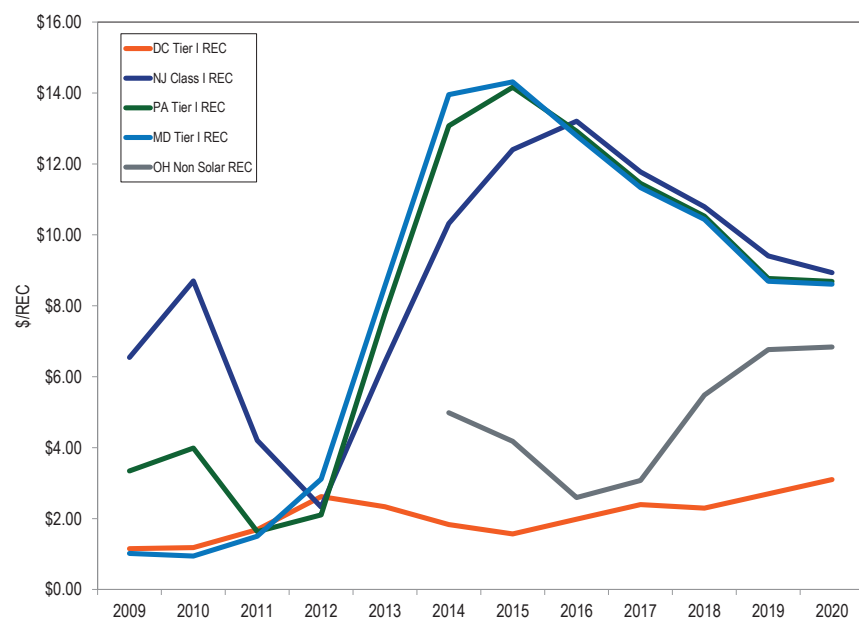


Figure 8-3 and Table 8-11 show the fulfillment of Tier I equivalent RPS requirement for 2016 through 2018 by state and by import and internal RECs and by carbon producing and noncarbon producing RECs.¹⁴⁰ Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro (“Noncarbon REC”) or with landfill gas, captured methane, wood, black liquor, and other fuels. (“Carbon Producing REC”). States’ Tier I requirements are not all carbon free. The DC New Eligible requirement is fulfilled by noncarbon RECs, but all

¹⁴⁰ Retired REC information obtained through PJM GATS <<https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear>> (Accessed October 21, 2020).

other state Tier I equivalent RPS requirements allow carbon producing RECs to fulfill the RPS requirements. Figure 8-3 shows the use of imported and local carbon producing RECs and imported and local noncarbon RECs by state to meet the RPS requirements. Table 8-11 shows the percent of imported and local carbon producing RECs and imported and local noncarbon RECs by state used to meet the RPS requirements. For example, Pennsylvania met its Tier I target using 73.9 percent imported RECs, and 26.2 percent State RECs for the 2016 compliance year. Pennsylvania met its Tier I target using 55.3 percent noncarbon producing RECs, and 44.8 percent carbon producing RECs for the 2016 compliance year. Pennsylvania met its Tier I target using 70.9 percent imported RECs, and 29.0 percent State RECs for the 2017 compliance year. Pennsylvania met its Tier I target using 58.5 percent noncarbon producing RECs, and 41.4 percent carbon producing RECs for the 2017 compliance year.

Figure 8-3 State fulfillment of Tier I equivalent RPS: 2016 through 2018

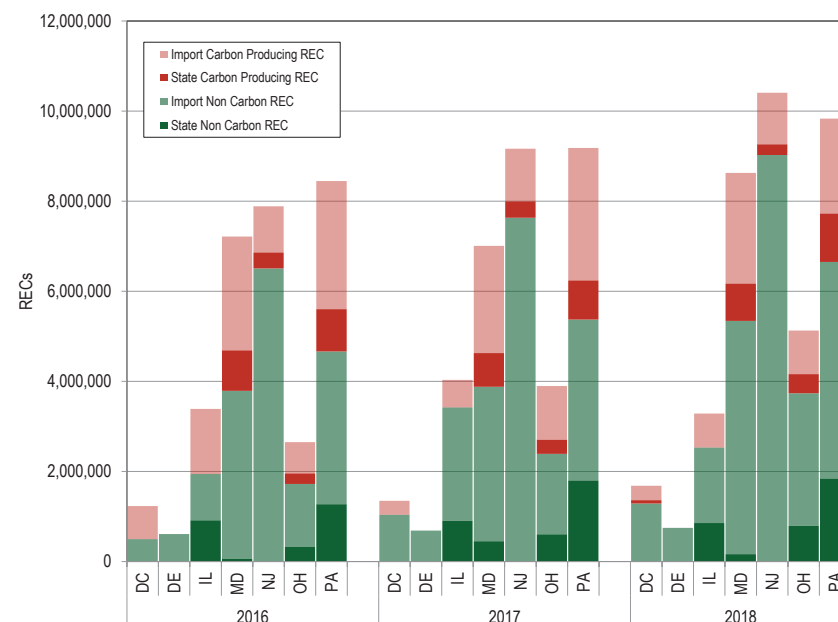


Table 8-11 State fulfillment of Tier I equivalent RPS: 2016 through 2018

Year	REC Type	State Non Carbon REC	Import Non Carbon REC	State Carbon Producing REC	Import Carbon Producing REC
2016	DE New Eligible	1.0%	99.0%	0.0%	0.0%
	DC Tier I	0.0%	40.5%	0.0%	59.5%
	OH Renewable Energy Source	12.3%	52.8%	8.7%	26.2%
	IL Renewable	27.1%	30.3%	0.1%	42.5%
	MD Tier I	0.8%	51.7%	12.5%	35.0%
	NJ Class I	0.0%	82.5%	4.5%	13.0%
	PA Tier I	15.1%	40.2%	11.1%	33.7%
2017	DE New Eligible	0.7%	99.3%	0.0%	0.0%
	DC Tier I	0.0%	77.2%	0.0%	22.8%
	OH Renewable Energy Source	15.6%	45.8%	8.1%	30.6%
	IL Renewable	22.5%	62.3%	0.0%	15.2%
	MD Tier I	6.5%	48.9%	10.7%	34.0%
	NJ Class I	0.1%	83.2%	3.9%	12.8%
	PA Tier I	19.6%	38.9%	9.4%	32.0%
2018	DE New Eligible	0.4%	99.6%	0.0%	0.0%
	DC Tier I	0.0%	76.5%	4.5%	19.0%
	OH Renewable Energy Source	15.4%	57.4%	8.3%	18.9%
	IL Renewable	26.1%	51.0%	0.0%	22.9%
	MD Tier I	1.9%	60.1%	9.6%	28.5%
	NJ Class I	0.0%	86.7%	2.3%	11.0%
	PA Tier I	18.7%	48.9%	10.9%	21.4%

Table 8-12 Additional renewable standards of PJM jurisdictions: 2020 to 2030

Jurisdiction	Type of Standard	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
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%
Maryland	Off Shore Wind		1.37%	1.36%	2.03%	2.01%	2.01%	1.99%	1.98%	1.96%	1.94%	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%
North Carolina	Swine Waste	0.07%	0.14%	0.14%	0.14%	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
Pennsylvania	Tier II Standard	10.00%	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	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 8-12 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 8-12 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-12 are

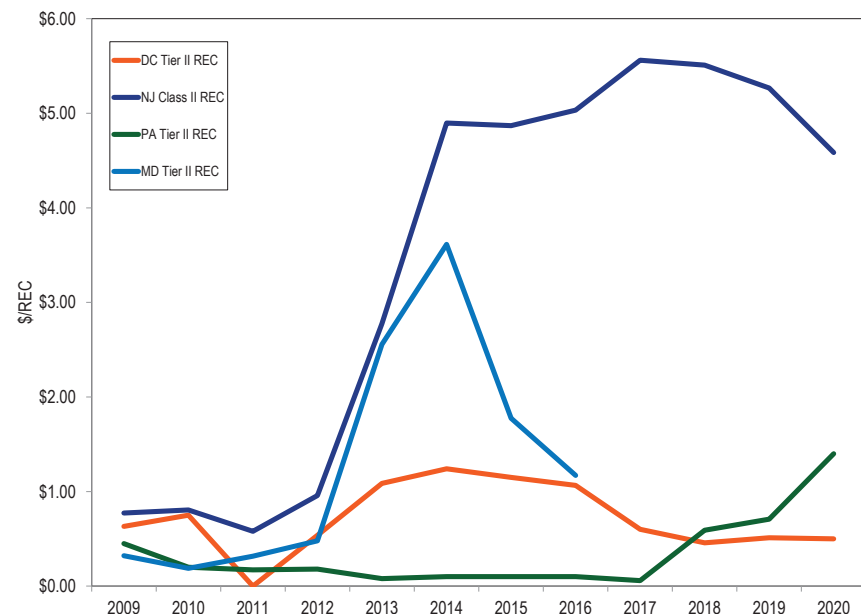
included in the total RPS requirements presented in Table 8-8. Maryland, New Jersey, Pennsylvania and Washington, DC all have Tier II or Class 2 standards, which allow specific nonrenewable technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. By 2024, North Carolina's RPS requires that 0.2 percent of power be generated using swine waste and that 900 GWh of power be produced by poultry waste in 2020. Maryland established a minimum standard for offshore wind in 2017 that takes effect in 2021 with a requirement that 1.37 percent of load be served by offshore wind. The standard increases to 2.03 percent in 2023.¹⁴¹

Tier II prices are lower than SREC and Tier I REC prices. Figure 8-4 shows the average Tier II REC price by jurisdiction for January 1, 2009 through September 30, 2020. Pennsylvania had the lowest average Tier II REC prices at \$1.40 per REC while New Jersey had the highest average Tier II REC prices at \$4.58 per REC.¹⁴²

¹⁴¹ Public Service Commission of Maryland, Offshore Wind Projects, Order No. 88192 (May 11, 2017) at 8, Table 2, <<https://www.psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf>>.

¹⁴² Tier II REC price information obtained through Evomarkets <<http://www.evomarkets.com>> [Accessed October 21, 2020]. There were not any reported cleared purchases for January 1, through September 30, 2020, for MD Tier II RECs.

Figure 8-4 Average Tier II REC price by jurisdiction: 2009 through September 2020



Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-10 but must be met by solar RECs (SRECs) only. Table 8-13 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. New Jersey closed registration for new SRECs on April 30, 2020, having met its milestone that solar power equal or exceed 5.1 percent of New Jersey electricity sales.¹⁴³ New Jersey is considering but has not finalized successor programs, such as a transitional 15 year fixed priced REC (TREC). Pennsylvania allows only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units

¹⁴³ See Clean Energy Act of 2019 (NJ AB-2723); N.J.A.C. 14:82.4(b)6; BPU, Monthly Report on Status toward Attainment of the 5.1 percent Milestone for Closure of the SREC Program (March 31, 2020).

like solar hot water heaters that do not generate electricity are Tier I resources in Pennsylvania. 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, 5.1 percent for 2020 through 2022 and decreases to 1.1 percent for 2032.¹⁴⁴ Maryland legislation in 2019 increased the solar carve out percentages from 2.5 percent to 14.5 percent in 2030. Ohio HB 6 removed the solar carve out from the Ohio RPS.¹⁴⁵

¹⁴⁴ "Assembly, No. 3723," State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_11.PDF>.

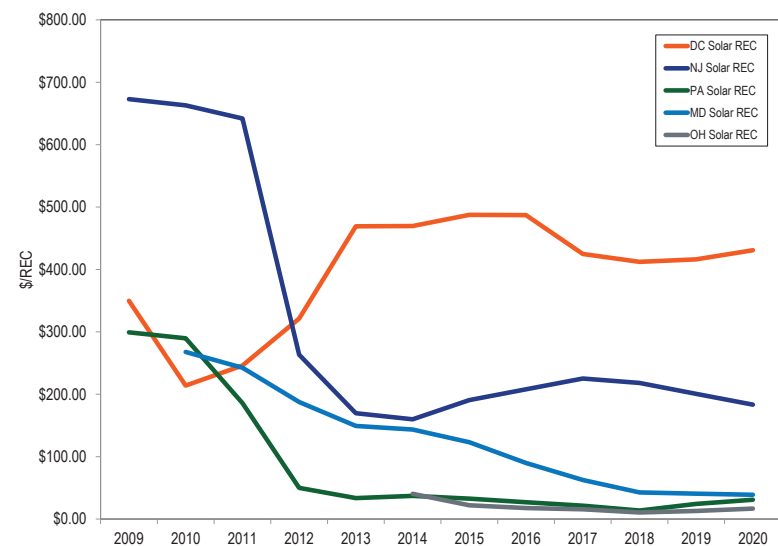
¹⁴⁵ Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <<https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>>.

Table 8-13 Solar renewable standards by percent of electric load for PJM jurisdictions: 2020 to 2030¹⁴⁶

Jurisdiction with RPS	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	2.25%	2.50%	2.75%	3.00%	3.25%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Illinois (RECs)	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	4,000,000
Maryland	6.00%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%	13.50%	14.50%	14.50%	14.50%
Michigan	No Minimum Solar Requirement										
New Jersey	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%
Ohio	No Minimum Solar Requirement										
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.	2.18%	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%
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 8-5 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009, through September 30, 2020. The average NJ SREC prices dropped from \$673 per SREC in 2009 to \$183 per SREC in the first nine months of 2020. The limited supply of solar facilities in Washington, DC compared to the RPS requirement resulted in higher SREC prices. The average Washington, DC SREC price increased from \$197 per SREC in 2011 to \$431 per SREC in the first nine months of 2020.¹⁴⁷

Figure 8-5 Average SREC price by jurisdiction: January 2009 through September 2020

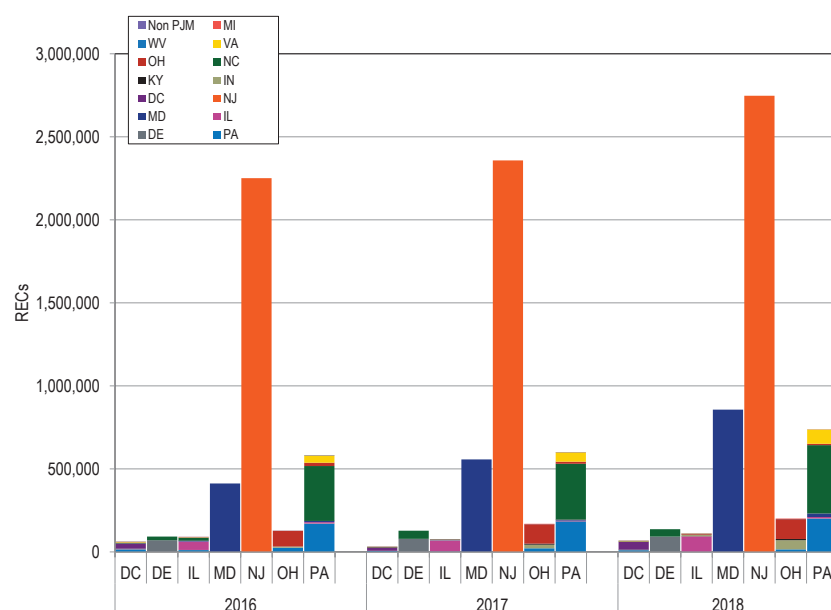


¹⁴⁶ The Illinois solar standard currently requires 2 million RECs from solar photovoltaic projects energized after June 1, 2017. Illinois Public Act 099-0906, June 1, 2017.

¹⁴⁷ Solar REC average price information obtained through Evomarkets, <<http://www.evomarkets.com>> (Accessed October 21, 2020).

Figure 8-6 and Table 8-14 shows where the SRECs originated that are used to satisfy the states' solar requirement by retiring RECs for 2016 through 2018.¹⁴⁸ Depending on the state, the solar RPS requirement can be fulfilled by in state or out of state SRECs. The SRECs purchased in some states are imported from other PJM states and from non PJM states. Table 8-14 shows the percent of imported and local SRECs used to meet the RPS requirements. For example, Washington, DC met its solar requirement using 50.2 percent imported SRECs for the 2016 compliance year.

Figure 8-6 State fulfillment of Solar RPS: 2016 through 2018



¹⁴⁸ Retired REC information obtained through PJM GATS <<https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear>> (Accessed October 21, 2020).

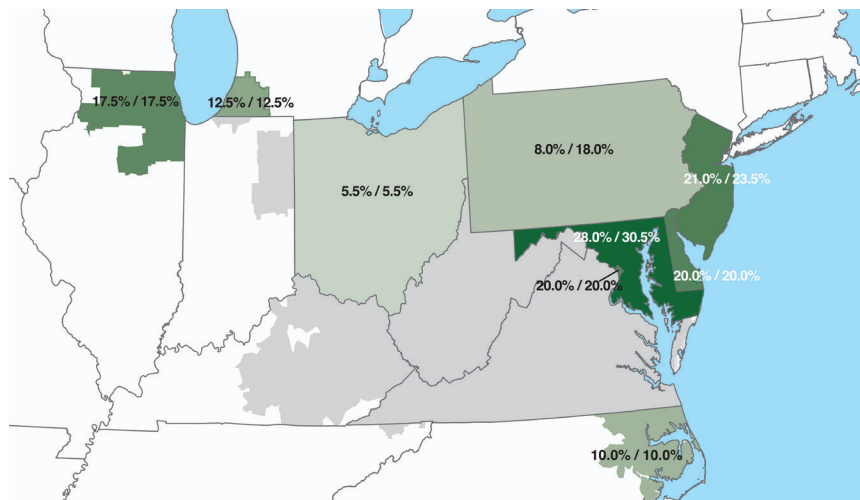
Table 8-14 State fulfillment of Solar RPS: 2016 through 2018

	State SREC	Import SREC
2016		
DC Solar	49.8%	50.2%
DE Solar Eligible	76.5%	23.5%
IL Solar Renewable	56.1%	43.9%
MD Solar	100.0%	0.0%
NJ Solar	100.0%	0.0%
OH Solar Renewable Energy Source	73.3%	26.7%
PA Solar	29.1%	70.9%
2017		
DC Solar	63.8%	36.2%
DE Solar Eligible	61.9%	38.1%
IL Solar Renewable	87.5%	12.5%
MD Solar	100.0%	0.0%
NJ Solar	100.0%	0.0%
OH Solar Renewable Energy Source	69.0%	31.0%
PA Solar	30.6%	69.4%
2018		
DC Solar	67.4%	32.6%
DE Solar Eligible	67.7%	32.3%
IL Solar Renewable	82.8%	17.2%
MD Solar	100.0%	0.0%
NJ Solar	100.0%	0.0%
OH Solar Renewable Energy Source	59.5%	40.5%
PA Solar	27.2%	72.8%

Figure 8-7 shows the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. For each state in Figure 8-7, the first number represents the RPS percent for Tier I or renewable energy resources; the second number represents the RPS percent for all eligible technologies which includes both renewable and alternative energy resources. States with higher percent requirements for renewable energy resources are shaded darker. Jurisdictions with no standards or with only voluntary RPS are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for renewable and alternative energy resources. The Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind, geothermal, biomass, and low-impact hydropower as Tier I resources. The Pennsylvania RPS identifies waste coal, demand side management, large-scale hydropower, integrated gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. As a result, the 18.0 percent number in Figure 8-7 overstates

the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 8.0 percent number in Figure 8-7 is a more accurate measure of the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-7 Map of retail electric load shares under RPS – Renewable / Alternative Energy resources: 2020¹⁴⁹



Under the existing state renewable portfolio standards, 11.8 percent of PJM load should have been served by Tier I and Tier II renewable and alternative energy resources in the first nine months of 2020. Tier I resources consist of landfill gas, run of river hydro, wind and solar resources. Tier II resources consist of pumped storage, solid waste and waste coal resources. In the first nine months of 2020, 7.0 percent of PJM generation was renewable and alternative energy resources, including carbon producing and noncarbon producing Tier I and Tier II generation as shown in Table 8-15. If the proportion of load among states remains constant, 17.5 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2030 under currently defined RPS rules. Approximately 9.5 percent of PJM

¹⁴⁹ The standards in this chart include the Tier I standards used by some states in the PJM footprint, as well as the total alternative energy standard for states that do not classify eligible technologies into tiers.

load should have been served by Tier I or renewable energy resources in the first nine months of 2020. In the first nine months of 2020, 5.0 percent of PJM generation was Tier I or renewable energy, which is 4.5 percentage points less than the amount required, as shown in Table 8-15. The current REC production from PJM generation resources was not enough to meet the 2020 state renewable requirements. LSEs use RECs from generators registered in GATS to fulfill state RPS standards. Not all generators registered in GATS are PJM resources. For example, there are 2,543.8 MW of installed capacity of solar that are PJM resources (Table 8-16), and 6,799 MW of installed capacity of solar that are not PJM resources (Table 8-17). The installed solar MW that are not PJM generation consist of rooftop solar and other small projects that do not participate in the wholesale energy markets. If the installed capacity not part of PJM had the same output per ICAP MW, approximately 7.5 percent of generation would be Tier I, compared to 5.0 percent with just PJM resources, which is 2.0 percentage points less than the expected amount required. RECs typically have a lifespan of five years. This allows unused RECs in one year to be used for future RPS goals. Once an LSE retires a REC to meet a state renewable requirement, that REC is no longer eligible for trading or use elsewhere. LSEs that are unable to meet the RPS with only RECs may use alternative compliance payments for unmet goals based on each state's requirements. If the proportion of load among states remains constant, 15.3 percent of PJM load must be served by Tier I or renewable energy resources in 2030 under defined RPS rules.

In jurisdictions with an RPS, load serving entities must either generate power from eligible technologies identified in each jurisdiction's RPS or purchase RECs from resources classified as eligible technologies. Table 8-15 shows generation by jurisdiction and resource type for the first nine months of 2020. Wind output was 17,977.8 GWh of 30,548.4 Tier I GWh, or 42.5 percent, in the PJM footprint. As shown in Table 8-15, 42,330.6 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 72.2 percent. Total wind and solar generation (noncarbon producing) was 3.4 percent of total generation in PJM for the first nine months of 2020. Tier I generation was 5.0 percent of total generation in PJM and Tier II was 1.9 percent of total

generation in PJM for the first nine months of 2020. Landfill gas, solid waste and waste coal (carbon producing) were 8,464.0 GWh, or 20.0 percent of the total Tier I and Tier II.

Table 8-15 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): January through September, 2020

Jurisdiction	Tier I					Tier II				Total Credit GWh
	Landfill Gas	Run-of-River Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Solid Waste	Waste Coal	Total Tier II Credit	
Delaware	31.3	0.0	0.0	0.0	31.3	0.0	0.0	0.0	0.0	31.3
Illinois	90.7	0.0	12.2	8,108.1	8,211.1	0.0	0.0	0.0	0.0	8,211.1
Indiana	15.5	27.5	12.3	3,618.4	3,673.7	0.0	0.0	0.0	0.0	3,673.7
Kentucky	0.0	266.1	0.0	0.0	266.1	0.0	0.0	0.0	0.0	266.1
Maryland	45.3	0.0	337.1	509.4	891.8	0.0	417.6	0.0	417.6	1,309.4
Michigan	44.5	48.9	4.0	0.0	97.4	0.0	0.0	0.0	0.0	97.4
New Jersey	146.2	12.0	667.8	9.1	835.1	218.8	1,020.0	0.0	1,238.8	2,073.9
North Carolina	0.0	637.9	1,077.2	420.2	2,135.3	0.0	0.0	0.0	0.0	2,135.3
Ohio	256.8	551.6	1.1	1,472.3	2,281.7	0.0	0.0	0.0	0.0	2,281.7
Pennsylvania	469.8	3,591.2	50.6	2,608.1	6,719.6	1,476.8	1,003.9	3,330.8	5,811.4	12,531.1
Tennessee	0.0	1,172.7	0.0	0.0	1,172.7	0.0	0.0	0.0	0.0	1,172.7
Virginia	396.6	1,144.8	746.7	0.0	2,288.1	3,147.0	689.9	0.0	3,836.9	6,125.0
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	27.6	657.4	27.3	1,232.2	1,944.4	0.0	0.0	477.5	477.5	2,421.9
Total	1,524.4	8,110.1	2,936.1	17,977.8	30,548.4	4,842.6	3,131.4	3,808.3	11,782.2	42,330.6
Percent of Renewable Generation	3.6%	19.2%	6.9%	42.5%	72.2%	11.4%	7.4%	9.0%	27.8%	100.0%
Percent of Total Generation	0.3%	1.3%	0.5%	3.0%	5.0%	0.8%	0.5%	0.6%	1.9%	7.0%

Figure 8-8 shows the average hourly output by fuel type for January 1 through September 30 of 2014 through 2020. 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.¹⁵⁰

¹⁵⁰ See the 2019 Quarterly State of the Market Report for PJM: January through June, Section 3: Energy Market, Table 3-9.

Figure 8-8 Average hourly output by fuel type: January through September, 2014 through 2020

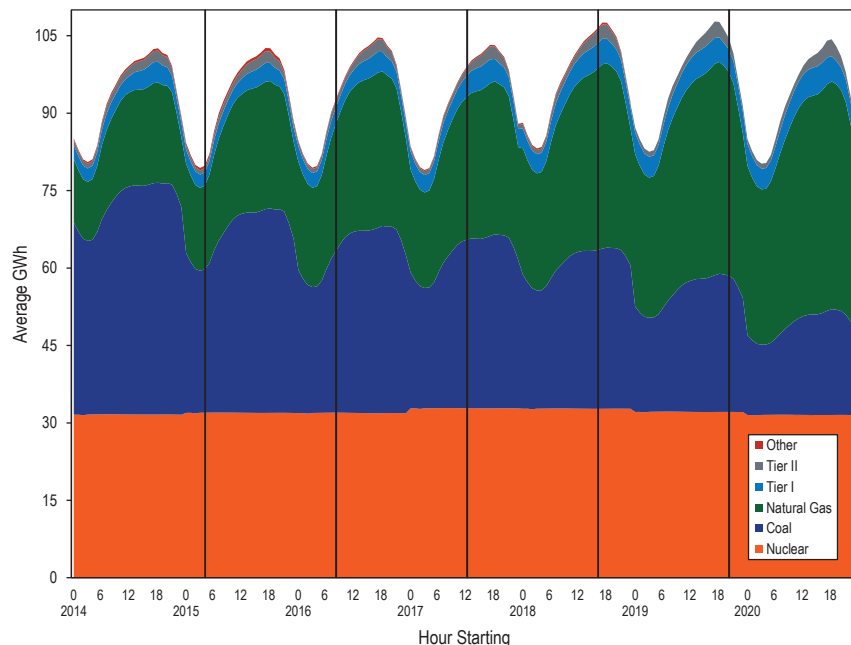


Table 8-16 shows the summer installed capacity rating of Tier I and Tier II resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that qualify as Tier II because they have a renewable fuel as an alternative fuel. For example, a coal generator 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. North Carolina has the largest amount of solar capacity in PJM, 817.5 MW, or 32.1 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 6,208.2 MW, or 63.7 percent of the total wind capacity.

PJM is developing new rules for determining the capacity value of intermittent generators. The new rules are expected to rely on the effective load carrying

capability (ELCC) method.¹⁵¹ Under the current rules a generator's capacity value is derated from the installed capacity level by multiplying the generator's net maximum capability by a capacity factor. The capacity factor is either based on the generator's historical performance during summer peak hours or is a class average value calculated by PJM. The intent of the current method is to obtain a MW value the generator can reliably produce during the summer peak hours.¹⁵² As of October 1, 2020, the derated capacity eligible for compensation in the PJM Capacity Market totaled 1,296.4 MW for wind generators and 946.9 MW for solar generators. This compares to installed wind capacity of 9,752.2 MW and installed solar capacity of 2,543.8 MW in Table 8-16. PJM posts class average capacity factors for wind and solar generators. There are two classes of wind based on location with class average capacity factors of 14.7 percent and 17.6 percent.¹⁵³

¹⁵¹ PJM's Capacity Capability Senior Task Force (CCSTF) is currently reviewing ELCC proposals. See the CCSTF webpage for additional details <<https://www.pjm.com/committees-and-groups/task-forces/ccstf.aspx>>.

¹⁵² See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <<https://pjm.com/-/media/documents/manuals/m21.ashx>>.

¹⁵³ See "Class Average Capacity Factors Wind and Solar Resources," PJM, June 1, 2017 <<https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>>.

Table 8-16 PJM renewable capacity by jurisdiction (MW): September 30, 2020

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	39.2	360.0	0.0	0.0	0.0	9.0	0.0	0.0	4,185.8	4,594.0
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	22.3	0.0	69.0	0.0	494.4	223.2	128.2	0.0	190.0	1,127.1
Michigan	0.0	12.0	0.0	0.0	0.0	13.9	4.6	0.0	0.0	0.0	30.5
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	70.3	0.0	0.0	453.0	11.0	679.6	152.0	0.0	4.5	1,370.3
North Carolina	0.0	0.0	0.0	0.0	0.0	465.0	817.5	0.0	0.0	208.0	1,490.5
Ohio	4,846.0	58.2	0.0	136.0	0.0	119.1	1.1	0.0	0.0	795.8	5,956.2
Pennsylvania	0.0	196.8	2,346.0	0.0	1,269.0	893.3	77.2	261.8	1,347.0	1,457.2	7,848.3
Tennessee	0.0	0.0	0.0	0.0	0.0	156.6	0.0	0.0	0.0	0.0	156.6
Virginia	585.0	127.7	0.0	17.0	5,386.0	430.4	721.4	123.0	0.0	0.0	7,390.5
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	3.2	0.0	0.0	0.0	257.9	0.0	0.0	96.0	742.5	1,099.6
PJM Total	5,431.0	545.7	4,503.0	235.0	7,108.0	3,015.6	2,543.8	665.0	1,443.0	9,752.2	35,242.4

There are three classes of solar generators with capacity factors ranging from 39.0 percent to 60.0 percent.¹⁵⁴

There are two approaches to calculating ELCC. The load approach measures, after the introduction of a class of intermittent generators, the additional load that can be added to the system while maintaining the 0.1 LOLE reliability standard. The generation approach measures the amount of 100 percent available generation that, when added to the system, results in an LOLE equivalent to the LOLE that results from the introduction of a class of intermittent generators.¹⁵⁵ PJM is planning to use the generation approach. Both approaches capture the interaction of intermittent generation and load. Unlike the current capacity value method that only uses data from summer peak hours, the ELCC method will consider all hours in a year. The ELCC method when properly designed will capture the changes in capacity values that result from a changing resource mix.

Once the ELCC is calculated, the impact on units' offers and market clearing needs to be defined. The correct approach is to price all intermittent MW in a class based on the marginal value of the intermittent resources as defined based on the interaction between the ELCC curve and the optimal clearing of the capacity market.¹⁵⁶ The marginal value of any class of intermittent resource generally declines the more resources are added. Interactions between classes can also be accounted for. Owners and developers of intermittent resources want to lock in high intermittent MW values, based on average rather than marginal values, for periods as long as, or longer than, 10 years.¹⁵⁷ While the goal of such owners and developers is to shift risk to customers and to other generation owners, using an average ELCC value and/or locking in an ELCC value is not required to provide the appropriate incentives for entry

and it is fundamentally incompatible with competitive markets. The use of average values and lock ins arbitrarily favor older renewable technologies over newer renewable technologies, arbitrarily favor renewable technologies over thermal technologies, and overstate the actual capacity available for reliability. Such lockins distort market outcomes and impose costs on other generation technologies and on customers who bear the costs of reduced reliability or of purchasing additional capacity to offset the overstatements. Building long term distortions into the market design will lead to negative and unintended consequences. Such long term distortions are inconsistent with an efficient, competitive market. The ELCC could be an advance in the sophistication of measuring the actual reliability contribution of renewable resources, but it will be a significant regression if the implementation is designed to ignore the actual reliability implications of the ELCC impacts of increased renewables penetration.

¹⁵⁴ Id.

¹⁵⁵ See "Effective Load Carrying Capability (ELCC) Review - Part II," PJM, November 14, 2019 <<https://pjm.com/-/media/committees-groups/committees/pc/20191114/20191114-item-15-elcc-review.ashx>>.

¹⁵⁶ "ELCC IMM Proposal," Monitoring Analytics, LLC, August 7, 2020. <http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_CCSTF_ELCC_IMM_Proposal_20200807.pdf>.

¹⁵⁷ PJM. Agenda. Capacity Capability Senior Task Force (CCSTF) (August 7, 2020). <<https://pjm.com/-/media/committees-groups/task-forces/ccstf/2020/20200807/20200807-agenda-doc.ashx>>.

Table 8-17 shows renewable capacity registered in the PJM generation attribute tracking system (GATS) not all of which are PJM resources.¹⁵⁸ For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM units. This includes solar capacity of 6,798.7 MW of which 2,560.3 MW are in New Jersey. These resources can earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. There are 1,505.3 MW of capacity located in jurisdictions outside PJM that may qualify for specific renewable energy credits in some PJM jurisdictions. For example, there are 54.0 MW of capacity registered with GATS located in Alabama.

Table 8-17 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): September 30, 2020¹⁵⁹

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	54.0	0.0	54.0
Delaware	0.0	0.0	2.2	0.0	0.0	0.0	127.2	0.0	2.0	131.4
Georgia	0.0	0.0	27.1	0.0	0.0	0.0	152.2	0.0	0.0	179.3
Illinois	0.0	21.4	55.4	0.0	5.2	0.0	365.6	0.0	600.7	1,048.3
Indiana	0.0	0.0	49.6	0.0	5.2	109.6	123.3	0.0	180.0	467.6
Iowa	0.0	0.0	1.6	0.0	0.0	0.0	2.1	0.0	336.8	340.5
Kentucky	600.0	162.2	20.2	0.0	0.4	0.0	38.2	93.0	0.0	914.0
Louisiana	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	65.0	0.0	12.7	0.0	0.0	0.0	1,090.0	13.8	0.3	1,181.8
Michigan	0.0	1.3	12.6	0.0	0.0	0.0	4.9	31.0	80.6	130.3
Missouri	0.0	0.0	5.6	0.0	0.0	0.0	61.2	0.0	451.0	517.8
New Jersey	0.0	0.0	45.8	0.0	11.6	0.0	2,560.3	0.0	4.7	2,622.3
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	520.4	0.0	0.0	0.0	0.0	1,197.0	151.5	0.0	1,868.9
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	19.7	52.0	10.7	33.0	235.1	92.8	50.7	500.6
Pennsylvania	109.7	31.5	45.2	97.6	13.6	0.0	430.9	8.6	3.2	740.2
South Carolina	0.0	0.0	30.8	0.0	0.0	0.0	91.3	0.0	0.0	122.1
Tennessee	0.0	99.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	99.6
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	0.0	29.6	11.3	0.0	2.6	0.0	208.8	287.6	0.0	539.9
Washington, D.C.	0.0	0.0	0.0	0.0	49.4	13.5	106.0	0.0	0.0	168.9
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	0.1	44.6	0.0	53.7
Total	774.7	881.6	339.7	149.6	98.6	156.1	6,798.7	776.9	2,069.9	12,045.9

¹⁵⁸ PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits. GATS publishes details on every renewable generator registered within the PJM footprint and aggregate emissions of renewable generation, but does not publish generation data by unit and does not make unit data available to the MMU.

¹⁵⁹ See PJM-EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <<https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS>> (Accessed January 24, 2020).

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.¹⁶⁰ REC 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 REC markets are revenues for PJM resources earned in addition to revenues earned from the sale of the same MWh in 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, 2014.¹⁶¹ This is equivalent to providing a REC price equal to three times its stated value per MWh.

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 8-18 shows the REC tracking systems used by each state within the PJM footprint. To ensure a REC is only used one time, REC tracking systems must keep an account of a REC from its creation until its retirement. A REC is considered to be retired when it has been used to satisfy an obligation associated with an RPS.

¹⁶⁰ 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 Allico Finance Limited*, 156 FERC ¶ 61,042 (2016).

¹⁶¹ See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <<http://programs.dsireusa.org/system/program/detail/1231>> (Accessed November 3, 2018).

Table 8-18 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 8-19 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.

Table 8-19 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must be purchased from resources located within Illinois or from resources located in adjacent states that meet certain public interest criteria.
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, deliverability must be demonstrated 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.

Alternative Compliance Payments

PJM jurisdictions have various methods for enforcing compliance with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments (ACPs), with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. The ACPs, which are penalties, function as a cap on the market value of RECs. In New Jersey, solar ACPs are currently \$258.00 per MWh.¹⁶² Pennsylvania requires that solar ACPs be 200 percent of the average credit price of Pennsylvania solar RECs sold during the reporting year plus the value of any solar rebates which was \$63.16 per MWh for 2019. Figure 8-9 shows the historical relationship between SREC prices and ACP levels. The SREC price is represented by a solid line in the figure and the corresponding ACP level is represented by a dashed line. For each jurisdiction, the ACP is an upper bound for the price level. In Michigan and North Carolina,

there are no defined values for ACPs. The public utility commissions in Michigan and North Carolina have discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

¹⁶² N.J. S. 2314/A. 3723.

Table 8-20 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-20 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions: September 30, 2020^{163 164}

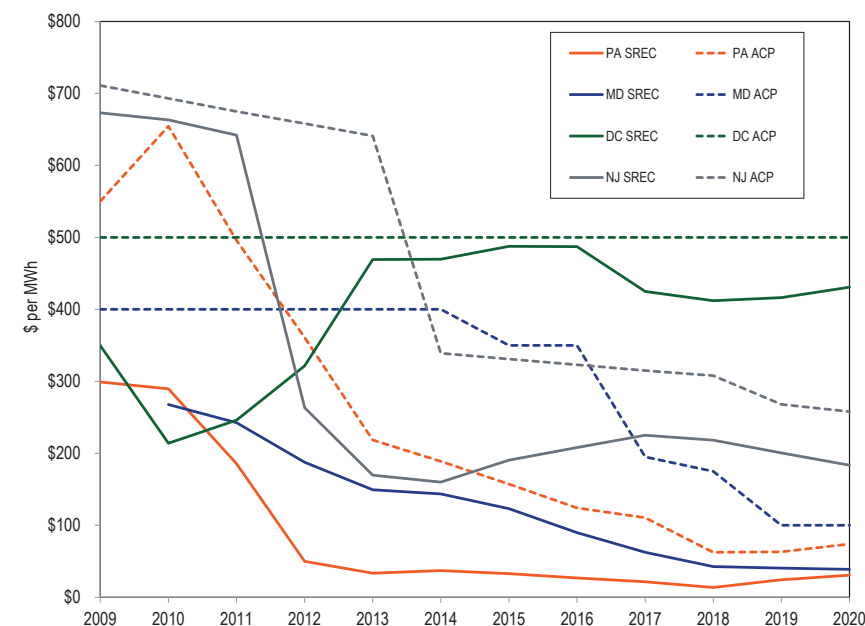
Jurisdiction with RPS	Standard Alternative Compliance (\$/MWh)	Tier II Alternative Compliance (\$/MWh)	Solar Alternative Compliance (\$/MWh)
Delaware	\$25.00		\$400.00
Illinois	\$0.35		
Maryland	\$30.00	\$15.00	\$100.00
Michigan	No specific penalties		
New Jersey	\$50.00	\$50.00	\$258.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	\$52.62		
Pennsylvania	\$45.00	\$45.00	\$74.00
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.

¹⁶³ The Ohio standard alternative compliance payment (ACP) is updated annually <<https://www.puco.ohio.gov/industry-information/industry-topics/acp-non-solar-alternative-compliance-payment-under-orc-492864/>>. The Illinois Commerce Commission periodically publishes updates to the effective ACP amount <<https://www.icc.illinois.gov/electricity/RPSCompliancePaymentNotices.aspx>>. For updated Maryland ACPs, see Table 3 of the 2018 Renewable Energy Portfolio Standard Report <<https://www.psc.state.md.us/commission-reports/>>.

¹⁶⁴ The entry for Pennsylvania reflects the solar ACP for the compliance year ending May 31, 2018. See "Pricing," <<https://www.pennaeps.com/reports/>> (Accessed July 16, 2019).

Figure 8-9 Comparison of SREC Price and Solar ACP: 2009 through 2020



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 2019 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 in September of 2020.¹⁶⁵ Pennsylvania reported that the 555,396 SRECs, 10,016,752 Tier I RECs and 11,645,974 Tier II RECs were retired during the 2019 reporting year (June 1, 2018 through May 31, 2019). Supplier obligations

¹⁶⁵ "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2020," (September 2019), <<https://www.pennaeps.com/wp-content/uploads/2020/09/2019-AEPS-Annual-Report.pdf>>.

for 2,219 SRECs, 65,662 Tier I RECs and 78,162 Tier II RECs were resolved through ACPs.

The Public Service Commission of the District of Columbia reported that 67,892 SRECs, 1,684,797 Tier I RECs and 112,484 Tier II RECs were retired during the 2018 compliance year. ACPs decreased from \$26,571,010 for 2017 to \$18,744,020 for 2018.¹⁶⁶

The Public Service Commission of Maryland reported that 857,232 SRECs, 8,627,737 Tier 1 RECs and 1,599,819 Tier 2 RECs were retired in 2018.¹⁶⁷ ACPs totaled \$67,796 for 2018 with the majority of payments “made in lieu of purchasing Tier 1 RECs to satisfy Industrial Load Process (“IPL”) obligations.”¹⁶⁸

The Public Utilities Commission of Ohio reported that 5,373,438 nonsolar RECs were retired in the 2018 compliance year, exceeding the REC obligation of 5,372,094 RECs; and 224,593 SRECs were retired in the 2018 compliance year, exceeding the SREC obligation of 224,481 SRECs.¹⁶⁹

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 670,488 credits for the compliance year ending May 31, 2019, with zero ACPs.¹⁷⁰ Delmarva Power satisfied their solar REC obligation of 124,073 credits with zero alternative compliance payments.

Prior to the 2017/2018 Delivery Year, the Illinois RPS had required electricity suppliers to satisfy at least 50 percent of their RPS obligation through ACPs. This requirement was removed for 2017/2018 Delivery Year and ACPs

for ComEd decreased to \$74,148. The 2016–2017 ACPs for ComEd totaled \$40,575,311.¹⁷¹

The North Carolina Utilities Commission reported that Dominion North Carolina Power submitted its 2018 compliance report on August 13, 2019. The compliance report stated that Dominion met its general RPS requirement by purchasing 397,643 credits that consisted of wind and hydro RECs and energy efficiency credits (EECs).¹⁷² Dominion also met its solar, poultry waste, and swine waste requirements by purchasing RECs.

The Michigan Public Service Commission reported that Indiana Michigan Power Company met the 2018 standard by generating or acquiring 283,473 RECs.¹⁷³

New Jersey’s Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2019.¹⁷⁴ Electric power suppliers retired 10,408,717 class I RECs and 1,835,664 class II RECs. There were no deficiencies for class I credits; 99 ACPs were submitted for class II. Electric power suppliers retired 2,747,676 solar RECs and there were no deficiencies requiring solar ACPs.

Table 8–21 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.¹⁷⁵ The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost by type in Table 8–21 is an estimate based on average REC prices and assigning the reported alternative compliance payments to the solar standard. The cost of complying with RPS, as reported by the states, was \$4.5 billion over the five year period from 2014 through 2018 for the nine jurisdictions that had RPS and reported compliance costs.¹⁷⁶ The average RPS compliance cost per year

171 “Annual Report Fiscal Year 2018,” Illinois Power Agency (Feb. 15, 2019) at 46, <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.

172 “Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina,” North Carolina Utilities Commission (Oct. 1, 2019) at 38, <<https://www.ncuc.net/Reps/reps.html>>.

173 “Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard,” Michigan Public Service Commission (Feb. 18, 2020), <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>.

174 See RPS Report Summary 2005–2019, New Jersey’s Clean Energy Program (Feb. 12, 2020), <<http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>>.

175 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.

176 The actual PJM RPS compliance cost exceeds the reported \$4.4 billion since this total does not include a value for Delaware in 2014 and a value for Pennsylvania in 2018.

166 “Report on the Renewable Energy Portfolio Standard for Compliance Year 2018,” Public Service Commission of the District of Columbia (May 1, 2019), <<https://www.dcpsc.org/Utility-Information/Electric/Renewables/Renewable-Energy-Portfolio-Standard-Program.aspx>>.

167 “Renewable Energy Portfolio Standard Report,” Public Service Commission of Maryland (Dec. 2019) at 8, <<https://www.psc.state.md.us/commission-reports/>>.

168 *Id.* at 9.

169 “Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2018,” Public Utilities Commission of Ohio (January 16, 2020), <<https://www.puco.ohio.gov/industry-information/industry-topics/ohioec28099s-renewable-and-advanced-energy-portfolio-standard/>>.

170 “Retail Electricity Supplier’s RPS Compliance Report, Compliance Period: June 1, 2018–May 31, 2019,” Delmarva Power, (Sept. 23, 2019), <<https://depdc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>>.

based on the reported compliance cost for the five year period from 2014 through 2019 was \$893.1 million. The compliance cost for 2018, the most recent year with complete data, was \$986.9 million.

Table 8-21 RPS Compliance Cost^{177 178 179 180 181 182 183 184 185 186}

Jurisdiction with RPS		2014	2015	2016	2017	2018
Delaware	Total RPS		\$16,013,421	\$18,409,631	\$18,772,855	\$18,341,916
	Solar		\$7,070,254	\$7,748,073	\$7,105,726	\$6,565,240
	Non-Solar		\$8,943,167	\$10,661,557	\$11,667,129	\$11,776,676
Illinois	Total RPS	\$21,701,688	\$24,817,068	\$25,718,863	\$25,919,372	\$25,775,523
Maryland	Total RPS	\$103,990,914	\$126,727,632	\$135,198,524	\$72,009,070	\$84,806,928
	Solar	\$29,372,737	\$39,055,714	\$45,556,987	\$21,275,664	\$27,351,388
	Tier I	\$70,630,620	\$85,054,001	\$88,200,121	\$50,045,621	\$56,406,247
	Tier II	\$3,987,557	\$2,617,917	\$1,441,416	\$687,785	\$1,049,293
Michigan	Total RPS	\$476,535	\$0	\$3,264,504	\$3,961,262	\$3,264,504
New Jersey	Total RPS	\$395,782,297	\$524,761,382	\$593,441,037	\$606,312,461	\$653,810,457
	Solar	\$322,504,920	\$417,359,783	\$481,540,738	\$503,797,182	\$560,509,712
	Class I	\$66,071,749	\$98,185,431	\$100,910,465	\$91,872,615	\$83,474,335
	Class II	\$7,205,628	\$9,216,167	\$10,989,834	\$10,642,664	\$9,826,410
North Carolina	Total RPS	\$297,513	\$358,436	\$317,644	\$234,264	\$442,579
Ohio	Total RPS	\$42,581,477	\$42,584,233	\$37,631,481	\$39,943,836	\$50,214,523
	Solar	\$17,666,730	\$14,843,052	\$11,564,584	\$9,435,730	\$9,419,092
	Non-Solar	\$24,914,747	\$27,741,181	\$26,066,897	\$30,508,106	\$40,795,431
Pennsylvania	Total RPS	\$86,184,477	\$114,586,932	\$125,041,911	\$115,585,212	\$99,681,713
	Solar	\$14,163,543	\$19,227,690	\$21,876,876	\$17,987,722	\$16,565,924
	Tier I	\$70,922,431	\$94,339,032	\$101,700,328	\$95,370,456	\$77,899,586
	Tier II	\$1,098,503	\$1,020,210	\$1,464,707	\$2,227,034	\$5,216,203
Washington D.C.	Total RPS	\$27,372,970	\$38,540,633	\$47,163,353	\$42,678,813	\$50,609,701
	Solar	\$25,145,143	\$36,526,662	\$44,897,161	\$38,571,061	\$45,673,261
	Tier I	\$2,140,860	\$1,899,232	\$2,132,072	\$3,960,018	\$4,809,857
	Tier II	\$86,966	\$114,738	\$134,119	\$147,734	\$126,583
PJM	Total RPS	\$678,387,871	\$888,389,738	\$986,186,949	\$925,417,144	\$986,947,843

¹⁷⁷ "Delmarva Power & Light's 2018 RPS Compliance Report," Delmarva Power (Sept. 23, 2019), <<https://depsec.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>>.

¹⁷⁸ "Fiscal Year 2018 Annual Report," February 15, 2019, "Report on Costs and Benefits of Renewable Resource Procurement," April 1, 2016, Illinois Power Agency (IPA), <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>. The compliance cost entry for Illinois represents the ComEd cost of RECs as given in Section 11, Table 2.

¹⁷⁹ "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (Dec. 2019) at 8, <<https://www.psc.state.md.us/commission-reports/>>.

¹⁸⁰ Appendix C in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 18, 2020, <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>. The compliance cost entry reflects the compliance cost of the Indiana Michigan Power Company, which is the only investor owned utilities whose service area is in the PJM footprint.

¹⁸¹ "RPS Report Summary 2005-2019," New Jersey's Clean Energy Program, February 12, 2020, <<http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>>.

¹⁸² "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2018," Public Utilities Commission of Ohio, January 16, 2020, <<https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>>.

¹⁸³ "2019 Annual Report Alternative Energy Portfolio Standards Act of 2004," Pennsylvania Public Utility Commission, September 2020 <<https://www.pennaeps.com/wp-content/uploads/2020/09/2019-AEPS-Annual-Report.pdf>>.

¹⁸⁴ "Report on the Renewable Energy Portfolio Standard for Compliance Year 2018," Public Service Commission of the District of Columbia, Executive Summary, May 1, 2019, <<https://dcpsec.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>>.

¹⁸⁵ "Application of Dominion Energy North Carolina for Approval of Cost Recovery for Renewable Energy and Energy Efficiency Portfolio Standard Compliance and Related Costs," Docket No. E-22, Sub 557, Sub 558, August 30, 2018 <<https://www.ncuc.net/>>. The North Carolina compliance cost entries reflects the compliance cost of Dominion Energy North Carolina.

¹⁸⁶ The reporting period for RPS compliance in Delaware, Illinois, New Jersey, and Pennsylvania corresponds to PJM capacity market delivery years, June 1 through May 31. The compliance cost amounts reported by these states were converted to calendar year by assuming the compliance cost was evenly spread across the months in the compliance year.

Emission Controlled Capacity and Emissions

Emission Controlled Capacity

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.¹⁸⁷ 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.^{188 189}

Table 8-22 shows SO₂ emission controls by fossil fuel fired units in PJM.^{190 191} Coal has the highest SO₂ emission rate, while natural gas and diesel oil have lower SO₂ emission rates.¹⁹³ Of the current 59,153.1 MW of coal capacity in PJM, 55,544.8 MW of capacity, 93.9 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO₂ emissions.

Table 8-22 SO₂ emission controls by fuel type (MW): September 30, 2020¹⁹⁴

	SO ₂ Controlled	No SO ₂ Controls	Total	Percent Controlled
Coal	55,544.8	3,608.3	59,153.1	93.9%
Diesel Oil	0.0	5,259.6	5,259.6	0.0%
Natural Gas	0.0	73,102.4	73,102.4	0.0%
Other	325.0	4,745.7	5,070.7	6.4%
Total	55,869.8	86,716.0	142,585.8	39.2%

Table 8-23 shows NO_x emission controls by fossil fuel fired units in PJM. Coal has the highest NO_x emission rate, while natural gas and diesel oil have lower NO_x emission rates. Of the current 59,153.1 MW of coal capacity in PJM,

58,941.6 MW of capacity, 99.6 percent, has some form of emissions controls to reduce NO_x emissions. Most units in PJM have NO_x emission controls in order to meet each state's emission compliance standards, based on whether a state is part of CSAPR, CAIR, Acid Rain Program (ARP) or a combination of the three. The NO_x compliance standards of MATS require the use of selective catalytic reduction (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.¹⁹⁵

Table 8-23 NO_x emission controls by fuel type (MW): As of September 30, 2020

	NO _x Controlled	No NO _x Controls	Total	Percent Controlled
Coal	58,941.6	211.5	59,153.1	99.6%
Diesel Oil	1,573.6	3,686.0	5,259.6	29.9%
Natural Gas	72,102.8	999.6	73,102.4	98.6%
Other	2,591.7	2,479.0	5,070.7	51.1%
Total	135,209.7	7,376.1	142,585.8	94.8%

Table 8-24 shows particulate emission controls by fossil fuel units in PJM. Almost all coal units (99.9 percent) in PJM have particulate controls, as well as a few natural gas units (3.8 percent) and units with other fuel sources (58.6 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.¹⁹⁶ Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Of the current 59,153.1 MW of coal capacity in PJM, 59,068.1 MW of capacity, 99.9 percent, have some type of particulate emissions control technology. 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, 121 of the 135 coal steam units have baghouse or FGD technology installed, representing 52,944.8 MW out of the 59,153.1 MW total coal capacity, or 89.5 percent.

¹⁸⁷ See EPA, "National Ambient Air Quality Standards (NAAQS)," <<https://www.epa.gov/criteria-air-pollutants/naaqs-table>> (Accessed March 7, 2020).

¹⁸⁸ On April 16, 2020, the EPA issued a revised final finding regarding the Mercury and Air Toxics Standards. See EPA, "Regulatory Actions," <<https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants>> (Accessed May 7, 2020).

¹⁸⁹ On April 9, 2020, the EPA created a new subcategory of six coal refuse power plants in Pennsylvania and West Virginia with reduced limits of HCl and SO₂ emissions under MATS. These units were all compliant with the previous MATS rules. "Mercury and Air Toxics Standards," <https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_coal_refuse_2060-au48_final_rule.pdf> (Accessed May 7, 2020).

¹⁹⁰ See EPA, "Air Market Programs Data," <<http://ampd.epa.gov/ampd/>> (Accessed May 7, 2020).

¹⁹¹ Air Markets Programs Data is submitted quarterly. Generators have 60 days after the end of the quarter to submit data, and all data is considered preliminary and subject to change until it is finalized in June of the following year. The most recent complete set of emissions data is from the second quarter of 2019.

¹⁹² The total MW are less than the 184,575.7 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 May 7, 2020).

¹⁹³ 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-id?SID=4f18612541a393473efb13acb879d470&mc=true&node=se40.18.72_12&rgn=div8> (Accessed May 7, 2020).

¹⁹⁴ 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.

¹⁹⁵ See EPA, "Mercury and Air Toxics Standards, Cleaner Power Plants," <<https://www.epa.gov/mats/cleaner-power-plants#controls>> (Accessed May 7, 2020).

¹⁹⁶ See EPA, "Air Pollution Control Technology Fact Sheet," <<https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf>> (Accessed May 7, 2020).

Table 8-24 Particulate emission controls by fuel type (MW): As of September 30, 2020

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	59,068.1	85.0	59,153.1	99.9%
Diesel Oil	0.0	5,259.6	5,259.6	0.0%
Natural Gas	2,786.0	70,316.4	73,102.4	3.8%
Other	2,970.5	2,100.2	5,070.7	58.6%
Total	64,824.6	77,761.2	142,585.8	45.5%

Emissions

Figure 8-10 shows the total CO₂ emissions and the CO₂ emissions per MWh within PJM for all CO₂ emitting units, for each quarter from 1999 to the third quarter of 2020. Figure 8-10 also shows the CO₂ emissions per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the third quarter of 2020.¹⁹⁷ ¹⁹⁸ For the period from the first quarter of 1999 through the third quarter of 2020, the minimum CO₂ produced per MWh was 0.66 short tons per MWh in the first quarter of 2020, and the maximum was 0.96 short tons per MWh in the first quarter of 2010. Total PJM generation decreased from 231,293.0 GWh in the third quarter of 2019 to 229,848.9 GWh in the third quarter of 2020, while CO₂ produced decreased from 112.9 million short tons in the third quarter of 2019 to 108.7 million short tons in the third quarter of 2020.¹⁹⁹ The reduction in total CO₂ emissions was primarily the result of a decrease in the use of coal and an increase in the use of natural gas for generation.

¹⁹⁷ Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.

¹⁹⁸ Emissions data for the second quarter of 2020 was not yet finalized at the time of this report because generators have 60 days after the end of the quarter to submit their emissions data.

¹⁹⁹ See the 2019 Quarterly State of the Market Report for PJM: January through March: Section 3: Energy Market, Table 3-10.

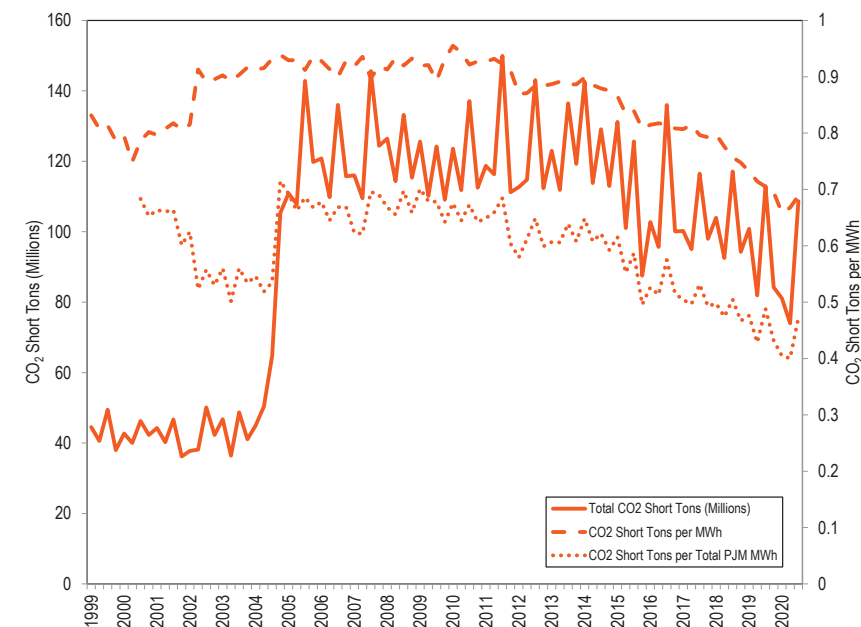
Figure 8-10 CO₂ emissions by quarter (millions of short tons), by PJM units: 1999 through September, 2020²⁰⁰ ²⁰¹

Figure 8-11 shows the total CO₂ emissions on peak and off peak and the CO₂ emissions per MWh for all CO₂ emitting units. Since the first quarter of 1999 the amount of CO₂ produced per MWh during off peak hours was at a minimum of 0.66 short tons per MWh in the first quarter of 2020, and a maximum of 0.97 short tons per MWh in the second quarter of 2010. Since the first quarter of 1999 the amount of CO₂ produced per MWh during on peak hours was at a minimum of 0.66 short tons per MWh in the first quarter of 2020, and a maximum of 0.94 short tons per MWh in the first quarter of 2010.

²⁰⁰ The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

²⁰¹ In 2004 and 2005, PJM integrated the American Electric Power (AEP), ComEd, Dayton Power & Light Company (DAY), Dominion, and Duquesne Light Company (DLCO) Control Zones. The large increase in total emissions from 2004 to 2005 was a result of these integrations. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC).

In the third quarter of 2020, CO₂ emissions were 0.69 short tons per MWh for off peak hours and 0.69 for on peak hours.

Figure 8-11 Total CO₂ emissions during on and off peak hours by quarter (millions of short tons), by PJM units: 1999 through September, 2020²⁰²

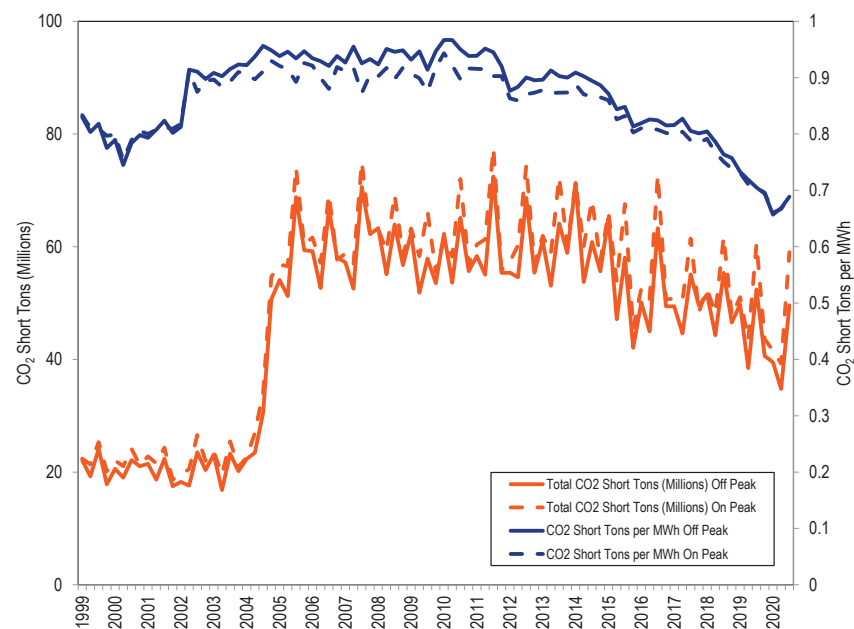


Figure 8-12 shows the total SO₂ and NO_x emissions and the short ton emissions per MWh for all SO₂ and NO_x emitting units, and the SO₂ and NO_x emissions per MWh of total PJM generation. For the period from the first quarter of 1999 through the third quarter of 2020, the minimum SO₂ produced per MWh was 0.000378 short tons per MWh in the first quarter of 2020, and the maximum was 0.008141 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the second quarter of 2020, the minimum NO_x produced per MWh was at a 0.000274 short tons per MWh in the third quarter of 2020, and the maximum was 0.002215 short tons per MWh

²⁰² The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

in the first quarter of 2005. In the third quarter of 2020, SO₂ emissions were 0.00090 short tons per MWh and NO_x emissions were 0.000274 short tons per MWh. The consistent decline in SO₂ 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 2020.^{203 204}

Figure 8-12 SO₂ and NO_x emissions by quarter (thousands of short tons), by PJM units: 1999 through September, 2020²⁰⁵

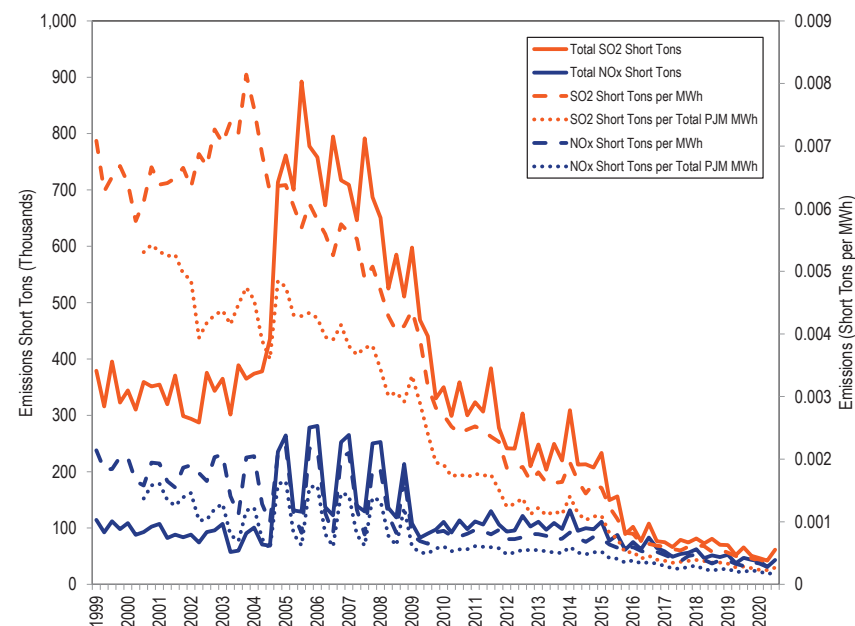


Figure 8-13 shows the total on peak hour and off peak hour SO₂ and NO_x emissions and the emissions per MWh from emitting resources for all SO₂ and NO_x emitting units. For the period from the first quarter of 1999 through the third quarter of 2020, the minimum SO₂ produced per MWh during off

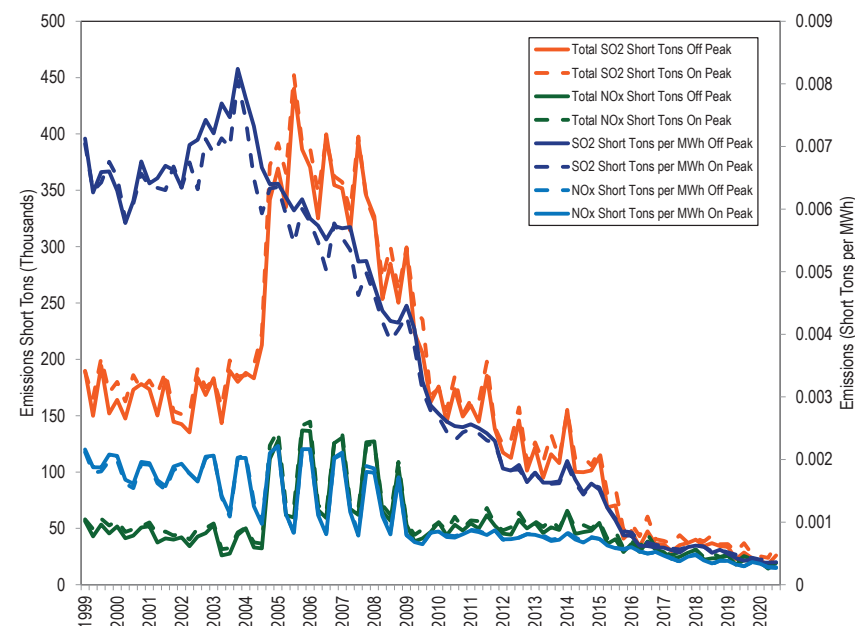
²⁰³ See EIA, "Changes in coal sector led to less SO₂ and NO_x emissions from electric power industry," <<https://www.eia.gov/todayinenergy/detail.php?id=37752>> (Accessed October 25, 2019).

²⁰⁴ See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <<https://www.eia.gov/todayinenergy/detail.php?id=29812>> (Accessed October 25, 2019).

²⁰⁵ The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

peak hours was 0.000352 short tons per MWh in the second quarter of 2020, and the maximum was 0.008239 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the third quarter of 2020, the minimum SO_2 produced per MWh during on peak hours was 0.000402 short tons per MWh in the first quarter of 2020, and the maximum was 0.008048 short tons per MWh in the fourth quarter of 2003. For the period from the first quarter of 1999 through the third quarter of 2020, the minimum NO_x produced per MWh during off peak hours was 0.000268 short tons per MWh in the third quarter of 2020, and the maximum was 0.002215 short tons per MWh in the first quarter of 2005. For the period from the first quarter of 1999 through the third quarter of 2020, the minimum NO_x produced per MWh during on peak hours was 0.000279 short tons per MWh in the third quarter of 2020 and the maximum was 0.002215 short tons per MWh in the first quarter of 2005. In the third quarter of 2020, SO_2 emissions were 0.000360 short tons per MWh and 0.000415 short tons per MWh for off and on peak hours. In the third quarter of 2020, NO_x emissions were 0.000268 short tons per MWh and 0.000279 short tons per MWh for off and on peak hours.

Figure 8-13 SO_2 and NO_x emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: 1999 through September, 2020²⁰⁶



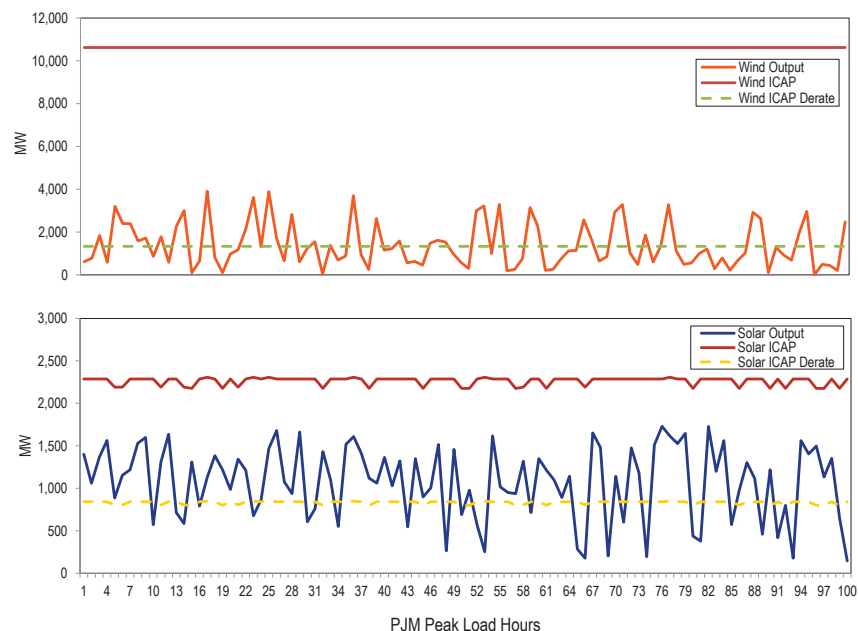
²⁰⁶ The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Renewable Energy Output

Wind and Solar Peak Hour Output

The capacity of solar and wind resources are derated from the nameplate or installed capacity value to a level intended to reflect that the resources are a substitute for other capacity resources in the PJM Capacity Market. The derating percentages are intended to reflect expected performance during high load hours and are based on actual historical performance. Figure 8-14 shows the wind and solar output during the top 100 load hours in PJM in the first nine months of 2020. Of the top 100 load hours in PJM in the first nine months of 2020, 90 are PJM defined peak load hours. The hours are in descending order by load. The solid lines are the total ICAP of wind or solar PJM resources. The dashed lines are the total capacity committed for each unit, or the ICAP of wind and solar PJM resources derated to 14.7 and 38.0 percent if the unit does not participate in the capacity market.²⁰⁷ The actual output of the wind and solar resources during the top 100 load hours ranges above and below the derated capacity values. Wind output was above the derated ICAP for 40 hours and below the derated ICAP for 60 hours of the top 100 load hours in the first nine months of 2020. The wind capacity factor for the top 100 load hours in the first nine months of 2020 was 13.1 percent. Wind output was above the derated ICAP for 4,273 hours and below the derated ICAP for 2,302 hours in the first nine months of 2020. The wind capacity factor in the first nine months of 2020 was 25.8 percent. Solar output was above the derated ICAP for 73 hours and below the derated ICAP for 27 hours of the top 100 load hours in the first nine months of 2020. The solar capacity factor for the top 100 load hours in the first nine months of 2020 was 47.5 percent. Solar output was above the derated ICAP for 1,709 hours and below the derated ICAP for 4,866 hours in the first nine months of 2020. The solar capacity factor in the first nine months of 2020 was 23.8 percent.

Figure 8-14 Wind and solar output during the top 100 load hours in PJM: January through September, 2020



Wind Units

Table 8-25 shows the capacity factors of wind units in PJM. In the first nine months of 2020, the capacity factor of wind units in PJM was 25.8 percent. Wind units that were capacity resources had a capacity factor of 26.6 percent and an installed capacity of 8,599 MW. Wind units that were energy only had a capacity factor of 22.6 percent and an installed capacity of 2,178 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.²⁰⁸

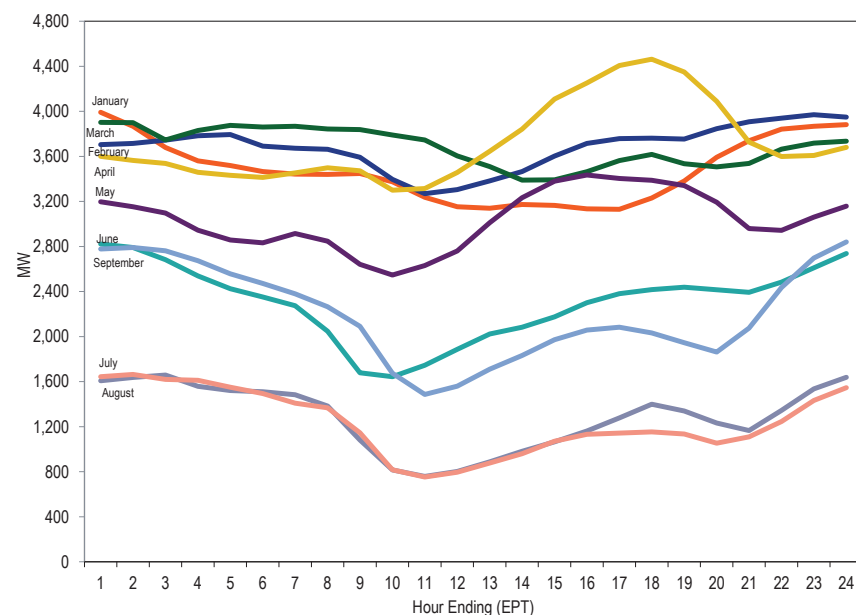
²⁰⁷ PJM used derating factors of 13 and 38 percent until June 1, 2017. The current derating factors depend on installation type. PJM, Class Average Capacity Factors, <<https://www.pjm.com/-/media/planning/res-adecq/class-average-wind-capacity-factors.ashx?la=en>> (Accessed October 17, 2019).

²⁰⁸ PJM, Class Average Capacity Factors, <<https://www.pjm.com/-/media/planning/res-adecq/class-average-wind-capacity-factors.ashx?la=en>> (Accessed October 17, 2019).

Table 8-25 Capacity factor of wind units in PJM: January through September, 2020²⁰⁹

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	22.6%	2,178
Capacity Resource	26.6%	8,599
All Units	25.8%	10,777

Figure 8-15 shows the average hourly real-time generation of wind units in PJM, by month for January 1 through September 30, 2020. The hour with the highest average output, 4,463 MW, occurred in April, and the hour with the lowest average output, 753 MW, occurred in August. Wind output in PJM is generally higher during off peak hours and lower during on peak hours.

Figure 8-15 Average hourly real-time generation of wind units in PJM: January through September, 2020

²⁰⁹ Capacity factor is calculated based on online date of the resource.

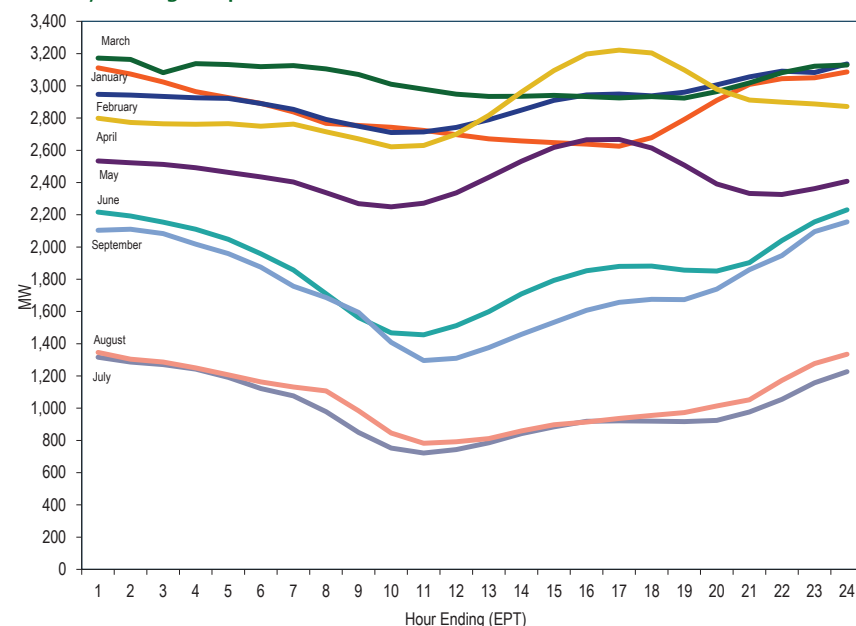
Table 8-26 shows the generation and capacity factor of wind units by month from January 1, 2019, through September 30, 2020.

Table 8-26 Capacity factor of wind units in PJM by month: January 2019 through September 2020

Month	2019		2020	
	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	2,611,714.5	36.9%	2,588,895.7	33.3%
February	2,228,415.9	34.9%	2,564,467.7	35.1%
March	2,467,063.3	34.9%	2,739,005.2	34.8%
April	2,665,719.5	38.9%	2,679,800.9	35.0%
May	1,925,357.2	27.2%	2,261,803.9	28.6%
June	1,746,607.4	25.5%	1,662,419.6	21.7%
July	1,056,020.4	14.9%	959,774.9	12.1%
August	930,466.2	13.1%	925,896.4	11.7%
September	1,342,423.1	19.6%	1,604,108.9	20.8%
October	2,179,433.7	30.8%		
November	2,157,505.1	30.6%		
December	2,855,933.5	37.7%		
Annual	24,166,659.8	28.8%	17,986,173.1	25.8%

Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-16 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

Figure 8-16 Average hourly day-ahead generation of wind units in PJM: January through September, 2020



Output from wind turbines displaces output from other generation types because, in general, wind turbines generate power when the wind is blowing, regardless of the price. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output.²¹⁰ Figure 8-17 and Table 8-27 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first nine months of 2020. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. In the first nine months of 2020, the dispatch instruction for marginal wind resources was to reduce output for 7270.6 percent of the unit intervals. When wind appears as the displaced fuel

²¹⁰ The measure is based on the principle that any incremental change in the wind output is balanced by the change in the output of marginal generators, while holding everything else equal.

at times when wind resources were on the margin this means that there was no displacement for those hours, if the dispatch instruction was to lower the generation. The level of wind displaced by wind is thus overstated.

Figure 8-17 Marginal fuel at time of wind generation in PJM: January through September, 2020

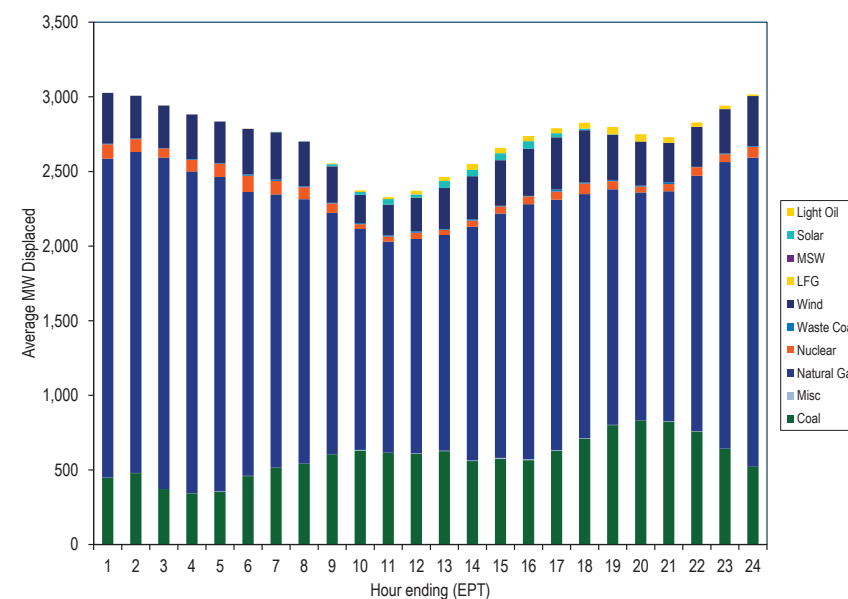


Table 8-27 Marginal fuel MW at time of wind generation in PJM: January through September, 2020

Hour	Natural			Waste			Light				Total
	Coal	Misc	Gas	Nuclear	Coal	Wind	LFG	MSW	Solar	Oil	
0	448.1	0.5	2,137.3	95.6	4.8	340.1	0.0	0.0	0.0	0.0	3,026.4
1	479.2	1.2	2,150.0	86.2	5.1	285.9	0.0	0.0	0.0	0.0	3,007.6
2	371.9	0.4	2,221.1	59.9	2.1	286.2	1.0	0.0	0.0	0.0	2,942.7
3	344.2	0.5	2,155.9	77.3	4.9	298.5	0.0	0.5	0.0	0.0	2,881.8
4	354.6	2.4	2,106.0	88.9	3.0	279.3	0.0	0.9	0.0	0.0	2,835.1
5	458.6	2.6	1,901.5	108.9	9.0	304.3	0.7	1.1	0.0	0.0	2,786.7
6	516.1	0.0	1,830.1	90.0	10.4	315.5	0.6	1.0	1.5	0.0	2,765.1
7	543.1	0.0	1,771.3	80.1	6.4	297.7	1.7	1.4	2.7	0.0	2,704.4
8	605.4	0.0	1,616.7	64.0	4.3	243.0	0.0	1.7	14.1	4.1	2,553.4
9	630.7	3.9	1,479.7	32.5	6.7	189.4	0.0	0.0	19.7	11.5	2,374.1
10	615.9	0.6	1,414.0	33.8	7.2	206.3	0.0	0.0	37.2	13.4	2,328.3
11	608.2	3.4	1,436.5	41.1	10.6	222.1	1.4	0.0	23.1	23.9	2,370.3
12	625.9	3.2	1,444.7	36.0	4.4	275.4	0.0	0.0	47.2	27.4	2,465.3
13	560.3	3.3	1,566.1	41.6	8.9	288.0	0.0	0.0	42.5	39.0	2,550.3
14	574.5	5.9	1,637.9	47.0	4.4	305.7	0.0	0.5	46.5	35.2	2,657.6
15	565.9	5.5	1,709.1	52.4	3.3	315.5	0.0	0.5	50.7	34.1	2,737.0
16	630.7	2.3	1,678.3	54.6	14.0	349.4	0.0	0.0	27.3	33.2	2,790.5
17	707.8	4.3	1,636.3	70.1	7.7	350.6	0.0	0.0	11.3	37.6	2,826.6
18	800.9	1.3	1,579.0	53.6	8.4	303.3	3.0	0.0	2.1	46.5	2,798.6
19	831.4	0.0	1,528.1	39.4	6.1	295.8	0.7	0.0	0.0	47.9	2,750.0
20	821.4	4.5	1,541.2	48.7	12.2	263.1	0.4	0.0	0.4	37.3	2,730.4
21	758.8	2.0	1,710.5	57.3	2.4	268.3	0.0	0.0	0.0	29.0	2,829.1
22	643.4	0.3	1,919.5	52.1	4.9	297.5	0.7	0.0	0.0	22.6	2,941.0
23	521.3	0.0	2,071.9	71.5	5.2	335.6	0.0	0.0	0.0	10.2	3,015.7
Average	584.1	2.0	1,760.1	61.8	6.5	288.2	0.4	0.3	13.6	18.9	2,736.2

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 8-16, there are 2,353.3 MW capacity of solar registered in GATS that are PJM units. As shown in Table 8-17, there are 6,311.7 MW capacity of solar registered in GATS that are not PJM units. Some behind the meter generation exists in clusters, such as community solar farms, 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 avoid their proper financial responsibility through badly designed rules, such as rules for

netting. The MMU recommends that load and generation located at separate nodes be treated as separate resources.

Table 8-28 shows the capacity factor of solar units in PJM. In the first six months of 2020, the capacity factor of solar units in PJM was 23.8 percent. Solar units that were capacity resources had a capacity factor of 24.6 percent and an installed capacity of 1,867 MW. Solar units that were energy only had a capacity factor of 19.2 percent and an installed capacity of 1,227 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.²¹¹

Table 8-28 Capacity factor of solar units in PJM: January through September, 2020

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	19.2%	1,227
Capacity Resource	24.6%	1,867
All Units	23.8%	3,094

Figure 8-18 shows the average hourly real-time generation of solar units in PJM, by month. The hour with the highest peak average output, 1,444 MW, occurred in June, and the hour with the lowest peak average output, 905 MW, occurred in January. Solar output in PJM is generally higher during peak hours and lower during off peak hours.

²¹¹ PJM, Class Average Capacity Factors, <<https://www.pjm.com/-/media/planning/res-adcq/class-average-wind-capacity-factors.ashx?la=en>> (Accessed October 17, 2019).

Figure 8-18 Average hourly real-time generation of solar units in PJM: January through September, 2020

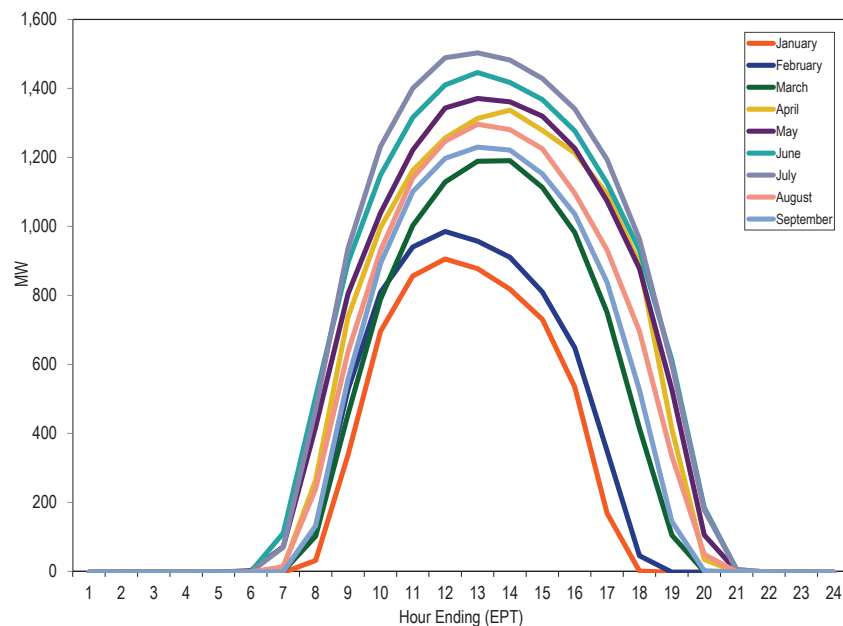


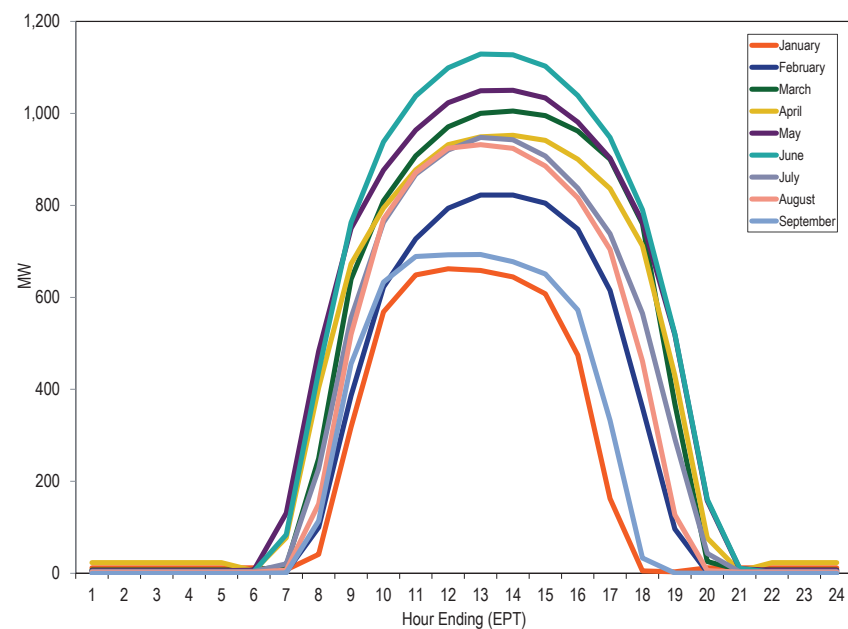
Table 8-29 shows the generation and capacity factor of solar units by month from January 1, 2019, through September 30, 2020.

Table 8-29 Capacity factor of solar units in PJM by month: January 2019 through September 2020

Month	2019		2020	
	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	120,957.1	14.4%	164,119.3	14.4%
February	130,178.1	16.5%	182,571.5	17.0%
March	209,107.5	23.4%	255,439.6	21.7%
April	234,395.2	26.8%	322,403.6	27.8%
May	270,502.0	28.8%	352,414.5	28.9%
June	270,516.0	29.2%	367,919.0	30.8%
July	319,914.9	31.7%	392,839.8	31.8%
August	276,196.9	27.5%	301,937.3	25.3%
September	242,606.8	25.4%	258,011.5	22.2%
October	183,319.8	18.5%		
November	157,567.3	15.8%		
December	127,723.7	11.6%		
Annual	2,542,985.4	22.5%	2,597,655.9	24.6%

Solar units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-19 shows the average hourly day-ahead generation offers of solar units in PJM, by month.²¹²

Figure 8-19 Average hourly day-ahead generation of solar units in PJM: January through September, 2020



²¹² 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.

Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or respond to price differentials. The external regions include both market and nonmarket balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2020, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.¹ In the first nine months of 2020, the real-time net interchange was -30,988.1 GWh. The real-time net interchange in the first nine months of 2019 was -25,916.9 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2020, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months. In the first nine months of 2020, the total day-ahead net interchange was -8,139.8 GWh. The day-ahead net interchange in the first nine months of 2019 was -4,540.7 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2020, gross imports in the day-ahead energy market were 640.5 percent of gross imports in the real-time energy market (527.0 percent in the first nine months of 2019). In the first nine months of 2020, gross exports in the day-ahead energy market were 111.3 percent of the gross exports in the real-time energy market (130.5 percent in the first nine months of 2019).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2020, there were net scheduled exports at 14 of PJM's 19 interfaces in the real-time energy market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2020, there were net scheduled exports at 10

of PJM's 17 interface pricing points eligible for real-time transactions in the real-time energy market.^{2 3}

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2020, there were net scheduled exports at 14 of PJM's 19 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2020, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for day-ahead transactions in the day-ahead energy market.⁴
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2020, up to congestion transactions were net exports at three of PJM's 18 interface pricing points eligible for day-ahead transactions in the day-ahead energy market.⁵
- **Inadvertent Interchange.** In the first nine months of 2020, net scheduled interchange was -30,988 GWh and net actual interchange was -31,044 GWh, a difference of 56 GWh. In the first nine months of 2019, the difference was 47 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first nine months of 2020, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -1,623 GWh of net scheduled interchange and -8,670 GWh of net actual interchange, a difference of 7,047 GWh. In the first nine months of 2020, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 2,649 GWh of net scheduled interchange and 18,703 GWh of net actual interchange, a difference of 16,054 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 the first five months of 2020, there was one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

³ On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP, DUKEXP and NIPSCO interface pricing points, reducing the number of real-time interfaces to 13.

⁴ On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points, reducing the number of day-ahead interfaces to 13.

⁵ On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points, reducing the number of day-ahead interfaces to 13.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2020, 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 67.3 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first nine months of 2020, 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 49.5 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2020, 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 66.8 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2020, 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 58.3 percent of the hours.
- **Hudson DC Line.** In the first nine months of 2020, 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 47.5 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued one TLR of level 3a or higher in the first nine months of 2020, compared to two such TLRs issued in the first nine months of 2019.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market increased by 5.2 percent, from 51,594 bids per day in the first nine months of 2019 to 54,299 bids per day in the first nine months of 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by

0.1 percent, from 490,421 MWh per day in the first nine months of 2019, to 489,871 MWh per day in the first nine months of 2020.

Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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: High. First reported 2013. Status: Partially adopted, Q2 2020.)
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SouthIMP/EXP interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends changing the assignment of the Saskatchewan Power Company and Manitoba Hydro balancing authorities from the

Northwest interface pricing point to the MISO interface pricing point and eliminating the Northwest interface pricing point from the day-ahead and real-time energy markets. (Priority: High. First reported Q1, 2020. Status: Not adopted.)

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the NCMPAIMP and NCMPAEXP interface pricing points. It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. (Priority: High. First reported Q2, 2020. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 2019. Status: Not adopted.)

Conclusion

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

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

Prior to the integration of NIPSCO with MISO, transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. Starting May 1, 2004, when NIPSCO integrated with MISO, 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 pricing point in the real-time energy market after the integration of NIPSCO into MISO. The MMU has recommended that PJM terminate the NIPSCO interface pricing point since 2013. The NIPSCO pricing point is a pricing point that could no longer be used to price actual transactions and did not reflect actual price formation. On June 1, 2020, PJM terminated the NIPSCO interface pricing point.

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

On June 1, 2020, PJM terminated the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP interface pricing points. It is not clear why PJM did not also terminate the NCMPAIMP and NCMPAEXP interface pricing points at that time. The MMU continues to recommend the termination of these interface pricing points.⁶ In addition to the NCMPAIMP and NCMPAEXP interface prices, the MMU recommends the termination of the Southeast and Southwest interface pricing points, the Northwest interface pricing point and the Ontario

⁶ At the September 2, 2020, Market Implementation Committee (MIC) meeting, PJM reported that the NCMPAIMP and NCMPAEXP interface pricing points would be retired effective November 3, 2020.

interface pricing point.⁷ These pricing points can no longer be used to price actual transactions, are inappropriately used to support special agreements, or are pricing points that are noncontiguous to the PJM footprint that create opportunities for market participants to engage in sham scheduling activities.

Interchange Transaction Activity

Charges and Credits Applied to Interchange Transactions

Interchange transactions are subject to various charges and credits. These charges and credits are dependent on whether the interchange transaction is submitted in the real-time or day-ahead energy market, the type of transaction, the transmission service used and whether the transaction is an import, export or wheel. Table 9-1 shows the billing line items that represent the charges and credits applied to real-time and day-ahead interchange transactions.⁸

⁷ At the September 2, 2020, Market Implementation Committee (MIC) meeting, PJM reported that the Northwest interface pricing point would be retired effective October 1, 2020.

⁸ For an explanation and current rate for each billing line item, see "Quick Reference Guide to Market Settlements By Type of Business" (June 1, 2019) <<https://www.pjm.com/-/media/training/core-curriculum/ip-ms-301/ms-301-quick-reference-guide-to-markets-settlements-by-type-of-business.ashx?la=en>>.

Table 9-1 Charges and credits applied to interchange transactions

Billing Item	Real-Time Transactions				Day-Ahead Transactions				Up to Congestion
	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	
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 MISO² No charge for spot in transmission

Aggregate Imports and Exports

Table 9-2 shows the real-time and day-ahead scheduled interchange totals for the first nine months of 2019 and 2020. In the first nine months of 2020, gross imports in the day-ahead energy market were 640.5 percent of gross imports in the real-time energy market (527.0 percent in the first nine months of 2019). In the first nine months of 2020, gross exports in the day-ahead energy market were 111.3 percent of gross exports in the real-time energy market (130.5 percent in the first nine months of 2019).

Table 9-2 Real-time and day-ahead scheduled interchange volumes (GWh): January through September, 2019 and 2020

Category	Jan-Sep 2019	Jan-Sep 2020	Percent Change
Real-Time Gross Imports	7,385.1	4,976.9	(32.6%)
Real-Time Gross Exports	33,302.0	35,965.1	8.0%
Real-Time Net Interchange	(25,916.9)	(30,988.1)	19.6%
Day-Ahead Gross Imports	38,921.1	31,875.1	(18.1%)
Day-Ahead Gross Exports	43,461.7	40,015.0	(7.9%)
Day-Ahead Net Interchange	(4,540.7)	(8,139.8)	79.3%
Monthly Average Real-Time Gross Exports	3,700.2	3,996.1	8.0%
Monthly Average Real-Time Gross Imports	820.6	553.0	(32.6%)
Monthly Average Day-Ahead Gross Exports	4,829.1	4,446.1	(7.9%)
Monthly Average Day-Ahead Gross Imports	4,324.6	3,541.7	(18.1%)

In the first nine months of 2020, PJM was a monthly net exporter of energy in the real-time energy market in all months. In the first nine months of 2020, PJM was a monthly net exporter of energy in the day-ahead energy market in all months (Figure 9-1).⁹

Figure 9-1 shows real-time and day-ahead import, export and net interchange volumes. The day-ahead totals include fixed, dispatchable and up to congestion transaction totals. The net interchange of up to congestion transactions are represented by the orange line.

Transactions in the day-ahead energy market create financial obligations to deliver in the real-time energy market and to pay operating reserve charges based on differences between the transaction MWh in the day-ahead and

⁹ 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.

real-time energy markets times the applicable operating reserve rates.¹⁰ In the first nine months of 2020, 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: January through September, 2020

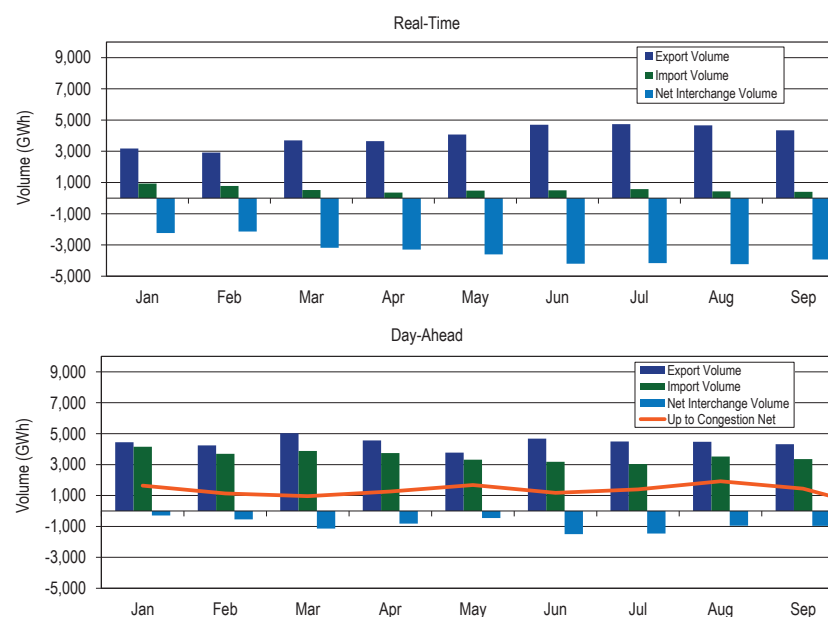
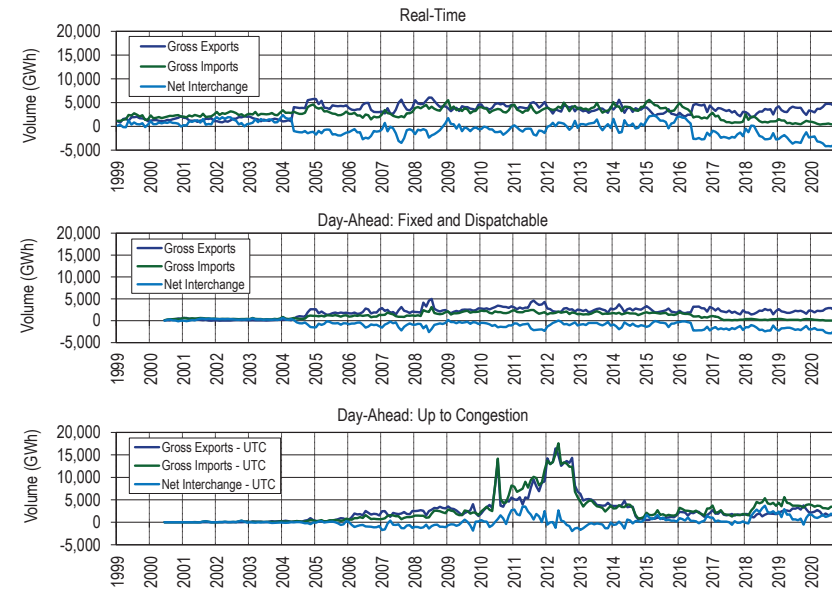


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from January 1999 through September 2020. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the real-time and day-ahead energy markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and

¹⁰ Up to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Light into PJM. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up to congestion product in September 2010, up to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the day-ahead energy market. On November 1, 2012, PJM eliminated the requirement that every up to congestion transaction include an interface pricing point as either the source or sink. As a result, the volume of import and export up to congestion transactions decreased, and the volume of internal up to congestion transactions increased. While the gross import and export volumes in the day-ahead energy market decreased, PJM has remained primarily a net exporter in the day-ahead energy market. The requirement for external capacity resources to be pseudo tied into PJM has affected the real-time and day-ahead import volumes. Prior to June 1, 2016, these units were dynamically scheduled into PJM or were block scheduled into PJM and were part of scheduled interchange as imports. Pseudo tied units are treated as internal generation and therefore do not affect interchange volume. The reduction of the import volume based on the switch to pseudo tie status contributed to PJM remaining a net exporter in the real-time and day-ahead energy markets. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.¹¹ As a result, the volume of import and export up to congestion transactions increased contributing to PJM becoming a net importer in the day-ahead energy market starting in March, 2018.

Figure 9-2 Scheduled import and export transaction volume history: January 1, 1999 through September 30, 2020



¹¹ 162 FERC ¶ 61,139.

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 9-18 includes a list of active interfaces in the first nine months of 2020. Figure 9-3 shows the approximate geographic location of the interfaces. In the first nine months of 2020, PJM had 19 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. Similarly, there are 10 separate interfaces that make up the MISO Interface between PJM and MISO. Table 9-3 through Table 9-5 show the real-time energy market scheduled interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the scheduled interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net scheduled interchange in the real-time energy market is shown by interface for the first nine months of 2020 in Table 9-3, while gross scheduled imports and exports are shown in Table 9-4 and Table 9-5.

In the real-time energy market, in the first nine months of 2020, there were net scheduled exports at 14 of PJM's 19 interfaces. The top three net exporting interfaces in the real-time energy market accounted for 50.5 percent of the total net scheduled exports: PJM/Cinergy (CIN) with 26.8 percent, PJM/MidAmerican Energy Company (MEC) with 12.3 percent and PJM/Alliant Energy - East (ALTE) with 11.4 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 22.6 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 nine of the 10 separate interfaces that connect PJM to MISO. Those nine exporting interfaces represented 75.6 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in the first nine months of 2020, there were net scheduled imports at four of PJM's 19 interfaces. The top three importing interfaces in the real-time energy market accounted for 98.8 percent of the total net scheduled imports: PJM/Duke Energy Corp. (DUK) with 72.2 percent, PJM/Carolina Power and Light East (CPLE) with 24.1 percent and PJM/Tennessee Valley Authority (TVA) with 2.5 percent of the net scheduled import volume.¹² 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 none of the 10 separate interfaces that connect PJM to MISO.

Table 9-3 Real-time scheduled net interchange volume by interface (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	50.4	78.1	197.3	82.2	112.5	14.6	(19.9)	(19.6)	(61.7)	451.8
CPLW	9.6	0.0	0.0	1.2	11.3	0.0	0.0	0.0	0.0	22.2
DUK	352.5	274.6	5.2	(0.7)	22.8	148.3	257.7	164.9	127.8	1,353.1
LGEE	(62.3)	(65.2)	(75.4)	(34.2)	(34.8)	(80.5)	(85.9)	(68.9)	(57.3)	(564.6)
MISO	(1,913.2)	(1,879.6)	(2,752.6)	(2,886.7)	(3,184.0)	(3,290.8)	(3,096.7)	(2,897.2)	(2,955.6)	(24,856.3)
ALTE	(353.2)	(330.2)	(518.7)	(581.9)	(408.5)	(454.4)	(331.4)	(352.3)	(407.2)	(3,737.8)
ALTW	(0.6)	(89.2)	(175.7)	(167.5)	(201.4)	(213.1)	(280.9)	(293.8)	(166.9)	(1,589.2)
AMIL	(32.2)	(40.7)	(48.5)	(57.0)	(66.2)	(52.6)	(45.1)	(25.3)	(49.0)	(416.6)
CIN	(516.6)	(447.4)	(637.8)	(885.2)	(1,044.8)	(1,282.6)	(1,485.8)	(1,175.2)	(1,332.0)	(8,807.3)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(42.9)	(89.7)	(134.8)	(119.5)	(160.5)	(122.7)	(128.8)	(140.1)	(119.9)	(1,059.0)
MEC	(466.4)	(436.0)	(505.8)	(356.3)	(515.4)	(427.1)	(449.0)	(454.5)	(436.5)	(4,047.0)
MECS	(132.7)	(211.3)	(368.4)	(370.9)	(391.2)	(336.7)	(306.8)	(392.6)	(393.4)	(2,904.1)
NIPS	(245.8)	(134.7)	(291.9)	(289.4)	(331.0)	(322.8)	(7.1)	0.0	0.0	(1,622.7)
WEC	(122.7)	(100.3)	(71.0)	(59.0)	(65.0)	(78.8)	(61.8)	(63.4)	(50.6)	(672.7)
NYISO	(863.7)	(673.5)	(573.7)	(427.8)	(530.5)	(936.4)	(1,137.1)	(1,332.6)	(966.2)	(7,441.5)
HUDS	(163.6)	(115.2)	(62.0)	(14.3)	(30.3)	(88.3)	(116.4)	(145.4)	(133.0)	(868.6)
LIND	(140.4)	(111.4)	(85.9)	(52.3)	(63.7)	(111.7)	(153.0)	(191.7)	(186.3)	(1,096.4)
NEPT	(426.5)	(386.2)	(395.6)	(386.0)	(375.9)	(445.2)	(487.1)	(473.6)	(277.3)	(3,653.4)
NYIS	(133.2)	(60.7)	(30.2)	24.8	(60.6)	(291.2)	(380.6)	(521.8)	(369.6)	(1,823.1)
TVA	187.0	124.2	23.0	(27.6)	1.3	(58.3)	(103.2)	(75.3)	(23.9)	47.2
Total	(2,239.7)	(2,141.4)	(3,176.2)	(3,293.5)	(3,601.4)	(4,203.0)	(4,167.3)	(4,228.7)	(3,936.9)	(30,988.1)

¹² In the real-time energy market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

**Table 9-4 Real-time scheduled gross import volume by interface (GWh):
January through September, 2020**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	85.2	158.6	253.7	162.9	173.4	109.1	54.7	36.8	9.1	1,043.5
CPLW	9.6	0.0	0.0	1.2	11.3	0.0	0.0	0.0	0.0	22.2
DUK	369.5	295.5	23.1	5.5	36.9	176.7	285.4	196.6	176.1	1,565.3
LGEE	24.0	14.4	1.1	1.8	2.1	2.0	4.5	8.1	1.4	59.2
MISO	104.8	47.8	27.4	24.4	28.5	59.1	65.1	34.5	49.9	441.5
ALTE	2.9	1.3	0.4	0.7	4.0	12.7	4.6	1.0	3.5	31.1
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	5.1	0.2	0.0	0.0	0.0	0.0	3.5	0.2	0.3	9.1
CIN	10.6	7.9	5.0	1.8	3.5	8.8	14.5	10.9	21.6	84.7
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	4.2	0.5	0.4	0.1	0.4	1.4	3.9	0.3	0.0	11.1
MEC	12.8	19.8	19.2	17.7	13.6	31.6	22.5	18.0	20.7	176.0
MECS	62.0	16.6	2.3	4.1	6.7	4.5	15.7	4.1	3.7	119.6
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	7.2	1.7	0.1	0.0	0.3	0.1	0.4	0.0	0.1	9.7
NYISO	124.8	112.5	135.1	137.3	124.8	130.7	141.4	122.3	117.0	1,145.8
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
LIND	0.9	0.4	0.2	1.2	0.4	0.5	1.0	0.3	0.0	4.9
NEPT	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.3
NYIS	123.8	112.0	135.0	136.1	124.3	130.2	140.3	121.9	116.9	1,140.5
TVA	216.6	151.7	78.5	24.8	98.9	19.6	24.5	34.4	50.5	699.5
Total	934.3	780.5	518.9	358.0	475.9	497.1	575.5	432.7	404.0	4,976.9

**Table 9-5 Real-time scheduled gross export volume by interface (GWh):
January through September, 2020**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	34.8	80.5	56.4	80.7	61.0	94.4	56.6	56.5	70.8	591.7
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	16.9	20.9	17.9	6.2	14.1	28.4	27.8	31.7	48.3	212.2
LGEE	86.3	79.6	76.5	36.0	36.9	82.4	90.4	77.0	58.7	623.7
MISO	2,017.9	1,927.4	2,780.0	2,911.1	3,212.5	3,349.9	3,161.8	2,931.7	3,005.6	25,297.8
ALTE	356.1	331.5	519.0	582.6	412.5	467.2	335.9	353.3	410.8	3,768.9
ALTW	0.6	89.2	175.7	167.5	201.4	213.1	280.9	293.8	166.9	1,589.2
AMIL	37.3	40.9	48.5	57.0	66.2	52.6	48.5	25.5	49.2	425.7
CIN	527.2	455.2	642.8	887.0	1,048.4	1,291.4	1,500.3	1,186.1	1,353.6	8,891.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	47.1	90.2	135.2	119.6	160.9	124.1	132.7	140.4	119.9	1,070.2
MEC	479.3	455.8	525.0	374.0	529.0	458.7	471.5	472.5	457.2	4,223.0
MECS	194.6	227.9	370.7	375.0	397.9	341.2	322.5	396.7	397.2	3,023.7
NIPS	245.8	134.7	291.9	289.4	331.0	322.8	7.1	0.0	0.0	1,622.7
WEC	129.9	102.0	71.1	59.0	65.3	78.8	62.3	63.4	50.7	682.4
NYISO	988.5	786.0	708.9	565.2	655.3	1,067.1	1,278.5	1,454.8	1,083.2	8,587.3
HUDS	163.6	115.2	62.0	14.3	30.3	88.3	116.4	145.4	133.0	868.7
LIND	141.4	111.9	86.1	53.5	64.1	112.1	154.0	192.0	186.3	1,101.4
NEPT	426.6	386.2	395.6	386.0	376.0	445.2	487.1	473.7	277.3	3,653.6
NYIS	256.9	172.7	165.1	111.4	184.9	421.4	520.9	643.7	486.6	2,963.6
TVA	29.6	27.5	55.5	52.4	97.7	77.9	127.7	109.7	74.4	652.3
Total	3,174.0	2,921.9	3,695.1	3,651.5	4,077.3	4,700.1	4,742.8	4,661.4	4,341.0	35,965.1

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.¹³ An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled path from a generation control area (GCA) to a load control area (LCA), this path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the

¹³ 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.

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.¹⁴

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.¹⁵ 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 9-19 presents the interface pricing points used in the first nine months of 2020. On October 22, 2019, PJM updated the mappings of external balancing authorities to individual pricing points. Figure 9-4 shows a map of the default interface pricing point assignments for all external balancing authorities. Figure 9-4 shows that all balancing authorities in the Western Interconnection are mapped to the Northwest interface pricing point. When power is scheduled across a DC tie line, its effects on the PJM system are as if a generator is located at the point in the Eastern Interconnection where the DC tie line connects. The electrical impact on PJM tie lines from sources in the Western Interconnection differ

based on the relevant DC tie line and could vary from the Northwest interface pricing point to the SouthIMP interface pricing point. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SouthIMP/EXP interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM.

Figure 9-4 shows that the only balancing authorities in the Eastern Interconnection assigned to the Northwest pricing point are Saskatchewan Power Company and Manitoba Hydro. The geographical location and the interconnection ties of these balancing authorities to PJM suggest that the majority of the expected power flows from or to these balancing authorities and PJM would go through MISO. The MMU recommends changing the assignment of the Saskatchewan Power Company and Manitoba Hydro balancing authorities from the Northwest interface pricing point to the MISO interface pricing point and eliminating the Northwest interface pricing point from the day-ahead and real-time energy.¹⁶ 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.¹⁷ 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

¹⁴ 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.

¹⁵ See "Interface Pricing Point Assignment Methodology," (June 1, 2020) <<http://www.pjm.com/~media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>>. PJM periodically updates these definitions on its website.

¹⁶ At the September 2, 2020, Market Implementation Committee (MIC) meeting, PJM reported that the Northwest interface pricing point would be retired effective October 1, 2020.

¹⁷ On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario interface pricing point.

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, DUKEEXP, 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.^{18 19}

In the real-time energy market, in the first nine months of 2020, there were net scheduled exports at 10 of PJM's 17 interface pricing points eligible for real-time transactions.^{20 21} The top three net exporting interface pricing points in the real-time energy market accounted for 88.8 percent of the total net scheduled exports: PJM/MISO with 72.4 percent, PJM/NEPTUNE with 10.6 percent and PJM/SouthEXP with 5.9 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 21.5 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in the first nine months of 2020, there were net scheduled imports at five of PJM's 17 interface pricing points eligible for real-time transactions. The top two net importing interface pricing points in the real-time energy market accounted for 94.0 percent of the total net

scheduled imports: PJM/SouthIMP with 74.8 percent and PJM/NCMPAIMP with 19.1 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.²²

Table 9-6 Real-time scheduled net interchange volume by interface pricing point (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	62.1	17.2	2.0	4.2	6.7	8.9	16.0	2.7	4.1	124.0
MISO	(1,992.8)	(1,899.2)	(2,751.4)	(2,886.0)	(3,186.1)	(3,295.1)	(3,115.6)	(2,900.3)	(2,957.3)	(24,983.7)
NORTHWEST	(0.4)	0.0	(0.7)	0.0	0.0	0.0	0.0	0.0	0.0	(1.1)
NYISO	(863.7)	(673.5)	(573.8)	(427.9)	(530.5)	(936.3)	(1,135.4)	(1,332.1)	(966.3)	(7,439.5)
HUDSONTP	(163.6)	(115.2)	(62.0)	(14.3)	(30.3)	(88.3)	(116.4)	(145.4)	(133.0)	(868.6)
LINDENVFT	(140.4)	(111.4)	(85.9)	(52.3)	(63.7)	(111.7)	(153.0)	(191.7)	(186.3)	(1,096.4)
NEPTUNE	(426.5)	(386.2)	(395.6)	(386.0)	(375.9)	(445.2)	(487.1)	(473.6)	(277.3)	(3,653.4)
NYIS	(133.2)	(60.7)	(30.2)	24.7	(60.6)	(291.1)	(378.9)	(521.3)	(369.8)	(1,821.1)
Southern Imports	723.9	623.5	356.5	196.3	322.7	307.4	372.2	275.9	238.1	3,416.5
CPLEIMP	0.0	0.0	0.0	0.0	0.6					0.6
DUKIMP	11.5	6.9	46.6	7.6	16.7					89.4
NCMPAIMP	124.5	92.7	82.8	45.6	59.7	83.8	54.9	70.6	62.8	677.3
SOUTHEAST	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
SOUTHIMP	587.9	524.0	227.0	143.1	245.7	223.5	317.3	205.3	175.3	2,649.2
Southern Exports	(168.9)	(209.5)	(208.9)	(180.0)	(214.2)	(287.9)	(304.4)	(274.9)	(255.5)	(2,104.3)
CPLEEXP	(8.0)	(13.0)	(22.4)	(8.0)	(1.9)					(53.3)
DUKEEXP	(1.9)	(4.3)	(0.7)	(1.6)	(3.0)					(11.5)
NCMPAEXP	0.0	0.0	0.0	(0.1)	0.0	0.0	0.0	0.0	0.0	(0.1)
SOUTHEAST	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
SOUTHEXP	(159.0)	(192.2)	(185.9)	(170.3)	(209.3)	(287.9)	(304.4)	(274.9)	(255.5)	(2,039.4)
Total	(2,239.7)	(2,141.4)	(3,176.2)	(3,293.5)	(3,601.4)	(4,203.0)	(4,167.3)	(4,228.7)	(3,936.9)	(30,988.1)

¹⁸ Use of the Southwest pricing point for grandfathered transactions is not appropriate, and the MMU recommends that no further such agreements be entered into.

¹⁹ On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEEXP interface pricing points. At the September 2, 2020, Market Implementation Committee (MIC) meeting, PJM reported that the NCMPAIMP and NCMPAEXP interface pricing points would be retired effective November 3, 2020.

²⁰ There was one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO). Effective June 1, 2020, PJM retired the NIPSCO interface pricing point.

²¹ On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP, DUKEEXP and NIPSCO interface pricing points, reducing the number of real-time interfaces to 13.

²² In the real-time energy market, two PJM interface pricing points had a net interchange of zero (Southeast and Southwest).

Table 9-7 Real-time scheduled gross import volume by interface pricing point (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	62.2	17.3	2.0	4.2	6.7	9.0	17.9	4.8	4.1	128.3
MISO	23.5	27.2	25.3	20.3	21.8	50.0	44.1	29.9	44.9	286.9
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	124.8	112.5	135.1	137.2	124.8	130.7	141.3	122.1	116.9	1,145.3
HUDSONTP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
LINDENVFT	0.9	0.4	0.2	1.2	0.4	0.5	1.0	0.3	0.0	4.9
NEPTUNE	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.3
NYIS	123.8	112.0	134.9	136.0	124.3	130.2	140.3	121.7	116.8	1,139.9
Southern Imports	723.9	623.5	356.5	196.3	322.7	307.4	372.2	275.9	238.1	3,416.5
CPLEIMP	0.0	0.0	0.0	0.0	0.6					0.6
DUKIMP	11.5	6.9	46.6	7.6	16.7					89.4
NCMPAIMP	124.5	92.7	82.8	45.6	59.7	83.8	54.9	70.6	62.8	677.3
SOUTHEAST	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
SOUTHIMP	587.9	524.0	227.0	143.1	245.7	223.5	317.3	205.3	175.3	2,649.2
Southern Exports	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
DUKEXP	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
SOUTHEAST	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
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	934.3	780.5	518.9	358.0	475.9	497.1	575.5	432.7	404.0	4,976.9

Table 9-8 Real-time scheduled gross export volume by interface pricing point (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	0.1	0.2	0.0	0.0	0.0	0.1	1.9	2.1	0.0	4.3
MISO	2,016.3	1,926.3	2,776.6	2,906.3	3,207.8	3,345.1	3,159.7	2,930.2	3,002.3	25,270.6
NORTHWEST	0.4	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	1.1
NYISO	988.5	786.0	708.9	565.2	655.3	1,066.9	1,276.7	1,454.2	1,083.2	8,584.7
HUDSONTP	163.6	115.2	62.0	14.3	30.3	88.3	116.4	145.4	133.0	868.7
LINDENVFT	141.4	111.9	86.1	53.5	64.1	112.1	154.0	192.0	186.3	1,101.4
NEPTUNE	426.6	386.2	395.6	386.0	376.0	445.2	487.1	473.7	277.3	3,653.6
NYIS	256.9	172.7	165.1	111.4	184.9	421.3	519.1	643.0	486.6	2,961.0
Southern Imports	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
DUKIMP	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
SOUTHEAST	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
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	168.9	209.5	208.9	180.0	214.2	287.9	304.4	274.9	255.5	2,104.3
CPLEEXP	8.0	13.0	22.4	8.0	1.9					53.3
DUKEXP	1.9	4.3	0.7	1.6	3.0					11.5
NCMPAEXP	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1
SOUTHEAST	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
SOUTHEXP	159.0	192.2	185.9	170.3	209.3	287.9	304.4	274.9	255.5	2,039.4
Total	3,174.0	2,921.9	3,695.1	3,651.5	4,077.3	4,700.1	4,742.8	4,661.4	4,341.0	35,965.1

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.²³ 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

²³ Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.

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.²⁴

In the day-ahead energy market, transaction sources and sinks are determined solely by market participants. In Table 9-9, Table 9-10, and Table 9-11, 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 9-9 through Table 9-11 show the day-ahead scheduled interchange totals at the individual interfaces. Net scheduled interchange in the day-ahead energy market is shown by interface for the first nine months of 2020 in Table 9-9, while gross scheduled imports and exports are shown in Table 9-10 and Table 9-11.

In the day-ahead energy market, in the first nine months of 2020, there were net scheduled exports at 14 of PJM's 19 interfaces. The top three net exporting interfaces in the day-ahead energy market accounted for 52.1 percent of the total net scheduled exports: PJM/ MidAmerican Energy Company (MEC) with 19.3 percent, PJM/Neptune (NEPT) with 17.4 percent and PJM/Alliant Energy - East (ALTE) with 15.5 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 30.6 percent of the total net PJM scheduled exports in the day-ahead energy market. In the first nine months of 2020, there were net exports in the day-ahead energy market at nine of the 10 separate interfaces that connect PJM to MISO. Those nine interfaces represented 65.2 percent of the total net PJM exports in the day-ahead energy market.

In the day-ahead energy market, in the first nine months of 2020, there were net scheduled imports at three of PJM's 19 interfaces. The top two net importing interfaces in the day-ahead energy market accounted for 98.3 percent of the total net scheduled imports: PJM/Duke Energy Corp. (DUK) with 80.6 percent and PJM/CPL²⁵ with 17.7 percent of the net scheduled import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the day-ahead energy market. In the first nine months of 2020, there were net imports in the day-ahead energy market at none of the 10 separate interfaces that connect PJM to MISO.²⁶

²⁵ The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPL) pricing point.

²⁶ In the day-ahead energy market, two PJM interfaces had a net interchange of zero (PJM/City Water Light & Power (CWLP) and PJM/Linden (LIND)).

²⁴ See the 2010 State of the Market Report for PJM, Volume 2, Section 4, "Interchange Transactions," for details.

Table 9-9 Day-ahead scheduled net interchange volume by interface (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPL	25.8	8.3	125.0	52.8	57.4	(40.1)	(40.0)	(34.8)	(56.7)	97.7
CPLW	0.0	0.0	0.0	1.4	7.8	0.0	0.0	0.0	0.0	9.2
DUK	196.9	122.4	22.5	4.4	25.1	(3.5)	34.2	4.9	37.2	444.1
LGEE	(118.5)	(135.7)	(109.7)	(52.2)	(25.3)	(74.4)	(89.8)	(78.4)	(55.4)	(739.5)
MISO	(1,311.7)	(1,085.8)	(1,574.8)	(1,602.3)	(1,645.8)	(1,702.6)	(1,717.2)	(1,665.4)	(1,579.0)	(13,884.8)
ALTE	(337.9)	(260.1)	(432.9)	(510.5)	(360.0)	(417.1)	(320.4)	(293.9)	(361.7)	(3,294.6)
ALTW	(1.2)	(94.0)	(171.8)	(175.5)	(203.6)	(214.1)	(282.4)	(302.2)	(169.0)	(1,613.9)
AMIL	(16.8)	0.0	(0.8)	0.0	0.0	(6.1)	(7.6)	(0.6)	(0.9)	(32.8)
CIN	(158.6)	(92.3)	(133.4)	(167.1)	(185.3)	(195.3)	(555.6)	(525.3)	(521.8)	(2,534.8)
CWLP	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	(0.9)	0.0	(1.0)	(1.9)
MEC	(482.3)	(451.0)	(460.0)	(379.3)	(478.3)	(458.4)	(470.7)	(472.4)	(457.0)	(4,109.5)
MECS	9.6	5.9	(15.8)	(18.0)	(27.8)	(24.5)	(14.4)	(13.1)	(19.1)	(117.3)
NIPS	(257.8)	(139.8)	(293.4)	(295.1)	(334.4)	(323.6)	(7.0)	0.0	0.0	(1,651.0)
WEC	(66.7)	(54.4)	(66.8)	(56.7)	(56.5)	(63.5)	(58.2)	(57.8)	(48.5)	(529.1)
NYISO	(746.2)	(596.9)	(560.9)	(466.9)	(534.0)	(829.3)	(982.2)	(1,076.6)	(730.9)	(6,523.9)
HUDS	(119.4)	(89.8)	(45.1)	(9.0)	(14.8)	(10.9)	(15.8)	(22.9)	(22.8)	(350.3)
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	(430.1)	(386.8)	(391.0)	(377.4)	(376.1)	(455.9)	(490.6)	(499.3)	(294.2)	(3,701.2)
NYIS	(196.7)	(120.3)	(124.9)	(80.5)	(143.1)	(362.6)	(475.8)	(554.5)	(414.0)	(2,472.4)
TVA	13.6	8.1	(4.9)	(13.9)	(19.9)	(21.7)	(63.1)	(26.1)	(26.7)	(154.6)
Total without Up To Congestion	(1,940.2)	(1,679.5)	(2,102.8)	(2,076.7)	(2,134.6)	(2,671.7)	(2,858.1)	(2,876.5)	(2,411.5)	(20,751.7)
Up To Congestion	1,643.1	1,130.3	959.6	1,260.6	1,680.0	1,171.8	1,398.1	1,919.7	1,448.7	12,611.9
Total	(297.1)	(549.3)	(1,143.2)	(816.0)	(454.6)	(1,500.0)	(1,460.0)	(956.8)	(962.8)	(8,139.8)

Table 9-10 Day-ahead scheduled gross import volume by interface (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPL	55.2	69.3	158.0	115.5	106.5	40.4	10.4	15.3	6.8	577.5
CPLW	0.0	0.0	0.0	1.4	7.8	0.0	0.0	0.0	0.0	9.2
DUK	198.4	129.9	27.2	6.6	30.8	4.8	34.3	10.1	44.1	486.3
LGEE	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
MISO	37.0	11.1	0.1	0.0	1.1	4.4	0.7	0.0	1.9	56.2
ALTE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ALTW	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
CIN	1.2	1.0	0.0	0.0	0.0	4.4	0.2	0.0	1.8	8.6
CWLP	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
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MECS	35.8	10.1	0.1	0.0	1.1	0.1	0.5	0.0	0.1	47.7
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	0.3	0.1	0.0	0.9	0.0	0.0	0.9	0.6	0.2	2.8
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	0.3	0.1	0.0	0.9	0.0	0.0	0.9	0.6	0.2	2.8
TVA	26.2	15.1	3.1	0.0	7.4	1.1	2.1	5.1	0.9	61.0
Total without Up To Congestion	317.3	225.4	188.4	124.4	153.6	50.8	48.4	31.1	53.9	1,193.2
Up To Congestion	3,833.8	3,467.0	3,695.1	3,618.6	3,166.4	3,125.9	2,981.6	3,487.7	3,305.8	30,681.9
Total	4,151.2	3,692.3	3,883.5	3,743.0	3,320.0	3,176.7	3,030.0	3,518.8	3,359.6	31,875.1

**Table 9-11 Day-ahead scheduled gross export volume by interface (GWh):
January through September, 2020**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	29.5	61.0	33.1	62.7	49.1	80.5	50.4	50.2	63.5	479.8
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	1.5	7.5	4.7	2.2	5.6	8.4	0.2	5.2	6.8	42.1
LGEE	118.8	135.7	109.7	52.2	25.3	74.4	89.8	78.4	55.4	739.7
MISO	1,348.7	1,096.9	1,574.9	1,602.3	1,646.9	1,707.0	1,717.9	1,665.5	1,580.9	13,941.0
ALTE	337.9	260.1	432.9	510.5	360.0	417.1	320.4	293.9	361.7	3,294.6
ALTW	1.2	94.0	171.8	175.5	203.6	214.1	282.4	302.2	169.0	1,613.9
AMIL	16.8	0.0	0.8	0.0	0.0	6.1	7.6	0.6	0.9	32.8
CIN	159.8	93.3	133.4	167.1	185.3	199.7	555.8	525.3	523.6	2,543.4
CWLP	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	0.9	0.0	1.0	1.9
MEC	482.3	451.0	460.0	379.3	478.3	458.4	470.7	472.4	457.0	4,109.5
MECS	26.2	4.3	15.9	18.0	28.9	24.6	14.8	13.1	19.2	164.9
NIPS	257.8	139.8	293.4	295.1	334.4	323.6	7.0	0.0	0.0	1,651.0
WEC	66.7	54.4	66.8	56.7	56.5	63.5	58.2	57.8	48.5	529.1
NYISO	746.5	596.9	560.9	467.7	534.0	829.3	983.1	1,077.2	731.1	6,526.7
HUDS	119.4	89.8	45.1	9.0	14.8	10.9	15.8	22.9	22.8	350.3
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	430.1	386.8	391.0	377.4	376.1	455.9	490.6	499.3	294.2	3,701.2
NYIS	197.0	120.4	124.9	81.4	143.1	362.6	476.7	555.0	414.2	2,475.2
TVA	12.6	7.0	8.0	14.0	27.3	22.9	65.2	31.1	27.6	215.6
Total without Up To Congestion	2,257.6	1,904.9	2,291.2	2,201.0	2,288.2	2,722.6	2,906.5	2,907.6	2,465.3	21,944.9
Up To Congestion	2,190.7	2,336.7	2,735.5	2,358.0	1,486.5	1,954.1	1,583.5	1,567.9	1,857.1	18,070.0
Total	4,448.3	4,241.6	5,026.7	4,559.0	3,774.6	4,676.7	4,490.0	4,475.6	4,322.4	40,015.0

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-12 through Table 9-17 show the day-ahead scheduled interchange totals at the interface pricing points. In the first nine months of 2020, up to congestion transactions accounted for 96.3 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 the first nine months of 2020, including up to congestion transactions, is shown by interface pricing point in Table 9-12. Scheduled up to congestion transactions by interface pricing point in the first nine months of 2020 are shown in Table 9-13. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-14 and Table

9-16, while gross scheduled import and export up to congestion transactions are shown in Table 9-15 and Table 9-17.

There was 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 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 remained an eligible interface pricing point in the PJM Day-Ahead Energy Market, and was 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. The MMU recommended that PJM eliminate the NIPSCO interface pricing point since 2013. On June 1, 2020, PJM retired the NIPSCO interface pricing point.

In the first nine months of 2020, the day-ahead net scheduled interchange at the NIPSCO interface pricing point was -4,530.7 GWh (Table 9-12). Table 9-13 shows that all -4,530.7 GWh of day-ahead net scheduled interchange submitted at the NIPSCO interface pricing point were made up of up to congestion transactions. The total profit of all up to congestion transactions in the first nine months of 2020 was \$25.8 million. The NIPSCO interface pricing point was an eligible bus for up to congestion transactions until it was terminated on June 1, 2020. When NIPSCO was selected as source or sink of an up to congestion transaction in those five months, the total profits were \$1.5 million (5.9 percent of the nine month total of \$25.8 million). 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 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 the first nine months of 2020, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for day-ahead transactions.²⁷ The top three net exporting interface pricing points in the day-ahead energy market accounted for 74.8 percent of the total net scheduled exports: PJM/MISO with 40.0 percent, PJM/NIPSCO with 19.1 percent and PJM/SOUTHEXP with 15.7 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 24.1 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 the first nine months of 2020, there were net scheduled imports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top three net importing interface pricing points in the day-ahead energy market accounted for 91.0 percent of the total net scheduled imports: PJM/NORTHWEST with 64.1 percent, PJM/SOUTHIMP with 22.6 percent and PJM/NCMPAIMP with 4.3 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 6.1 percent of the total net PJM scheduled imports in the day-ahead energy market. However, the PJM/NYIS, PJM/NEPTUNE and PJM/HUDSONTP interface pricing points had net scheduled exports in the day-ahead energy market.²⁸

In the day-ahead energy market, in the first nine months of 2020, up to congestion transactions had net scheduled exports at three of PJM's 18 interface pricing points eligible for day-ahead transactions.²⁹ The top two net exporting interface pricing points eligible for up to congestion transactions

²⁷ On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points, reducing the number of day-ahead interfaces to 13.

²⁸ In the day-ahead energy market, two PJM interface pricing points had a net interchange of zero (Southeast and Southwest).

²⁹ On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points reducing the number of day-ahead interfaces to 13.

accounted for 84.5 percent of the total net up to congestion scheduled exports: PJM/NIPSCO with 54.6 percent and PJM/SouthEXP with 29.9 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 15.5 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 the first nine months of 2020, up to congestion transactions had net scheduled imports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top three net importing interface pricing points eligible for up to congestion transactions accounted for 88.3 percent of the total net up to congestion scheduled imports: PJM/NORTHWEST with 67.3 percent, PJM/SOUTHIMP with 15.8 percent and PJM/NEPTUNE with 5.3 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 14.5 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.³⁰

Table 9-12 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	77.8	24.8	(0.8)	(0.5)	11.5	27.1	9.1	27.9	27.0	203.9
MISO	(592.1)	(705.2)	(1,033.9)	(1,375.9)	(1,276.7)	(1,407.2)	(853.1)	(1,077.7)	(1,148.9)	(9,470.8)
NIPSCO	(820.1)	(993.9)	(1,308.7)	(1,221.3)	(186.7)					(4,530.7)
NORTHWEST	1,289.5	1,337.7	1,297.0	1,613.2	1,069.0	870.4	397.1	875.9	1,204.4	9,954.2
NYISO	(355.5)	(245.5)	(196.9)	(270.6)	(391.8)	(846.5)	(933.2)	(841.6)	(683.8)	(4,765.3)
HUDSONTP	(333.4)	(258.2)	(180.8)	(93.6)	(65.4)	(184.5)	(132.8)	(160.0)	(218.6)	(1,627.3)
LINDENVFT	80.7	61.4	42.0	41.0	25.4	112.5	190.2	206.4	180.9	940.3
NEPTUNE	(69.8)	(88.5)	(161.7)	(332.8)	(364.6)	(435.5)	(459.9)	(418.2)	(269.6)	(2,600.6)
NYIS	(33.0)	39.8	103.7	114.9	12.9	(339.0)	(530.7)	(469.7)	(376.6)	(1,477.7)
Southern Imports	455.9	425.6	440.7	663.0	607.5	493.5	492.9	483.2	372.0	4,434.5
CPLEIMP	0.0	16.9	44.2	37.5	44.1					142.7
DUKIMP	60.3	29.4	9.7	3.8	11.7					115.0
NCMPAIMP	166.4	125.0	119.1	78.9	86.8	32.5	4.3	11.4	37.4	661.8
SOUTHEAST	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
SOUTHIMP	229.2	254.3	267.6	542.8	465.0	461.1	488.6	471.8	334.6	3,515.0
Southern Exports	(352.6)	(392.7)	(340.5)	(223.9)	(287.6)	(637.3)	(572.8)	(424.6)	(733.5)	(3,965.6)
CPLEEXP	(28.5)	(57.9)	(32.4)	(61.5)	(46.0)					(226.3)
DUKEXP	(1.5)	(3.7)	(4.7)	(2.2)	(6.2)					(18.3)
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	(1.4)	(6.7)	0.0	(8.1)
SOUTHEAST	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
SOUTHIMP	(322.6)	(331.2)	(303.4)	(160.2)	(235.4)	(637.3)	(571.4)	(417.9)	(733.5)	(3,712.9)
Total	(297.1)	(549.3)	(1,143.2)	(816.0)	(454.6)	(1,500.0)	(1,460.0)	(956.8)	(962.8)	(8,139.8)

³⁰ In the day-ahead energy market, eight PJM interface pricing points had up to congestion net interchange of zero (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP, PJM/NCMPAEXP, PJM/Southeast and PJM/Southwest).

Table 9-13 Up to congestion scheduled net interchange volume by interface pricing point (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	42.0	16.0	(0.9)	(0.5)	10.5	27.1	10.7	28.1	26.9	159.8
MISO	273.1	(61.6)	82.1	(152.2)	(108.8)	(163.0)	393.8	103.8	(14.8)	352.5
NIPSCO	(820.1)	(993.9)	(1,308.7)	(1,221.3)	(186.7)					(4,530.7)
NORTHWEST	1,771.9	1,788.7	1,755.8	1,992.5	1,547.3	1,328.7	867.8	1,348.3	1,661.4	14,062.5
NYISO	390.7	351.3	364.0	195.6	142.2	(17.1)	47.0	239.7	35.1	1,748.5
HUDSONTP	(215.4)	(168.5)	(139.5)	(85.4)	(50.6)	(173.6)	(116.9)	(137.1)	(195.8)	(1,282.9)
LINDENVFT	80.7	61.4	42.0	41.0	25.4	112.5	190.2	206.4	180.9	940.3
NEPTUNE	360.3	298.3	229.2	44.6	11.5	20.4	30.6	81.1	24.6	1,100.6
NYIS	165.1	160.1	232.3	195.5	156.0	23.6	(56.9)	89.3	25.4	990.4
Southern Imports	175.9	211.3	252.4	539.5	455.0	447.2	446.1	452.7	320.2	3,300.3
CPLEIMP	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
NCMPAIMP	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
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	175.9	211.3	252.4	539.5	455.0	447.2	446.1	452.7	320.2	3,300.3
Southern Exports	(190.3)	(181.6)	(185.1)	(92.9)	(179.6)	(451.1)	(367.3)	(252.9)	(580.2)	(2,481.1)
CPLEEXP	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
NCMPAEXP	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
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(190.3)	(181.6)	(185.1)	(92.9)	(179.6)	(451.1)	(367.3)	(252.9)	(580.2)	(2,481.1)
Total Interfaces	1,643.1	1,130.3	959.6	1,260.6	1,680.0	1,171.8	1,398.1	1,919.7	1,448.7	12,611.9
INTERNAL	9,125.2	8,563.7	8,904.1	7,928.9	9,243.6	12,187.1	11,723.6	12,270.5	11,870.8	91,817.5
Total	10,768.3	9,693.9	9,863.8	9,189.6	10,923.6	13,358.8	13,121.7	14,190.2	13,319.5	104,429.4

Table 9-14 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	102.5	43.6	22.1	21.5	36.8	73.7	45.5	55.3	53.5	454.3
MISO	808.6	599.5	603.1	414.4	430.8	554.9	691.4	691.4	445.6	5,239.6
NIPSCO	70.0	55.7	29.1	52.3	179.2					386.3
NORTHWEST	1,979.5	1,957.5	2,162.5	2,204.5	1,759.8	1,589.2	1,194.4	1,618.0	1,941.2	16,406.7
NYISO	734.7	610.5	626.0	387.3	305.8	465.5	605.8	670.8	547.3	4,953.8
HUDSONTP	25.6	13.2	18.3	5.3	11.6	33.9	82.0	51.3	52.1	293.3
LINDENVFT	114.0	92.1	92.9	82.0	67.7	180.9	236.2	230.8	224.7	1,321.4
NEPTUNE	398.1	318.0	246.4	84.7	46.0	155.4	221.7	221.5	140.2	1,831.9
NYIS	197.0	187.2	268.4	215.2	180.5	95.2	65.9	167.3	130.3	1,507.1
Southern Imports	455.9	425.6	440.7	663.0	607.5	493.5	492.9	483.2	372.0	4,434.5
CPLEIMP	0.0	16.9	44.2	37.5	44.1					142.7
DUKIMP	60.3	29.4	9.7	3.8	11.7					115.0
NCMPAIMP	166.4	125.0	119.1	78.9	86.8	32.5	4.3	11.4	37.4	661.8
SOUTHEAST	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
SOUTHIMP	229.2	254.3	267.6	542.8	465.0	461.1	488.6	471.8	334.6	3,515.0
Southern Exports	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
DUKEXP	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
SOUTHEAST	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
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,151.2	3,692.3	3,883.5	3,743.0	3,320.0	3,176.7	3,030.0	3,518.8	3,359.6	31,875.1

Table 9-15 Up to congestion scheduled gross import volume by interface pricing point (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	66.7	33.5	22.0	21.5	35.7	73.6	45.1	55.3	53.4	406.7
MISO	807.4	598.5	603.1	414.4	430.8	550.5	691.1	691.4	443.8	5,231.0
NIPSCO	70.0	55.7	29.1	52.3	179.2					386.3
NORTHWEST	1,979.5	1,957.5	2,162.5	2,204.5	1,759.8	1,589.2	1,194.4	1,618.0	1,941.2	16,406.7
NYISO	734.4	610.5	626.0	386.4	305.8	465.5	604.9	670.3	547.1	4,950.9
HUDSONTP	25.6	13.2	18.3	5.3	11.6	33.9	82.0	51.3	52.1	293.3
LINDENVFT	114.0	92.1	92.9	82.0	67.7	180.9	236.2	230.8	224.7	1,321.4
NEPTUNE	398.1	318.0	246.4	84.7	46.0	155.4	221.7	221.5	140.2	1,831.9
NYIS	196.7	187.2	268.4	214.4	180.5	95.2	65.0	166.7	130.1	1,504.3
Southern Imports	175.9	211.3	252.4	539.5	455.0	447.2	446.1	452.7	320.2	3,300.3
CPLEIMP	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
NCMPAIMP	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
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	175.9	211.3	252.4	539.5	455.0	447.2	446.1	452.7	320.2	3,300.3
Southern Exports	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
DUKEXP	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
SOUTHEAST	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
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Interfaces	3,833.8	3,467.0	3,695.1	3,618.6	3,166.4	3,125.9	2,981.6	3,487.7	3,305.8	30,681.9

Table 9-16 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	24.7	18.8	22.9	22.0	25.2	46.5	36.4	27.4	26.5	250.4
MISO	1,400.7	1,304.7	1,637.1	1,790.3	1,707.5	1,962.1	1,544.5	1,769.1	1,594.5	14,710.5
NIPSCO	890.0	1,049.6	1,337.8	1,273.7	365.9					4,916.9
NORTHWEST	690.0	619.8	865.5	591.4	690.8	718.8	797.3	742.1	736.8	6,452.5
NYISO	1,090.3	856.0	822.9	657.9	697.6	1,311.9	1,539.0	1,512.4	1,231.1	9,719.1
HUDSONTP	359.0	271.4	199.1	99.0	77.0	218.5	214.8	211.3	270.6	1,920.7
LINDENVFT	33.4	30.7	50.9	41.0	42.4	68.4	46.0	24.4	43.8	381.1
NEPTUNE	467.9	406.5	408.1	417.6	410.6	590.8	681.6	639.7	409.8	4,432.5
NYIS	230.0	147.4	164.8	100.3	167.6	434.2	596.6	637.0	506.9	2,984.8
Southern Imports	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
DUKIMP	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
SOUTHEAST	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
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	352.6	392.7	340.5	223.9	287.6	637.3	572.8	424.6	733.5	3,965.6
CPLEEXP	28.5	57.9	32.4	61.5	46.0					226.3
DUKEXP	1.5	3.7	4.7	2.2	6.2					18.3
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	1.4	6.7	0.0	8.1
SOUTHEAST	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
SOUTHEXP	322.6	331.2	303.4	160.2	235.4	637.3	571.4	417.9	733.5	3,712.9
Total	4,448.3	4,241.6	5,026.7	4,559.0	3,774.6	4,676.7	4,490.0	4,475.6	4,322.4	40,015.0

Table 9-17 Up to congestion scheduled gross export volume by interface pricing point (GWh): January through September, 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	24.7	17.5	22.9	22.0	25.2	46.5	34.4	27.2	26.5	246.9
MISO	534.3	660.1	521.1	566.6	539.6	713.5	297.2	587.6	458.6	4,878.5
NIPSCO	890.0	1,049.6	1,337.8	1,273.7	365.9					4,916.9
NORTHWEST	207.6	168.8	406.6	212.0	212.5	260.4	326.6	269.7	279.9	2,344.2
NYISO	343.8	259.1	262.0	190.8	163.6	482.6	558.0	430.6	512.0	3,202.4
HUDSONTP	241.0	181.7	157.8	90.7	62.2	207.6	199.0	188.4	247.9	1,576.2
LINDENVFT	33.4	30.7	50.9	41.0	42.4	68.4	46.0	24.4	43.8	381.1
NEPTUNE	37.8	19.7	17.2	40.2	34.5	135.0	191.0	140.4	115.6	731.3
NYIS	31.6	27.1	36.1	18.9	24.5	71.7	121.9	77.4	104.7	513.8
Southern Imports	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
DUKIMP	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
SOUTHEAST	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
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	190.3	181.6	185.1	92.9	179.6	451.1	367.3	252.9	580.2	2,481.1
CPLEEXP	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
NCMPAEXP	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
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	190.3	181.6	185.1	92.9	179.6	451.1	367.3	252.9	580.2	2,481.1
Total Interfaces	2,190.7	2,336.7	2,735.5	2,358.0	1,486.5	1,954.1	1,583.5	1,567.9	1,857.1	18,070.0

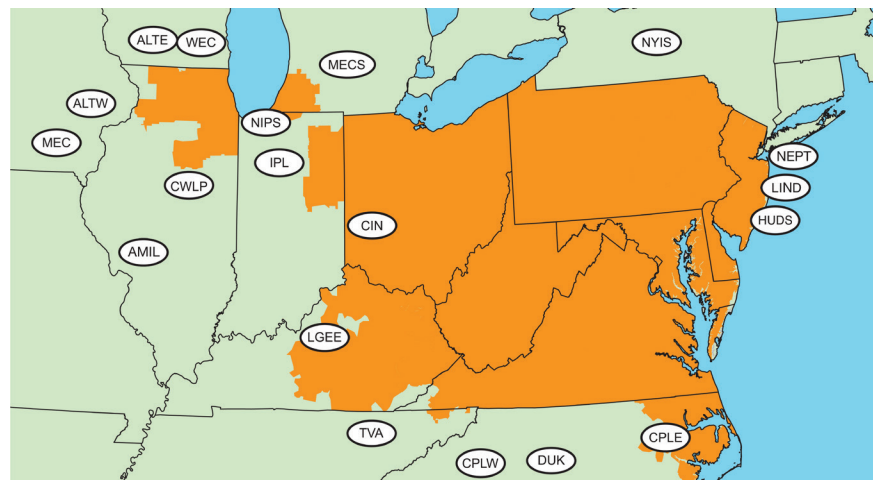
Table 9-18 Active scheduling interfaces: January through September, 2020³¹

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPL	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active

Table 9-19 Active scheduled interface pricing points: January through September, 2020³²

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
CPLLEXP	Active	Active	Active	Active	Active				
CPLLEIMP	Active	Active	Active	Active	Active				
DUKEXP	Active	Active	Active	Active	Active				
DUKIMP	Active	Active	Active	Active	Active				
HUDSONTP	Active	Active	Active	Active	Active	Active	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPTUNE	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active				
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active

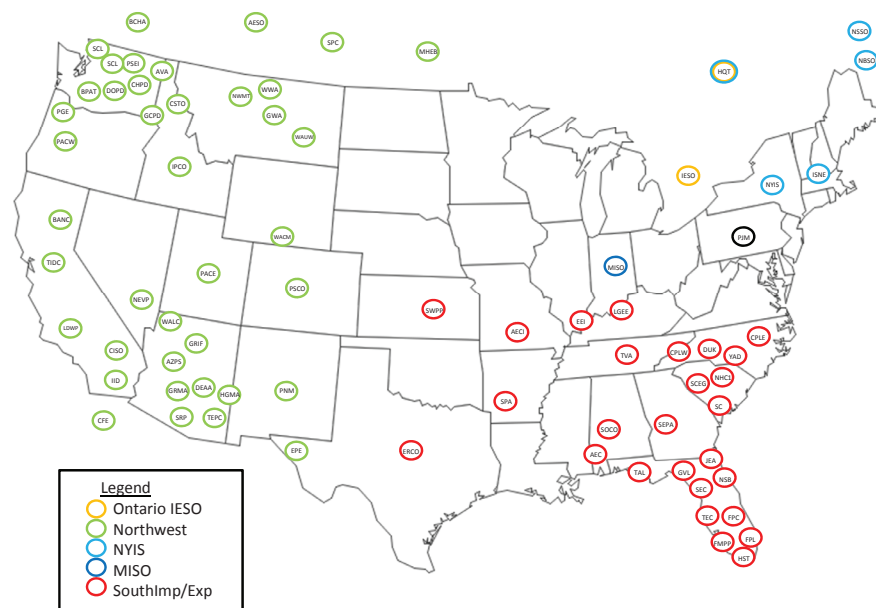
Figure 9-3 PJM's footprint and its external scheduling interfaces



³¹ On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPL and CPLW). As of September 30, 2020, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

³² The NIPSCO interface pricing point was valid only in the day-ahead energy market.

Figure 9-4 External balancing authority default interface pricing point assignments



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.³³

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 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 the first nine months of 2020, there were net scheduled flows of 3 GWh through MISO that received an interface pricing point associated with the southern interface but there were no net scheduled

³³ See the 2012 State of the Market Report for PJM, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

flows across the southern interface that received the MISO interface pricing point.

In the first nine months of 2020, net scheduled interchange was -30,988 GWh and net actual interchange was -31,044 GWh, a difference of 56 GWh. In the first nine months of 2019, net scheduled interchange was -25,917 GWh and net actual interchange was -25,870 GWh, a difference of 47 GWh. This difference is inadvertent interchange. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange. PJM can reduce the accumulation of inadvertent interchange using unilateral or bilateral paybacks. Inadvertent interchange accumulations that are paid back unilaterally are paid by controlling to a non-zero area control error (ACE). For example, Table 9-20 shows that PJM had 56 GW of inadvertent interchange in the first nine months of 2020. To reduce this inadvertent interchange, PJM can control to an ACE greater than zero, which would result in over generating. By way of the power balance equation, the excess generation would flow out of PJM and into its neighboring balancing authority areas. This would create additional actual exports that were not scheduled, thus reducing the overall inadvertent. To maintain reliability, unilateral paybacks are accounted for in the control performance standard calculations. Bilateral paybacks are scheduled with other balancing authority areas by scheduling a correction and incorporating that amount as a bias in the energy management system.³⁴

Table 9-20 shows that in the first nine months of 2020, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -1,623 GWh of net scheduled interchange and -8,670 GWh of net actual interchange, a difference of 7,047 GWh.

³⁴ See PJM, "Manual 12: Balancing Operations," Rev. 40 (March 26, 2020).

Table 9-20 Net scheduled and actual PJM flows by interface (GWh): January through September, 2020

	Actual	Net Scheduled	Difference (GWh)
CPL	(1,233)	452	(1,685)
CPLW	(30)	22	(53)
DUK	1,204	1,353	(149)
LGEE	370	(565)	934
MISO	(29,014)	(24,856)	(4,158)
ALTE	(1,642)	(3,738)	2,095
ALTW	(1,338)	(1,589)	251
AMIL	371	(417)	788
CIN	(6,647)	(8,807)	2,160
CWLP	(382)	0	(382)
IPL	(2,088)	(1,059)	(1,029)
MEC	(6,108)	(4,047)	(2,061)
MECS	(8,079)	(2,904)	(5,175)
NIPS	(8,670)	(1,623)	(7,047)
WEC	5,570	(673)	6,243
NYISO	(7,579)	(7,441)	(138)
HUDS	(869)	(869)	0
LIND	(1,096)	(1,096)	0
NEPT	(3,653)	(3,653)	0
NYIS	(1,961)	(1,823)	(138)
TVA	5,238	47	5,191
Total	(31,044)	(30,988)	(56)

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.³⁵ 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.

³⁵ 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.

The differences between the scheduled MWh mapped to a specific interface pricing point and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. The scheduled transactions are mapped to interface pricing points based on the expected flow from the generation balancing authority and load balancing authority, whereas scheduled transactions are assigned to interfaces based solely on the OASIS path that the market participants reflect the transmission path into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 9-21 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPEEXP, and NCMPEIMP 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.³⁶

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 (18,703 GWh) and the total southern export actual flows (-13,154 GWh) for 5,549 GWh of net imports. The net scheduled flows from the southern region are determined by summing the total southern import scheduled flows (3,416 GWh) and the total southern export scheduled flows (-2,104 GWh) for 1,312 GWh of net

imports. In the first nine months of 2020, the loop flows at the southern region were the difference between the southern region net scheduled flows (1,312 GW) and the southern region net actual flows (5,549 GWh) for a total of 4,236 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 9-21 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.

³⁶ On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP, DUKEXP interface pricing points. At the September 2, 2020, Market Implementation Committee (MIC) meeting, PJM reported that the NCMPEIMP and NCMPEEXP interface pricing points would be retired effective November 3, 2020.

Table 9-21 PJM flows by interface pricing point (GWh): January through September, 2020

	Actual	Net Scheduled	Difference (GWh)
IMO	0	124	(124)
MISO	(29,014)	(24,984)	(4,030)
NORTHWEST	0	(1)	1
NYISO	(7,579)	(7,439)	(140)
HUDSONTP	(869)	(869)	0
LINDENVFT	(1,096)	(1,096)	0
NEPTUNE	(3,653)	(3,653)	0
NYIS	(1,961)	(1,821)	(140)
Southern Imports	18,703	3,416	15,287
CPLEIMP	0	1	(1)
DUKIMP	0	89	(89)
NCMPAIMP	0	677	(677)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	18,703	2,649	16,054
Southern Exports	(13,154)	(2,104)	(11,050)
CPLEEXP	0	(53)	53
DUKEXP	0	(12)	12
NCMPAEXP	0	(0)	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(13,154)	(2,039)	(11,115)
Total	(31,044)	(30,988)	(56)

Table 9-22 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 9-24 shows that 126 of the 128 GWh (98.4 percent) of gross scheduled transactions that were mapped to the IMO interface pricing point were scheduled as imports through MISO.

Table 9-22 shows that in the first nine months of 2020, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 2,649 GWh of net scheduled interchange and 18,703 GWh of net actual interchange, a difference of 16,054 GWh.

Table 9-22 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through September, 2020

	Actual	Net Scheduled	Difference (GWh)
MISO	(29,014)	(24,858)	(4,156)
NORTHWEST	0	(1)	1
NYISO	(7,579)	(7,441)	(138)
HUDSONTP	(869)	(869)	0
LINDENVFT	(1,096)	(1,096)	0
NEPTUNE	(3,653)	(3,653)	0
NYIS	(1,961)	(1,823)	(138)
Southern Imports	18,703	3,416	15,287
CPLEIMP	0	1	(1)
DUKIMP	0	89	(89)
NCMPAIMP	0	677	(677)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	18,703	2,649	16,054
Southern Exports	(13,154)	(2,104)	(11,050)
CPLEEXP	0	(53)	53
DUKEXP	0	(12)	12
NCMPAEXP	0	(0)	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(13,154)	(2,039)	(11,115)
Total	(31,044)	(30,988)	(56)

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 9-23 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 9-23 shows that in the first nine months of 2020, the majority of imports to the PJM energy market for which a market participant specified Ameren-Illinois (AMIL) as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the SOUTHIMP Interface, and thus actual flows were assigned the SOUTHIMP interface pricing point (8 GWh). The majority of exports from the PJM energy market for which a market participant specified AMIL as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM energy market at the MISO Interface, and were assigned the MISO interface pricing point (-423 GWh).

Table 9-23 Net scheduled and actual flows by interface and interface pricing point (GWh): January through September, 2020

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(1,642)	(3,738)	2,095	HUDS		(869)	(869)	0
	IMO	0	9	(9)		HUDSONTP	(869)	(869)	0
	MISO	(1,642)	(3,747)	2,105	IPL		(2,088)	(1,059)	(1,029)
	SOUTHEXP	0	(0)	0		IMO	0	2	(2)
ALTW		(1,338)	(1,589)	251		MISO	(2,088)	(1,061)	(1,027)
	MISO	(1,338)	(1,589)	251		SOUTHEXP	0	(1)	1
AMIL		371	(417)	788	LGEE		370	(565)	934
	MISO	371	(423)	794		SOUTHEXP	(5,843)	(624)	(5,219)
	SOUTHEXP	0	(1)	1		SOUTHIMP	6,213	59	6,153
	SOUTHIMP	0	8	(8)	LIND		(1,096)	(1,096)	0
CIN		(6,647)	(8,807)	2,160		LINDENVFT	(1,096)	(1,096)	0
	IMO	0	6	(6)	MEC		(6,108)	(4,047)	(2,061)
	MISO	(6,647)	(8,798)	2,151		MISO	(6,108)	(4,047)	(2,061)
	NORTHWEST	0	(1)	1		SOUTHEXP	0	(0)	0
	SOUTHEXP	0	(20)	20	MECS		(8,079)	(2,904)	(5,175)
	SOUTHIMP	0	6	(6)		IMO	0	108	(108)
CPLE		(1,233)	452	(1,685)		MISO	(8,079)	(3,015)	(5,064)
	CPLEEXP	0	(53)	53		SOUTHEXP	0	(2)	2
	CPLEIMP	0	1	(1)		SOUTHIMP	0	4	(4)
	DUKEXP	0	(3)	3	NEPT		(3,653)	(3,653)	0
	DUKIMP	0	66	(66)		NEPTUNE	(3,653)	(3,653)	0
	NCMPAIMP	0	310	(310)	NIPS		(8,670)	(1,623)	(7,047)
	SOUTHEXP	(3,812)	(536)	(3,277)		MISO	(8,670)	(1,623)	(7,047)
	SOUTHIMP	2,579	667	1,912	NYIS		(1,961)	(1,823)	(138)
CPLW		(30)	22	(53)		IMO	0	(2)	2
	NCMPAIMP	0	21	(21)		NYIS	(1,961)	(1,821)	(140)
	SOUTHEXP	(267)	0	(267)	TVA		5,238	47	5,191
	SOUTHIMP	236	1	235		SOUTHEXP	(2,640)	(652)	(1,988)
CWLP		(382)	0	(382)		SOUTHIMP	7,878	699	7,179
	MISO	(382)	0	(382)	WEC		5,570	(673)	6,243
DUK		1,204	1,353	(149)		MISO	5,570	(681)	6,251
	DUKEXP	0	(9)	9		SOUTHEXP	0	(1)	1
	DUKIMP	0	23	(23)		SOUTHIMP	0	9	(9)
	NCMPAEXP	0	(0)	0	Grand Total		(31,044)	(30,988)	(56)
	NCMPAIMP	0	347	(347)					
	SOUTHEXP	(592)	(203)	(389)					
	SOUTHIMP	1,797	1,196	601					

Table 9-24 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-23. Table 9-24 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-24 shows that in the first nine months of 2020, 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 (108 GWh). The majority of exports from 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 exited the PJM energy market at the NYIS Interface (2 GWh).

Table 9-24 Net scheduled and actual flows by interface pricing point and interface (GWh): January through September, 2020

Interface Pricing Point	Interface	Actual	Scheduled	Net Difference (GWh)	Interface Pricing Point	Interface	Actual	Scheduled	Net Difference (GWh)
CPLEEXP		0	(53)	53	NEPTUNE		(3,653)	(3,653)	0
	CPLE	0	(53)	53		NEPT	(3,653)	(3,653)	0
CPLEIMP		0	1	(1)	NORTHWEST		0	(1)	1
	CPLE	0	1	(1)		CIN	0	(1)	1
DUKEEXP		0	(12)	12	NYIS		(1,961)	(1,821)	(140)
	CPLE	0	(3)	3		NYIS	(1,961)	(1,821)	(140)
	DUK	0	(9)	9	SOUTHEXP		(13,154)	(2,039)	(11,115)
DUKIMP		0	89	(89)		ALTE	0	(0)	0
	CPLE	0	66	(66)		AMIL	0	(1)	1
	DUK	0	23	(23)		CIN	0	(20)	20
HUDSONTP		(869)	(869)	0		CPLW	(267)	0	(267)
	HUDS	(869)	(869)	0		DUK	(592)	(203)	(389)
IMO		0	124	(124)		IPL	0	(1)	1
	ALTE	0	9	(9)		LGEE	(5,843)	(624)	(5,219)
	CIN	0	6	(6)		MEC	0	(0)	0
	IPL	0	2	(2)		MECS	0	(2)	2
	MECS	0	108	(108)		TVA	(2,640)	(652)	(1,988)
	NYIS	0	(2)	2		WEC	0	(1)	1
LINDENVFT		(1,096)	(1,096)	0	SOUTHIMP		18,703	2,649	16,054
	LIND	(1,096)	(1,096)	0		AMIL	0	8	(8)
MISO		(29,014)	(24,984)	(4,030)		CIN	0	6	(6)
	ALTE	(1,642)	(3,747)	2,105		CPLW	2,579	667	1,912
	ALTW	(1,338)	(1,589)	251		DUK	236	1	235
	AMIL	371	(423)	794		LGEE	1,797	1,196	601
	CIN	(6,647)	(8,798)	2,151		MECS	6,213	59	6,153
	CWLP	(382)	0	(382)		TVA	0	4	(4)
	IPL	(2,088)	(1,061)	(1,027)		WEC	7,878	699	7,179
	MEC	(6,108)	(4,047)	(2,061)			0	9	(9)
	MECS	(8,079)	(3,015)	(5,064)	Grand Total		(31,044)	(30,988)	(56)
	NIPS	(8,670)	(1,623)	(7,047)					
	WEC	5,570	(681)	6,251					
NCMPAEXP		0	(0)	0					
	DUK	0	(0)	0					
NCMPAIMP		0	677	(677)					
	CPLW	0	310	(310)					
	DUK	0	21	(21)					
		0	347	(347)					

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.³⁷

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.³⁸

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

³⁷ 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.

³⁸ 141 FERC ¶ 61,235 (2012).

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 form, and the underlying data is not available for analysis.

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, but, equally important, requests that FERC and NERC ensure that the underlying data are provided to market monitors and other approved entities.

Generation and Load Data

Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

Market areas are transparent in providing real-time load while nonmarket areas are not. For example, PJM posts real-time load via its eDATA application. Most nonmarket balancing authorities provide only the expected peak load on their individual websites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU recommends, that in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.

PJM and MISO Interface Prices

Both the PJM/MISO and MISO/PJM interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows.

Under the PJM/MISO Joint Operating Agreement, the two RTOs mutually determine a set of transmission facilities on which both RTOs have an impact, and therefore jointly operate to those constraints. These jointly controlled facilities are M2M (Market to Market) flowgates. When a M2M constraint binds, PJM's LMP calculations at the buses that make up PJM's MISO interface pricing point are based on the PJM model's distribution factors of the selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint. MISO's LMP calculations at the buses that make up MISO's PJM interface pricing point are based on the MISO model's distribution factors of the selected buses to the binding M2M constraint and MISO's shadow price of the binding M2M constraint.

Prior to June 1, 2014, the PJM interface definition for MISO consisted of nine buses located near the middle of the MISO system and not at the border between the RTOs. The interface definitions led to questions about the level of congestion included in interchange pricing.³⁹

PJM modified the definition of the PJM/MISO interface price effective June 1, 2014. PJM's new MISO interface pricing point includes 10 equally weighted buses that are close to the PJM/MISO border. The 10 buses were selected based on PJM's analysis that showed that over 80 percent of the hourly tie line flows between PJM and MISO occurred on 10 ties composed of MISO and PJM monitored facilities. On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

Real-Time and Day-Ahead PJM/MISO Interface Prices

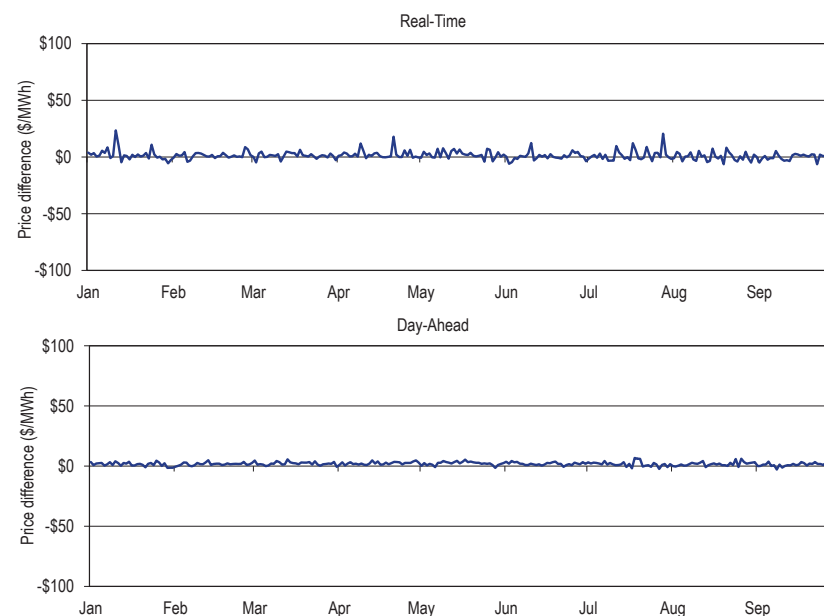
In the first nine months of 2020, the direction of flow was consistent with price differentials in 67.3 percent of the hours. Table 9-25 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. Figure 9-5 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 9-29).

Table 9-25 PJM and MISO flow based hours and price differences: January through September, 2020

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	4,427	\$4.87
	Consistent Flow (PJM to MISO)	4,427	\$4.87
	Inconsistent Flow (MISO to PJM)	0	\$0.00
	No Flow	0	\$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	2,148	\$5.72
	Consistent Flow (MISO to PJM)	0	\$0.00
	Inconsistent Flow (PJM to MISO)	2,148	\$5.72
	No Flow	0	\$0.00

Figure 9-5 Price differences (MISO/PJM Interface minus PJM/MISO Interface): January through September, 2020



³⁹ See "LMP Aggregate Definitions," (July 15, 2020) <<http://www.pjm.com/~media/markets-ops/energy/lmp-model-info/lmp-aggregate-definitions.ashx>>. PJM periodically updates these definitions on its website. See <<http://www.pjm.com>>.

Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In the first nine months of 2020, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 4,427 hours (67.3 percent of all hours), and was inconsistent with price differentials in 2,148 hours (32.7 percent of all hours). Table 9-26 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 2,148 hours where flows were in a direction inconsistent with price differences, 1,426 of those hours (66.4 percent) had a price difference greater than or equal to \$1.00 and 529 of those hours (24.6 percent) had a price difference greater than or equal to \$5.00. The largest price difference with such flows was \$139.32. Of the 4,427 hours where flows were consistent with price differences, 3,429 of those hours (77.5 percent) had a price difference greater than or equal to \$1.00 and 834 of all such hours (18.8 percent) had a price difference greater than or equal to \$5.00. The largest price difference with such flows was \$292.12.

Table 9-26 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January through September, 2020

Price Difference Range (Greater Than or Equal To)	Percent of		Percent of	
	Inconsistent Hours	Inconsistent Hours	Consistent Hours	Consistent Hours
\$0.00	2,148	100.0%	4,427	100.0%
\$1.00	1,426	66.4%	3,429	77.5%
\$5.00	529	24.6%	834	18.8%
\$10.00	337	15.7%	365	8.2%
\$15.00	236	11.0%	233	5.3%
\$20.00	171	8.0%	170	3.8%
\$25.00	126	5.9%	135	3.0%
\$50.00	27	1.3%	51	1.2%
\$75.00	7	0.3%	27	0.6%
\$100.00	2	0.1%	16	0.4%
\$200.00	0	0.0%	3	0.1%
\$300.00	0	0.0%	0	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.⁴⁰

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

⁴⁰ See the 2012 State of the Market Report for PJM, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

price is based on four buses within NYISO. The four buses were chosen based on a power flow analysis of transfers between PJM and the NYISO and the resultant distribution of flows across the free flowing A/C ties.

Real-Time and Day-Ahead PJM/NYISO Interface Prices

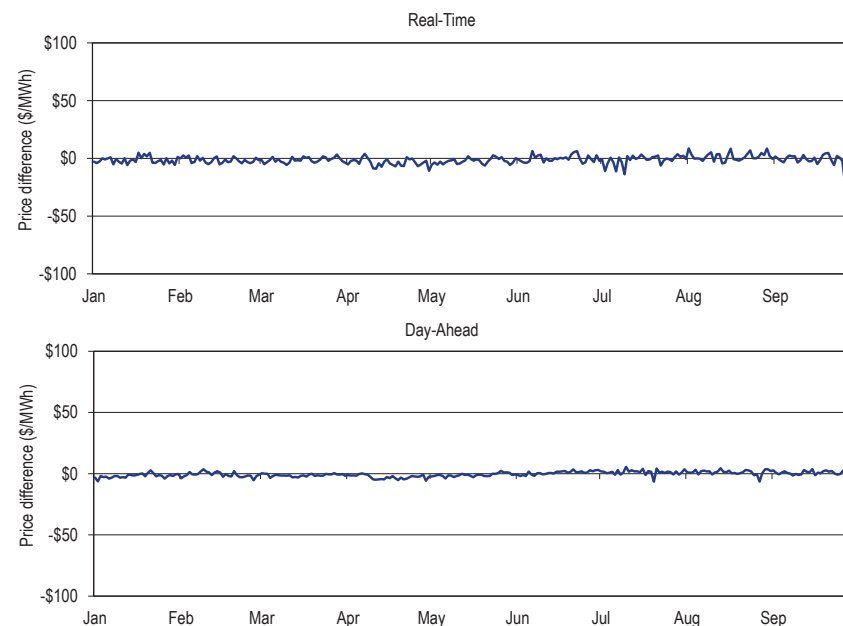
In the first nine months of 2020, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. The direction of flow was consistent with price differentials in 49.5 percent of the hours in the first nine months of 2020. Table 9-27 shows the number of hours and average hourly price differences between the PJM/NYIS Interface and the NYIS/PJM proxy bus based on LMP differences and flow direction. Figure 9-6 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-29).

Table 9-27 PJM and NYISO flow based hours and price differences: January through September, 2020⁴¹

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	2,667	\$4.77
	Consistent Flow (PJM to NYIS)	2,077	\$4.75
	Inconsistent Flow (NYIS to PJM)	590	\$4.83
	No Flow	0	\$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	3,908	\$5.26
	Consistent Flow (NYIS to PJM)	1,180	\$4.15
	Inconsistent Flow (PJM to NYIS)	2,728	\$5.74
	No Flow	0	\$0.00

⁴¹ The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Figure 9-6 Price differences (NY/PJM proxy – PJM/NYIS Interface): January through September, 2020



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In the first nine months of 2020, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 3,257 hours (49.5 percent of all hours), and was inconsistent with price differences in 3,318 hours (50.5 percent of all hours). Table 9-28 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 3,318 hours where flows were in a direction inconsistent with price differences, 2,709 of those hours (81.6 percent) had a price difference greater than or equal to \$1.00 and 1,014 of all those hours (30.6 percent) had a price difference greater than or equal to \$5.00. The largest price difference with such flows was \$222.35. Of the 3,257 hours where flows were consistent with price differences, 2,640 of

those hours (81.1 percent) had a price difference greater than or equal to \$1.00 and 847 of all such hours (26.0 percent) had a price difference greater than or equal to \$5.00. The largest price difference with such flows was \$249.71.

Table 9-28 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January through September, 2020

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
\$0.00	3,318	100.0%	3,257	100.0%
\$1.00	2,709	81.6%	2,640	81.1%
\$5.00	1,014	30.6%	847	26.0%
\$10.00	388	11.7%	247	7.6%
\$15.00	232	7.0%	117	3.6%
\$20.00	159	4.8%	83	2.5%
\$25.00	115	3.5%	55	1.7%
\$50.00	23	0.7%	17	0.5%
\$75.00	11	0.3%	4	0.1%
\$100.00	6	0.2%	1	0.0%
\$200.00	1	0.0%	1	0.0%
\$300.00	0	0.0%	0	0.0%
\$400.00	0	0.0%	0	0.0%
\$500.00	0	0.0%	0	0.0%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Table 9-29, including average prices and measures of variability.

Table 9-29 PJM, NYISO and MISO border price averages: January through September, 2020⁴²

Description	Real-Time		Day-Ahead	
	NYISO	MISO	NYISO	MISO
PJM Price at ISO Border	\$18.54	\$19.08	\$18.23	\$19.03
ISO Price at PJM Border	\$17.35	\$20.49	\$17.81	\$20.92
Average Interval Price				
Difference at Border (PJM-ISO)	\$1.19	(\$1.41)	\$0.41	(\$1.89)
Average Absolute Value of Interval Difference at Border	\$18.07	\$26.41	\$2.01	\$1.96
Sign Changes per Day	36.0	45.6	3.0	2.5
Standard Deviation				
PJM Price at ISO Border	\$15.28	\$15.64	\$5.98	\$6.70
ISO Price at PJM Border	\$14.99	\$24.67	\$6.20	\$6.73
Difference at Border (PJM-ISO)	\$19.01	\$27.11	\$2.88	\$2.44

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 66.8 percent of the hours in the first nine months of 2020. Table 9-30 shows the number of hours and average hourly price differences between the PJM/NEPT Interface and the NYIS/Neptune bus based on LMP differences and flow direction.

⁴² 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.

Table 9-30 PJM and NYISO flow based hours and price differences (Neptune): January through September, 2020

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	4,404	\$8.64
	Consistent Flow (PJM to NYIS)	4,395	\$8.65
	Inconsistent Flow (NYIS to PJM)	0	\$0.00
	No Flow	9	\$6.71
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	2,171	\$6.14
	Consistent Flow (NYIS to PJM)	0	\$0.00
	Inconsistent Flow (PJM to NYIS)	2,170	\$6.14
	No Flow	1	\$0.36

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”).⁴³ The PJM Out Service is covered by normal PJM OASIS business operations.⁴⁴ 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 September 30, 2020, the rate for the nonfirm service released by default was \$10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

⁴³ See OASIS “PJM Business Practices for Neptune Transmission Service,” (August 21, 2015) <<http://www.pjm.com/~media/etools/oasis/merch-trans-facilities/neptune-oasis-Business-practices-doc-clean.ashx>>.

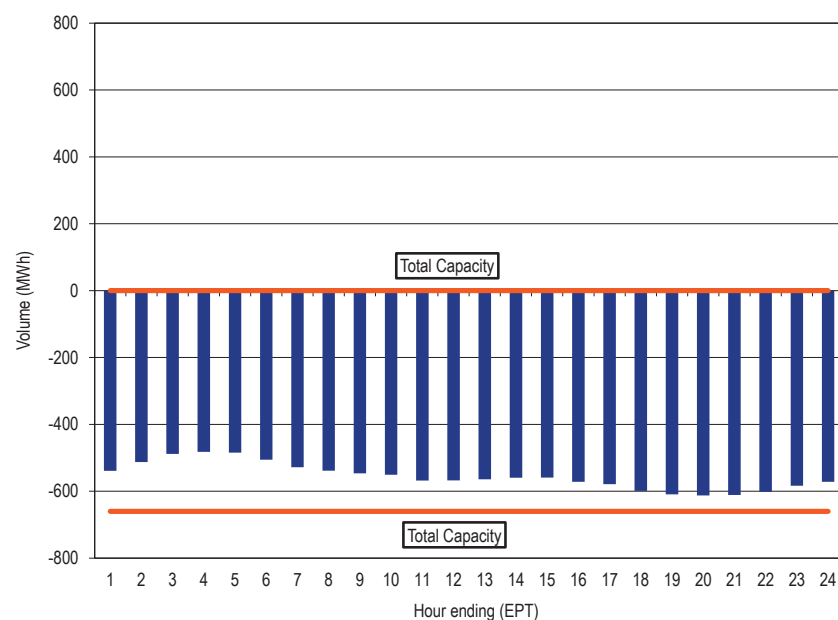
⁴⁴ See OASIS “Regional Transmission and Energy Scheduling Practices,” Rev. 8 (June 23, 2019) <<http://www.pjm.com/~media/etools/oasis/regional-practices-clean-pdf.ashx>>.

Table 9-31 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July 2007. Table 9-31 shows that in the first nine months of 2020, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-7 shows the hourly average flow across the Neptune Line for the first nine months of 2020.

Table 9-31 Percent of scheduled interchange across the Neptune Line by primary rights holder: July 2007 through September 2020

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	100.00%	100.00%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
July	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
August	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
September	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
October	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Figure 9-7 Neptune hourly average flow: January through September, 2020



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 58.3 percent of the hours in the first nine months of 2020. Table 9-32 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 9-32 PJM and NYISO flow based hours and price differences (Linden): January through September, 2020

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	3,940	\$4.88
	Consistent Flow (PJM to NYIS)	3,832	\$4.88
	Inconsistent Flow (NYIS to PJM)	0	\$0.00
	No Flow	108	\$4.94
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	2,635	\$4.81
	Consistent Flow (NYIS to PJM)	0	\$0.00
	Inconsistent Flow (PJM to NYIS)	2,572	\$4.78
	No Flow	63	\$6.26

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”).⁴⁵ The PJM Out Service is covered by normal PJM OASIS business operations.⁴⁶ 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 September 30, 2020, 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.

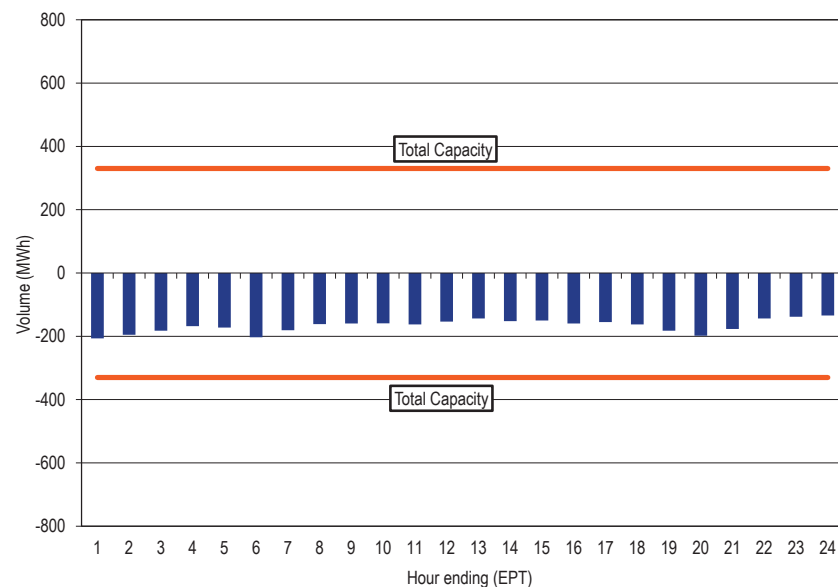
Table 9-33 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-33 shows that in the first nine months of 2020, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line in all months. Figure 9-8 shows the hourly average flow across the Linden VFT Line for the first nine months of 2020.

Table 9-33 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through September 2020

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	94.95%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	96.46%	100.00%	100.00%	100.00%	100.00%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%	49.32%	100.00%	100.00%	100.00%	100.00%
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%	27.27%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%	100.00%	100.00%	100.00%	

⁴⁵ See OASIS “PJM Business Practices for Linden VFT Transmission Service,” (June 1, 2011) <<http://www.pjm.com/~media/etools/oasis/merch-trans-facilities/linden-vft-oasis-Business-practices-doc-clean.ashx>>.

⁴⁶ See OASIS “Regional Transmission and Energy Scheduling Practices,” Rev. 8 (June 23, 2019) <<http://www.pjm.com/~media/etools/oasis/regional-practices-clean-doc.ashx>>.

Figure 9-8 Linden hourly average flow: January through September, 2020⁴⁷

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 Ridgely, 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 57.5 percent of the hours in the first nine months of 2020. Table 9-34 shows the number of

⁴⁷ 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.

hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-34 PJM and NYISO flow based hours and price differences (Hudson): January through September, 2020

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	3,786	\$4.90
	Consistent Flow (PJM to NYIS)	3,779	\$4.90
	Inconsistent Flow (NYIS to PJM)	0	\$0.00
	No Flow	7	\$1.19
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	2,789	\$5.35
	Consistent Flow (NYIS to PJM)	0	\$0.00
	Inconsistent Flow (PJM to NYIS)	2,762	\$5.35
	No Flow	27	\$4.84

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").⁴⁸ The PJM Out Service is covered by normal PJM OASIS business operations.⁴⁹ 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 September 30, 2020, the rate for the nonfirm service released by default was \$10.00 per MWh. The

⁴⁸ See OASIS "PJM Business Practices for Hudson Transmission Service," <<http://www.pjm.com/~media/etools/oasis/merch-trans-facilities/http-Business-practices.ashx>>.

⁴⁹ See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 8 (June 23, 2019) <<http://www.pjm.com/~media/etools/oasis/regional-practices-clean-doc.ashx>>.

primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-35 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-35 shows that in the first nine months of 2020, the primary rights holder was responsible for less than 100 percent of the scheduled interchange across the Hudson Line in all months.⁵⁰ Figure 9-9 shows the hourly average flow across the Hudson Line for the first nine months of 2020.

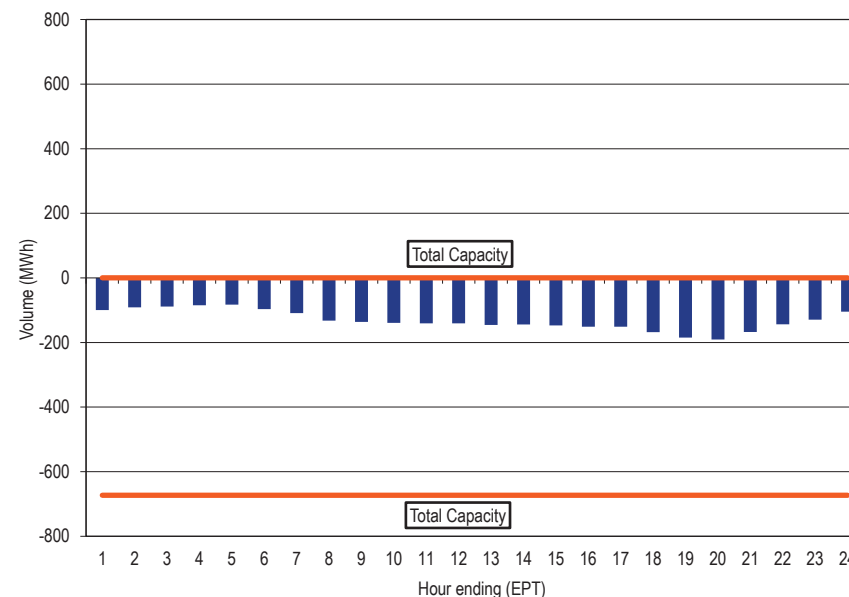
Table 9-35 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through September 2020⁵¹

	2013	2014	2015	2016	2017	2018	2019	2020
January	NA	51.22%	16.27%	100.00%	NA	24.44%	52.21%	29.70%
February	NA	49.00%	14.67%	NA	NA	23.25%	77.12%	23.61%
March	NA	40.40%	71.88%	NA	NA	9.55%	72.42%	87.24%
April	NA	100.00%	100.00%	NA	NA	15.13%	100.00%	10.02%
May	100.00%	26.87%	100.00%	100.00%	NA	92.18%	100.00%	20.53%
June	100.00%	5.89%	59.72%	100.00%	NA	44.89%	44.98%	38.26%
July	100.00%	18.51%	84.34%	NA	NA	16.26%	36.43%	27.56%
August	100.00%	75.17%	65.48%	NA	NA	19.24%	43.10%	35.64%
September	100.00%	75.31%	78.73%	NA	NA	22.90%	43.42%	30.75%
October	100.00%	99.71%	18.65%	100.00%	NA	22.67%	33.60%	
November	85.57%	99.60%	24.67%	100.00%	80.12%	50.44%	44.36%	
December	28.32%	1.68%	100.00%	NA	21.93%	29.38%	41.78%	

⁵⁰ The values in 2019 have changed slightly from previous reports to account for interchange scheduled by the primary rights holder on released transmission. Previous versions of this table only included interchange scheduled by the primary rights holder on their primary transmission reservation.

⁵¹ The designation of "NA" means there was no flow on the Hudson Line during those months.

Figure 9-9 Hudson hourly average flow: January through September, 2020



Interchange Activity During High Load Hours

The PJM metered system peak load during the first nine months of 2020 was 141,449 MW in the HE 1700 on July 20, 2020. PJM issued a hot weather alert in that hour. PJM was a net scheduled exporter of energy in all hours on July 20, 2020, with average hourly scheduled exports of 5,542 MW. During HE 1700 on July 20, 2020, PJM had net scheduled exports of 6,030 MW and net metered actual exports of 6,116 MW. Net transaction exports during this time were consistent with the price differences between PJM and MISO. Net transaction exports were also consistent with price differences between PJM and the NYISO interfaces (NYIS, Neptune, Linden and Hudson). During July 2020, PJM was a net scheduled exporter of energy in all hours. During July 2020, the average hourly scheduled interchange was -5,601 MW (representing 5.3 percent of the average hourly load of 105,846 MW in July 2020).

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 9-36 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-36 Summary of elements included in operating agreements with bordering areas

Agreement:	PJM-MISO	PJM-NYISO	PJM-TVA	PJM-DEP	PJM-VACAR	VACAR Reserve Sharing Agreement	PJM-WEP	Northeastern Protocol
Data Exchange								
Real-Time Data	YES	YES	YES	YES	YES	NO	YES	NO
Projected Data	YES	YES	YES	YES	NO		NO	NO
SCADA Data	YES	YES	YES	YES	NO		NO	NO
EMS Models	YES	YES	YES	YES	NO		NO	YES
Operations Planning Data	YES	YES	YES	YES	NO		NO	YES
Available Flowgate Capability Data	YES	YES	YES	YES	NO		NO	YES
Near-Term System Coordination								
Operating Limit Violation Assistance	YES	YES	YES	YES	YES		NO	NO
Over/Under Voltage Assistance	YES	YES	YES	YES	YES		NO	NO
Emergency Energy Assistance	YES	YES	NO	YES	YES		NO	NO
Outage Coordination	YES	YES	YES	YES	YES		NO	NO
Long-Term System Coordination	YES	YES	YES	YES	NO		NO	YES
Congestion Management Process								
ATC Coordination	YES	YES	YES	YES	NO		NO	NO
Market Flow Calculations	YES	YES	YES	NO	NO		NO	NO
Firm Flow Entitlements	YES	YES	YES	NO	NO		NO	NO
Market to Market Redispatch	YES - Redispatch	YES - Redispatch	NO	NO	NO		NO	NO
Joint Checkout Procedures	YES	YES	YES	YES	NO		YES	NO

PJM-MISO = MISO/PJM Joint Operating Agreement

PJM-NYISO = New York ISO/PJM Joint Operating Agreement

PJM-TVA = Joint Reliability 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 Agreement⁵²

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.⁵³

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses 10 buses along the PJM/MISO border to calculate the PJM/MISO interface pricing point LMP. Prior to June 1, 2017, MISO used all of the PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.⁵⁴ On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.⁵⁵

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.⁵⁶ 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.⁵⁷ 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, 2020, PJM had 141 flowgates eligible for M2M (Market to Market) coordination. In the first nine months of 2020, PJM added eight flowgates and deleted 11 flowgates, leaving 138 flowgates eligible for M2M coordination as of September 30, 2020. As of January 1, 2020, MISO had 186 flowgates eligible for M2M coordination. In the first nine months of 2020, MISO added 48 flowgates and deleted 93 flowgates, leaving 141 flowgates eligible for M2M coordination as of September 30, 2020.

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 nonmonitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the nonmonitoring RTO for congestion relief provided by the nonmonitoring RTO based on the difference between the nonmonitoring RTO's market flow and their FFE.

April 1, 2004, known as the freeze date, is used to determine the firm rights on flowgates based on historic premarket firm flows as of that date. In the past 15 years, topology and market changes have occurred, making the 2004 flows irrelevant in 2020. The RTOs and stakeholders recognize that a modification

⁵² 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>>.

⁵³ See "PJM/MISO Joint and Common Market Initiative," <<http://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common.aspx>>.

⁵⁴ See the 2012 *State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

⁵⁵ 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-item-03a-interface-pricing-post-implementation.ashx>>.

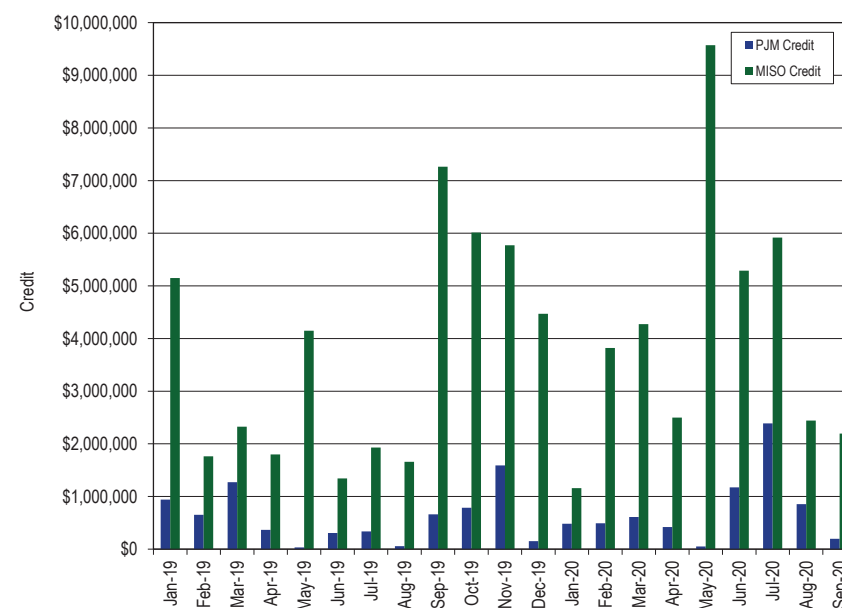
⁵⁶ See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <<http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>>.

⁵⁷ See "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>>.

to the freeze date is necessary.⁵⁸ PJM and MISO stakeholders have spent several years on the freeze date issues. Discussions regarding the Firm Flow Limit (FFL) solutions between market and nonmarket areas are also ongoing. No resolution to these issues appears imminent. The final resolution to the freeze date alternative should account for the investments made by each RTO in the transmission system. The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues.

In the first nine months of 2020, 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 9-10 shows credits for coordinated congestion management between PJM and MISO.

Figure 9-10 PJM/MISO credits for coordinated congestion management: January 2019 through September 2020⁵⁹



PJM and New York Independent System Operator Joint Operating Agreement (JOA)⁶⁰

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders.

On June 28, 2019, NYISO and PJM submitted revisions to the NYISO-PJM Joint Operating Agreement (JOA). The revisions would address RTO concerns identified in their joint request for limited waiver of the JOA to authorize redispatch of generation in PJM. The intent of the redispatch would be to mitigate post-contingency overloads of transmission equipment on the

⁵⁸ See "Freeze Date Alternatives," (May 21, 2019) <<https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20190521/20190521-item-01-freeze-date-update.ashx>>.

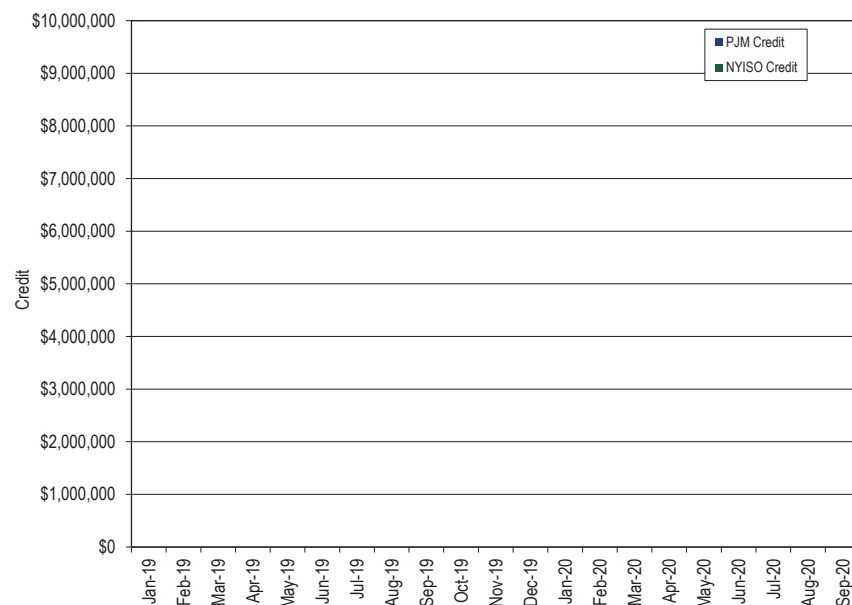
⁵⁹ The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

⁶⁰ 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>>.

New York side of the East Towanda-Hillside 230 kV Transmission Line. The agreement allows for the RTOs to control for this contingency without the exchange of payments for redispatch.⁶¹

In the first nine months of 2020, market to market operations did not result in NYISO and PJM redispatching units to control congestion on M2M flowgates. Therefore, there was no exchange of payments for redispatch in the first nine months of 2020. Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

Figure 9-11 PJM/NYISO credits for coordinated congestion management (flowgates): January 2019 through September 2020⁶²



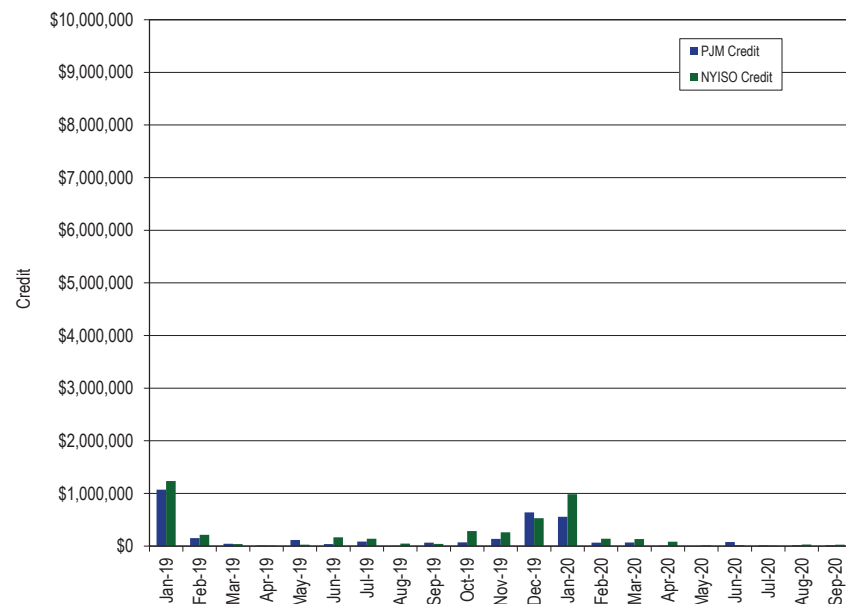
⁶¹ See NYISO Filing, FERC Docket No. ER19-2282-000 (June 28, 2019).

⁶² The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on M2M flowgates in a cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the PARs that are located at the PJM/NYIS border. This real-time coordination results in an efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real time to manage constraints.⁶³ For each M2M flowgate, a PAR settlement will occur for each interval during coordinated operations. The PAR settlements are determined based on whether the measured real-time flow on each of the PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. Effective May 1, 2017, coincident with the termination of the ConEd wheel, PJM and NYISO began M2M coordination at all of the PARs along the PJM/NYISO seam. Prior to May 1, 2017, only the Ramapo PARs were included in the M2M process. In the first nine months of 2020, market to market operations resulted in NYISO and PJM adjusting PARs to control congestion and the exchange of payments for this coordination. Figure 9-12 shows the PAR credits for coordinated congestion management between PJM and NYISO.

⁶³ See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, LLC," (June 21, 2017) <<http://www.pjm.com/~media/documents/agreements/nyiso-joa.ashx>>.

Figure 9–12 PJM/NYISO credits for coordinated congestion management (PARs): January 2019 through September 2020⁶⁴



PJM and TVA Joint Reliability Coordination Agreement (JRCA)⁶⁵

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

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 "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, LLC, and Tennessee Valley Authority," (October 15, 2014) <<http://www.pjm.com/~media/documents/agreements/joint-reliability-coordination-agreement-miso-pjm-tva.ashx>>.

constraint. Unlike the M2M procedure between MISO and PJM, this redispatch does not result in M2M payments. However, electing to redispatch generation within PJM can avoid potential market disruption by curtailing transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. The agreement remained in effect in the first nine months of 2020.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement⁶⁶

On September 9, 2005, FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to include a CMP under Article 14 of the JOA.⁶⁷ On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. At that time, Progress Energy Carolinas Inc., now a subsidiary of Duke Energy, changed its name to Duke Energy Progress (DEP).

On May 20, 2019, PJM and DEP submitted revisions to the JOA to delete Article 14.⁶⁸ These revisions eliminate the congestion management agreement and also change the interface price calculation from the marginal cost proxy method to the high low interface pricing method. PJM and DEP requested an effective date of July 22, 2019, for the filed revisions. On July 2, 2019, the Commission issued a letter order accepted the revisions to the JOA to delete the congestion management agreement effective July 22, 2019.⁶⁹

PJM and VACAR South Reliability Coordination Agreement⁷⁰

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), DEP, South Carolina Public Service Authority (SCPSA),

⁶⁶ See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, LLC, and Duke Energy Progress Inc.," (December 3, 2014) <<http://www.pjm.com/directory/merged-tariffs/progress-joa.pdf>>.

⁶⁷ See *PJM Interconnection, LLC and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

⁶⁸ See *PJM Interconnection, LLC*, Docket No. ER19-1905-000 (May 20, 2019).

⁶⁹ FERC Docket No. ER19-1905-000 (July 2, 2019).

⁷⁰ See "PJM-VACAR South RC Agreement," (November 7, 2014) <<http://www.pjm.com/~media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>>.

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 the first nine months of 2020.

VACAR Reserve Sharing Agreement

The VACAR Reserve Sharing Arrangement (VRSA) is a combination of agreements and procedures among the entities in the VACAR subregion including Dominion. The VACAR Reserve Sharing Group (VRSG) includes Duke Energy Progress (DEP), South Carolina Electric and Gas (SCE&G), South Carolina Public Service Authority (SCPSA) and Dominion Virginia Power. VACAR is a subregion of the SERC Reliability Corporation (SERC) region.⁷¹ The agreement requires that each entity maintain primary reserves to meet the VACAR contingency reserve commitment (VACAR reserves) and deploy such reserves in the case of an emergency (e.g. loss of a unit in VACAR).⁷² Dominion is the only party in the VRSA in PJM. PJM is not a party to this agreement; however, as the reliability coordinator for Dominion Virginia Power, PJM is responsible for scheduling their required reserves in the SERC region as described in the PJM manuals.⁷³ The agreement remained in effect in the first nine months of 2020.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC⁷⁴

The Balancing Authority Operations Coordination Agreement executed on July 20, 2013, provides for the exchange of information between WEC and PJM. The purpose of the data exchange is to allow for the coordination of balancing authority actions to ensure the reliable operation of the systems. The agreement remained in effect in the first nine months of 2020.

⁷¹ Duke Energy Progress, Duke Energy Carolinas, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas.

⁷² See SERC Regional Criteria, Contingency Reserve Policy, NERC Reliability Standard BAL-002 at 10-11.

⁷³ See PJM, "Manual 13: Emergency Operations," Rev. 76 (March 26, 2020).

⁷⁴ See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, LLC," (July 20, 2013) <<http://www.pjm.com/~media/documents/agreements/balancing-authority-operations-coordination-agreement.ashx>>.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol⁷⁵

The Northeastern ISO-RTO Planning Coordination Protocol executed on December 8, 2004, provides for the exchange of information among PJM, NYISO and ISO New England. The purpose of the data exchange is to allow for the long-term planning coordination among and between the ISOs and RTOs in the Northeast. The agreement remained in effect in the first nine months of 2020.

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 1, 2006.

Table 9-37 shows the real-time LMP calculated per the high/low pricing method, as defined in Section 2.6A (1) of the PJM Tariff, for the DUKE, PEC and NCPMA interface pricing points for the first nine months of 2020.⁷⁶ The values shown in Table 9-37 are the average LMP over only the hours in the first nine months of 2020 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 NCPMA to \$0.50 with DUKE. This means that under the specific interface pricing agreements, transactions settling at the DUKE interface price would receive, on average, \$0.50 more for importing energy into PJM than if they were to receive the SouthIMP pricing point. In the first nine months of 2020, market participants received \$33,603 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 -\$0.31 with DUKE to \$1.04 with NCPMA. This means that under the specific interface pricing agreements, transactions settling at the DUKE interface price would pay, on average, \$0.31 less for exporting energy from

⁷⁵ See "Northeastern ISO/RTO Planning Coordination Protocol," (December 8, 2004) <<http://www.pjm.com/~media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>>.

⁷⁶ On June 1, 2020, PJM retired the DUKE and PEC interface pricing points. At the September 2, 2020, Market Implementation Committee (MIC) meeting, PJM reported that the NCPMAIMP and NCPMAEXP interface pricing points would be retired effective November 3, 2020.

PJM than they would have if they were to pay the SouthEXP pricing point. In the first nine months of 2020, market participants paid \$5,667 more for exporting energy using this pricing point than they would have if they were to have paid the SouthEXP pricing point.

Table 9-37 Real-time LMP comparison for DUKE, PEC and NCMPA: January through September, 2020

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
DUKE	\$16.76	\$14.37	\$16.26	\$14.67	\$0.50	(\$0.31)
PEC	\$13.36	\$17.77	\$13.58	\$17.53	(\$0.22)	\$0.24
NCMPA	\$18.10	\$19.65	\$18.50	\$18.62	(\$0.40)	\$1.04

Table 9-38 shows the day-ahead LMP calculated per the high/low pricing method, as defined in Section 2.6A (1) of the PJM Tariff, for the DUKE, PEC and NCMPA interface pricing points for the first nine months of 2020.⁷⁷ The values shown in Table 9-38 are the average LMP over only the hours in the first nine months of 2020 where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from -\$0.75 with PEC to -\$0.27 with NCMPA. This means that under the specific interface pricing agreements, transactions settling at the PEC interface price would receive, on average, \$0.75 less for importing energy into PJM than if they were to receive the SouthIMP pricing point. In the first nine months of 2020, market participants received \$120,290 less 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 -\$0.15 with PEC to \$1.04 with NCMPA. This means that under the specific interface pricing agreements, transactions settling at the NCMPA interface price would pay, on average, \$1.04 more for exporting energy from PJM than if they were to pay the SouthEXP pricing point. In the first nine months of 2020, market participants paid \$2,579 more for exporting energy using this pricing point than they would have if they were to have paid the SouthEXP pricing point.

⁷⁷ On June 1, 2020, PJM retired the DUKE and PEC interface pricing points. At the September 2, 2020, Market Implementation Committee (MIC) meeting, PJM reported that the NCMPAIMP and NCMPAEXP interface pricing points would be retired effective November 3, 2020.

Table 9-38 Day-ahead LMP comparison for DUKE, PEC and NCMPA: January through September, 2020

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
DUKE	\$20.22	\$15.80	\$20.58	\$15.45	(\$0.36)	\$0.35
PEC	\$16.51	\$18.25	\$17.25	\$18.39	(\$0.75)	(\$0.15)
NCMPA	\$17.89	\$34.49	\$18.16	\$33.45	(\$0.27)	\$1.04

The MMU recommends that PJM eliminate the NCMPAIMP and NCMPAEXP interface pricing points.⁷⁸ It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. External entities wishing to receive the benefits of the PJM LMP market should join PJM.

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

The number of PJM issued TLRs of level 3a or higher decreased from two in the first nine months of 2019 to one in the first nine months of 2020.⁷⁹ The number of different flowgates for which PJM declared a TLR 3a or higher was one in the first nine months of 2019 and one in the first nine months of 2020. The total MWh of transactions curtailed decreased by 2.0 percent from 1,499 MWh in the first nine months of 2019 to 1,469 MWh in the first nine months of 2020.

The number of MISO issued TLRs of level 3a or higher increased from 35 in the first nine months of 2019 to 83 in the first nine months of 2020. The number of different flowgates for which MISO declared a TLR 3a increased from 15 in the first nine months of 2019 to 16 in the first nine months of

⁷⁸ At the September 2, 2020, Market Implementation Committee (MIC) meeting, PJM reported that the NCMPAIMP and NCMPAEXP interface pricing points would be retired effective November 3, 2020.

⁷⁹ TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the 2019 State of the Market Report for PJM, Volume 2, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

2020. The total MWh of transaction curtailments increased by 63.3 percent from 33,893 MWh in the first nine months of 2019 to 55,358 MWh in the first nine months of 2020.

The number of NYISO issued TLRs of level 3a or higher decreased from eight in the first nine months of 2019 to two in the first nine months of 2020. The number of different flowgates for which NYISO declared a TLR 3a or higher was two in the first nine months of 2019 and one in the first nine months of 2020. The total MWh of transaction curtailments decreased by 93.2 percent from 15,092 MWh in the first nine months of 2019 to 1,030 MWh in the first nine months of 2020.

Table 9–39 PJM, MISO, and NYISO TLR procedures: January through September, 2020⁸⁰

Month	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-20	0	2	2	0	2	1	0	1,865	1,030
Feb-20	0	2	0	0	1	0	0	776	0
Mar-20	0	6	0	0	4	0	0	3,441	0
Apr-20	0	7	0	0	3	0	0	14,509	0
May-20	0	6	0	0	3	0	0	12,861	0
Jun-20	0	23	0	0	6	0	0	12,412	0
Jul-20	1	23	0	1	4	0	1,469	5,156	0
Aug-20	0	8	0	0	4	0	0	717	0
Sep-20	0	6	0	0	6	0	0	3,621	0
Total	1	83	2	1	16	1	1,469	55,358	1,030

⁸⁰ The total row in the columns of the number of unique flowgates that experience TLRs are not a sum of the individual months. The total row represents the number of unique flowgates that have experienced TLRs for the year to date.

Table 9–40 Number of TLRs by TLR level by reliability coordinator: January through September, 2020⁸¹

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2020	MISO	33	18	0	12	20	0	83
	NYIS	2	0	0	0	0	0	2
	ONT	29	1	0	0	0	0	30
	PJM	1	0	0	0	0	0	1
	SOCO	2	2	0	0	0	0	4
	SWPP	5	7	0	8	4	0	24
	TVA	10	13	0	8	15	0	46
	VACS	0	4	0	0	0	0	4
Total		82	45	0	28	39	0	194

Up To Congestion

The original purpose, in 2000, of up to congestion transactions (UTC) was to allow market participants to submit a maximum congestion charge, up to \$25 per MWh, they were willing to pay on an import, export or wheel through transaction in the day-ahead energy market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the real-time energy market.⁸²

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.⁸³

The average number of up to congestion bids submitted in the day-ahead energy market increased by 5.2 percent, from 51,594 bids per day in the first nine months of 2019 to 54,299 bids per day in the first nine months of 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 0.1 percent, from 490,421 MWh per day in the first nine months of 2019, to 489,871 MWh per day in the first nine months of 2020.

⁸¹ 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.

⁸² See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

⁸³ See the *2020 Quarterly State of the Market Report for PJM: January through September*, Section 13: FTRs and ARR, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

Figure 9-13 Monthly up to congestion cleared bids in MWh: January 2005 through September 2020

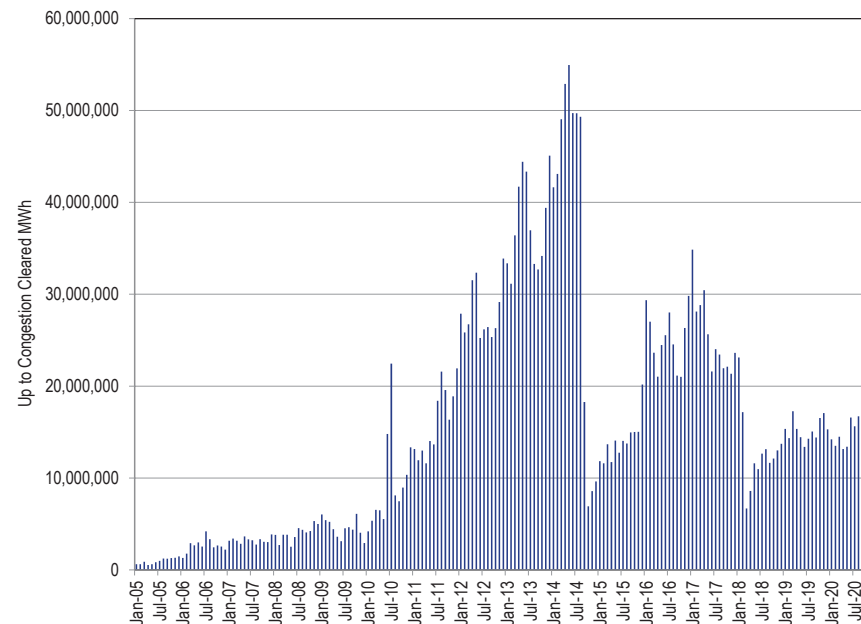


Table 9-41 Monthly volume of cleared and submitted up to congestion bids: January 2019 through September 2020

Month	Bid MW					Bid Volume					Cleared MW					Cleared Volume				
	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-19	9,353,494	3,989,206	2,204,341	33,209,495	48,756,536	317,900	137,306	61,239	1,335,488	1,851,933	3,646,671	1,270,480	719,143	9,708,127	15,344,421	163,962	69,096	25,497	648,338	906,893
Feb-19	7,584,708	5,424,852	1,991,198	29,512,609	44,513,366	242,071	142,957	50,914	916,766	1,352,708	2,891,175	1,759,853	660,811	9,029,295	14,341,133	113,778	70,552	21,952	469,157	675,439
Mar-19	11,841,555	4,801,188	3,292,862	36,636,988	56,572,593	320,490	105,336	58,064	1,115,308	1,599,198	4,473,700	1,543,428	1,126,598	10,124,498	17,268,224	153,456	50,367	23,840	550,873	778,536
Apr-19	7,500,490	5,206,737	2,465,809	30,466,646	45,639,682	210,977	99,870	51,861	839,285	1,201,993	3,399,991	1,718,522	917,569	9,316,753	15,352,837	114,678	51,233	25,154	436,881	627,946
May-19	7,645,790	5,234,141	3,161,264	28,363,918	44,405,113	257,707	114,116	60,815	841,562	1,274,200	3,312,686	1,572,184	875,397	8,678,534	14,438,801	131,807	51,047	23,406	434,766	641,026
Jun-19	6,110,456	5,605,115	2,611,193	22,881,326	37,208,089	265,643	160,729	65,564	914,109	1,406,045	2,818,707	2,198,956	871,722	7,500,886	13,390,271	138,482	86,395	32,233	478,224	735,334
Jul-19	7,056,992	4,330,830	3,316,928	27,078,704	41,783,454	299,274	158,591	62,817	1,164,220	1,684,902	2,622,343	1,980,537	1,054,098	8,625,452	14,282,430	130,706	101,912	30,468	576,429	839,515
Aug-19	6,498,469	6,138,104	4,180,281	26,961,166	43,778,021	300,981	231,654	84,937	1,279,890	1,897,462	2,596,501	2,164,346	1,093,209	9,209,462	15,063,518	136,493	114,788	33,781	647,784	932,846
Sep-19	8,573,470	7,472,142	7,582,592	30,007,306	53,635,511	330,868	198,568	110,558	1,176,657	1,816,651	2,533,520	1,735,695	1,101,876	9,032,182	14,403,273	129,191	83,956	33,247	571,636	818,030
Oct-19	7,348,136	8,853,713	4,538,131	35,139,349	55,879,328	259,530	197,958	86,660	1,168,584	1,712,732	2,346,484	2,877,525	894,232	10,422,816	16,541,056	115,182	85,179	30,010	582,716	813,087
Nov-19	8,987,595	5,918,112	4,344,925	36,908,236	56,158,867	289,785	150,439	95,526	1,097,503	1,633,253	2,918,127	1,944,440	944,351	11,264,708	17,071,627	116,200	67,868	30,548	520,053	734,669
Dec-19	7,830,824	3,546,465	2,221,854	27,335,527	40,934,670	296,081	133,197	82,788	1,053,592	1,565,658	3,180,715	1,392,082	805,641	9,923,068	15,301,506	125,299	75,667	36,033	536,749	773,748
Jan-20	5,709,294	2,231,205	1,944,774	18,039,136	27,924,410	275,752	162,609	75,183	1,039,001	1,552,545	2,898,979	1,255,867	934,870	9,125,163	14,214,879	137,826	96,035	40,542	564,363	838,766
Feb-20	5,676,276	2,666,146	2,199,490	17,493,382	28,035,292	242,264	146,844	65,051	1,030,601	1,484,760	2,612,370	1,482,095	854,591	8,563,657	13,512,713	110,759	87,190	32,242	535,392	765,583
Mar-20	6,665,180	2,978,585	2,003,110	18,814,938	30,461,812	251,993	161,948	66,569	983,109	1,463,619	2,858,559	1,898,911	836,553	8,904,119	14,498,142	104,922	101,540	33,173	495,693	735,328
Apr-20	6,091,885	2,682,191	1,468,174	16,612,116	26,854,366	254,545	137,594	52,775	893,782	1,338,696	2,865,235	1,604,592	753,404	7,928,948	13,152,179	119,135	85,209	28,416	454,794	687,554
May-20	6,271,609	1,965,274	1,075,904	21,565,323	30,878,110	331,575	137,922	60,794	1,273,857	1,804,148	2,683,033	1,003,073	483,381	9,243,633	13,413,120	145,382	69,535	29,462	590,351	834,730
Jun-20	6,831,949	2,804,284	1,743,982	31,474,224	42,854,440	334,466	159,856	63,796	1,404,345	1,962,463	2,446,275	1,274,509	679,616	12,187,056	16,587,456	153,982	93,233	28,630	734,369	1,010,214
Jul-20	7,876,157	2,322,606	1,988,024	35,708,931	47,895,717	288,710	109,436	65,635	1,425,030	1,888,811	2,327,354	929,229	654,258	11,723,592	15,634,434	122,042	67,440	30,594	692,881	912,957
Aug-20	7,758,436	2,285,138	2,157,739	34,944,219	47,145,532	246,363	101,479	60,503	1,307,254	1,715,599	2,885,456	965,737	602,209	12,270,529	16,723,930	114,008	56,585	26,662	665,354	862,609
Sep-20	7,498,635	3,279,523	2,074,365	34,571,326	47,423,850	236,272	113,749	68,013	1,249,116	1,667,150	2,759,958	1,311,305	545,808	11,870,827	16,487,899	112,007	54,772	24,409	626,387	817,575
Total	156,711,400	89,735,557	58,566,940	593,724,864	898,738,761	5,853,247	3,062,158	1,450,062	23,509,059	33,874,526	61,077,839	33,883,368	17,409,337	204,653,305	317,023,848	2,689,297	1,619,599	620,299	11,813,190	16,742,385

In the first nine months of 2020, the cleared MW volume of up to congestion transactions was comprised of 18.1 percent imports, 8.7 percent exports, 4.7 percent wheeling transactions and 68.4 percent internal transactions. Less than 0.1 percent of the up to congestion transactions had matching real-time energy market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority cannot see how the power will flow to the load, which can create loop flows and result in inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM energy market, at the PJM/NYIS Interface regardless of the submitted path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT path, and a second segment on the ONT-MISO-PJM path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source were Ontario (the ONT interface price).

Sham scheduling can also be achieved by submitting a transaction that is in the opposite direction of a portion of a larger transaction schedule.

For example, market participants can submit one transaction with multiple segments among balancing authorities and another transaction which offsets all or part of a segment of the first transaction. If a market participant submits two separate transactions, one on the ONT-MISO-PJM path, and a second on the PJM-MISO

path, the result of these transactions would be a net scheduled transaction from ONT to MISO, as the MISO-PJM segment of the first transaction is offset by the PJM-MISO transaction. In this example, PJM is not required to raise or lower generation as a result of these transactions, as they would for an import or an export, and there are no associated power flows across PJM. Nonetheless, the market participant is paid the price difference between the PJM/ONT interface pricing point and the PJM/MISO interface pricing point. The market participant would be paid the PJM/ONT interface pricing point for the first transaction (ONT to PJM import) and the market participant would pay the PJM/MISO interface pricing point for the second transaction (PJM to MISO export). If the PJM/ONT interface price were higher than the PJM/MISO interface price, the market participant would be paid a net profit from the PJM market even though there was no impact on PJM operations.

At the April 10, 2013, PJM Market Implementation Committee (MIC), the MMU presented a problem statement and issue charge to address sham scheduling activities.⁸⁴ The expected deliverables from the stakeholder meetings were revisions to the Tariff and PJM business manuals. The topic was discussed at several MIC meetings. While there was stakeholder agreement that sham scheduling activity was inappropriate, consensus on revised tariff and manual language was not achieved. The topic was closed. The MMU clarified that it would continue to monitor transactions for sham scheduling activities and that the MMU could refer market participants for sham scheduling activities.

The MMU monitors for sham scheduling activities on a daily basis. Following the stakeholder discussions in 2013, the net profits obtained from sham scheduling activities fell by 100.8 percent, from net profits of \$15.5 million in 2014, to a net loss of \$124,535 in 2019. The total number of hours of sham scheduling segments where the MW profile matched exactly across all segments of the path combinations in the same hour, fell by 95.0 percent, from 1,898 hours in 2014 to 94 hours in 2019.

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement

⁸⁴ See Market Path/Interface Pricing Point alignment Problem Statement, at: <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_Market_Path_Interface_Pricing_Point_Alignment_Problem_Statement_201304010.pdf>.

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.⁸⁵ 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-

⁸⁵ See "Sham Scheduling," Presented at the PJM Market Monitoring Unit Advisory Committee (MMUAC) meeting held on December 6, 2013 <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_Shams_Scheduling_20131206.pdf>.

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 \$42.00.⁸⁶

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

The MMU recommends that if the PJM/IMO interface price remains and with PJM's new method in place, that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. Such rules would prohibit the same market participant

from scheduling an export transaction from PJM to any balancing authority while at the same time an import transaction is scheduled to PJM that receives the PJM/IMO interface price. PJM should also prohibit the same market participant from scheduling an import transaction to PJM from any balancing authority while at the same time an export transaction is scheduled from PJM that receives the PJM/IMO interface price.

In the first nine months of 2020, of the 128 GWh of gross scheduled transactions between PJM and IESO, 126 GWh (98.4 percent) wheeled through MISO (Table 9-24). 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.⁸⁷

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.⁸⁸ The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price IT SCED results with the NYISO. The NYISO compares the PJM/NYISO interface price with its RTC calculated NYISO/PJM interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for the first nine months of 2020. Table 9-42 shows

⁸⁶ 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>>.

⁸⁷ On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

⁸⁸ PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

that over all 12 forecast ranges, IT SCED predicted the real-time PJM/NYIS interface LMP within the range of \$0.00 to \$5.00 in 48.4 percent of the intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was \$1.48 per MWh. In 3.3 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than \$20.00. The average price differences were \$47.44 when the price difference was greater than \$20.00, and \$56.73 when the price difference was greater than -\$20.00.

Table 9-42 Differences between forecast and actual PJM/NYIS interface prices: January through September, 2020

Range of Price Differences	Percent of All Intervals	Average Price Difference
> \$20	1.7%	\$47.44
\$10 to \$20	2.6%	\$13.89
\$5 to \$10	5.2%	\$6.91
\$0 to \$5	48.4%	\$1.48
\$0 to -\$5	37.2%	\$1.25
-\$5 to -\$10	2.1%	\$6.85
-\$10 to -\$20	1.2%	\$14.30
< -\$20	1.6%	\$56.73

Table 9-43 shows how the accuracy of the IT SCED forecasted LMPs changes as the cases approach real-time. In the final IT SCED results prior to real time, in 87.8 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- \$5.00 of the actual PJM/NYIS interface real-time LMP, compared to 81.3 percent in the 135 minute ahead IT SCED results.

Table 9-43 Differences between forecast and actual PJM/NYIS interface prices: January through September, 2020

	~ 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	1.9%	\$49.23	1.9%	\$48.88	0.9%	\$43.99	1.0%	\$42.53
\$10 to \$20	4.3%	\$13.93	4.3%	\$13.79	1.5%	\$13.51	1.7%	\$13.61
\$5 to \$10	7.7%	\$6.93	7.5%	\$6.92	4.1%	\$6.85	4.2%	\$6.83
\$0 to \$5	48.8%	\$1.75	49.4%	\$1.74	47.1%	\$1.47	47.2%	\$1.44
\$0 to -\$5	32.5%	\$1.38	32.1%	\$1.37	40.7%	\$1.36	40.6%	\$1.34
-\$5 to -\$10	2.1%	\$6.82	2.0%	\$6.87	2.7%	\$6.84	2.6%	\$6.85
-\$10 to -\$20	1.1%	\$14.11	1.1%	\$14.10	1.4%	\$14.24	1.4%	\$14.21
< -\$20	1.6%	\$55.90	1.6%	\$56.03	1.8%	\$55.30	1.8%	\$55.91

In 2.8 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than \$20.00. The average price difference was \$42.53 when the price difference was greater than \$20.00, and \$55.91 when the price difference was greater than -\$20.00.

Table 9-44 and Table 9-45 show the monthly differences between forecasted and actual PJM/NYIS interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-44 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): January through September, 2020

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> \$20	0.6%	0.0%	0.0%	0.1%	0.1%	0.7%	3.8%	2.0%	0.2%	1.0%
	\$10 to \$20	1.1%	0.4%	0.0%	0.3%	0.9%	1.2%	4.6%	3.5%	1.3%	1.7%
	\$5 to \$10	3.4%	1.7%	0.8%	2.1%	3.1%	4.3%	10.8%	7.2%	4.4%	4.2%
	\$0 to \$5	42.3%	52.3%	47.6%	52.3%	43.8%	47.5%	46.7%	43.1%	49.4%	47.2%
	\$0 to -\$5	44.4%	42.7%	47.7%	41.4%	45.2%	40.3%	27.7%	37.3%	38.7%	40.6%
	-\$5 to -\$10	3.7%	1.3%	2.2%	1.8%	4.1%	2.5%	2.1%	2.4%	2.9%	2.6%
	-\$10 to -\$20	2.4%	0.8%	0.8%	1.1%	1.5%	1.4%	1.2%	1.7%	1.2%	1.4%
	< -\$20	2.1%	0.9%	1.0%	0.9%	1.3%	2.0%	3.0%	2.7%	2.0%	1.8%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> \$20	0.6%	0.1%	0.0%	0.1%	0.2%	0.6%	3.9%	2.0%	0.0%	0.9%
	\$10 to \$20	1.3%	0.4%	0.0%	0.2%	0.8%	1.1%	4.5%	3.5%	1.5%	1.5%
	\$5 to \$10	3.4%	1.5%	0.7%	2.3%	2.8%	4.0%	10.9%	7.0%	4.5%	4.1%
	\$0 to \$5	42.7%	51.8%	48.0%	52.0%	43.5%	47.5%	46.0%	43.5%	49.0%	47.1%
	\$0 to -\$5	43.8%	43.0%	47.4%	41.5%	45.6%	40.5%	28.2%	37.1%	38.8%	40.7%
	-\$5 to -\$10	3.7%	1.5%	2.0%	1.9%	4.3%	2.6%	2.3%	2.8%	2.8%	2.7%
	-\$10 to -\$20	2.4%	0.8%	0.9%	1.0%	1.5%	1.5%	1.2%	1.6%	1.3%	1.4%
	< -\$20	2.1%	0.9%	1.0%	1.0%	1.3%	2.1%	3.0%	2.6%	2.0%	1.8%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> \$20	0.8%	0.4%	0.0%	0.1%	0.6%	1.1%	5.7%	4.1%	4.5%	1.9%
	\$10 to \$20	2.7%	0.9%	0.6%	0.4%	2.0%	4.1%	11.4%	7.7%	8.7%	4.3%
	\$5 to \$10	5.9%	3.2%	2.4%	3.0%	7.3%	8.7%	11.7%	10.1%	15.3%	7.5%
	\$0 to \$5	47.4%	63.2%	57.6%	51.3%	48.8%	46.5%	39.3%	43.8%	47.2%	49.4%
	\$0 to -\$5	36.7%	29.9%	36.1%	41.2%	35.4%	33.7%	26.3%	29.5%	20.4%	32.1%
	-\$5 to -\$10	2.8%	0.9%	1.4%	2.1%	3.4%	2.6%	1.6%	1.7%	1.5%	2.0%
	-\$10 to -\$20	1.6%	0.8%	0.8%	1.0%	1.4%	1.3%	1.2%	1.2%	0.7%	1.1%
	< -\$20	1.8%	0.8%	1.0%	1.0%	1.1%	2.0%	2.8%	2.1%	1.7%	1.6%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> \$20	0.9%	0.5%	0.1%	0.0%	0.7%	1.0%	5.6%	4.1%	4.3%	1.9%
	\$10 to \$20	2.4%	0.7%	0.6%	0.5%	1.9%	4.3%	11.5%	7.6%	8.7%	4.3%
	\$5 to \$10	6.4%	3.4%	2.5%	3.1%	7.3%	8.7%	11.4%	10.6%	15.9%	7.7%
	\$0 to \$5	46.9%	62.0%	57.3%	50.7%	48.7%	46.0%	38.7%	43.1%	46.0%	48.8%
	\$0 to -\$5	37.1%	30.9%	35.9%	41.6%	35.3%	34.1%	27.0%	29.5%	21.0%	32.5%
	-\$5 to -\$10	2.9%	0.9%	1.9%	2.0%	3.7%	2.5%	1.7%	1.7%	1.6%	2.1%
	-\$10 to -\$20	1.7%	0.8%	0.8%	0.9%	1.3%	1.4%	1.3%	1.1%	0.8%	1.1%
	< -\$20	1.8%	0.8%	0.9%	1.1%	1.1%	2.0%	2.8%	2.3%	1.7%	1.6%

Table 9-45 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): January through September, 2020

Interval	Range of Price Differences										YTD
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
~ 30 Minutes Prior to Real-Time	> \$20	\$52.02	\$23.29	\$0.00	\$25.08	\$28.86	\$34.36	\$41.98	\$46.10	\$29.24	\$42.53
	\$10 to \$20	\$14.05	\$13.78	\$0.00	\$13.60	\$13.50	\$13.81	\$13.48	\$13.75	\$13.12	\$13.61
	\$5 to \$10	\$6.92	\$6.57	\$6.55	\$6.45	\$6.63	\$6.84	\$6.92	\$6.95	\$6.75	\$6.83
	\$0 to \$5	\$1.40	\$1.18	\$1.23	\$1.43	\$1.51	\$1.52	\$1.68	\$1.55	\$1.51	\$1.44
	\$0 to -\$5	\$1.36	\$1.18	\$1.28	\$1.31	\$1.54	\$1.36	\$1.22	\$1.31	\$1.44	\$1.34
	-\$5 to -\$10	\$6.86	\$6.88	\$6.52	\$6.90	\$6.80	\$7.13	\$7.06	\$6.72	\$6.79	\$6.85
	-\$10 to -\$20	\$13.86	\$14.73	\$15.76	\$14.56	\$14.04	\$14.62	\$13.87	\$13.96	\$13.68	\$14.21
	< -\$20	\$56.21	\$51.33	\$56.70	\$53.77	\$45.91	\$53.45	\$56.78	\$47.40	\$77.51	\$55.91
Interval	Range of Price Differences										YTD
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
~ 45 Minutes Prior to Real-Time	> \$20	\$51.50	\$22.47	\$0.00	\$24.44	\$26.74	\$32.52	\$42.62	\$50.81	\$40.51	\$43.99
	\$10 to \$20	\$13.53	\$14.34	\$10.56	\$13.93	\$13.59	\$13.10	\$13.57	\$13.58	\$13.16	\$13.51
	\$5 to \$10	\$6.89	\$6.28	\$6.78	\$6.57	\$6.79	\$6.79	\$6.97	\$6.99	\$6.77	\$6.85
	\$0 to \$5	\$1.38	\$1.21	\$1.24	\$1.46	\$1.53	\$1.58	\$1.72	\$1.58	\$1.53	\$1.47
	\$0 to -\$5	\$1.39	\$1.17	\$1.32	\$1.32	\$1.53	\$1.38	\$1.23	\$1.34	\$1.48	\$1.36
	-\$5 to -\$10	\$6.90	\$6.67	\$6.53	\$6.79	\$6.75	\$7.00	\$7.22	\$6.69	\$6.95	\$6.84
	-\$10 to -\$20	\$14.15	\$14.86	\$14.95	\$14.30	\$13.83	\$14.58	\$14.11	\$14.30	\$13.66	\$14.24
	< -\$20	\$55.29	\$51.28	\$56.61	\$51.75	\$44.60	\$52.69	\$54.81	\$48.21	\$78.52	\$55.30
Interval	Range of Price Differences										YTD
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
~ 90 Minutes Prior to Real-Time	> \$20	\$46.45	\$31.41	\$23.02	\$23.81	\$25.45	\$36.01	\$40.96	\$56.63	\$60.85	\$48.88
	\$10 to \$20	\$13.71	\$14.02	\$14.64	\$13.40	\$13.86	\$13.09	\$13.79	\$14.00	\$13.87	\$13.79
	\$5 to \$10	\$6.82	\$6.38	\$6.22	\$6.86	\$6.64	\$6.90	\$7.11	\$7.07	\$7.09	\$6.92
	\$0 to \$5	\$1.61	\$1.48	\$1.59	\$1.65	\$1.95	\$1.83	\$1.69	\$1.84	\$2.16	\$1.74
	\$0 to -\$5	\$1.31	\$1.12	\$1.24	\$1.41	\$1.60	\$1.45	\$1.27	\$1.43	\$1.47	\$1.37
	-\$5 to -\$10	\$6.84	\$6.65	\$6.48	\$6.83	\$6.73	\$6.92	\$7.35	\$7.10	\$6.94	\$6.87
	-\$10 to -\$20	\$13.88	\$14.55	\$13.78	\$13.92	\$13.77	\$14.23	\$14.52	\$14.74	\$13.39	\$14.10
	< -\$20	\$58.54	\$52.76	\$55.48	\$51.37	\$46.82	\$52.52	\$54.67	\$48.99	\$79.12	\$56.03
Interval	Range of Price Differences										YTD
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
~ 135 Minutes Prior to Real-Time	> \$20	\$44.17	\$29.91	\$22.78	\$28.32	\$29.48	\$35.06	\$42.20	\$56.71	\$61.91	\$49.23
	\$10 to \$20	\$13.70	\$13.82	\$14.09	\$14.58	\$13.75	\$13.16	\$14.02	\$14.19	\$14.02	\$13.93
	\$5 to \$10	\$6.80	\$6.46	\$6.28	\$6.80	\$6.57	\$6.90	\$7.21	\$7.08	\$7.07	\$6.93
	\$0 to \$5	\$1.62	\$1.49	\$1.61	\$1.66	\$1.96	\$1.85	\$1.69	\$1.83	\$2.18	\$1.75
	\$0 to -\$5	\$1.32	\$1.10	\$1.23	\$1.42	\$1.61	\$1.50	\$1.26	\$1.48	\$1.47	\$1.38
	-\$5 to -\$10	\$6.72	\$6.53	\$6.53	\$6.79	\$6.73	\$6.92	\$7.22	\$6.95	\$7.03	\$6.82
	-\$10 to -\$20	\$14.09	\$14.19	\$13.93	\$13.79	\$13.78	\$14.18	\$14.76	\$14.41	\$13.51	\$14.11
	< -\$20	\$59.21	\$52.72	\$56.62	\$49.44	\$47.23	\$52.26	\$56.26	\$47.10	\$78.70	\$55.90

The NYISO uses PJM's IT SCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO approves CTS (spread bid) transactions when the offered spread is less than or equal to the spread between

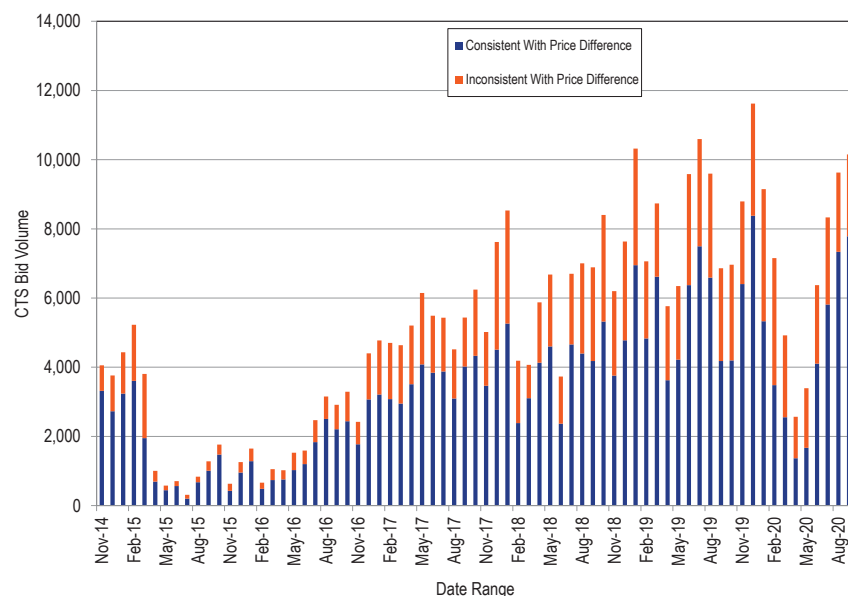
the IT SCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences between forecast and actual LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve charges are applied and CTS transactions are optional, the CTS proposal represents a small incremental step toward better interface pricing. The NYISO has a 75 minute bid submission deadline. While market participants have the option to specify bid data on 15 minute intervals, market participants must submit their bids 75 minutes prior to the requested transaction start time. The 75 minute bid submission deadline associated with scheduling energy transactions in the NYISO should be shortened. Reducing this deadline could significantly improve pricing efficiency at the PJM/NYISO border for non-CTS transactions and for CTS transactions as market participants would be able to adjust their bids in response to real-time price signals.

CTS transactions were evaluated for each 15 minute interval. From November 4, 2014, through September 30, 2020, 360,804 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 118,031 (32.7 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 32.7 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 67.3 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 September 30, 2020



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/NYIS interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and NYISO.

Reserving Ramp on the PJM/NYISO Interface

Prior to the implementation of CTS, PJM held ramp space for all transactions submitted between PJM and the NYISO as soon as the NERC Tag was approved. At that time, once transactions were evaluated by the NYISO through their real-time market clearing process, any adjustments made to the submitted transactions would be reflected on the NERC Tags and the PJM ramp was adjusted accordingly.

As part of this process, PJM was often required to make adjustments to transactions on its other interfaces in order to bring total system ramp back to within its limit. The default ramp limit in PJM is $\pm 1,000$ 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 $\pm 1,000$. These curtailments were made on a last in first out basis as determined by the timestamp on the NERC Tag.

With the implementation of the CTS product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, does PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process would violate ramp, PJM would make additional adjustments based on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO interface from holding (or creating) ramp until NYISO has completed its economic evaluation and the transactions are approved through the NYISO market clearing process.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market Initiative. The PJM/MISO coordinated transaction scheduling (CTS) process provides the option for market participants to submit intra-hour transactions between the MISO and PJM that include an interface spread bid on which transactions are evaluated. Similar to the PJM/NYISO approach, the evaluation is based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED). Unlike the PJM/NYISO CTS process in which the NYISO performs the evaluation, the PJM/MISO CTS process uses a joint clearing process in which both RTOs share forward looking prices. On October 3, 2017, PJM and MISO implemented the CTS process.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/MISO interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for the first nine months of 2020. Table 9-46 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/MISO interface LMP within the range of \$0.00 to \$5.00 in 46.1 percent of all intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was \$1.59. In 4.6 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than \$20.00. The average price differences were \$45.06 when the price difference was greater than \$20.00, and \$60.30 when the price difference was greater than -\$20.00.

Table 9-46 Differences between forecast and actual PJM/MISO interface prices: January through September, 2020

Range of Price Differences	Percent of All Intervals	Average Price Difference
> \$20	2.4%	\$45.06
\$10 to \$20	3.3%	\$13.82
\$5 to \$10	6.4%	\$6.98
\$0 to \$5	46.1%	\$1.59
\$0 to -\$5	35.2%	\$1.33
-\$5 to -\$10	2.8%	\$6.94
-\$10 to -\$20	1.6%	\$14.27
< -\$20	2.2%	\$60.30

Table 9-47 shows how the accuracy of the IT SCED forecasted LMPs change as the cases approach real-time. In the final IT SCED results prior to real-time, in 82.8 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- \$5.00 of the actual PJM/MISO interface real-time LMP, compared to 78.7 percent in the 135 minute ahead IT SCED results.

Table 9-47 Differences between forecast and actual PJM/MISO interface prices: January through September, 2020

Range of Price Differences	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
	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	2.2%	\$37.69	2.1%	\$37.65	1.7%	\$40.62	1.5%	\$41.03
\$10 to \$20	4.7%	\$13.86	4.7%	\$13.80	2.5%	\$13.55	2.4%	\$13.59
\$5 to \$10	7.2%	\$7.01	6.9%	\$7.03	6.2%	\$6.92	6.3%	\$6.95
\$0 to \$5	44.2%	\$1.71	44.8%	\$1.72	45.0%	\$1.61	45.6%	\$1.59
\$0 to -\$5	34.5%	\$1.49	34.2%	\$1.48	37.8%	\$1.39	37.2%	\$1.38
-\$5 to -\$10	3.3%	\$6.91	3.3%	\$6.92	3.0%	\$6.91	3.0%	\$6.92
-\$10 to -\$20	1.7%	\$13.98	1.7%	\$13.95	1.7%	\$14.37	1.7%	\$14.40
< -\$20	2.2%	\$59.77	2.2%	\$59.36	2.3%	\$59.69	2.3%	\$59.63

In 3.8 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than \$20.00, the average price differences were \$41.03 when the price difference was greater than \$20.00, and \$59.63 when the price difference was greater than -\$20.00.

Table 9-48 and Table 9-49 show the monthly differences between forecasted and actual PJM/MISO interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-48 Monthly differences between forecast and actual PJM/MISO interface prices (percent of intervals): January through September, 2020

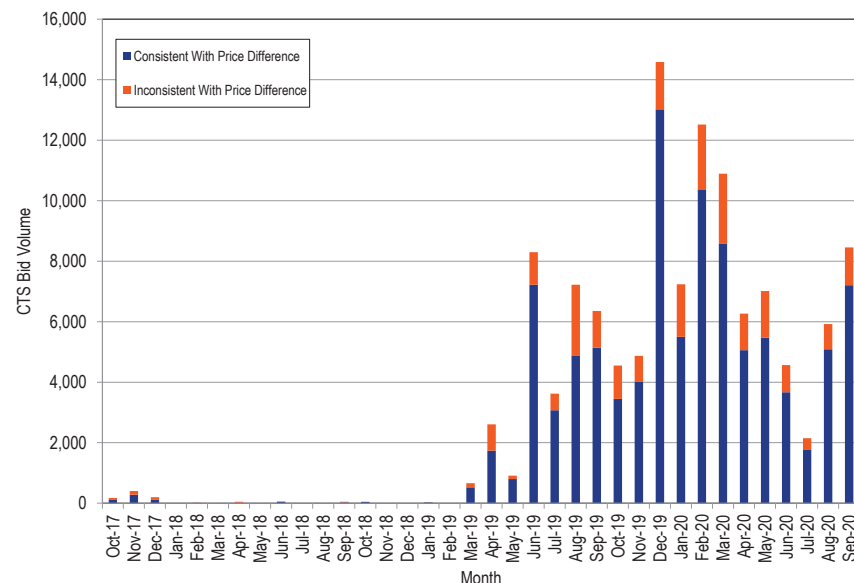
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> \$20	0.4%	0.0%	0.0%	0.5%	1.2%	1.3%	6.0%	2.8%	0.9%	1.5%
	\$10 to \$20	1.8%	0.4%	0.6%	1.4%	2.5%	2.0%	5.3%	5.0%	2.3%	2.4%
	\$5 to \$10	4.3%	1.9%	2.8%	5.3%	9.4%	6.9%	10.4%	8.3%	6.7%	6.3%
	\$0 to \$5	44.2%	54.5%	47.6%	46.5%	38.3%	43.7%	46.0%	42.9%	47.2%	45.6%
	\$0 to -\$5	44.0%	39.9%	43.1%	40.0%	37.2%	38.0%	25.7%	32.3%	35.3%	37.2%
	-\$5 to -\$10	2.4%	1.1%	3.0%	3.2%	6.6%	3.1%	1.8%	2.8%	3.3%	3.0%
	-\$10 to -\$20	1.1%	1.3%	1.4%	1.7%	2.5%	1.9%	1.6%	2.0%	1.9%	1.7%
	< -\$20	1.8%	0.9%	1.3%	1.4%	2.3%	3.1%	3.3%	4.0%	2.3%	2.3%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> \$20	0.3%	0.0%	0.0%	0.4%	1.2%	1.4%	5.9%	2.8%	0.9%	1.7%
	\$10 to \$20	1.7%	0.6%	0.7%	1.6%	2.8%	1.7%	5.6%	5.3%	2.1%	2.5%
	\$5 to \$10	4.7%	1.6%	2.8%	4.9%	9.0%	6.8%	10.8%	8.0%	7.1%	6.2%
	\$0 to \$5	43.8%	53.6%	48.1%	46.0%	37.8%	43.1%	44.6%	42.5%	46.3%	45.0%
	\$0 to -\$5	44.2%	40.9%	42.8%	40.5%	37.7%	38.9%	26.5%	33.1%	36.1%	37.8%
	-\$5 to -\$10	2.1%	1.1%	2.9%	3.7%	6.5%	3.1%	1.9%	2.3%	3.2%	3.0%
	-\$10 to -\$20	1.4%	1.1%	1.3%	1.5%	2.7%	2.0%	1.5%	1.8%	2.0%	1.7%
	< -\$20	1.7%	1.0%	1.3%	1.5%	2.3%	3.1%	3.3%	4.1%	2.3%	2.3%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> \$20	0.9%	0.1%	0.0%	0.3%	1.4%	2.0%	7.6%	4.9%	1.7%	2.1%
	\$10 to \$20	3.5%	1.0%	1.2%	1.8%	3.5%	4.9%	11.4%	8.9%	5.4%	4.7%
	\$5 to \$10	5.0%	2.8%	4.4%	5.6%	11.2%	8.4%	8.3%	7.9%	8.6%	6.9%
	\$0 to \$5	45.9%	60.5%	51.1%	45.7%	37.6%	41.9%	39.3%	36.7%	45.6%	44.8%
	\$0 to -\$5	39.4%	32.5%	37.3%	38.4%	34.7%	35.0%	27.0%	33.4%	30.4%	34.2%
	-\$5 to -\$10	2.4%	1.0%	3.3%	4.8%	6.8%	2.8%	2.1%	2.6%	4.0%	3.3%
	-\$10 to -\$20	1.3%	1.1%	1.3%	1.8%	2.5%	1.9%	1.4%	2.1%	1.8%	1.7%
	< -\$20	1.6%	0.9%	1.3%	1.5%	2.3%	3.1%	3.0%	3.6%	2.6%	2.2%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> \$20	0.9%	0.1%	0.1%	0.3%	1.4%	2.2%	8.2%	4.8%	1.7%	2.2%
	\$10 to \$20	3.4%	1.1%	1.3%	1.7%	3.9%	5.0%	10.6%	9.1%	5.5%	4.7%
	\$5 to \$10	5.2%	3.0%	4.7%	5.6%	11.3%	8.3%	8.8%	8.5%	9.3%	7.2%
	\$0 to \$5	45.7%	59.8%	50.6%	45.0%	37.8%	41.7%	38.0%	35.4%	44.3%	44.2%
	\$0 to -\$5	39.3%	32.8%	37.8%	39.0%	33.7%	35.1%	28.0%	33.9%	30.9%	34.5%
	-\$5 to -\$10	2.4%	1.1%	3.0%	4.9%	7.2%	2.8%	1.9%	2.5%	4.2%	3.3%
	-\$10 to -\$20	1.3%	1.1%	1.3%	1.8%	2.7%	1.8%	1.5%	2.2%	1.7%	1.7%
	< -\$20	1.6%	0.9%	1.3%	1.6%	2.2%	3.1%	2.9%	3.7%	2.5%	2.2%

Table 9-49 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): January through September, 2020

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> \$20	\$24.92	\$30.34	\$24.25	\$32.19	\$28.56	\$40.75	\$46.84	\$39.16	\$37.64	\$41.03
	\$10 to \$20	\$13.55	\$12.50	\$13.84	\$13.05	\$12.91	\$13.72	\$14.15	\$13.48	\$13.64	\$13.59
	\$5 to \$10	\$7.08	\$6.74	\$6.66	\$6.76	\$6.91	\$6.78	\$7.05	\$7.35	\$6.74	\$6.95
	\$0 to \$5	\$1.36	\$1.23	\$1.52	\$1.65	\$1.87	\$1.55	\$1.72	\$1.75	\$1.73	\$1.59
	\$0 to -\$5	\$1.26	\$1.11	\$1.39	\$1.55	\$1.69	\$1.36	\$1.14	\$1.42	\$1.44	\$1.38
	-\$5 to -\$10	\$7.18	\$6.87	\$6.53	\$6.73	\$7.07	\$6.88	\$6.85	\$7.09	\$6.93	\$6.92
	-\$10 to -\$20	\$14.08	\$14.77	\$15.01	\$14.56	\$14.06	\$13.88	\$13.95	\$15.07	\$14.39	\$14.40
	< -\$20	\$70.03	\$54.84	\$61.61	\$49.47	\$52.87	\$62.45	\$58.94	\$57.91	\$65.44	\$59.63
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> \$20	\$23.65	\$30.28	\$0.00	\$33.96	\$31.88	\$36.01	\$46.15	\$39.38	\$36.10	\$40.62
	\$10 to \$20	\$13.60	\$13.45	\$13.86	\$12.89	\$12.67	\$13.76	\$14.26	\$13.35	\$13.56	\$13.55
	\$5 to \$10	\$6.99	\$6.60	\$6.42	\$6.86	\$6.82	\$7.00	\$6.94	\$7.23	\$6.83	\$6.92
	\$0 to \$5	\$1.35	\$1.28	\$1.52	\$1.70	\$1.89	\$1.60	\$1.71	\$1.77	\$1.75	\$1.61
	\$0 to -\$5	\$1.28	\$1.11	\$1.38	\$1.51	\$1.65	\$1.37	\$1.18	\$1.48	\$1.47	\$1.39
	-\$5 to -\$10	\$7.21	\$6.92	\$6.54	\$6.73	\$6.95	\$6.93	\$6.98	\$7.08	\$7.00	\$6.91
	-\$10 to -\$20	\$13.84	\$14.68	\$15.18	\$14.65	\$13.65	\$14.36	\$14.42	\$14.88	\$14.32	\$14.37
	< -\$20	\$71.52	\$52.59	\$62.23	\$47.79	\$52.58	\$63.06	\$60.03	\$57.03	\$67.15	\$59.69
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> \$20	\$25.49	\$23.79	\$24.28	\$37.15	\$29.71	\$37.13	\$42.59	\$35.64	\$35.60	\$37.65
	\$10 to \$20	\$13.97	\$14.46	\$13.33	\$13.31	\$12.65	\$13.18	\$13.98	\$14.31	\$13.96	\$13.80
	\$5 to \$10	\$7.11	\$6.50	\$6.61	\$6.78	\$6.99	\$7.09	\$7.18	\$7.36	\$7.06	\$7.03
	\$0 to \$5	\$1.47	\$1.48	\$1.67	\$1.85	\$2.07	\$1.73	\$1.65	\$1.75	\$1.93	\$1.72
	\$0 to -\$5	\$1.26	\$1.17	\$1.42	\$1.72	\$1.73	\$1.48	\$1.26	\$1.59	\$1.63	\$1.48
	-\$5 to -\$10	\$7.09	\$6.75	\$6.56	\$6.82	\$7.01	\$6.77	\$6.97	\$7.03	\$7.12	\$6.92
	-\$10 to -\$20	\$13.87	\$13.75	\$13.94	\$13.89	\$13.64	\$13.69	\$14.63	\$14.01	\$14.32	\$13.95
	< -\$20	\$72.02	\$54.41	\$61.52	\$47.71	\$51.49	\$61.39	\$59.36	\$60.37	\$61.74	\$59.36
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> \$20	\$24.67	\$25.62	\$22.27	\$36.37	\$32.55	\$35.43	\$42.37	\$36.13	\$34.90	\$37.69
	\$10 to \$20	\$14.10	\$14.51	\$13.35	\$13.72	\$12.78	\$13.12	\$14.03	\$14.52	\$13.71	\$13.86
	\$5 to \$10	\$6.96	\$6.29	\$6.64	\$6.81	\$6.95	\$7.08	\$7.36	\$7.28	\$7.00	\$7.01
	\$0 to \$5	\$1.48	\$1.49	\$1.68	\$1.89	\$2.05	\$1.71	\$1.63	\$1.73	\$1.90	\$1.71
	\$0 to -\$5	\$1.29	\$1.15	\$1.44	\$1.72	\$1.77	\$1.52	\$1.29	\$1.61	\$1.63	\$1.49
	-\$5 to -\$10	\$6.96	\$6.74	\$6.59	\$6.78	\$7.01	\$6.91	\$6.93	\$6.94	\$7.16	\$6.91
	-\$10 to -\$20	\$13.61	\$14.13	\$13.75	\$14.00	\$13.89	\$13.87	\$14.60	\$14.10	\$13.89	\$13.98
	< -\$20	\$72.51	\$54.16	\$61.55	\$46.61	\$52.85	\$61.21	\$60.22	\$60.34	\$63.42	\$59.77

CTS transactions were evaluated for each interval. From October 3, 2017, through September 30, 2020, 119,740 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 22,434 (18.7 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 18.7 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 81.3 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 September 30, 2020



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and MISO.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving nonfirm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system if necessary to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost

(and losses) that the market participant pays in order for their transaction to continue to flow.

The MMU recommended that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations addressed most of the MMU concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be appropriate to address this exposure.

Table 9-50 shows that since the inception of the business rule change on April 12, 2013, there was uncollected congestion in only two months (January 2016 and February 2019). In both months, there was negative uncollected congestion. The negative congestion means that market participants who used the not willing to pay congestion transmission option for their wheel through transactions had transactions that flowed in the direction opposite to congestion. When market participants use the not willing to pay congestion product, it also means that they are not willing to receive congestion credits, which was the case in both January 2016 and February 2019.

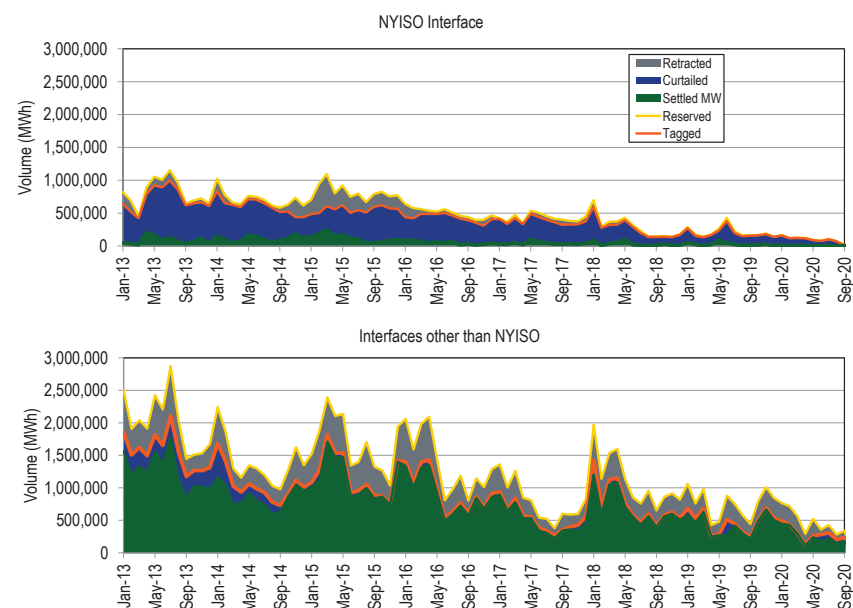
Table 9-50 Monthly uncollected congestion charges: January 2010 through September 2020

Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Jan	\$148,764	\$3,102	\$0	\$5	\$0	\$0	(\$44)	\$0	\$0	\$0	\$0
Feb	\$542,575	\$1,567	(\$15)	\$249	\$0	\$0	\$0	\$0	\$0	(\$69,992)	\$0
Mar	\$287,417	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Apr	\$31,255	\$4,767	(\$68)	(\$3,114)	\$0	\$0	\$0	\$0	\$0	\$0	\$0
May	\$41,025	\$0	(\$27)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Jun	\$169,197	\$1,354	\$78	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Jul	\$827,617	\$1,115	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Aug	\$731,539	\$37	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Sep	\$119,162	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Oct	\$257,448	(\$31,443)	(\$6,870)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Nov	\$30,843	(\$795)	(\$4,678)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Dec	\$127,176	(\$659)	(\$209)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total	\$3,314,018	(\$20,955)	(\$11,789)	(\$2,860)	\$0	\$0	(\$44)	\$0	\$0	(\$69,992)	\$0

Spot Imports

Figure 9-16 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 1, 2013 through September 30, 2020. The yellow line shows the total monthly MWh of spot import service reserved and the orange line shows the total monthly MWh of tagged spot import service. The gray shaded area between the yellow and orange lines represents the MWh of retracted spot import service and may represent potential hoarding volumes. This ATC was initially reserved, but not tagged (used). It is possible that in some instances the reserved transmission consisted of the only available ATC which could have been used by another market participant had it not been reserved and not used. The blue shaded area between the orange line and green shaded area represents the MWh of curtailed transactions using spot import service. This area may also represent hoarding opportunities, particularly at the NYISO Interface. In this instance, it is possible that while the market participant reserved and scheduled the transmission, they may have submitted purposely uneconomic bids in the NYISO market so that their transaction would be curtailed, yet their transmission would not be retracted. The NYISO allows for market participants to modify their bids on an hourly basis, so these market participants can hold their transmission service and evaluate their bids hourly, while withholding the transmission from other market participants that may wish to use it. The green shaded area represents

the total settled MWh of spot import service. Figure 9-16 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.⁸⁹

Figure 9-16 Spot import service use: January 2013 through September 2020

⁸⁹ See the 2018 State of the Market Report for PJM, Volume 2, Section 9, "Interchange Transactions," for a more complete discussion of the history of spot import transmission service.

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.⁹⁰ These changes would give PJM a more flexible product that could be used to meet load based on economic dispatch rather than guessing the sensitivity of the transactions to price changes.

In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments affect the duration of interchange transactions.

The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach

that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point to point transmission. An interchange cap is a nonmarket intervention which should be a temporary solution and should be replaced with a market based solution as soon as possible. Since the approval of this process on October 30, 2014, PJM has not yet needed to implement an interchange cap.

The purpose of the interchange cap is to help ensure that actual interchange more closely meets operators' expectations of interchange levels when internal PJM resources, e.g. CTs or demand response, are dispatched to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange then materializes. Therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift.

PJM will notify market participants of the possible use of the interchange cap the day before. The interchange cap will be implemented for the forecasted peak and surrounding hours during emergency conditions.

The interchange cap will limit the acceptance of spot import and hourly nonfirm point to point interchange (imports and exports) not submitted as real time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly nonfirm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap.

The calculation of the interchange cap is based on the operator expectation of interchange at the time the cap is calculated plus an additional margin.

⁹⁰ The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order No. 764.

The margin is set at 700 MW, which is half of the largest contingency on the system. The additional margin also allows interchange to adjust to the loss of a unit or deviation between actual load and forecasted load. The interchange cap is based on the maximum sustainable interchange from PJM reliability studies.

45 Minute Schedule Duration Rule

PJM limits the change in interchange volumes on 15 minute intervals. These changes are referred to as ramp. The PJM ramp limit is designed to limit the change in the amount of imports or exports in each 15 minute interval to account for the physical characteristics of the generation to respond to changes in the level of imports and exports. The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit per 15 minute interval was based on the availability of ramping capability by generators in the PJM system. The limit is based on the assumption that the available generation in the PJM system can only move 1,000 MW over any 15 minute period, although there is no supporting analysis. As an example of how the ramp limit works, if at 0800 the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intrahour LMP changes. This activity was due to market participants' ability to observe price differences between RTOs in the first third of the hour, and predict the direction of the price difference on an hourly integrated basis. Large quantities of MW would then be scheduled between the RTOs for the last 15 minute interval to capture those hourly integrated price differences with relatively little risk of prices changing. This increase in interchange on 15 minute intervals created operational control issues, and in some cases led to an increase in uplift charges due to calling on resources with minimum run times greater than 15 minutes needed to support the interchange transactions. As a result, a new

business rule was proposed and approved that required all transactions to be at least 45 minutes in duration.

On June 22, 2012, FERC issued Order No. 764, which required transmission providers to give transmission customers the option to schedule transmission service at 15 minute intervals to reflect more accurate power production forecasts, load and system conditions.⁹¹ ⁹² On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.⁹³

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.⁹⁴

MISO Multi-Value Project Usage Rate (MUR)

MISO defines a multi-value project (MVP) to be a project which, according to MISO, enables the reliable and economic delivery of energy in support of public policy needs, provides multiple types of regional economic value or provides a combination of regional reliability and economic value.⁹⁵ On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.⁹⁶ On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.⁹⁷ 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.

⁹¹ Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).

⁹² Order No. 764 at P 51.

⁹³ See *Id.* at P 12.

⁹⁴ 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>.

⁹⁵ See MISO. MTEP "Multi Value Project Portfolio Analysis," <<https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf>>.

⁹⁶ See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).

⁹⁷ 133 FERC ¶ 61,221 (2010); *order on reh'g*, 137 FERC ¶ 61,074 (2011).

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.⁹⁸ 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.⁹⁹ 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.¹⁰⁰

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.¹⁰¹ 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."¹⁰²

The policy rationale for permitting MISO to impose transmission costs on PJM market participants without clear criteria is weak and results in pancaking of rates. The impact is expected to increase.

Table 9-51 shows the projected usage rate to be collected for all wheels through and exports from MISO, including those that sink in PJM, for 2020 through 2039.¹⁰³ As shown in Table 9-4, there were 441.5 GWh of imports from MISO in the first nine months of 2020. At the 2020 MUR of \$1.70 per MWh, PJM market participants paid \$750,550 towards the costs of MISO's multi value

projects. It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-51 MISO projected multi value project usage rate: 2020 through 2039

Year	Total Indicative MVP Usage Rate (\$/MWh)
2020	\$1.70
2021	\$1.69
2022	\$1.70
2023	\$1.69
2024	\$1.77
2025	\$1.71
2026	\$1.69
2027	\$1.67
2028	\$1.65
2029	\$1.64
2030	\$1.62
2031	\$1.60
2032	\$1.59
2033	\$1.57
2034	\$1.55
2035	\$1.54
2036	\$1.52
2037	\$1.50
2038	\$1.49
2039	\$1.47

98 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).

99 *Id.* at 780.

100 *Id.* at 779.

101 156 FERC ¶ 61,034 (2016).

102 *Id.* at P 55.

103 See MISO, "Schedule 26A Indicative Annual Charges," (July 30, 2019) <<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 in the first nine months of 2020.

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 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.

¹ 75 FERC ¶ 61,080 (1996).

² Energy imbalance service refers to the real-time energy market.

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 DASR market would have failed a three pivotal supplier test in zero hours in the first nine months of 2020. The day-ahead scheduling reserve market structure remains evaluated as not competitive based on persistent structural issues.
- 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. The day-ahead scheduling reserve market clearing price was above \$0 in 855 hours in the first nine months of 2020. In those hours, 60.1 percent of the clearing price was the offer price of the marginal unit and the remaining 39.9 percent was based on lost opportunity cost.
- 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 not competitive

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

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 94.8 percent of the hours in the first nine months of 2020.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first nine months of 2020 because market power mitigation requires competitive offers when the three pivotal supplier test is failed, although the inclusion of a positive margin raises questions.
- Market performance was evaluated as not competitive, because all units are not paid the same price on an equivalent MW basis.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Overview

Primary Reserve

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

PJM determines the primary reserve requirement based on the most severe single contingency in every approved RT SCED case. Every real-time market solution calculates the available tier 1 synchronized reserve. The required synchronized reserve and nonsynchronized reserve are calculated and dispatched in every real-time market solution, and there are associated clearing prices (SRMCP and NSRMCP) assigned every five minutes. Scheduled resources are credited based on a dispatched assignment and a five minute clearing price.

³ See PJM, "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 38 (Aug. 22, 2019)).

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 the first nine months of 2020, the average primary reserve requirement was 2,460.0 MW in the RTO Zone and 2,422.2 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 in response to a PJM declared synchronized reserve event. 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 the first nine months of 2020, there was an average hourly supply of 2,067.7 MW of tier 1 available in the RTO Zone and an average hourly supply of 956.6 MW of tier 1 synchronized reserve available within the MAD Subzone.
- **Demand.** The synchronized reserve requirement is calculated for each real-time dispatch solution as the most severe single contingency within both the RTO Zone and the MAD Subzone. The requirement is reduced by the amount of estimated tier 1. The remaining unfilled requirement (if any) is met with 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 for increasing its output (or reducing load for demand response) at the rate of \$50 per MWh in addition to LMP.⁴ This is the Synchronized Energy Premium Price.
- **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 synchronized energy premium price of \$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, \$4,732,025 in 2018, and \$3,217,178 in 2019. The hourly nonsynchronized reserve market clearing price was above \$0 in 682 intervals in the first nine months of 2020 resulting in a payment to tier 1 resources of \$986,042.

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, and that have an obligation to respond to PJM declared synchronized reserve events. Tier 2 synchronized reserve is penalized for failure to respond to a PJM declared synchronized reserve event. PJM has established a required amount of synchronized reserve as no less than the largest single contingency, and a 10 minute primary reserve at no less than 150 percent of the largest single contingency. This is stricter than the NERC standard of the greater of 80 percent of the largest single contingency or 900 MW.⁵

⁴ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 109 (Oct. 15, 2020).

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

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 the first nine months of 2020, the supply of daily offered and eligible tier 2 synchronized reserve was 30,240.0 MW in the RTO Zone of which 4,996.2 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,699.0 MW in the RTO Reserve Zone and 1,683.8 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 178.1 MW in the MAD Subzone and 329.9 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 2020.

The average HHI for tier 2 synchronized reserve in the RTO Zone was 6043 which is classified as highly concentrated. The MMU calculates that the three pivotal supplier test would have been failed in 14 percent of intervals in the first nine months of 2020.

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 intervals in the Mid-Atlantic Dominion (MAD) Subzone was \$2.62 per MW in the first nine months of 2020, a decrease of \$0.45 from the \$3.07 in the first nine months of 2019.

The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the RTO Synchronized Reserve Zone was \$3.58 per MW in the first nine months of 2020, an increase of \$0.39 from \$3.19 in the first nine months of 2019.

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 the first nine months of 2020, the average five minute interval supply of eligible and available nonsynchronized reserve was 1,405.0 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.⁶ The actual amount of nonsynchronized reserve scheduled often exceeds the demand and the

⁶ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 5b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 109 (Oct. 15, 2020). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

corresponding price is \$0.00. In the RTO Zone, the market scheduled an hourly average of 1,247.7 MW of nonsynchronized reserve in the first nine months of 2020.

- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 99.7 percent of intervals where the price was above \$0.01 in the first nine months of 2020.

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 intervals in the RTO Reserve Zone was \$0.10 in the first nine months of 2020.

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 is not required to maintain this level of secondary reserve in real time.

PJM maintains a day-ahead, offer-based market for 30 minute day-ahead secondary reserve. The PJM 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.⁷ If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

⁷ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 109 (Oct. 15, 2020).

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 the first nine months of 2020, the average available hourly DASR was 44,991.3 MW.
- **Demand.** The DASR requirement for November 2019 through October 2020 is 5.07 percent of peak load forecast, which is a 0.22 percentage point decrease from the previous twelve month period. The average hourly DASR MW purchased in the first nine months of 2020 was 4,987.2 MW. This is a reduction from the 5,460.3 hourly MW in 2019.
- **Concentration.** The three pivotal supplier test would have failed in zero hours in the first nine months of 2020.

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 the first nine months of 2020, 39.6 percent of daily unit offers were above \$0.00 and 16.4 percent of daily unit offers were 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 the first nine months of 2020.

Market Performance

- **Price.** In the first nine months of 2020 the weighted average DASR price for all hours when the DASRMCP was above \$0.00 was \$2.17.

Regulation Market

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

Market Structure

- **Supply.** In the first nine months of 2020, the average hourly offered supply of regulation for nonramp hours was 704.1 performance adjusted MW (709.1 effective MW). This was a decrease of 92.6 performance adjusted MW (a decrease of 88.5 effective MW) from the first nine months of 2019. In the first nine months of 2020, the average hourly offered supply of regulation for ramp hours was 1,008.9 performance adjusted MW (1,053.1 effective MW). This was a decrease of 113.1 performance adjusted MW (a decrease of 74.4 effective MW) from the first nine months of 2019, when the average hourly offered supply of regulation was 1,122.0 performance adjusted MW (1,127.4 effective MW).
- **Demand.** The hourly regulation demand is 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources

equal to 490.0 hourly average performance adjusted actual MW in the first nine months of 2020. This is an increase of 22.2 performance adjusted actual MW from the first nine months of 2019, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 467.9 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 703.0 hourly average performance adjusted actual MW in the first nine months of 2020. This is a decrease of 19.8 performance adjusted actual MW from the first nine months of 2019, where the average hourly regulation cleared MW for ramp hours were 722.8 performance adjusted actual MW.

The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.43 in the first nine months of 2020 (1.55 in the first nine months of 2019). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.44 in the first nine months of 2020 (1.70 in the first nine months of 2019).

- **Market Concentration.** In the first nine months of 2020, the three pivotal supplier test was failed in 04.8 percent of hours. In the first nine months of 2020, the actual MW weighted average HHI of RegA resources was 2519 which is highly concentrated and the weighted average HHI of RegD resources was 1850 which is moderately concentrated. The weighted average HHI of all resources was 1443, which is moderately concentrated.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.⁸ In the first nine months of 2020, there were 217 resources following the RegA signal and 52 resources following the RegD signal.

⁸ See the 2019 State of the Market Report for PJM, Vol. 2, Appendix F "Ancillary Services Markets."

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was \$12.59 per MW of regulation in the first nine months of 2020. This is a decrease of \$2.38 per MW, or 15.9 percent, from the weighted average clearing price of \$14.97 per MW in the first nine months of 2019. The weighted average cost of regulation in the first nine months of 2020 was \$15.59 per MW of regulation. This is a decrease of 18.6 percent, from the weighted average cost of \$19.15 per MW in the first nine months of 2019.
- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the regulation market were functioning efficiently and competitively, RegD and RegA resources would be paid the same price per effective MW. 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.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF 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 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 filed requests for rehearing.¹⁰ On March 26, 2020, the Commission issued an order denying the MMU and PJM's requests for rehearing.¹¹

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).¹²

In the first nine months of 2020, total black start charges were \$49.3 million, including \$49.1 million in revenue requirement charges and \$0.160 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 the first nine months of 2020 ranged from \$0.04 per MW-day in the DLCO Zone (total charges were \$32,721) to \$3.95 per MW-day in the PENELEC Zone (total charges were \$3,260,274).

The capital recovery factor (CRF) defines the revenue requirement of black start units. The CRF is a rate, which when multiplied by the investment, provides for a return on and of capital over a defined time period. The PJM CRF table was created in 2007 as part of the new RPM capacity market design and incorporated in Attachment DD to the PJM OATT (Table 10-51). The

⁹ 162 FERC ¶ 61,295.

¹⁰ FERC Docket No. ER18-87-002.

¹¹ 170 FERC ¶ 61,259.

¹² OATT Schedule 1 § 1.3BB.

CRF values were later added to the black start rules. The CRF table includes assumptions about tax rates that are no longer correct. The new depreciation rules allow for a more accelerated depreciation and therefore lower taxes. The tax code also reduced the corporate tax rate to 21 percent which also reduces taxes. The CRF values are significantly too high as a result. The PJM tariff tables including CRF values should have been changed for both black start and the capacity market when the tax laws changed in 2017. As a result, CRF values have overcompensated black start units since the changes to the tax code.

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

For the future, the CRF rates should be updated at least annually to reflect changes in federal or state taxes, including depreciation treatment and tax rates.

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVar). Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW). The same equipment provides both MVar and MW. The current rules permit double recovery of some fixed costs.

Reactive capability charges are based on FERC approved filings that permit recovery based on a cost of service approach.¹³ Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Total reactive charges increased 6.16 percent from \$250.6 million in the first nine months of 2019 to \$266.0 million in the first nine months of 2020. Reactive capability

¹³ OATT Schedule 2.

charges increased 6.2 percent from \$250.1 million in the first nine months of 2019 to \$265.6 million in the first nine months of 2020. Total reactive service charges in the first nine months of 2020 ranged from \$0 in the RECO and OVEC Zones, to \$36.5 million in the AEP 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 nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.¹⁴ PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.¹⁵

The PJM Tariff requires that all new generator interconnection customers (Nuclear Regulatory Commission regulated facilities are exempt from this provision) have hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust real power output in a direction to correct for frequency deviations. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 0.036 deadband.¹⁶ In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

The response of generators within PJM to NERC identified frequency events in 2019 remains under evaluation. NERC uses a threshold value (L_{10}) equal to 262 MW/0.1 Hz and has selected 23 events in 2019 to evaluate. Evaluation will continue until later in 2020 when further recommendations will be discussed within PJM and the NERC Operating Committee.

¹⁴ See 157 FERC ¶ 61,122 (2016).

¹⁵ See 164 FERC ¶ 61,224 (2018).

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

Ancillary Services Costs per MWh of Load

Table 10-4 shows PJM ancillary services costs for the first nine months of 1999 through 2020, 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.¹⁷ 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: January through September, 1999 through 2020^{18 19}

Year (Jan-Sep)	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	\$0.16	\$0.22	\$0.25	\$0.00	\$0.63
2000	\$0.33	\$0.29	\$0.31	\$0.00	\$0.93
2001	\$0.55	\$0.70	\$0.22	\$0.00	\$1.47
2002	\$0.42	\$0.82	\$0.19	\$0.00	\$1.43
2003	\$0.53	\$1.01	\$0.23	\$0.13	\$1.90
2004	\$0.50	\$0.99	\$0.25	\$0.14	\$1.88
2005	\$0.78	\$0.73	\$0.26	\$0.11	\$1.88
2006	\$0.55	\$0.74	\$0.28	\$0.07	\$1.64
2007	\$0.65	\$0.72	\$0.27	\$0.06	\$1.70
2008	\$0.78	\$0.44	\$0.33	\$0.07	\$1.62
2009	\$0.36	\$0.34	\$0.36	\$0.04	\$1.10
2010	\$0.38	\$0.36	\$0.36	\$0.06	\$1.16
2011	\$0.36	\$0.37	\$0.38	\$0.09	\$1.20
2012	\$0.23	\$0.42	\$0.44	\$0.03	\$1.12
2013	\$0.27	\$0.42	\$0.67	\$0.03	\$1.39
2014	\$0.36	\$0.43	\$0.40	\$0.14	\$1.33
2015	\$0.25	\$0.42	\$0.36	\$0.12	\$1.15
2016	\$0.11	\$0.43	\$0.37	\$0.05	\$0.96
2017	\$0.13	\$0.48	\$0.42	\$0.06	\$1.09
2018	\$0.20	\$0.47	\$0.40	\$0.06	\$1.13
2019	\$0.11	\$0.47	\$0.43	\$0.04	\$1.05
2020	\$0.10	\$0.48	\$0.47	\$0.02	\$1.07

¹⁷ The total prices in this table are a load weighted average system price per MWh by category, even if each category is not charged on that basis. These totals are presented for informational purposes and should not be used to calculate the costs of any specific market activity in PJM.

¹⁸ Note: The totals in Table 10-4 account for after the fact billing adjustments made by PJM and may not match totals presented in past reports.

¹⁹ Reactive totals include FERC approved rates for reactive capability.

Recommendations

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.²⁰)
- 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.²¹ FERC rejected.²²)
- 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.²³)
- 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

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

²¹ 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.

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

²³ *Id.*

assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.²⁴)

- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.²⁵)
- 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 PJM replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: 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 2018. Status: Not adopted.)
- The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources 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.)

²⁴ *Id.*

²⁵ *Id.*

- 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: Adopted April 2019.)
- 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 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: 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 mitigate market power. (Priority: Low. First reported 2009. Modified, 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. The PJM capacity and energy markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. The CRF rates for units going into service since the change in the tax code should incorporate applicable changes to depreciation treatment and tax rates. The CRF rates for units constructed prior to the new tax law and to which the new tax law depreciation rules did not apply should incorporate only the applicable changes to the tax rate. The black start units should be required to commit to providing black start service for the life of the unit. (Priority: High. First reported Q2, 2020. 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 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 2018. Status: Not adopted.)

- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019.²⁶ Status: Partially 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.²⁷

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, 2017.²⁸ 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. 755.²⁹ The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.³⁰

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 economic withholding and is therefore not consistent with a competitive outcome. The \$7.50 margin should be eliminated. The variable operating and maintenance component of the synchronized reserve offer should also be eliminated. All variable operating and maintenance costs are incurred to provide energy and to make units available to provide energy. There are no variable operating and maintenance costs associated with providing synchronized reserve.

Participant performance has not been adequate for tier 2 synchronized reserve. Compliance with calls to respond to actual synchronized reserve events remains significantly less than 100 percent. Actual participant performance means that the penalty structure is not an adequate incentive for 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 to a synchronized reserve event. 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 has added more than \$100 million to the cost of primary reserve since 2014.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets,

²⁶ The MMU has discussed this recommendation in state of the market reports since 2016 but Q3, 2019 was the first time it was reported as a formal MMU recommendation.

²⁷ Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

²⁸ 18 CFR § 385.211 (2017)

²⁹ 162 FERC ¶ 61,295.

³⁰ 170 FERC ¶ 61,259.

there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the regulation market results were not competitive, and the market design is significantly flawed. The MMU concludes that the synchronized reserve market results were competitive, 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. NERC standards set the Contingency Event Recovery Period as 15 minutes and Contingency Reserve Restoration Period as 90 minutes.³¹ The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.³² PJM maintains 10 minute reserves (primary reserve) to ensure reliability in the event of disturbances. PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. PJM does not currently have a Contingency Reserve Restoration Period standard.

³¹ See PJM "Manual 12: Balancing Operations," Rev. 40 (March 26, 2020) 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."

³² See PJM "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating) Reserve, Rev. 38 (Aug. 22, 2019).

Market Structure

Demand

PJM requires that 150 percent of the largest single 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 set equal to 150 percent of the largest single contingency for each market solution, ASO, IT SCED, and RT SCED. This is usually the output of the largest generating unit. In cases where temporary switching conditions create the risk that a single fault could remove several generators, PJM will define the largest single contingency as the sum of the output of those generators.³³

PJM can also increase the primary and synchronized reserve requirement in cases of hot weather or cold weather alerts or escalating emergency procedures.³⁴ Such additional reserves are committed as part of the hourly (ASO) and five minute (RT SCED) processes. In the first nine months of 2020, the average primary reserve requirement for the RTO Zone was 2,453.6 MW. The average primary reserve requirement in the MAD Subzone was also 2,430.7 MW. These averages include the hours when PJM raised the requirements.

The MMU identified instances when PJM increased the primary and synchronized reserve requirements (Table 10-5). The amounts of the increases are estimated against average requirement levels before and after the periods of increase.

³³ PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 109 (Oct. 15, 2020)

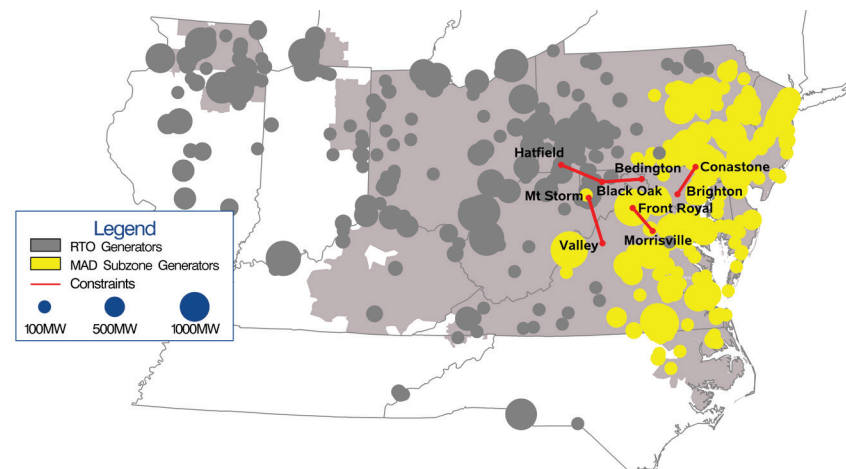
³⁴ PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 109 (Oct. 15, 2020), p. 84

Table 10-5 Temporary adjustments to primary and synchronized reserve: January through September, 2020

From	To	Number of Hours	Amount of Adjustment
15-Jan-20	17-Jan-20	40	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
3-Mar-20	16-Mar-20	320	Primary Reserve (100 MW), Synchronized Reserve (75 MW)
12-Apr-20	1-May-20	432	Primary Reserve (320 MW), Synchronized Reserve (220 MW)
1-Jun-20	7-Jun-20	160	Primary Reserve (200 MW), Synchronized Reserve (150 MW)
8-Jun-20	8-Jun-20	10	Primary Reserve (400 MW), Synchronized Reserve (250 MW)
9-Jun-20	9-Jun-20	9	Primary Reserve (750 MW), Synchronized Reserve (400 MW)
26-Sep-20	26-Sep-20	7	Primary Reserve (1,730 MW), Synchronized Reserve (1,160 MW)

Transmission constraints can limit the deliverability of reserves within the RTO, requiring the definition of a subzone. PJM defines a single subzone, the Mid-Atlantic Dominion (MAD) Subzone (Figure 10-1).³⁵ Figure 10-1 is a map of constraints and major generation sources. The constraints separating the RTO Zone and MAD Subzone are defined by underlying grid topology. The RTO Zone into MAD Subzone constraints reflect limits on the transmission line capacity that separate the RTO Zone and MAD Subzone. If, in the case of a spinning event, the current economic dispatch plus the current synchronized market dispatch would overload the constraint, then all additional synchronized reserve MW must be cleared from the unconstrained side of the constraints. When this occurs, the synchronized reserve prices between the RTO Zone and the MAD Subzone will diverge. PJM operators are authorized to define additional separate subzones under certain conditions.³⁶ In practice, PJM has always maintained only the MAD Subzone but for any market solution several distinct constraining paths are analyzed and the most limiting one becomes the definition for that solution.

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



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, Belmont-Stonewall, Bedington-Black Oak, Cloverdale-Lexington, and Mt. Storm-Valley constraints.

The NERC standard requires a control area to carry primary reserve MW equal to or greater than the most severe single contingency (MSSC).³⁷ PJM requires primary reserves in the amount of 150 percent of the largest single contingency with at least 100 percent of the requirement made up of synchronized reserves.³⁸ In the first nine months of 2020, the average synchronized reserve requirement was 1,683.8 MW in the MAD Subzone and 1,699.0 MW in the RTO Zone. The synchronized reserve requirement is calculated for every real-time market dispatch solution.

³⁵ 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. 109 (Oct. 15, 2020).

³⁶ PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 109 (Oct. 15, 2020), p. 86.

³⁷ 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>>.

³⁸ "PJM Manual 13: Emergency Operations," Rev 76 (March 26, 2020), p. 18.

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 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 1,052.4 MW of tier 1 was identified by the RT SCED market solution as available in the first nine months of 2020 (Table 10-6).³⁹ 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 16.0 percent of real-time pricing intervals in the first nine months of 2020. In the RTO Zone, an average of 2,220.0 MW of tier 1 was available (Table 10-7) fully satisfying the synchronized reserve requirement in 62.5 percent of real-time pricing 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. 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.⁴⁰

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the first nine months of 2020, in the RTO Zone, there were

32,025.3 MW of tier 2 synchronized reserve offered daily. Of this, 4,996.2 MW were located in the MAD Subzone and available to meet the average MAD tier 2 hourly demand of 162.6 MW (Table 10-6).

In the first nine months of 2020, in the MAD Subzone, there was an average of 1,334.3 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 1,698.1 MW supply was available to meet the average pricing interval demand of 330.7 MW (Table 10-7).

Table 10-6 provides the average hourly reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone from January 2019 through September 2020.

Table 10-6 Average reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2019 through September 2020

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2019	Jan	1,270.6	173.7	1,405.5	2,849.8
2019	Feb	999.8	239.7	1,557.6	2,797.1
2019	Mar	935.3	276.1	1,602.7	2,814.1
2019	Apr	666.0	283.6	1,593.0	2,542.6
2019	May	878.8	196.2	1,426.4	2,501.5
2019	Jun	1,159.6	205.5	1,449.8	2,815.0
2019	Jul	1,146.5	212.6	1,342.4	2,701.5
2019	Aug	1,178.5	228.4	1,466.2	2,873.1
2019	Sep	809.5	318.0	1,491.4	2,619.0
2019	Oct	713.0	402.9	1,462.9	2,578.9
2019	Nov	985.8	290.9	1,684.3	2,961.0
2019	Dec	1,256.8	224.9	1,611.6	3,093.3
2019	Average	1,000.0	254.4	1,507.8	2,762.2
2020	Jan	1,273.4	228.9	1,588.3	3,090.6
2020	Feb	1,028.9	136.5	1,435.4	2,600.8
2020	Mar	972.1	185.2	1,373.4	2,530.7
2020	Apr	1,148.8	176.6	1,260.9	2,586.3
2020	May	911.4	159.2	1,264.9	2,335.5
2020	Jun	1,274.8	137.7	1,134.2	2,546.7
2020	Jul	991.9	209.3	1,318.2	2,519.4
2020	Aug	879.1	149.7	1,283.5	2,312.3
2020	Sep	1,017.7	80.1	1,350.3	2,448.1
2020	Average	1,055.4	162.6	1,334.3	2,552.3

³⁹ 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.

⁴⁰ See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2 PJM Synchronized Reserve Market Business Rules, Rev. 109 (Oct. 15, 2020).

Table 10-7 shows the average hourly reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the RTO Zone in January 2019 through September 2020.

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2019 through September 2020

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2019	Jan	2,524.1	331.6	1,542.2	4,397.9
2019	Feb	2,056.7	567.0	1,818.6	4,442.2
2019	Mar	1,947.7	596.4	1,848.0	4,392.1
2019	Apr	1,592.9	647.5	1,878.5	4,119.0
2019	May	2,003.0	494.0	1,657.0	4,153.9
2019	Jun	2,522.4	331.7	1,862.6	4,716.7
2019	Jul	2,590.3	369.4	1,652.5	4,612.2
2019	Aug	2,473.5	442.4	1,871.8	4,787.8
2019	Sep	1,887.1	667.5	1,820.3	4,374.9
2019	Oct	1,530.8	773.4	1,743.0	4,047.2
2019	Nov	1,921.4	546.4	2,133.0	4,600.7
2019	Dec	2,429.2	408.6	2,144.3	4,982.1
2019	Average	2,123.3	514.7	1,831.0	4,468.9
2020	Jan	2,410.7	390.6	1,950.9	4,752.2
2020	Feb	2,285.5	226.2	1,766.0	4,277.7
2020	Mar	2,142.0	386.7	1,758.5	4,287.2
2020	Apr	2,223.8	321.5	1,682.6	4,227.9
2020	May	2,130.4	255.5	1,651.8	4,037.8
2020	Jun	2,723.9	280.6	1,460.9	4,465.5
2020	Jul	2,102.5	401.1	1,575.6	4,079.2
2020	Aug	1,961.6	402.0	1,703.1	4,066.8
2020	Sep	2,054.2	288.8	1,733.1	4,076.1
2020	Average	2,226.1	328.1	1,698.1	4,252.3

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).

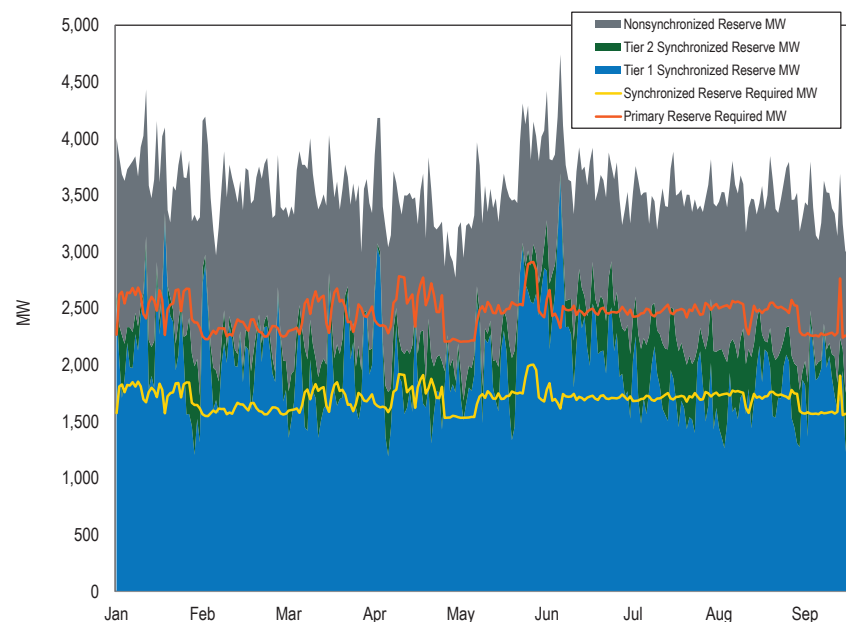
All market solutions determine the actual primary reserves required each hour as 150 percent of the largest contingency plus 190 MW. Of this, synchronized reserves must be 100 percent of the largest contingency plus 190 MW.

Ten to 14 minutes before each five minute target dispatch time, RT SCED runs. If the tier 1 synchronized reserve plus ASO committed inflexible tier 2 synchronized reserve does not meet the requirement, RT SCED will commit available flexible tier 2 synchronized reserve. If there is an excess of synchronized reserve, the RT SCED may decommit previously committed flexible synchronized reserve. On an hourly basis, 51.4 percent of all tier 2 synchronized reserve during hours when a tier 2 synchronized reserve market was cleared were flexible during the first nine months of 2020.

The ASO satisfied the primary reserve requirement for the RTO Zone in the first nine months of 2020. The RT SCED satisfied the primary reserve requirement in all solutions used for five minute pricing in the first nine months of 2020. One RT SCED case failed to satisfy the tier 2 synchronized reserve in the RTO Zone on April 30. That RT SCED case was used to price two consecutive five minute pricing intervals. The market solutions must first satisfy the synchronized reserve requirement which is calculated each time the market solver runs. The market solution first estimates how much tier 1 synchronized reserve is available. If there is enough tier 1 MW available to satisfy the synchronized reserve requirement, then the RT SCED economically assigns available synchronized reserve and nonsynchronized reserve to meet the remaining primary reserve requirement. If there is not enough tier 1 synchronized reserve then the remaining synchronized reserve requirement is filled with tier 2 synchronized reserve. After synchronized reserve is assigned, the primary reserve requirement is filled by economically assigning synchronized reserve and nonsynchronized reserve. 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.

The solution method is the same for the RTO Reserve Zone.⁴¹ Figure 10-2 shows how the market solutions satisfy the primary reserve requirement for the RTO Zone.

Figure 10-2 RTO reserve zone primary reserve MW by source (Daily Averages): January through September, 2020



In the first nine months of 2020, tier 1 and tier 2 were both essential to satisfying the synchronized reserve requirement. Tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirement in both the RTO Zone and the MAD Subzone.

⁴¹ 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.

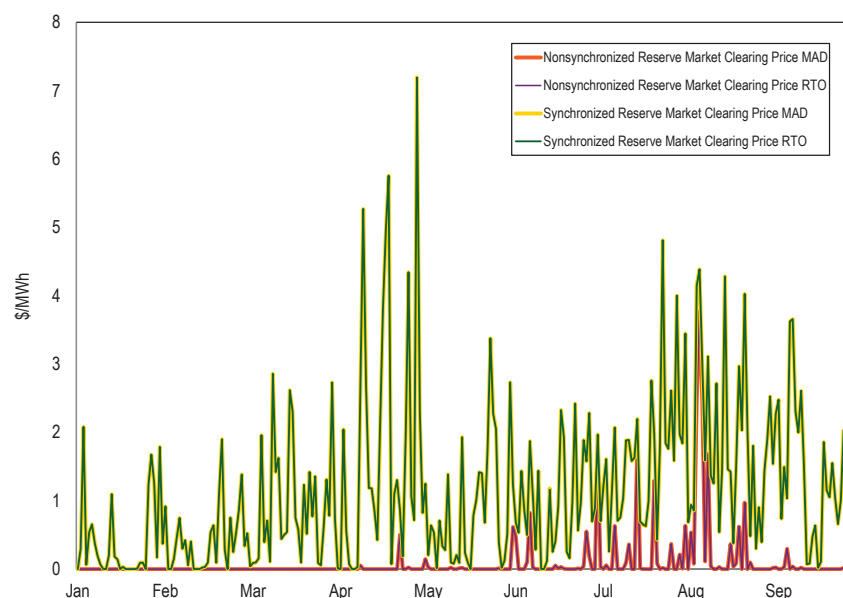
Price and Cost

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 nonsynchronized reserves. Offer prices for synchronized reserve are capped at \$7.50 plus costs plus opportunity costs.

Figure 10-3 shows daily weighted average synchronized and nonsynchronized market clearing prices in the first nine months of 2020. The MAD SRMCP and RTO SRMCP price diverged in only three five minute intervals in the first nine months of 2020. Nonsynchronized reserve prices averaged \$0.09 per MW over all intervals in the first nine months of 2020.

Figure 10-3 Daily average market clearing prices (\$/MWh) for synchronized reserve and nonsynchronized reserve: January through September, 2020



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, including uplift credits, 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.

The ratio of price to cost for all primary reserve during the first nine months of 2020 was 35.7 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 clear at a nonzero price.

Table 10-8 Primary reserve requirement components, RTO Reserve Zone: January through September, 2020

Product	MW Share of Credited Primary Reserve Requirement	MW	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve
Tier 1 Synchronized Reserve Response	NA	2,952	\$147,598	NA	\$50.00
Tier 1 Synchronized Reserve in Market Solution	1.1%	96,397	\$986,042	\$7.92	\$10.23
Tier 2 Synchronized Reserve Scheduled	19.0%	1,599,414	\$14,015,413	\$3.58	\$8.76
Non Synchronized Reserve Scheduled	79.8%	6,727,996	\$4,910,953	\$0.10	\$0.73
Primary Reserve (total of above)	100.0%	8,426,759	\$20,060,006	\$0.85	\$2.38

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.⁴² 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.

⁴² See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 109 (Oct. 15, 2020).

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 eligible 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.⁴³ DGP should be documented in PJM's market rules. DGP violates the basic PJM principle that generation owners are solely responsible for their own offers. In addition, DGP is a crude estimate of ramp rates and does not account for the actual discontinuities along unit offer curves.

The supply of tier 1 synchronized reserve available to the market solution is adjusted by eliminating from the DGP estimate 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.⁴⁴ 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 by default from the tier 1 estimate that wish to be included.⁴⁵ This limitation by unit type necessarily restricts the fuel type supplying tier 1 synchronized

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

⁴⁴ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 109 (Oct. 15, 2020)

⁴⁵ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 109 (Oct. 15, 2020)

reserve. PJM also excludes units, regardless of type, that it deems unreliable as tier 1, though it allows those resources to provide tier 2 synchronized reserve.

Table 10-9 provides tier 1 synchronized reserve supplied by unit and fuel type in the first nine months of 2020.

Table 10-9 Supply of tier 1 synchronized reserve by unit and fuel type: January through September, 2020

Unit / Fuel Type	Percent by MW	Percent by Credits
Steam – Coal	52.7%	48.3%
Combined Cycle	29.8%	30.4%
Hydro – Run of River	6.2%	7.5%
CT – Natural Gas	5.3%	5.9%
Steam – Natural Gas	3.0%	3.3%
Wind	1.4%	1.9%
Solar	0.6%	0.8%
Hydro – Pumped Storage	0.4%	0.5%
Steam – Other	0.3%	0.5%
RICE – Natural Gas	0.3%	0.3%
DSR	0.0%	0.2%

In the first nine months of 2020, the market solutions estimated that tier 1 MW from an average of 59 units could contribute ramp in a spinning event. In the RTO Reserve Zone, the average estimated tier 1 synchronized reserve was 2,226.1 MW (Table 10-10). In 62.5 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.

In the first nine months of 2020, the average estimated tier 1 synchronized reserve available was 1,055.4 MW in the MAD Subzone (Table 10-10). In 16.0 percent of 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 and no tier 2 market needed to be cleared.

Table 10-10 Monthly average interval market solutions for tier 1 synchronized reserve (MW): January 2019 through September 2020

Year	Month	Average Tier 1 Local to MAD	Average Tier 1 Used in MAD Solution	Average RTO Tier 1 MW
2019	Jan	1,270.6	1,526.0	2,524.1
2019	Feb	999.8	1,558.2	2,056.7
2019	Mar	935.3	1,464.5	1,947.7
2019	Apr	667.0	1,301.1	1,592.9
2019	May	878.8	1,361.0	2,003.0
2019	Jun	1,159.6	1,491.4	2,522.4
2019	Jul	1,146.5	1,505.0	2,590.3
2019	Aug	1,178.5	1,508.8	2,473.5
2019	Sep	809.5	1,430.2	1,887.1
2019	Oct	713.0	1,218.4	1,530.8
2019	Nov	985.8	1,442.2	1,921.4
2019	Dec	1,256.8	1,536.2	2,429.2
2019	Average	1,000.1	1,445.2	2,123.3
2020	Jan	1,273.4	1,533.7	2,410.7
2020	Feb	1,028.9	1,467.9	2,285.5
2020	Mar	972.1	1,504.7	2,142.0
2020	Apr	1,148.8	1,441.1	2,223.8
2020	May	911.4	1,489.1	2,130.4
2020	Jun	1,274.8	1,607.5	2,723.9
2020	Jul	991.9	1,498.8	2,102.5
2020	Aug	879.1	1,575.7	1,961.6
2020	Sep	1,017.7	1,559.0	2,054.2
2020	Average	1,055.4	1,519.7	2,226.1

Demand

There is no required amount of tier 1 synchronized reserve. The estimated tier 1 MW are used to satisfy the total required amounts of synchronized and primary 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.

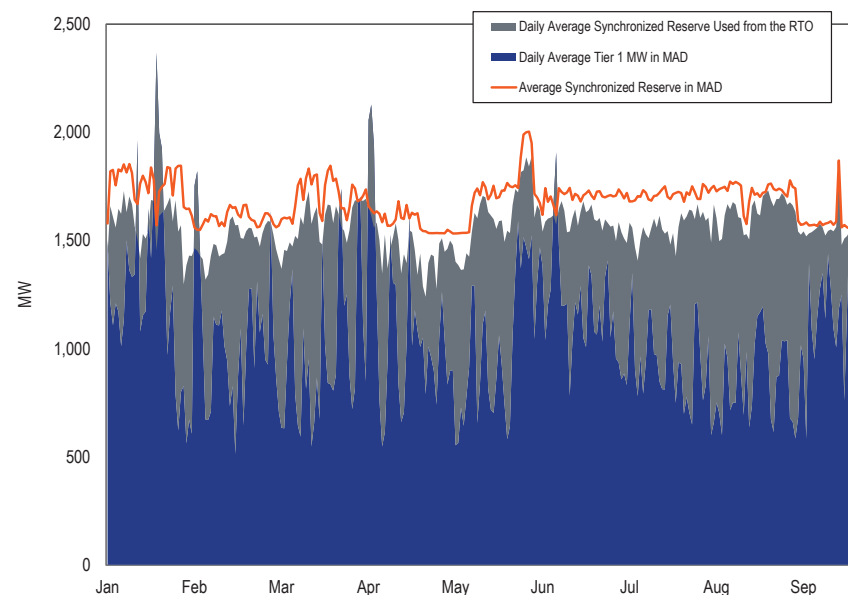
Supply and Demand

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 estimates the amount of tier 1 available from the energy dispatch. If the requirement is not filled by tier 1, it then commits tier 2 beginning with all self scheduled synchronized reserve..

In the MAD Subzone, the market solution takes all tier 1 MW estimated to be available within the MAD Subzone (blue area of Figure 10-4) as well as the synchronized reserve MW estimated to be available within the MAD Subzone from the RTO Zone (gray area of Figure 10-2). 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 (green area in Figure 10-2).

Figure 10–4 Daily average tier 1 synchronized reserve supply (MW) in the MAD Subzone: January through September, 2020



Tier 1 Synchronized Reserve Payments

Tier 1 synchronized reserve is awarded credits under two distinct circumstances. In response to a spinning event, all resources (except scheduled tier 2 resources) are paid for increasing output (or reducing load for demand response) at the rate of \$50 per MWh in addition to LMP.⁴⁶ This is the Synchronized Energy Premium Price. Spinning event response is calculated as the highest output between 9 minutes and 11 minutes after the event is declared minus the lowest output between one minute before and one minute after the event is declared. Generator outputs are measured and reported to PJM every four seconds via SCADA. Total response credited to a resource is capped at 110 percent of estimated capability. These rules apply to all resources that are not scheduled tier 2 resources. As a result spinning event response involves more MW response than the original DGP estimate of tier 1. Many resources

⁴⁶ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 109 (Oct. 15, 2020).

that are not included in PJM's estimate of tier 1 based on DGP nevertheless respond to spinning events and in accordance with the PJM Tariff are paid the Synchronized Energy Premium Price. This can include incidental response from nuclear units or steam turbines running at maximum output. Such response is expected when the response is measured as the highest output for the two minute period around the end of an event minus lowest output from the two minute period around the start of an event. Tier 1 synchronized reserve that is part of the DGP estimation (at market solution time) when there is no spinning event is also credited for its full DGP estimated MW whenever the nonsynchronized reserve market clearing price is above \$0.

In the event that the nonsynchronized reserve market clearing price is above \$0 and there is a spinning event, DGP estimated tier 1 is credited with the lesser of its actual response or its DGP estimated capability times the SRMCP. Tier 1 synchronized reserve not part of the DGP estimate is credited the SRMCP times its actual response.⁴⁷ In the first nine months of 2020, the nonsynchronized reserve market clearing price was above \$0 in 692 intervals.

In the first nine months of 2020, tier 1 synchronized reserve spinning event response credits of \$147,598 were paid for 13 spinning events covering 34 five minute intervals. The average tier 1 response over the 13 spinning events was 227.1 MWh (Table 10-11).

Table 10–11 Tier 1 synchronized reserve event response costs: January through September, 2020

Year	Month	Number of Spinning Events	Total Tier 1 Spinning Event Credits	Total Tier 1 Spinning Event MWh
2020	Jan	2	\$22,662	453.2
2020	Feb	4	\$57,412	1,148.2
2020	Mar	1	\$3,514	70.3
2020	Apr	1	\$5,910	118.2
2020	May	1	\$11,302	226.0
2020	Jun	0	NA	NA
2020	Jul	3	\$34,988	699.8
2020	Aug	0	NA	NA
2020	Sep	1	\$11,809	236.2

⁴⁷ See PJM "Manual 28: Operating Agreement Accounting," Rev. 83 (Dec. 3, 2019) p. 54.

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 10-13). 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 10-12). In the first nine months of 2020, the nonsynchronized reserve market clearing price was above \$0.00 in 692 intervals. For those intervals, tier 1 synchronized reserve was paid \$986,042 for an average of 138.8 MWh per interval.

Table 10-12 Price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: January through September, 2020

Year	Month	Number of Intervals When NSRMCP>\$0	Weighted Average SRMCP When NSRMCP>\$0	Total Tier 1 MWh When NSRMCP>\$0	Total Tier 1 Credits When NSRMCP>\$0	Average Tier 1 MWh When NSRMCP>\$0
2020	Jan	0	NA	NA	NA	NA
2020	Feb	0	NA	NA	NA	NA
2020	Mar	0	NA	NA	NA	NA
2020	Apr	27	\$6.12	3,654.9	\$22,372	135.4
2020	May	24	\$6.20	3,105.4	\$19,262	129.4
2020	Jun	116	\$7.58	17,163.0	\$130,140	148.0
2020	Jul	166	\$11.18	22,696.6	\$253,682	136.7
2020	Aug	309	\$12.52	42,499.8	\$531,928	137.5
2020	Sep	50	\$3.94	7,277.5	\$28,658	145.6
2020		692	\$7.92	96,397.2	\$986,042	138.8

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 the first nine months of 2020, there were three spinning events of 10 minutes or longer. In those events, 52.4 percent of the DGP estimated tier 1 responded and 82.9 percent of tier 2 responded.

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.⁴⁸ 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 synchronized energy premium price.

PJM's current tier 1 compensation rules are presented in Table 10-13.

Table 10-13 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 10-14.

Table 10-14 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

⁴⁸ 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.

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 a 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. Some tier 2 resources are scheduled by the ASO 60 minutes before the operating hour and are committed to provide synchronized reserve for the entire hour. Tier 2 resources 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 condensing mode, resources with an economic minimum (EcoMin) equal to economic maximum (EcoMax), offline CTs and hydro that can operate in the condense mode, and demand resources. Inflexible tier 2 synchronized reserve resources are committed for a full hour by the hour ahead ASO market solution. Inflexible resources require a 30 minute notification time and cannot be released for energy during the operating hour. The inflexible commitments made by the hour ahead ASO solution may satisfy only part of the tier 2 requirement. The actual requirement is determined by the RT SCED solution and the requirement not satisfied by inflexible units is satisfied by flexible units. Flexible resources are already online for energy, require no notification time, and can be automatically dispatched.

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 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.⁴⁹

In the first nine months of 2020, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 4,996.2 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 30,240.2 MW of tier 2 synchronized reserve offers (Figure 10-7).

The supply of tier 2 synchronized reserve offered in the first nine months of 2020 was sufficient to cover the ASO hourly requirement net of tier 1 in both the RTO Reserve Zone and the MAD Reserve Subzone.

The largest portion of cleared tier 2 synchronized reserve in the first nine months of 2020 was from CTs running on natural gas or oil (Table 10-15). Although demand resources are limited to providing no more than 33 percent of the total synchronized reserve requirement, the amount of tier 2

⁴⁹ See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 109 (Oct. 15, 2020).

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 some hours demand resources make up considerably more than 33 percent of the cleared Tier 2 MW. Demand resources often offer at a price of \$0, do not incur an LOC, and clear even when the price is \$0. For that reason, their percentage of credits in the synchronized reserve market is much less than their percentage of cleared MW.

Table 10-15 Supply of Generation Tier 2 Synchronized Reserve by Unit Type and Fuel Type: January through September, 2020

Unit / Fuel Type	Percent by MW	Percent by Credits
CT - Natural Gas	36.6%	41.9%
DSR	27.0%	9.3%
CT - Oil	14.8%	23.3%
Combined Cycle	11.1%	18.0%
Hydro - Run of River	5.9%	2.9%
Steam - Coal	3.2%	3.4%
Hydro - Pumped Storage	0.8%	0.6%
RICE - Natural Gas	0.3%	0.3%
Steam - Natural Gas	0.2%	0.3%

Demand

On July 12, 2017, PJM adopted a dynamic synchronized reserve requirement set equal to 100 percent of the most severe single contingency (MSSC), determined by RT SCED. There are two circumstances in which PJM may alter the synchronized reserve requirement from its 100 percent of the largest contingency value. Reserve requirements may be increased during a temporary switching condition when transmission outages or configuration problems cause several generation resources to be subject to a single contingency. 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.⁵⁰

In the first nine months of 2020, the average synchronized reserve requirement was 1,699.0 MW in the RTO Zone and 1,683.8 MW in the MAD Subzone. These averages include temporary increases to the synchronized reserve requirement.

The RTO Reserve Zone scheduled and identified an average of 329.9 MW of tier 2 synchronized reserves in the first nine months of 2020. Of this, an average of 45.0 MW was scheduled hourly.

Figure 10-5 and Figure 10-6 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self scheduled) from January 2018 through September 2020, for the RTO Reserve Zone and MAD Reserve Subzone. There were 33 intervals of shortage in 2019. There were 13 spinning events in 2019 but only two lasted longer than 10 minutes. There were two intervals of shortage in the first nine months of 2020.

⁵⁰ PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 109 (Oct. 15, 2020).

Figure 10-5 MAD hourly average tier 2 synchronized reserve scheduled MW: January 2018 through September 2020

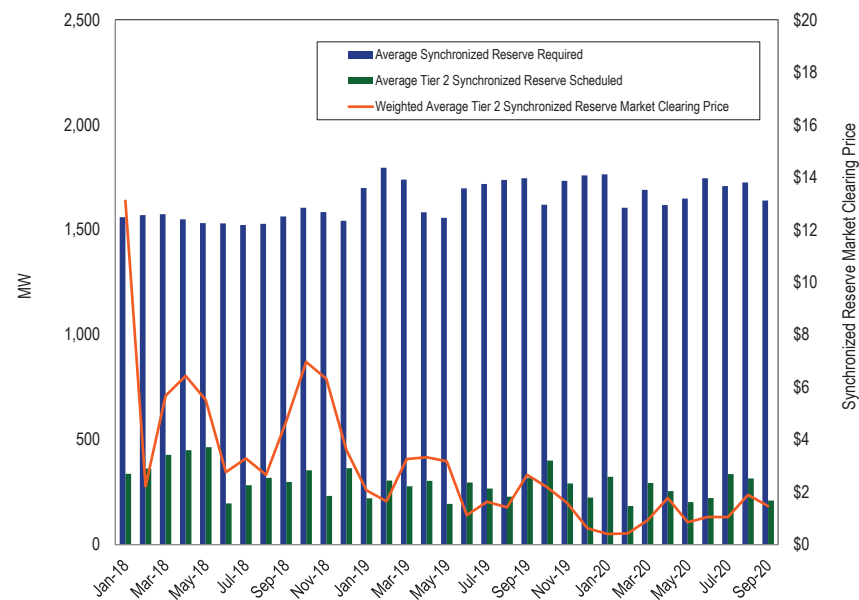
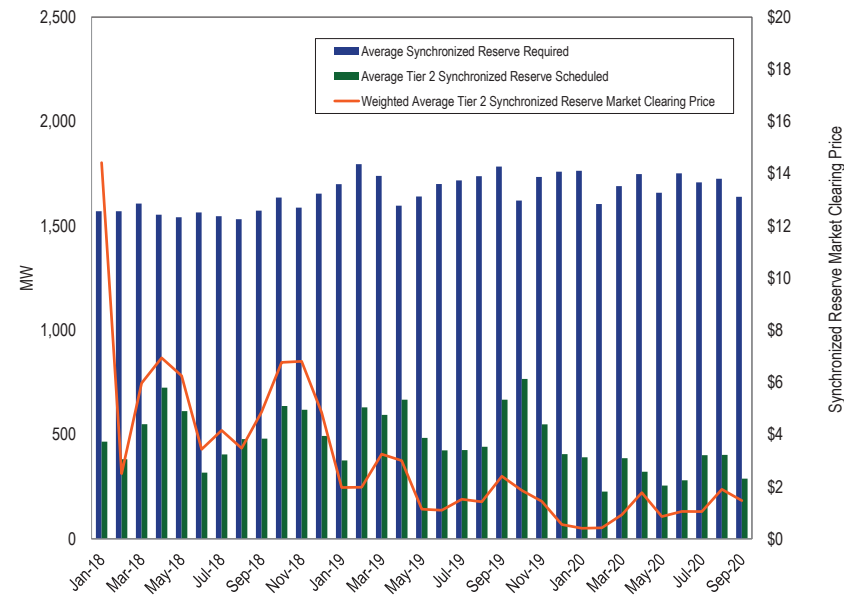


Figure 10-6 RTO hourly average tier 2 synchronized reserve scheduled MW: January 2018 through September 2020



Market Concentration

The average HHI for tier 2 synchronized reserve cleared intervals in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in the first nine months of 2020 was 5953, which is defined as highly concentrated. In 81.5 percent of all cleared pricing intervals the maximum market share was greater than or equal to 40 percent.

The average HHI for tier 2 synchronized reserve for cleared pricing intervals of the RTO Zone Tier 2 Synchronized Reserve Market in the first nine months of 2020 was 6043, which is defined as highly concentrated. In 94.3 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 13.3 percent of all tier 2 synchronized reserve in the first nine months of 2020 and averaged 18.8 percent of each RTSCED interval. In the RTO Zone, flexible synchronized reserve was 17.1 percent of all tier 2 synchronized reserve in the first nine months of 2020 and averaged 18.5 percent of each RTSCED interval.

In the first nine months of 2020, 14.0 percent of intervals would have failed a three pivotal supplier test in the RTSCED five minute market solution (Table 10-16).

Table 10-16 Three pivotal supplier test results for Tier 2 five minute market solution: January through September, 2020

Year	Month	RTO Zone Pivotal Supplier Intervals
2020	Jan	49.1%
2020	Feb	20.0%
2020	Mar	30.8%
2020	Apr	25.0%
2020	May	22.0%
2020	Jun	8.6%
2020	Jul	5.1%
2020	Aug	3.6%
2020	Sep	5.0%
2020	Average	14.0%

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.⁵¹ 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 zero 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.⁵²

Figure 10-7 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone.

PJM 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.⁵³ The tier 2 synchronized reserve market is not cleared based on daily offers but based on hourly updates to the daily offers. As a result of hourly updates the actual amount of eligible tier 2 MW can change significantly every hour (Figure 10-7). 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,

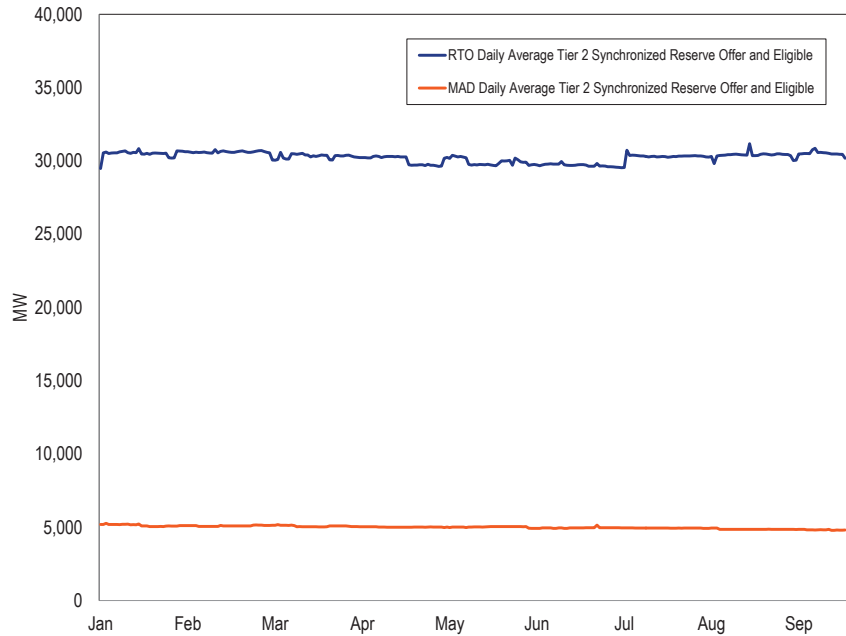
⁵¹ See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 109 (Oct. 15, 2020).

⁵² See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 109 (Oct. 15, 2020).

⁵³ 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...").

resource operators can make their units unavailable for an hour or block of hours without having to provide a reason.

Figure 10-7 Tier 2 synchronized reserve hourly offer and eligible volume (MW): January through September, 2020



For the first nine months of 2020, 94.5 percent of generation resources expected to offer have daily tier 2 synchronized reserve offers. However, there were a large number of hours when many units made 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 to 0 MW.⁵⁴

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. The tier 2 synchronized reserve market price is determined not only by the offer price of each cleared MW of tier 2, but additionally by the net cost of jointly optimizing the dispatch of energy and synchronized reserve. For each MW assigned, the clearing engines determine a product substitution price, i.e. the marginal cost of replacing the reserve MW with energy from other resources. The product substitution cost is a function of the LMPs of the MW of reserve, the marginal cost of energy for the resources providing reserves, and the minimized cost of substituted MW providing energy. At the margin, the price is the sum of the offer price plus the product substitution cost of the marginal unit(s).⁵⁵ In the first nine months of 2020 there were 31,724 marginal units (approximately five per cleared interval) where the price was greater than \$0 per MWh. The number of marginal units by schedule type is shown in Table 10-17.

Table 10-17 Schedule used for LOC of Marginal Units in Tier 2 Synchronized Reserve Market LOC Calculation, January through September, 2020

Number of Marginal Units	Percent of Marginal Units with LOC Based on Cost Schedule	Percent of Marginal Units with LOC Based on Price Schedule
32,019	5.8%	94.2%

For the first nine months of 2020, the RTO cleared a tier 2 synchronized reserve market in 37.5 percent of hours. In all other hours there was enough tier 1 synchronized reserve to cover the synchronized reserve requirement. For hours when the synchronized reserve requirement could not be met with tier

54 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.
55 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 109 (Oct. 15, 2020), p. 92.

1, the market cleared an average of 537.6 MW of synchronized reserve and 140.7 MW of demand response at a MW weighted average or \$3.02 per hour.

The market clearing price for the MAD Subzone diverged from the RTO Zone in only three intervals during the first nine months of 2020.

Supply, performance, and demand are reflected in the price of synchronized reserve (Table 10-18).

Table 10-18 RTO Zone, average SRMCP and average scheduled, tier 1 estimated and demand response MW in five minute market solutions: January 2019 through September 2020

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Interval Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Interval Tier 1 Synchronized Reserve Estimated (MW)	Average Interval Demand Response Cleared (MW)
2019	Jan	\$2.26	258.2	2,524.1	73.3
2019	Feb	\$1.96	448.5	2,056.7	118.2
2019	Mar	\$3.48	458.8	1,947.7	136.5
2019	Apr	\$3.10	488.1	1,592.9	157.8
2019	May	\$2.61	359.6	2,003.0	134.1
2019	Jun	\$2.55	277.1	2,522.4	54.0
2019	Jul	\$4.30	299.3	2,590.3	68.7
2019	Aug	\$3.34	359.4	2,473.5	82.5
2019	Sep	\$5.07	532.0	1,887.1	133.3
2019	Oct	\$3.05	620.5	1,530.8	148.8
2019	Nov	\$3.10	428.2	1,921.4	117.7
2019	Dec	\$1.32	337.4	2,429.2	71.0
2019	Average	\$3.01	405.6	2,177.5	108.0
2020	Jan	\$0.41	322.4	2,410.7	67.2
2020	Feb	\$0.42	183.7	2,285.5	42.6
2020	Mar	\$0.93	293.8	2,142.0	92.8
2020	Apr	\$1.77	255.0	2,223.8	66.5
2020	May	\$0.85	202.5	2,130.4	52.6
2020	Jun	\$1.05	221.9	2,723.9	58.6
2020	Jul	\$1.05	335.4	2,102.5	65.3
2020	Aug	\$1.90	314.7	1,961.6	86.5
2020	Sep	\$1.47	209.6	2,054.2	79.2
2020	Average	\$1.09	259.9	2,226.1	67.9

Settlement Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices do not always cover the full cost to customers, including the final LOC for each resource. Because price formation occurs within the hour (on a five minute basis) but inflexible synchronized reserve commitment occurs prior to the hour, the realized, within hour price can be zero even when some tier 2 synchronized reserve is cleared. All resources cleared in the 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 100 percent, the more the market price reflects the full cost of tier 2 synchronized reserve. The price to cost ratio shows much tier 2 compensation results from price rather than uplift. A lower price to cost ratio indicates higher uplift.

In the first nine months of 2020, the price to cost (including self scheduled) ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 43.0 percent, which was higher than the 39.9 percent price to cost ratio for the first nine months of 2019 (Table 10-19). The price to cost ratio of the MAD Subzone (Table 10-20) averaged 38.0 percent, which was lower than the 43.3 percent of the first nine months of 2019.

Table 10-19 RTO Zone tier 2 synchronized reserve MW, credits, price, and cost: January 2019 through September 2020

Zone	Year	Month	Tier 2 Credited MW	Tier 2 SRMCP Credits	LOC Credits	Weighted Average Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Cost	Price/Cost Ratio
RTO Zone	2019	Jan	198,030	\$447,932	\$1,021,911	\$2.26	\$7.42	30.5%
RTO Zone	2019	Feb	329,482	\$644,828	\$1,464,022	\$1.96	\$6.40	30.6%
RTO Zone	2019	Mar	384,207	\$1,338,602	\$2,131,555	\$3.48	\$9.03	38.6%
RTO Zone	2019	Apr	382,642	\$1,187,948	\$1,662,252	\$3.10	\$7.45	41.7%
RTO Zone	2019	May	294,931	\$768,953	\$902,854	\$2.61	\$5.67	46.0%
RTO Zone	2019	Jun	238,489	\$609,117	\$598,266	\$2.55	\$5.06	50.4%
RTO Zone	2019	Jul	255,474	\$1,098,202	\$2,423,239	\$4.30	\$13.78	31.2%
RTO Zone	2019	Aug	321,004	\$1,072,026	\$1,063,812	\$3.34	\$6.65	50.2%
RTO Zone	2019	Sep	430,647	\$2,195,569	\$2,309,443	\$5.07	\$10.46	48.5%
RTO Zone	2019	Oct	526,071	\$1,607,391	\$3,009,725	\$3.05	\$8.78	34.8%
RTO Zone	2019	Nov	343,170	\$1,063,969	\$981,674	\$3.10	\$5.96	52.0%
RTO Zone	2019	Dec	272,592	\$359,785	\$827,129	\$1.32	\$4.35	30.3%
RTO Zone	2019		3,976,739	\$12,394,321	\$18,395,884	\$3.01	\$7.59	39.7%
RTO Zone	2020	Jan	217,719	\$315,239	\$694,483	\$1.20	\$4.64	25.8%
RTO Zone	2020	Feb	117,139	\$185,358	\$253,545	\$1.30	\$3.75	34.8%
RTO Zone	2020	Mar	176,109	\$568,509	\$385,942	\$2.56	\$5.42	47.3%
RTO Zone	2020	Apr	147,829	\$1,081,508	\$335,184	\$6.42	\$9.58	67.0%
RTO Zone	2020	May	124,219	\$380,582	\$390,111	\$2.65	\$6.20	42.8%
RTO Zone	2020	Jun	164,722	\$660,183	\$582,410	\$3.58	\$7.54	47.4%
RTO Zone	2020	Jul	263,183	\$1,114,424	\$2,603,710	\$3.80	\$14.13	26.9%
RTO Zone	2020	Aug	246,204	\$1,474,766	\$1,479,595	\$5.19	\$12.00	43.3%
RTO Zone	2020	Sep	142,289	\$913,999	\$595,865	\$5.47	\$10.61	51.6%
RTO Zone	2020		1,599,414	\$6,694,568	\$7,320,845	\$3.58	\$8.21	43.0%

Table 10-20 MAD Subzone tier 2 synchronized reserve MW, credits, price, and cost: January 2019 through September 2020

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
MAD Subzone	2019	Jan	112,251	\$230,121	\$425,740	\$2.05	\$5.84	35.1%
MAD Subzone	2019	Feb	141,165	\$244,758	\$360,138	\$1.73	\$4.29	40.5%
MAD Subzone	2019	Mar	177,502	\$558,138	\$538,231	\$3.14	\$6.18	50.9%
MAD Subzone	2019	Apr	163,121	\$459,355	\$423,531	\$2.82	\$5.41	52.0%
MAD Subzone	2019	May	109,987	\$303,464	\$215,643	\$2.76	\$4.72	58.5%
MAD Subzone	2019	Jun	132,344	\$301,032	\$189,586	\$2.27	\$3.71	61.4%
MAD Subzone	2019	Jul	142,123	\$574,936	\$1,804,671	\$4.05	\$16.74	24.2%
MAD Subzone	2019	Aug	159,394	\$489,036	\$562,488	\$3.07	\$6.60	46.5%
MAD Subzone	2019	Sep	205,722	\$1,179,380	\$924,732	\$5.72	\$10.23	55.9%
MAD Subzone	2019	Oct	268,899	\$819,523	\$752,395	\$3.04	\$5.85	52.1%
MAD Subzone	2019	Nov	193,474	\$645,450	\$376,602	\$3.34	\$5.28	63.2%
MAD Subzone	2019	Dec	153,336	\$194,903	\$252,904	\$1.27	\$2.92	43.5%
MAD Subzone	2019		1,959,318	\$6,000,096		\$2.94	\$6.48	45.3%
MAD Subzone	2020	Jan	144,345	\$139,076	\$303,961	\$0.91	\$3.07	29.8%
MAD Subzone	2020	Feb	80,588	\$66,425	\$144,348	\$0.77	\$2.62	29.4%
MAD Subzone	2020	Mar	101,867	\$163,734	\$165,868	\$1.42	\$3.24	43.9%
MAD Subzone	2020	Apr	89,346	\$429,503	\$152,888	\$4.42	\$6.52	67.8%
MAD Subzone	2020	May	85,997	\$185,057	\$226,069	\$1.98	\$4.78	41.3%
MAD Subzone	2020	Jun	74,472	\$226,673	\$270,520	\$2.72	\$6.68	40.8%
MAD Subzone	2020	Jul	131,033	\$410,478	\$1,828,221	\$2.88	\$17.08	16.9%
MAD Subzone	2020	Aug	85,607	\$407,104	\$636,481	\$4.16	\$12.19	34.1%
MAD Subzone	2020	Sep	36,705	\$192,202	\$224,418	\$4.34	\$11.35	38.2%
MAD Subzone	2020		829,961	\$2,220,252	\$3,952,775	\$2.62	\$7.50	38.0%

Performance

Tier 1 resource owners are paid for the actual amount of synchronized reserve they provide in response to a synchronized reserve event.⁵⁶ Tier 2 resource owners are paid for being available but are not paid based on the actual response to a synchronized reserve event. 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 2011.⁵⁷ 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.⁵⁸ 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.

Participant performance has not been adequate. Compliance with calls to respond to actual synchronized reserve events remains significantly 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. In 2017, 87.6 percent of scheduled tier 2 synchronized reserve responded. In 2018, the response was 74.2 percent of scheduled tier 2 MW. There were only two spinning events that lasted longer than 10 minutes in 2019. The first spinning event occurred on September 23. During the September 23 event, tier 2 response was 87.4 percent of the amount scheduled and tier 1 response was 81.6 percent of DGP estimated amount. The second spinning event occurred on October 1, 2019.

During the October 1 event tier 2 response was 86.3 percent of DGP estimated amount and tier 1 response was 54.1 percent of DGP estimated amount. In the first nine months of 2020, there have been three spinning events 10 minutes or longer. In the first event, on February 18, 2020, tier 1 synchronized reserve responded at 65.7 percent of the DGP estimated amount. The tier 2 response was only 4.3 percent of the DGP estimated amount. Tier 2 response in the other two 10 minute events in 2020 was 87.1 percent of the DGP estimated amount. Actual participant performance means that the penalty structure is not adequate to incent performance.

⁵⁶ See *id.* at 98.

⁵⁷ See 2011 *State of the Market Report for PJM*, Vol. 2, Section 9, "Ancillary Services," at 250.

⁵⁸ See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements Rev. 109 (Oct. 15, 2020).

In the first nine months of 2020 there were 13 spinning events, including the three that lasted 10 minutes or longer.

The penalty structure when a tier 2 resource fails to respond fully to a spinning event involves two components. The resource forfeits all SRMCP credits and LOC credits in the amount of the MW shortage for the day on which the event occurred. The resource also receives a penalty for all hours in the Immediate Past Interval (IPI) in the amount of MW it falls short of its scheduled MW. The penalty is applied only to the SRMCP credits, not to the LOC credits. The penalty period is calculated as the lesser of the average number of days between spinning events over the past two years (ISI) or the number of days since the resource last failed to respond fully. For November 2019 through October 2020, PJM used the average number of days between spinning events from November 2017 through October 2019, which is 25 days. This is an increase from 20 days in 2019. The MMU has identified several problems with this penalty structure. Resource owners are permitted to aggregate the response of multiple units to offset an underresponse from one unit with an overresponse from a different unit to reduce an underresponse penalty.⁵⁹ The IPI of 25 days stops at the last spinning event when the resource did comply. But for all spin events less than 10 minutes compliance is automatically counted as 100 percent. This effectively shortens the IPI. The penalty applies only to the SRMCP credits not the LOC credits. But most credits awarded are for LOC (see Table 10-20).

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.

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 MMU continues to recommend that the IPI should be defined as the number of days between spinning events 10 minutes or longer. PJM has had three 10 minute or longer spinning events in 2020 (February 18, July 6, and July 25). If only events 10 minutes or longer were

considered, the IPI would increase to approximately 60 days. The penalty period for the February 18 event was terminated by the nine minute event on February 10. The penalty period for the July 25 event was terminated by the July 24 nine minute event. Use of the currently defined 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 because performance is only measured for events 10 minutes or longer. Even using the proposed MMU IPI the penalties may be insufficient to ensure response. A tier 2 shortfall penalty needs to include LOC payments as well as SRMCP and MW of shortfall.

Table 10-21 Comparison of tier 2 shortfall penalties under current IPI vs. MMU recommended IPI: January through September, 2020

Actual SRMCP Credits Using Current IPI	Actual Retroactive Penalty Charges Using Current IPI	Retroactive Penalty Using MMU Recommended IPI	Retroactive Penalty Using MMU Recommended IPI and LOC Forfeiture	Synchronized Reserve LOC Credits
\$149,144	\$24,146	\$38,330	\$61,224	\$241,310

Including aggregate responses from all online resources weakens the incentive to perform and creates an incentive to withhold reserves from other resources. Synchronized reserve commitment is unit specific, so the obligation to respond should also be 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.

Spinning event response data is shown in Table 10-22. The tier 1 Estimate is from the most recent five minute market solution. The tier 1 Estimate includes estimated ramp from the units that are DGP eligible. PJM dispatchers rely on this data to ensure they have sufficient reserves at all times. Actual tier 1 response is from real-time SCADA data. This actual tier 1 data is used to calculate settlement credits for tier 1 response from all units including

⁵⁹ See PJM "Manual 28: Operating Agreement Accounting," § 6.3 Charges for Synchronized Reserve, Rev. 83 (Dec. 3, 2019.)

those which are not part of the DGP estimate used by the five minute market solution.

Table 10-22 Synchronized reserve events 10 minutes or longer, tier 2 response compliance, RTO Reserve Zone: January 2018 through September 2020

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
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	1,635.4	464.6	372.5	92.1	153.8%	80.2%
Jun 30, 2018 09:46	11	2,710.1	3,993.8	71.6	56.8	14.8	147.4%	79.3%
Jul 10, 2018 15:45	12	784.3	2,219.5	494.6	308.8	185.8	283.0%	62.4%
Aug 12, 2018 11:06	11	1,824.5	2,915.0	274.5	229.8	44.7	159.8%	83.7%
Sep 30, 2018 11:29	11	1,430.9	2,355.8	231.2	216.9	14.3	164.6%	93.8%
Oct 30, 2018 06:40	11	239.7	816.0	607.7	431.5	176.2	340.4%	71.0%
2018 Average	11	1,421.4	2,063.6	322.4	239.1	83.3	145.2%	74.2%
Sep 23, 2019 12:07	11	1,485.1	1,212.1	723.2	632.1	91.1	81.6%	87.4%
Oct 1, 2019 14:56	11	265.4	143.7	1,177.4	1,016.4	161.0	54.1%	86.3%
2019 Average	11	924.7	664.1	723.2	632.1	91.1	71.8%	87.4%
Feb 18, 2020 20:15	10	2,216.1	1,434.8	40.0	1.7	38.3	64.7%	4.3%
Jul 6, 2020 21:22	10	1,464.0	526.1	479.7	415.1	64.6	35.9%	86.5%
Jul 25, 2020 16:39	11	868.4	421.6	302.3	264.8	37.5	48.5%	87.6%
2020 Average	10	1,516.2	794.2	274.0	227.2	46.8	49.7%	59.5%

Until April 2019, PJM's ASO market solution software allowed operators to bias the inflexible tier 2 synchronized reserve solution by forcing the software to assume a different tier 1 MW value than the actual estimate. PJM, in response to the MMU recommendation, no longer uses tier 1 biasing in any of its market solutions. Biasing means manually modifying (decreasing or increasing) the tier 1 synchronized reserve estimate of the market solution.

Tier 1 biasing was never referenced in PJM manuals or any public document. PJM could resume tier 1 biasing at its discretion. Although tier 1 biasing has been discontinued, PJM can and does still deselect tier 1 resources based on PJM judgment.

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.^{60 61} A disturbance is defined as loss of the lesser of 900 MW or 80 percent of the most severe single contingency within 60 seconds. In the absence of a disturbance, PJM operators have used synchronized reserve as a source of energy to provide relief from low ACE.

The risk of using synchronized reserves for energy or any other nondisturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for only up to 30 minutes. When the need is for reserve extending past 30 minutes, secondary reserve is the appropriate source of the response. 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 2010, through September 2020, PJM experienced 243 synchronized reserve events (Table 10-23), approximately 2.0 events per month. During this period, synchronized reserve events had an average duration of 11.9 minutes.

⁶⁰ 2013 State of the Market Report for PJM, Appendix F – PJM's DCS Performance, at 451–452.

⁶¹ See PJM "Manual 12: Balancing Operations," Rev. 40 (March 26, 2020) § 4.1.2 Loading Reserves.

Table 10-23 Synchronized reserve events: January 2017 through September 2020⁶²

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-08-2017 03:21	RTO	7	JAN-01-2018 02:41	RTO	7	JAN-22-2019 22:30	RTO	8	JAN-20-2020 14:06	MAD	8
JAN-09-2017 19:24	RTO	9	JAN-03-2018 03:00	RTO	13	JAN-31-2019 01:26	RTO	5	JAN-23-2020 16:17	RTO	9
JAN-10-2017 13:05	MAD	9	JAN-07-2018 14:15	RTO	9	JAN-31-2019 09:26	RTO	9	FEB-07-2020 12:06	RTO	6
JAN-15-2017 20:13	RTO	8	APR-12-2018 13:28	RTO	10	FEB-25-2019 00:25	RTO	9	FEB-08-2020 03:44	RTO	8
JAN-23-2017 09:08	RTO	7	JUN-04-2018 10:22	RTO	6	MAR-03-2019 12:31	RTO	9	FEB-10-2020 20:15	RTO	9
FEB-13-2017 18:30	RTO	7	JUN-29-2018 15:21	RTO	9	MAR-06-2019 22:06	RTO	9	FEB-18-2020 11:16	RTO	10
FEB-14-2017 00:11	RTO	6	JUN-30-2018 09:46	RTO	11	JUL-27-2019 23:31	RTO	7	MAR-08-2020 05:17	MAD	5
FEB-15-2017 06:37	RTO	6	JUL-04-2018 10:56	RTO	7	AUG-11-2019 12:14	RTO	8	APR-13-2020 20:01	RTO	8
MAR-23-2017 06:48	RTO	24	JUL-10-2018 15:45	RTO	13	SEP-03-2019 13:39	MAD	9	MAY-03-2020 12:29	RTO	6
APR-08-2017 11:53	RTO	10	JUL-23-2018 09:02	RTO	8	SEP-23-2019 16:06	RTO	11	JUL-06-2020 21:22	RTO	10
MAY-08-2017 04:18	RTO	10	JUL-23-2018 15:43	RTO	6	OCT-01-2019 18:56	RTO	11	JUL-24-2020 01:03	RTO	9
JUN-08-2017 03:39	RTO	10	JUL-24-2018 16:17	RTO	7	DEC-11-2019 21:08	RTO	8	JUL-25-2020 16:39	MAD	11
JUN-20-2017 05:38	RTO	9	AUG-12-2018 11:06	RTO	11	DEC-18-2019 15:07	RTO	9	SEP-10-2020 00:19	RTO	9
SEP-04-2017 20:18	MAD	15	SEP-13-2018 09:47	RTO	7						
SEP-07-2017 09:16	RTO	9	SEP-14-2018 13:24	RTO	7						
SEP-21-2017 14:15	RTO	16	SEP-26-2018 19:08	RTO	8						
			SEP-30-2018 11:29	RTO	11						
			OCT-30-2018 10:40	RTO	11						

⁶² For full history of spinning events, see the 2019 State of the Market Report for PJM, Appendix F - Ancillary Service Markets.

Figure 10-8 Synchronized reserve events duration distribution curve: January 2013 through September 2020

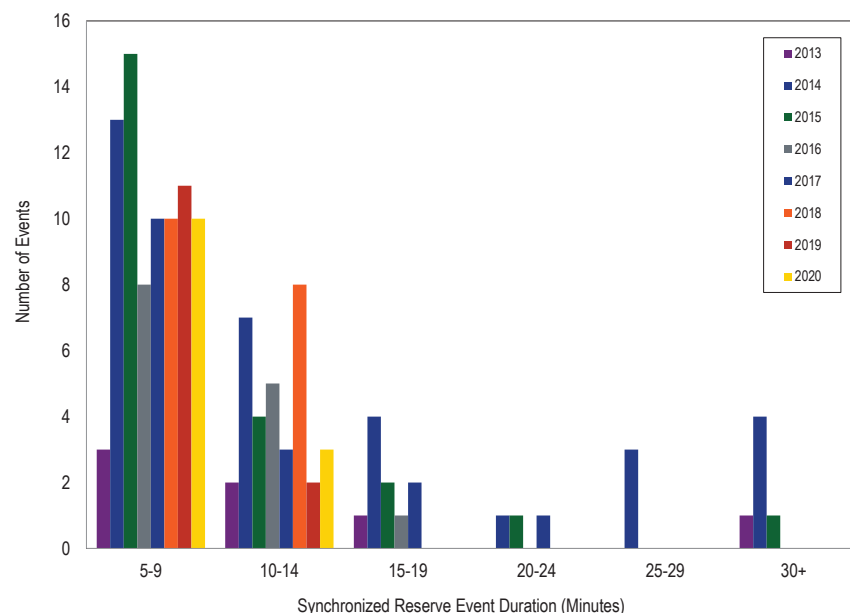


Figure 10-8 shows spin event durations over the past eight years.

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

Demand for primary reserve is established by PJM as one and a half times the largest contingency. Demand for primary reserve is calculated dynamically in every synchronized and nonsynchronized reserve market solution. After filling the synchronized reserve requirement the balance of primary reserve can be made up by the most economic combination of synchronized and nonsynchronized reserve. In practice this means that the primary reserve requirement minus the scheduled synchronized reserve is the nonsynchronized requirement for the interval. 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.⁶³

The average scheduled nonsynchronized reserve in the RTO Zone in the first nine months of 2020 was 1,696.2 MW. The average scheduled nonsynchronized reserve in the MAD Subzone for primary reserve was 1,333.4 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).

⁶³ See PJM "Manual 11: Energy and Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 109 (Oct. 15, 2020).

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

The market solution optimizes synchronized reserve, nonsynchronized reserve, and energy to satisfy the primary reserve requirement at the lowest estimated 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, combined cycles that can start in 10 minutes or less, and diesels.⁶⁴ In the first nine months of 2020, an average of 1,692.2 MW of nonsynchronized reserve was scheduled per hour out of 3,916.2 available MW as part of the primary reserve requirement in the RTO Zone.

In the first nine months of 2020, CTs provided 87.1 percent of scheduled nonsynchronized reserve (Table 10-24). Natural gas was the primary fuel for nonsynchronized reserve.

⁶⁴ See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4b.2 Non-Synchronized Reserve Market Business Rules, Rev. 109 (Oct. 15, 2020)

Table 10-24 Supply of nonsynchronized reserve by fuel and unit type: January through September, 2020

Unit / Fuel Type	Percent by MW	Percent by Credits
CT - Natural Gas	54.5%	68.4%
CT - Oil	32.6%	22.8%
Hydro - Run of River	12.8%	8.7%
Hydro - Pumped Storage	0.1%	0.0%
CT - Other	0.1%	0.0%

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in the first nine months of 2020.

Table 10-25 Nonsynchronized reserve market pivotal supplier test: January 2020 through September 2020

Year	Month	Number Intervals of Clearing	
		Price > \$0.01	RTO Pivotal Supplier Intervals
2020	Jan	0	NA
2020	Feb	0	NA
2020	Mar	0	NA
2020	Apr	21	100.0%
2020	May	17	100.0%
2020	Jun	105	98.1%
2020	Jul	153	100.0%
2020	Aug	286	100.0%
2020	Sep	44	100.0%
2020	Average	70	99.7%

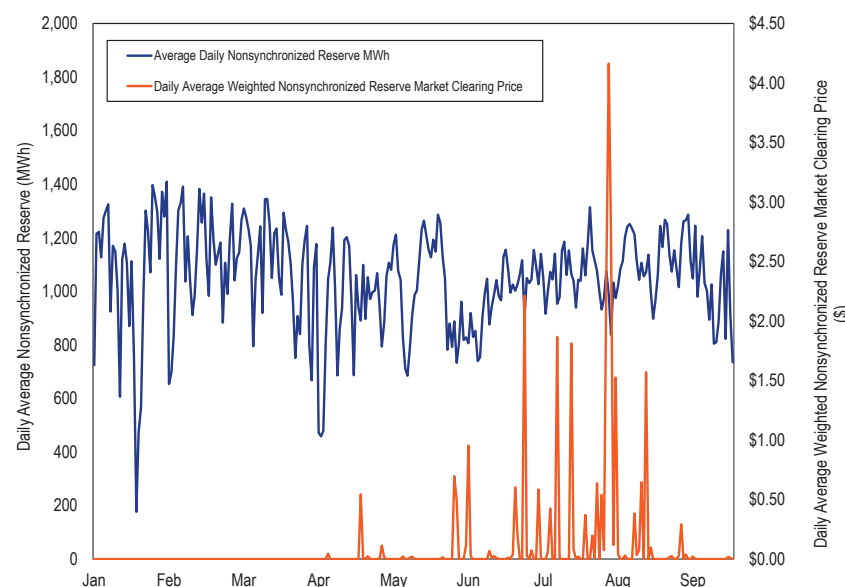
Price

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

Figure 10-9 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average scheduled MW for the RTO Zone. In the first nine months of 2020, the weighted average nonsynchronized market clearing price

was \$0.10 per MW. The hourly average nonsynchronized reserve scheduled was 1,047.3 MW.

Figure 10-9 Daily average RTO Zone nonsynchronized reserve market clearing price and MW purchased: January through September, 2020



Price and Cost

As a result of changing grid conditions, load forecasts, incorrect LMP and lost opportunity cost projections, and unexpected generator performance, prices frequently 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 is greater than the generator's incremental energy offer at economic minimum, then an LOC is paid, even if LMP revenue would not have covered the unit's start and no load costs.⁶⁵

⁶⁵ See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 2.16 Minimum Capacity Emergency in Day-ahead Market, Rev. 109 (Oct. 15, 2020).

The full cost to customers of nonsynchronized reserve, including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-26). The closer the price to cost ratio comes to one, the more compensation is provided through market prices rather than uplift.

In the first nine months of 2020, the average price of nonsynchronized reserve was \$0.10. The average cost per MW of nonsynchronized reserve was \$0.55.

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.

The nonsynchronized reserve market cleared at an average price of \$0.10 in the first nine months of 2020.

Table 10–26 RTO zone nonsynchronized reserve MW, charges, price, and cost: January 2019 through September 2020

Market	Year	Month	Total Nonsynchronized Reserve MW	Total Nonsynchronized Reserve Charges	Weighted Nonsynchronized Reserve Market Price	Nonsynchronized Reserve Cost	Price/Cost Ratio
RTO Zone	2019	Jan	691,682	\$808,141	\$0.16	\$1.29	12.0%
RTO Zone	2019	Feb	777,009	\$549,304	\$0.02	\$0.67	3.3%
RTO Zone	2019	Mar	865,531	\$1,209,490	\$0.22	\$1.35	16.2%
RTO Zone	2019	Apr	870,167	\$1,441,716	\$0.09	\$1.70	5.6%
RTO Zone	2019	May	779,072	\$624,877	\$0.29	\$0.94	31.0%
RTO Zone	2019	Jun	727,972	\$458,230	\$0.01	\$0.61	1.7%
RTO Zone	2019	Jul	707,373	\$870,865	\$0.34	\$1.52	22.2%
RTO Zone	2019	Aug	764,814	\$429,814	\$0.10	\$0.57	18.2%
RTO Zone	2019	Sep	819,107	\$1,841,551	\$0.54	\$2.39	22.6%
RTO Zone	2019	Oct	733,284	\$1,805,352	\$1.04	\$3.30	31.5%
RTO Zone	2019	Nov	865,763	\$1,324,640	\$0.06	\$1.71	3.5%
RTO Zone	2019	Dec	785,686	\$636,444	\$0.04	\$0.75	5.4%
RTO Zone	2019	Total	9,387,459	\$12,000,424	\$0.24	\$1.40	17.4%
RTO Zone	2020	Jan	775,929	\$377,336	\$0.00	\$0.49	NA
RTO Zone	2020	Feb	758,614	\$138,939	\$0.00	\$0.18	NA
RTO Zone	2020	Mar	806,059	\$170,156	\$0.00	\$0.21	NA
RTO Zone	2020	Apr	665,747	\$644,306	\$0.02	\$0.97	2.1%
RTO Zone	2020	May	774,183	\$425,791	\$0.01	\$0.55	1.1%
RTO Zone	2020	Jun	619,391	\$649,601	\$0.11	\$1.05	10.4%
RTO Zone	2020	Jul	767,222	\$648,118	\$0.24	\$0.84	28.4%
RTO Zone	2020	Aug	799,233	\$1,106,678	\$0.49	\$1.38	35.4%
RTO Zone	2020	Sep	761,617	\$750,028	\$0.02	\$0.98	2.0%
RTO Zone	2020	Total	6,727,996	\$4,910,953	\$0.10	\$0.57	17.1%

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 currently have a defined reserve product 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.⁶⁶

Market Structure

Supply

Both generation and demand resources are eligible to offer DASR. 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 January through September 2020, the average available hourly DASR was 44,991.3 MW, a 1.0 percent decrease from the same period in 2019. The DASR hourly MW purchased averaged 5,315.3 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.⁶⁷ The intent of this proposal is to limit cleared DASR resources to those resources actually capable of providing reserves in the real-time market.

⁶⁶ See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 10.5 Aggregation for Economic and Emergency Demand Resources, Rev. 109 (Oct. 15, 2020).

⁶⁷ See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 109 (Oct. 15, 2020).

Owners of excluded resources may request an exemption from their default noneligibility.

Of the scheduled DASR MW cleared in January through June 2020, 80.3 percent was from CTs (Table 10-27).

Table 10-27 Scheduled DASR by fuel and unit type: January through September, 2020

Unit Type	Percent of DASR MW	Percent of DASR Credits
CT - Natural Gas	61.3%	51.3%
CT - Oil	19.0%	18.0%
Hydro - Pumped Storage	10.3%	3.7%
Steam - Coal	5.8%	9.1%
Combined Cycle	2.9%	13.3%
Steam - Natural Gas	0.4%	3.1%
RICE - Oil	0.2%	0.7%
RICE - Other	0.1%	0.4%
RICE - Natural Gas	0.0%	0.3%

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 rates.⁶⁸ 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 November 1, 2019 through October 31, 2020, the day-ahead scheduling reserve requirement is 5.07 percent of the peak load forecast. This is based on a 2.15 percent load forecast error component and a 2.92 percent forced outage rate component. The DASR requirement is applicable for all hours of the operating day.

The DASR requirement can be increased by PJM operators under conditions of “hot weather or cold weather alert or max emergency generation alert or

other escalating emergency.”⁶⁹ The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.⁷⁰ 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 2019 through October 2020, the SCD values are 2.95 percent for winter and 3.19 percent for summer. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.⁷¹ 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.⁷² The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand on 19 days during 2019. The 32 hours with the highest DASR market clearing prices during 2019 were all on these days. In the first nine months of 2020, PJM invoked adjusted fixed demand on 18 days.

The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. The MMU further recommends that PJM attach a reason code to all hours when adjusted fixed demand is dispatched.

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

70 See PJM “Manual 11: Energy & Ancillary Services Market Operations,” § 11.2.1 Day-Ahead Scheduling Reserve Market Requirement, Rev. 109 (Oct. 15, 2020).

71 See PJM “Manual 11: Energy & Ancillary Services Market Operations,” § 11.2.1 Day-Ahead Scheduling Reserve Market Reserve Requirement, Rev. 109 (Oct. 15, 2020).

72 See PJM “Manual 13: Emergency Operations,” § 3.2 Conservative Operations, Rev. 76, (March 26, 2020).

68 See PJM “Manual 13: Emergency Operations,” § 2.2 Reserve Requirements, Rev. 76 (March 26, 2020).

Market Concentration

DASR market three pivotal supplier test results are provided in Table 10-28.

Table 10-28 DASR market three pivotal supplier test results and number of hours with DASRMCP above \$0.01: January 2019 through September 2020

Year	Month	Number of Hours When DASRMCP > \$0	Percent of Hours Pivotal
2019	Jan	32	1.5%
2019	Feb	22	1.4%
2019	Mar	24	0.0%
2019	Apr	15	0.0%
2019	May	43	0.0%
2019	Jun	72	0.0%
2019	Jul	237	0.0%
2019	Aug	173	0.0%
2019	Sep	182	0.0%
2019	Oct	218	0.0%
2019	Nov	89	0.0%
2019	Dec	18	0.0%
2019	Average	94	0.2%
2020	Jan	3	0.0%
2020	Feb	3	0.0%
2020	Mar	1	0.0%
2020	Apr	0	0.0%
2020	May	31	0.0%
2020	Jun	156	0.0%
2020	Jul	333	0.0%
2020	Aug	223	0.0%
2020	Sep	105	0.0%
2020	Average	95	0.0%

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.⁷³ 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

⁷³ See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 109 (Oct. 15, 2020).

withholding. In the first nine months of 2020, 39.4 percent of generation units offered DASR at a daily price above \$0.00 per MW, compared to 39.6 percent in 2019. In the first nine months of 2020, 16.4 percent of daily offers were above \$5.00 per MW.

The MMU recommends that market solutions for the DASR market be based on opportunity cost only in order to eliminate economic withholding.

Market Performance

In the first nine months of 2020, the DASR market cleared at a price above \$0.00 per MW in 13.0 percent of all hours. The weighted average DASR price for all cleared hours was \$0.38 per MW. The average cleared MW in all hours was 5,074.6 MW. The average cleared MW in all hours when the DASRMCP was above \$0.00 was 6,338.5 MW. The highest DASR price was \$28.98 per MW on August 27, 2020.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market. 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. In 2019, PJM added AFD to the normal 5.29 percent in 447 hours. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial. Table 10-29 shows the differences in price and MW between AFD hours and non-AFD hours.

Table 10-29 Impact of Adjusted Fixed Demand on DASR prices and demand: January through September, 2020

Metric	Number Hours	Weighted Day-Ahead Scheduling Reserve Market	Average Hourly Total DASR MW
		Clearing Price (DASRMCP)	
All Hours	6,576	\$0.38	5,074.6
All Hours when DASRMCP > \$0	855	\$2.17	6,822.3
All Hours when AFD is used	430	\$2.55	9,253.7

While the new rules allow PJM operators' 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 operators add 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.

Comparing the Normal Hour column against the AFD Hour column for five metrics (Table 10-30) shows that the use of AFD for 598 hours in 2018, and 248 hours in 2019 significantly increased the cost of DASR. Table 10-30 shows that the cost increase was a result of a substantial increase in DASR MW cleared. The average DASR clearing price in the first nine months of 2020 was \$2.17 for hours when the clearing price was above \$0.00 and \$2.55 during hours when adjusted fixed demand was invoked by PJM Dispatch.

Table 10-30 DASR market, regular hours vs. adjusted fixed demand hours: January 2019 through September 2020

Year	Month	Number of Hours DASRMCP>\$0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
		Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2019	Jan	8	24	\$0.00	\$0.28	95,058	117,071	5,359	8,907	\$20	\$2,521
2019	Feb	6	16	\$0.00	\$0.20	91,649	116,426	5,201	10,812	\$6	\$2,175
2019	Mar	24	NA	\$0.01	NA	86,172	NA	4,915	NA	\$42	NA
2019	Apr	15	NA	\$0.01	NA	75,107	NA	4,406	NA	\$37	NA
2019	May	43	NA	\$0.02	NA	79,257	NA	4,544	NA	\$77	NA
2019	Jun	31	42	\$0.03	\$1.72	85,713	105,502	5,138	11,076	\$139	\$19,030
2019	Jul	137	101	\$0.16	\$2.74	102,486	115,059	6,179	10,207	\$984	\$27,990
2019	Aug	127	46	\$0.11	\$4.52	95,624	110,089	5,846	11,056	\$631	\$49,964
2019	Sep	163	19	\$0.20	\$3.52	87,318	105,508	5,234	11,840	\$1,053	\$41,629
2019	Oct	203	21	\$0.19	\$16.07	75,626	100,061	4,365	10,563	\$848	\$169,764
2019	Nov	93	NA	\$0.06	NA	83,994	NA	4,775	NA	\$272	NA
2019	Dec	20	NA	\$0.01	NA	88,761	NA	5,067	NA	\$32	NA
2019		870	248	\$0.07	\$2.10	87,230	109,959	5,086	10,650	\$345	\$44,725
2020	Jan	3	NA	\$0.00	NA	89,919	NA	4,939	NA	\$2	NA
2020	Feb	3	NA	\$0.00	NA	88,655	NA	4,863	NA	\$2	NA
2020	Mar	1	NA	\$0.00	NA	78,508	NA	4,449	NA	\$1	NA
2020	Apr	0	NA	\$0.00	NA	70,687	NA	4,045	NA	\$0	NA
2020	May	31	NA	\$0.01	NA	71,826	NA	4,106	NA	\$57	NA
2020	Jun	156	48	\$1.28	\$1.87	110,779	97,191	6,512	10,250	\$8,788	\$20,556
2020	Jul	333	358	\$3.20	\$2.41	123,379	110,399	8,269	9,055	\$27,660	\$22,838
2020	Aug	223	24	\$1.71	\$5.74	118,231	110,971	6,051	10,223	\$10,535	\$59,981
2020	Sep	105	NA	\$0.39	NA	102,265	NA	5,077	NA	\$1,982	NA
2020		855	430	\$0.73	\$2.55	94,916	106,187	5,368	9,843	\$5,447	\$34,458

Table 10-31 shows total number of hours when a DASR market cleared at a price above \$0 along with average load, cleared MW, additional MW under AFD, and total charges for the DASR market in the first nine months of 2020.

Table 10-31 DASR market all hours of DASR market clearing price greater than \$0: January 2019 through September 2020

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 Credits
2019	Jan	32	\$0.61	123,223	297,046	97,612	\$182,645
2019	Feb	22	\$0.31	111,730	220,097	85,339	\$67,211
2019	Mar	24	\$0.26	105,987	123,430	0	\$31,569
2019	Apr	15	\$0.39	90,323	67,501	0	\$26,475
2019	May	43	\$0.28	98,135	204,957	0	\$57,122
2019	Jun	72	\$2.12	117,694	689,662	251,385	\$1,459,315
2019	Jul	237	\$2.55	125,398	1,965,812	440,096	\$5,025,492
2019	Aug	173	\$3.03	120,698	1,327,657	251,622	\$4,021,391
2019	Sep	182	\$1.57	106,434	1,100,092	122,187	\$1,731,695
2019	Oct	224	\$4.08	86,872	1,146,952	101,076	\$4,684,745
2019	Nov	93	\$0.43	95,062	455,808	0	\$195,637
2019	Dec	20	\$0.23	107,995	104,216	0	\$24,046
2019	Total	802	\$1.32	107,463	7,703,229	1,349,317	\$17,507,344
2020	Jan	3	\$0.10	111,016	14,817	0	\$1,462
2020	Feb	3	\$0.10	109,218	15,961	0	\$1,524
2020	Mar	1	\$0.19	92,457	4,532	0	\$861
2020	Apr	0	NA	NA	NA	0	NA
2020	May	31	\$0.29	96,413	146,365	0	\$42,334
2020	Jun	156	\$1.28	110,779	1,015,850	491,982	\$2,357,557
2020	Jul	333	\$3.20	123,379	2,753,429	3,241,749	\$17,386,688
2020	Aug	223	\$1.71	118,232	1,349,321	245,362	\$3,788,869
2020	Sep	105	\$0.39	102,265	533,115	0	\$208,097
2020	Total	38	\$0.38	107,970	5,833,389	0	\$23,787,392

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. Adjusted Fixed Demand related increases in the DASR requirement (Table 10-31) in 2019 caused prices to increase. The lack of Adjusted Fixed Demand in the first six months of 2020 kept DASR price and cost lower than those observed in 2019. This was reversed in the third quarter of 2020 with a very high use of Adjusted Fixed Demand, resulting in high prices and costs.

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. 755.⁷⁴ 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.

⁷⁴ Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

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

The regulation market converts performance adjusted RegD MW into effective MW using the MBF in the PJM design. The MBF is used to convert incremental additions of RegD MW into incremental effective MW. The total effective MW for a given amount of RegD MW equal the area under the MBF curve (the sum of the incremental effective MW contributions). RegA and RegD resources should be paid the same price per 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 per MW with a MBF of 0.5 and a performance score of 100 percent would be calculated as offering 0.5 effective MW (0.5 MBF times 1.00 performance score times 1 MW). The total offer price would be \$4 per effective MW (\$2 per MW offer divided by the 0.5 effective MW).

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every 10 seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.⁷⁵ Performance scores are reported on an hourly basis for each resource.

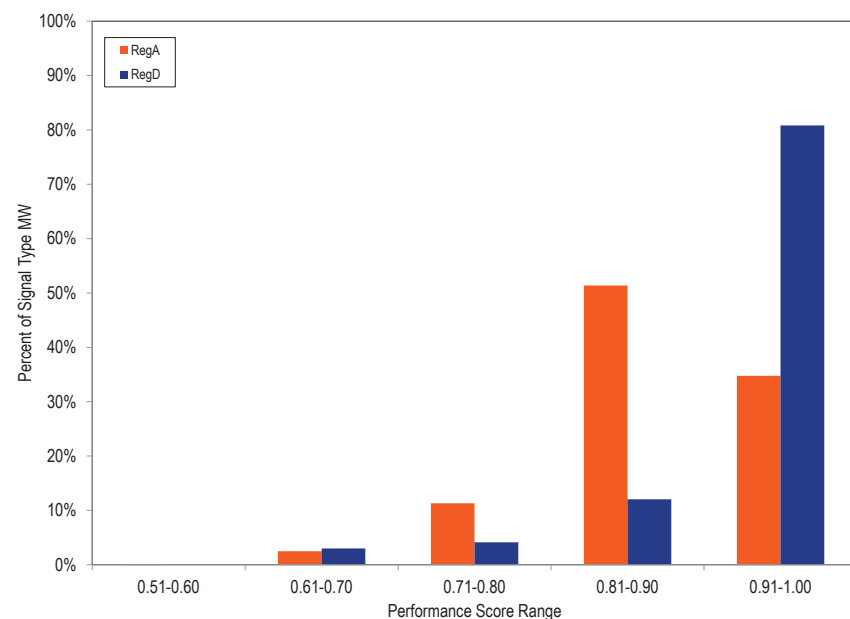
Table 10-32 and Figure 10-10 show the average performance score by resource type and the signal followed in the first nine months of 2020. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.⁷⁶ Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-10 shows, 80.8 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 34.8 percent of RegA resources had average performance scores within that range in the first nine months of 2020. These scores are higher than the scores for both product types in the first nine months of 2019, where 70.7 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 22.1 percent of RegA resources had average performance scores within that range.

⁷⁵ PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 40 (March 26, 2020).

⁷⁶ Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

Table 10-32 Hourly average performance score by unit type: January through September, 2020

		Performance Score Range				
		51-60	61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-	-
	CT	-	0.0%	2.2%	43.4%	54.4%
	Diesel	-	-	-	-	96.5%
	DSR	-	2.9%	3.4%	93.6%	0.1%
	Hydro	-	-	0.1%	39.2%	60.7%
	Steam	0.1%	3.5%	15.8%	56.5%	24.1%
RegD	Battery	-	3.2%	2.6%	10.3%	83.9%
	CT	-	0.0%	2.2%	97.8%	0.0%
	Diesel	-	-	0.0%	86.2%	-
	DSR	0.0%	0.0%	33.3%	40.4%	26.3%
	Hydro	-	0.0%	-	0.3%	99.7%
	Steam	-	-	-	-	-

Figure 10-10 Hourly average performance score by regulation signal type: January through September, 2020

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

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

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

Market Design Issues

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

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

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

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

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

problem requires that PJM pay RegD for the same effective MW it provides in regulation, 0.001 MW.

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

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

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

The January 9, 2017, design changes appear to have been intended to make RegD more valuable. That is not a reasonable design goal. The design goal should be to determine the least cost way to provide needed regulation. The RegA signal is now slower than it was previously, which may make RegA following resources less useful as ACE control. RegA is now explicitly used to support the conditional energy neutrality of RegD. The RegD signal is now the difference between ACE and RegA. RegA is required to offset RegD when RegD moves in the opposite direction of that required by ACE control in order to permit RegD to recharge. These changes in the signal design will

allow PJM to accommodate more RegD in its market solutions. The new signal design is not making the most efficient use of RegA and RegD resources. The explicit reliance on RegA to offset issues with RegD is a significant conceptual change to the design that is inconsistent with the long term design goal for regulation. PJM increased the regulation requirement as part of these changes.

The January 9, 2017, design changes replaced off peak and on peak hours with nonramp and ramp hours with definitions that vary by season. The regulation requirement for ramp hours was increased from 700 MW to 800 MW (Table 10-33). 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 10-33 Seasonal regulation requirement definitions⁷⁷

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 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.

⁷⁷ See PJM, "Regulation Requirement Definition," <<http://www.pjm.com/~media/markets-ops/ancillary/regulation-requirement-definition.ashx>>.

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. The result is that only a small amount of energy limited RegD is economic. The current and proposed signals and corresponding MBF functions do not reflect these principles or the actual substitutability of resource types.

Marginal Benefit Factor Issues

The MBF function, as implemented in the PJM Regulation Market, is not equal to the MRTS between RegA and RegD. The MBF is not consistently applied throughout the market design, from optimization to settlement, and market clearing does not confirm that the resulting combinations of RegA and RegD are realistic and can meet the defined regulation demand. The calculation of total regulation cleared using the MBF is incorrect.⁷⁸

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, but was rejected by FERC.⁷⁹

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, 2012.⁸⁰ 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

⁷⁸ The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.

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

⁸⁰ 145 FERC ¶ 61,011 (2013).

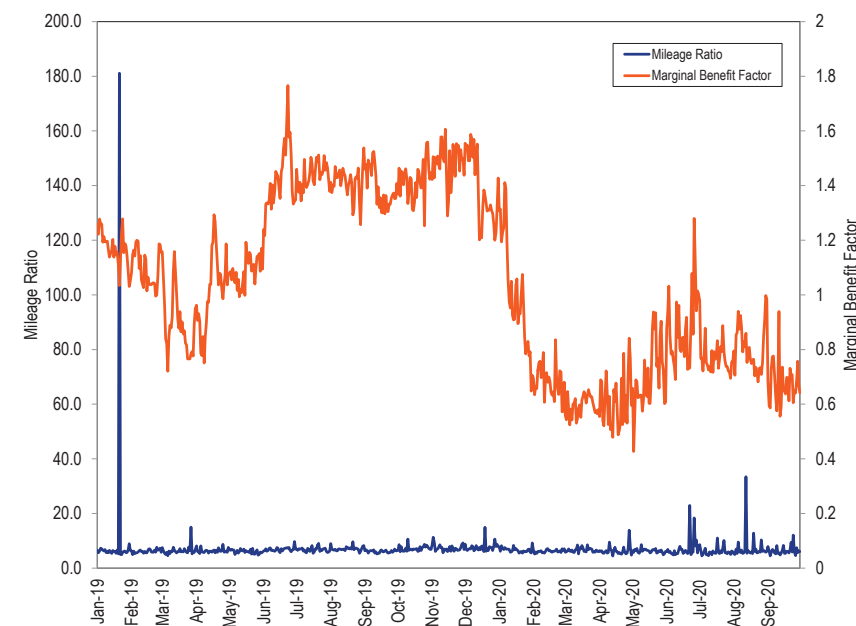
applied and resources do not receive the same clearing price per marginal effective MW.

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

Figure 10-11 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio decreased from 7.09 in the first nine months of 2019, to 6.57 in the first nine months of 2020 (a decrease of 7.3 percent). The average MBF in the first nine months of 2019 was 1.22, and the average MBF in the first nine months of 2020 was 0.75. 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 10-11 Daily average MBF and mileage ratio: January 2019 through September 2020



The decrease 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 10-34 shows RegD resource payments on a performance adjusted actual MW basis and RegA resource payments on a performance adjusted MW basis by month, from January 1, 2019, through September 30, 2020. Although the average regulation market clearing price in the first nine months of 2020 was \$2.38 lower than in the first nine months of 2019 (See Table 10-47), RegD was still overpaid due to the lower average MBF. In the first nine months of 2019, RegD resources earned 39.7 percent more per performance adjusted actual MW than RegA resources. In the first nine months of 2020, RegD resources

earned 22.8 percent more per performance adjusted actual MW than RegA resources due to the inclusion of the mileage ratio in RegD MW settlement.

Table 10-34 Average monthly price paid per performance adjusted actual MW of RegD and RegA: January 2019 through September 2020

Year	Month	Settlement Payments		
		RegD (\$/Performance Adjusted MW)	RegA (\$/Performance Adjusted MW)	Percent RegD Overpayment (\$/Performance Adjusted MW)
2019	Jan	\$19.00	\$13.89	36.8%
	Feb	\$16.64	\$11.68	42.4%
	Mar	\$18.28	\$13.79	32.6%
	Apr	\$20.44	\$15.85	28.9%
	May	\$16.36	\$12.04	36.0%
	Jun	\$17.62	\$10.66	65.3%
	Jul	\$22.81	\$15.78	44.6%
	Aug	\$21.22	\$13.99	51.7%
	Sep	\$26.45	\$20.35	29.9%
	Oct	\$33.07	\$25.21	31.2%
	Nov	\$21.64	\$17.86	21.1%
	Dec	\$19.17	\$15.10	27.0%
Yearly		\$21.09	\$15.54	35.7%
2020	Jan	\$16.51	\$13.05	26.5%
	Feb	\$11.83	\$9.57	23.6%
	Mar	\$11.06	\$8.60	28.6%
	Apr	\$14.29	\$11.45	24.8%
	May	\$14.72	\$12.46	18.2%
	Jun	\$15.09	\$11.85	27.3%
	Jul	\$18.02	\$15.63	15.3%
	Aug	\$18.11	\$14.83	22.2%
	Sep	\$12.68	\$10.33	22.7%
Average		\$14.73	\$12.00	22.8%

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, $(RMCCP + RMPCP) \times MBF$, RegD resources are currently paid based on the mileage ratio $(RMCCP + (RMPCP \times \text{mileage ratio}))$. Because the RMCCP component makes up the majority of the overall clearing price, when the MBF is above one, RegD resources can be underpaid on a per effective MW basis by the current payment method, unless offset by a high mileage ratio. When the MBF is less

than one, RegD resources are overpaid on a per effective MW basis, unless offset by a low mileage ratio. The average MBF was greater than 1.0 in the first nine months of 2019 (1.22). However, RegD resources were still overpaid on average compared to payment on a per effective MW basis. In the first nine months of 2020, the average MBF was equal to 0.75.

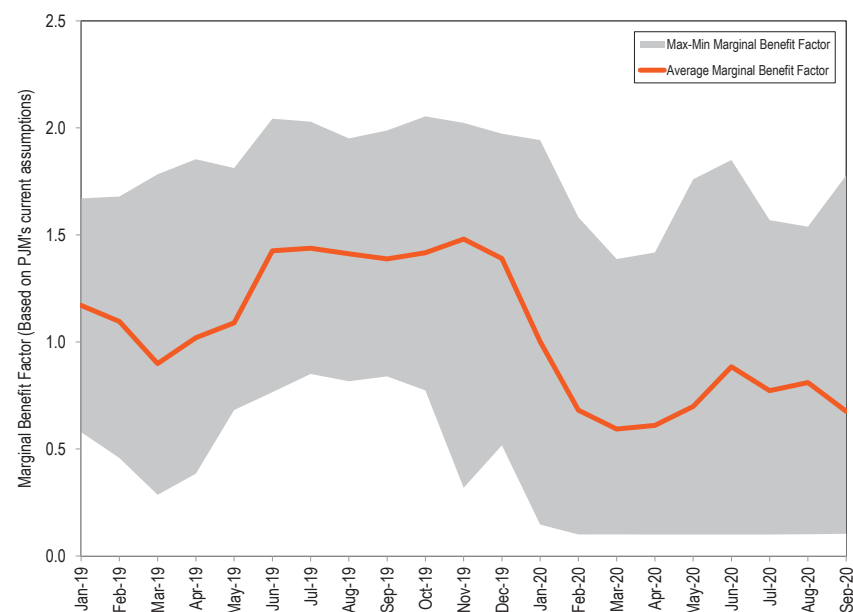
The effect of using the mileage ratio instead of the MBF to convert RegD MW into effective MW for purposes of settlement is illustrated in Table 10-35. Table 10-35 compares the monthly average payment of RegD per effective MW under the current settlement process to the monthly average payment RegD resources 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 more than 1.0 in the first nine months of 2019 (1.22), while the average daily mileage ratio was 7.09, resulting in RegD resources being paid \$22.7 million more than they would have been if the MBF were correctly implemented. In the first nine months of 2020, the MBF averaged 0.75, while the average daily mileage ratio was 6.57, resulting in RegD resources being paid \$67.2 million more than they would have been if the MBF were correctly implemented.

Table 10-35 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2019 through September 2020

		RegD Settlement Payments				
		Marginal Rate of				Total RegD
Year	Month	Mileage Based RegD (\$/Effective MW)	Technical Substitution Based RegD (\$/Effective MW)	RegA (\$/Effective MW)	Percent RegD Overpayment (\$/Effective MW)	
2019	Jan	\$16.87	\$13.89	\$13.89	21.4%	\$2,722,074
	Feb	\$15.86	\$11.68	\$11.68	35.8%	\$3,702,121
	Mar	\$21.72	\$13.79	\$13.79	57.5%	\$5,996,358
	Apr	\$21.36	\$15.85	\$15.85	34.8%	\$5,564,565
	May	\$14.80	\$12.04	\$12.04	22.9%	\$3,180,576
	Jun	\$12.17	\$10.66	\$10.66	14.2%	\$2,477,292
	Jul	\$15.94	\$15.78	\$15.78	1.0%	\$41,895
	Aug	\$14.87	\$13.99	\$13.99	6.3%	\$1,380,304
	Sep	\$19.09	\$20.35	\$20.35	(6.2%)	(\$2,393,162)
	Oct	\$23.94	\$25.21	\$25.21	(5.1%)	(\$2,786,558)
	Nov	\$15.39	\$17.86	\$17.86	(13.8%)	(\$4,720,066)
	Dec	\$13.94	\$15.10	\$15.10	(7.7%)	(\$3,169,913)
Yearly		\$17.17	\$15.54	\$15.54	10.5%	\$11,995,485
2020	Jan	\$19.61	\$13.05	\$13.05	50.3%	\$3,822,718
	Feb	\$25.79	\$9.57	\$9.57	169.5%	\$6,060,440
	Mar	\$29.47	\$8.60	\$8.60	242.6%	\$7,982,625
	Apr	\$38.85	\$11.45	\$11.45	239.4%	\$8,946,335
	May	\$37.37	\$12.46	\$12.46	199.9%	\$8,953,641
	Jun	\$25.00	\$11.85	\$11.85	111.0%	\$6,585,517
	Jul	\$34.99	\$15.63	\$15.63	123.9%	\$7,891,533
	Aug	\$31.78	\$14.83	\$14.83	114.4%	\$9,038,391
	Sep	\$28.51	\$10.33	\$10.33	175.9%	\$7,942,871
Average		\$30.18	\$12.00	\$12.00	151.5%	\$67,224,071

Figure 10-12 shows, the monthly maximum, minimum and average MBF, for January 2019 through September 2020. The average daily MBF in the first nine months of 2020 was 0.75. The average daily MBF in the first nine months of 2019 was 1.22. The flat line at the bottom of the MBF range from February 2020 to September 2020 is caused by the MBF reaching the minimum threshold of 0.1, administratively set by PJM.

Figure 10-12 Maximum, minimum, and average PJM calculated MBF by month: January 2019 through September 2020



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.⁸¹

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

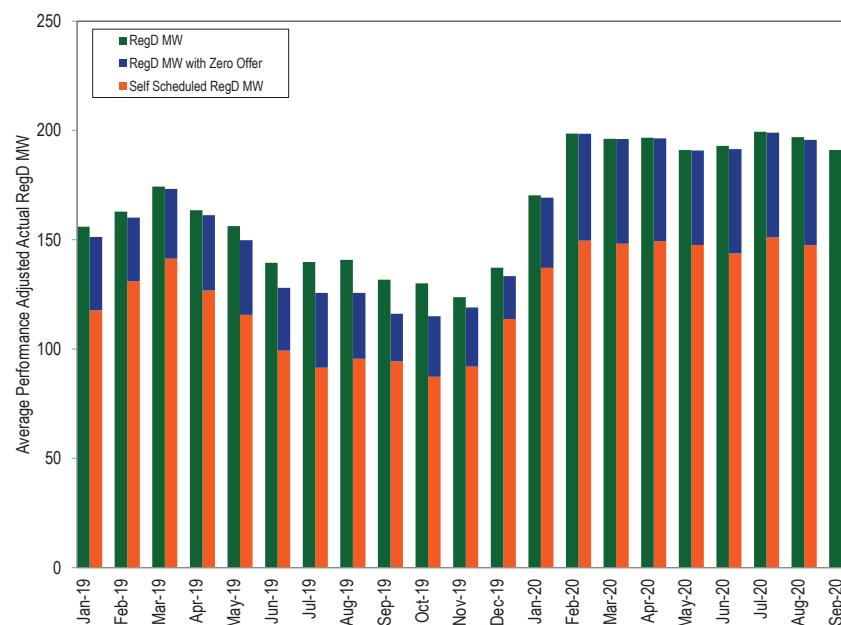
Figure 10-12 shows, by month, the proportion of cleared RegD MW with an effective price of \$0.00 (units with zero offers plus self scheduled units) for

⁸¹ See "Regulation Market Review," Operating Committee (May 5, 2015) <<http://www.pjm.com/~media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>>.

January 2019 through September 2020. In the first nine months of 2020, an average of 99.7 percent of all RegD MW clearing the market had an effective offer of \$0.00. In the first nine months of 2019, an average of 94.3 percent of all cleared RegD MW had an effective cost of \$0.00. In the first nine months of 2020, an average of 76.5 percent of all RegD offers were self scheduled, compared to an average of 73.8 percent of all RegD offers in the first nine months of 2019.

The high percentage of self scheduled offers is a result of the incentives created by the flaws in the regulation market. Because self scheduled offers are price takers, they are cleared along with the zero cost offers in the market clearing engine. However, unlike zero cost offers, self scheduled offers will not risk having an LOC added to their offer during the market clearing process, ensuring that self scheduled offers remain at a cost of zero during market clearing. Given the increasing saturation of the regulation market with RegD MW, specifically demand response and battery units which do not receive LOC, market participants eligible for LOC that offer at zero instead of self scheduling, run the risk of an LOC added to their offer, and thus not clearing the market. The average monthly RegD cleared in the market increased 40.9 MW (27.0 percent), from 151.6 MW in the first nine months of 2019 to 192.6 MW in the first nine months of 2020. The average monthly RegD cleared with an effective cost of zero increased 48.5 MW (33.8 percent), from 143.5 MW in the first nine months of 2019 to 191.9 MW in the first nine months of 2020. Self scheduled RegD cleared MW increased 34.5 MW (30.7 percent), from 112.6 MW in the first nine months of 2019 to 147.1 MW in the first nine months of 2020. Average cleared RegD MW with a zero cost offer increased 13.9 MW (45.1 percent), from 30.9 MW in the first nine months of 2019 to 44.8 MW in the first nine months of 2020. The increase in the average monthly RegD cleared resulted in the reduction of the average monthly MBF seen in Figure 10-12.

Figure 10-13 Average cleared RegD MW and average cleared RegD with an effective price of \$0.00 by month: January 2019 through September 2020



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

Under PJM market rules, regulation units that have the capability to provide both RegA and RegD MW are permitted to submit an offer for both signal types in the same market hour. While the objective of the PJM market design is to find the least cost combination of RegA and RegD resources to provide the required level of regulation service, the method of clearing the regulation market for an hour in which one or more units has a dual offer is incorrect and leads to solutions that are not the most economic.

In order for the clearing engine to provide the correct economic solution when the pool of available resources contains one or more units with dual offers, the calculation would have to be performed iteratively to determine which of

the dual offers would provide the least cost solution. This is not, however, how PJM clears the regulation market when there are dual offer units. Instead, PJM rank orders the regulation supply curve by potential effective cost assuming the dual offer resources are available as both RegA and RegD resources simultaneously. When the clearing engine rank orders each available resource based on their potential effective cost, every RegD resource, including dual offer resources, is assigned a unit specific benefit factor.

After rank ordering the resources, each dual offer resource is assigned to run as either a RegD or RegA resource based on which of the two offers has a lower effective cost. While this recognizes that the dual offer resource cannot supply both RegA MW and RegD MW at the same time, PJM does not redefine the supply curve using appropriately recalculated unit specific benefit factors for the remaining RegD resources prior to clearing the market.

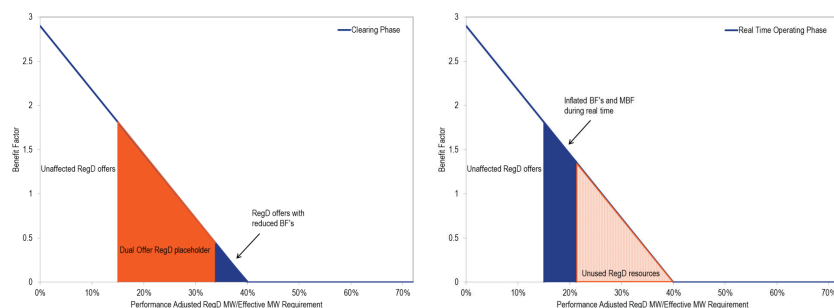
During the clearing phase, the MBF of RegD resources is a function of the RegD MW that clear. The MBF for all RegD resources declines as more RegD resources are cleared. Based on this relationship, in the case where a dual offer unit is assigned to be a RegA resource rather than a RegD resource, the MBF of remaining RegD resources in the supply curve should increase. But PJM does not recalculate the MBF values for the remaining RegD resources. The result is that the MBF in the clearing is incorrectly low.

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

The issue is illustrated in Figure 10-14. The example shows a clearing phase and a real time operating phase. In this example, a 150 MW unit offers both

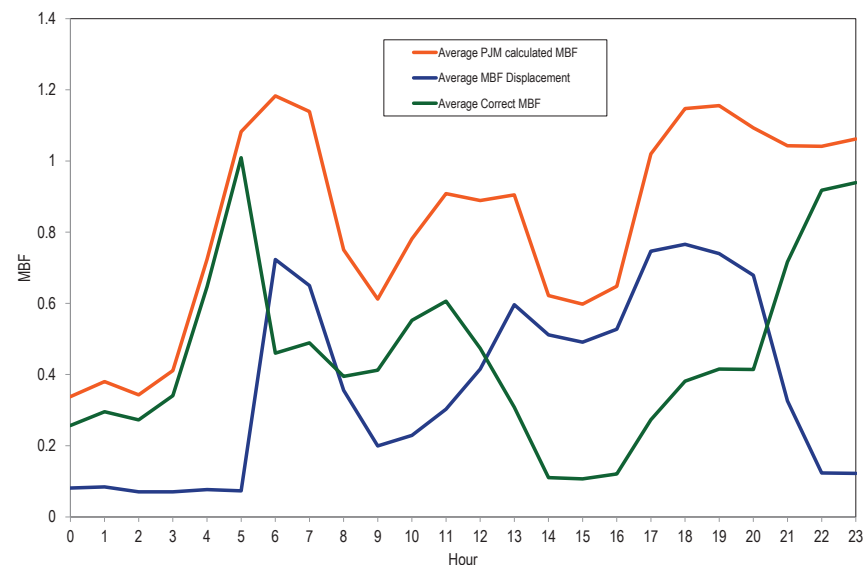
RegA and RegD. The 150 MW unit's position in the RegD effective cost curve and the potential effective MW are represented as the orange area under the curve in the clearing phase. The effective MW of the cleared RegD resources with higher effective costs are represented by the blue triangle in the clearing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

Figure 10-14 Clearing phase BF/effective MW reduction, real time BF/effective MW inflation, and exclusion of available RegD resources



In the first nine months of 2020, all but four hours had at least one unit with a dual offer. In the first nine months of 2020, 81.4 percent of all hours had at least one dual offer unit that was chosen to run as RegA, resulting in an average MBF increase of 0.47 in the operating phase. If the market had been cleared correctly, the average MBF would have been significantly lower in real time (operating phase), because additional RegD offers with lower benefit factors that were initially excluded, would have been included after the removal of the dual offer placeholder, reducing the MBF. Figure 10-15 illustrates the PJM calculated average MBF in real time (operating phase), the average MBF displacement due to dual offers clearing as RegA, and what the correct average MBF would have been in each hour of the day for the first nine months of 2020 if the clearing solution was solved correctly.

Figure 10-15 Effect of PJM's current dual offer clearing method on the average MBF in each hour of the day: January through September, 2020



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

Price Spikes

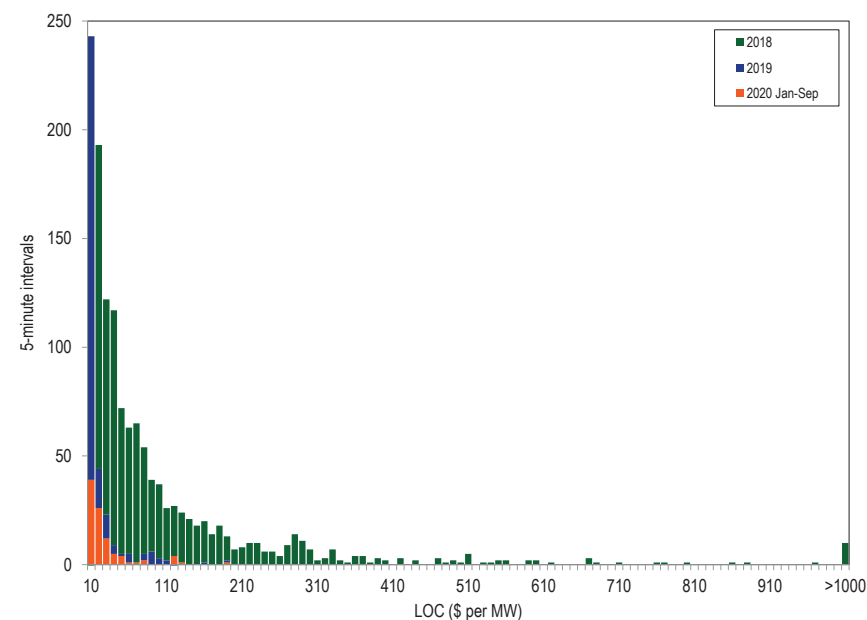
Beginning in 2018, extreme price spikes were identified in the regulation market. The price spikes were caused by a combination of the inconsistent application of the MBF in the market design and the discrepancy between the hour ahead estimated LOC and the actual realized within hour LOC.

The regulation market is cleared on an hour ahead basis, using offers that are adjusted by dividing each component of an offer (capability, performance, and lost opportunity cost) by the product of the unit specific benefit factor and unit specific performance score. To calculate the hour ahead estimate

of the adjusted LOC offer component, hour ahead projections of LMPs are used. Units are then cleared based on the sum of each of their hour ahead adjusted offer components. The actual LOC is used to determine the final, actual interval specific all-in offer of RegD resources.

In some cases the estimated LOC is very low or zero but the actual within hour LOC is a positive number. In instances where the MBF of the within hour marginal unit 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. In January 2019, FERC approved PJM's proposal to create a 0.1 floor for the MBF to reduce the occurrence of these price spikes.⁸² This change reduced the amount and frequency of the price spikes, but it was not designed to eliminate them and it did not eliminate them. PJM's new MBF floor of 0.1 did not and will not eliminate unjust and unreasonable outcomes for market participants. PJM's market change does not correct the underlying problem with the current market design because it does not address the overpayment of RegD MW when the MBF is less than 1.0. Correspondingly, RegD is still underpaid when the MBF is greater than 1.0. Figure 10-16 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, 2019, and the first nine months of 2020.

Figure 10-16 LOC distribution in each five minute interval with a RegD marginal unit and an LOC greater than zero: 2018, 2019, and January through September, 2020



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

⁸² See 166 FERC ¶ 61,040 (2019).

While an incorrect estimate of a potential LOC can result in an extremely high price, the resulting regulation market prices are mathematically correct for the price of each effective MW. The prices in every interval reflect the marginal costs of regulation given the resources dispatched and accurately reflect the marginal offer of minimally effective resources which had unexpectedly high LOC components of their within hour offers. But, due to the current market design's failure to 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 price 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 10-36 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first nine months of 2020.⁸³ Actual MW are adjusted by the historic 100-hour moving average performance score to get performance adjusted MW, and by the resource specific benefit factor to get effective MW. A resource can choose to follow either signal. For that reason, the sum of each signal type's capability can exceed the full regulation capability. Offered MW are calculated based on the offers from units that are designated as available for the day. These are daily offers that can be modified on an hourly basis up to 65 minutes before the hour.⁸⁴ Eligible MW are calculated from the hourly offers from units with daily offers and units that are offered as unavailable for the day, but still offer MW into some hours. Units with daily offers are permitted to offer above or below their daily offer from hour to hour. As a result of these hourly MW adjustments, the average hourly Eligible MW can be higher than the Offered MW.

In the first nine months of 2020, the average hourly offered supply of regulation for nonramp hours was 704.1 actual MW (709.1 effective MW). This was a decrease of 92.6 actual MW (a decrease of 88.5 effective MW) from the first nine months of 2019, when the average hourly offered supply of regulation was 796.7 actual MW (797.7 effective MW). In the first nine months of 2020, the average hourly offered supply of regulation for ramp hours was 1,008.9 actual MW (1,053.1 effective MW). This was a decrease of 113.1 actual MW (a decrease of 74.4 effective MW) from the first nine months of 2019, when the average hourly offered supply of regulation was 1,122.0 actual MW (1,127.4 effective MW).

⁸³ 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.

⁸⁴ See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 109 (Oct. 15, 2020).

The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for ramp hours was 1.43 in the first nine months of 2020 (1.55 in the first nine months of 2019). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for nonramp hours was 1.44 in the first nine months of 2020 (1.70 in the first nine months of 2019).

Table 10-36 Hourly average actual and effective MW offered and cleared: January through September, 2020⁸⁵

		By Resource Type			By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Actual Offered MW	Ramp	1,008.9	996.3	12.6	765.1	243.9
	Nonramp	704.1	694.8	9.2	499.5	204.6
Effective Offered MW	Ramp	1,053.1	1,038.6	14.5	664.5	388.6
	Nonramp	709.1	702.8	6.3	434.6	274.6
Actual Cleared MW	Ramp	703.3	690.7	12.6	488.0	215.4
	Nonramp	489.8	480.6	9.2	286.9	202.8
Effective Cleared MW	Ramp	800.0	785.6	14.4	425.2	374.8
	Nonramp	525.2	518.9	6.2	251.3	273.9

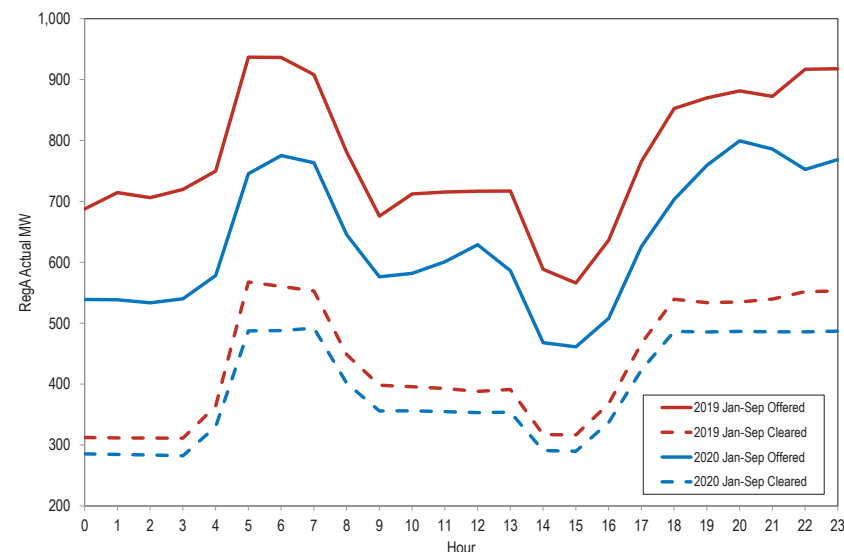
The average hourly offered and cleared actual MW from RegA resources are shown in Figure 10-17. The average hourly offered MW from RegA resources during ramp hours for the first nine months of 2020 was 765.1 actual MW, a decrease of 15.7 percent from the first nine months of 2019 (908.0 actual MW).

The average hourly offered MW from RegA resources during nonramp hours for the first nine months of 2020 was 499.5 actual MW, a decrease of 20.3 percent from the first nine months of 2019 (626.4 actual MW).

The average hourly cleared MW from RegA resources during ramp hours for the first nine months of 2020 was 488.0 actual MW, a decrease of 11.3 percent from the first nine months of 2019 (550.2 actual MW). The average hourly cleared MW from RegA resources during nonramp hours for the first nine months of 2020 was 286.9 actual MW, a decrease of 7.2 percent from the first nine months of 2019 (309.4 actual MW).

⁸⁵ PJM operations treats some nonramp hours as ramp hours, with a regulation requirement of 800 MW rather than 525 MW. All ramp/nonramp analysis performed is based on the requirement used in each hour rather than the definitions given in Table 10-2. A ramp hour occurring during what is normally a nonramp period is treated as a ramp hour.

Figure 10-17 Average hourly RegA actual MW offered and cleared: January through September, 2019 and 2020



The average hourly offered MW from RegD resources during ramp hours for the first nine months of 2020 was 243.9 actual MW, an increase of 13.9 percent from the first nine months of 2019 (214.1 actual MW). (Figure 10-18) The average hourly offered MW from RegD resources during nonramp hours for the first nine months of 2020 was 204.6 actual MW, an increase of 20.2 percent from the first nine months of 2019 (170.2 actual MW). (Figure 10-17) The average hourly cleared MW from RegD resources during ramp hours for the first nine months of 2020 was 215.4 actual MW, an increase of 24.0 percent from the first nine months of 2019 (173.6 actual MW). The average hourly cleared MW from RegD resources during nonramp hours for the first nine months of 2020 was 202.8 actual MW, an increase of 27.7 percent from the first nine months of 2019 (158.9 actual MW).

Figure 10-18 Average hourly RegD actual MW offered and cleared: January through September, 2019 and 2020

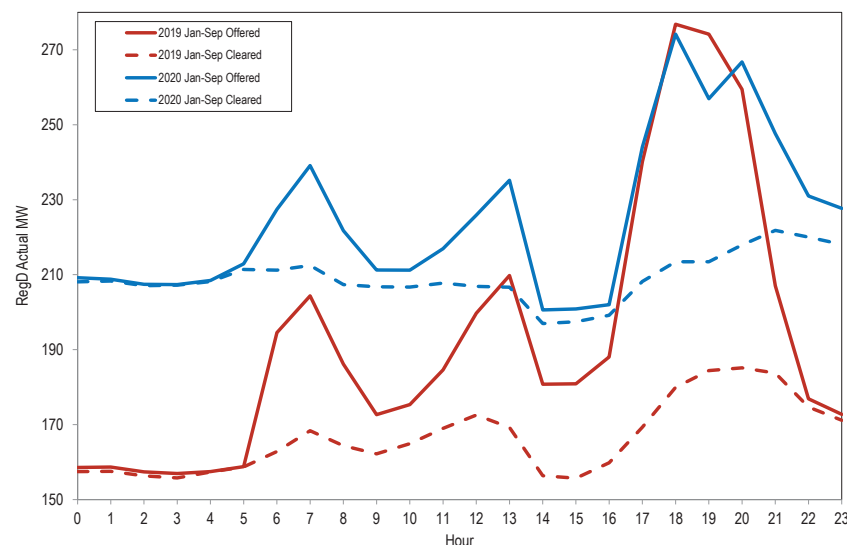


Table 10-37 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, the percent of settled regulation provided by unit type, and the clearing price, uplift, and total regulation credits. In Table 10-37 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW increased 2.33 percent from 3,393,216.5 MW in the first nine months of 2019 to 3,472,110.9 MW in the first nine months of 2020. The average proportion of regulation provided by battery units had the largest increase (9.6 percent), providing 24.5 percent of regulation in the first nine months of 2019 and 34.1 percent of regulation in the first nine months of 2020. Natural gas units had the largest decrease in average proportion of regulation provided (7.6 percent), decreasing from 46.8 percent in the first nine months of 2019, to 39.2 percent in the first nine months of 2020. The total regulation credits in the first nine months of 2020 were \$53,725,322, down 15.8 percent from \$63,837,649 in the first nine months of 2019. The reduction in regulation

credits is due, in part, to a lower LOC component of regulation prices as a result of lower energy prices in the first nine months of 2020 compared to the first nine months of 2019.

When a resource offers into the regulation market, an estimated regulation LOC is added by PJM to form a total offer (units self scheduled, or not providing in the energy market, have a regulation LOC of zero). After a unit clears and has provided regulation, their regulation LOC is calculated again during settlements, using the actual LMP. If this actual regulation LOC causes the unit's total offer to be larger than the clearing price, the unit receives uplift credits. The uplift credits received for each unit type are shown in Table 10-37. The total uplift credits received decreased 16.5 percent from \$7,255,701 in the first nine months of 2019 to \$6,057,720 in the first nine months of 2020. This reduction, like the reduction in total credits, is due in part to lower LOC components of regulation prices and offers as a result of lower energy prices in the first nine months of 2020 compared to the first nine months of 2019. Coal units had the largest increase in uplift payments, increasing 8.1 percentage points from 37.4 percent in the first nine months of 2019, to 45.5 percent in the first nine months of 2020, while only responsible for 8.0 percent of the provided settled regulation. Natural gas units had the largest decrease in uplift payments, decreasing 9.7 percentage points from 33.4 percent in the first nine months of 2019, to 23.6 percent in the first nine months of 2020.

Table 10-37 PJM regulation by source: January through September, 2019 and 2020⁸⁶

Source	2019 (Jan-Sep)						2020 (Jan-Sep)					
	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits
Battery	24	830,956	24.5%	\$16,472,536	\$0	\$16,472,536	22	1,184,247	34.1%	\$17,619,989	\$0	\$17,619,989
Coal	19	262,284	7.7%	\$4,236,252	\$2,713,559	\$6,949,810	19	278,421	8.0%	\$3,992,115	\$2,757,549	\$6,749,663
Hydro	25	623,305	18.4%	\$10,688,435	\$2,120,773	\$12,809,209	26	587,676	16.9%	\$7,877,236	\$1,869,213	\$9,746,449
Natural Gas	165	1,587,991	46.8%	\$23,359,788	\$2,421,370	\$25,781,158	168	1,361,799	39.2%	\$17,214,404	\$1,430,959	\$18,645,363
DR	26	88,680	2.6%	\$1,824,937	\$0	\$1,824,937	20	59,967	1.7%	\$963,858	\$0	\$963,858
Total	259	3,393,216.5	100.0%	\$56,581,948	\$7,255,701	\$63,837,649	255	3,472,110.9	100.0%	\$47,667,602	\$6,057,720	\$53,725,322

The MMU has identified a potential issue in the calculation of regulation uplift payments. The desired amount of MW output at LMP used in the calculation of regulation LOC uses a unit's energy schedule, but does not take into account the physical ability of a unit to achieve that desired output given the unit's ramp rate.

Significant flaws in the regulation market design have led to an over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals have contributed to more storage projects entering PJM's interconnection queue, despite clear evidence that the market design is flawed and despite operational evidence that the RegD market is saturated (Table 10-38).

Table 10-38 Active battery storage projects in the PJM queue by submitted year: 2014 through September 2020

Year	Number of Storage Projects	Total Capacity (MW)
2014	1	10.0
2015	5	61.0
2016	1	19.9
2017	3	2.5
2018	21	690.3
2019	74	4,527.7
2020	71	4,629.0
Total	176	9,940.3

⁸⁶ 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 2020 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 10-33).

Table 10-39 shows the average hourly required regulation by month and the ratio of supply to demand for both actual and effective MW, for ramp and nonramp hours. The average hourly required regulation by month is an average of the ramp and nonramp hours in the month. Changes in the actual MW required to satisfy the regulation requirement are the result of the amount of RegD actual MW cleared. When more RegD MW are cleared, the MBF is lower, resulting in those actual MW being worth less effective MW, requiring more actual MW to satisfy the requirement. When MBFs are higher, the actual MW of RegD are worth more effective MW, reducing the amount of actual MW needed to satisfy the requirement.

The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 490.0 hourly average performance adjusted actual MW in the first nine months of 2020. This is an increase of 22.2 performance adjusted actual MW from the first nine months of 2019, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 467.9 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 703.0 hourly average performance adjusted actual MW in the first nine months of 2020. This is a decrease of 19.8 performance adjusted actual MW from the first nine months of 2019, where the average hourly regulation cleared MW for ramp hours were 722.8 performance adjusted actual MW.

Table 10-39 Required regulation and ratio of supply to requirement: January 2019 through September 2020

Hours	Month	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	
		2019	2020	2019	2020	2019	2020	2019	2020
Ramp	Jan	719.3	712.9	799.9	800.1	1.71	1.36	1.51	1.25
	Feb	710.3	694.3	799.9	800.0	1.74	1.31	1.53	1.22
	Mar	707.3	692.5	799.9	800.1	1.56	1.33	1.39	1.24
	Apr	718.8	707.5	799.9	800.1	1.48	1.41	1.36	1.29
	May	717.5	711.8	800.0	800.1	1.47	1.42	1.35	1.31
	Jun	728.5	705.5	800.0	800.0	1.48	1.52	1.37	1.38
	Jul	736.9	702.8	800.0	800.1	1.50	1.57	1.39	1.42
	Aug	733.3	705.1	799.9	800.0	1.51	1.47	1.39	1.34
	Sep	733.1	694.8	800.0	799.8	1.50	1.46	1.39	1.33
	Oct	743.3		800.0		1.49		1.39	
	Nov	753.3		800.1		1.47		1.37	
	Dec	731.7		800.0		1.46		1.35	
Nonramp	Jan	465.5	479.5	525.5	525.1	1.97	1.43	1.72	1.33
	Feb	466.6	495.9	525.1	525.1	2.11	1.45	1.83	1.37
	Mar	474.0	493.1	525.3	525.1	1.73	1.36	1.55	1.29
	Apr	472.4	492.7	525.1	525.2	1.65	1.46	1.48	1.36
	May	465.9	486.6	525.6	525.3	1.56	1.45	1.41	1.36
	Jun	466.9	490.0	526.8	525.1	1.59	1.45	1.42	1.36
	Jul	467.0	498.1	525.8	525.4	1.57	1.46	1.43	1.38
	Aug	463.7	489.8	525.3	525.0	1.59	1.43	1.43	1.35
	Sep	469.0	484.8	525.3	525.2	1.58	1.46	1.43	1.36
	Oct	473.8		525.0		1.53		1.40	
	Nov	479.6		525.0		1.65		1.50	
	Dec	469.9		525.0		1.60		1.46	

Market Concentration

In the first nine months of 2020, the effective MW weighted average HHI of RegA resources was 2519 which is highly concentrated and the weighted average HHI of RegD resources was 1850 which is highly concentrated. The weighted average HHI of all resources was 1443, which is moderately concentrated. The weighted average HHI reflects the fact that different owners have large market shares in the RegA and RegD markets.

Table 10-40 includes a monthly summary of three pivotal supplier (TPS) results. In the first nine months of 2020, 94.8 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market

in the first nine months of 2020 was characterized by structural market power. The results presented here are calculated by PJM. The MMU has been unable to verify these results, as some of the underlying data necessary to replicate these calculations is not saved. PJM has submitted a request to the vendor to save all data necessary for verification.

Table 10-40 Regulation market monthly three pivotal supplier results: 2018 through September 2020

Month	Percent of Hours Pivotal		
	2018	2019	2020
Jan	88.7%	77.8%	99.1%
Feb	77.5%	76.0%	97.4%
Mar	83.9%	93.3%	98.3%
Apr	90.3%	93.1%	96.5%
May	87.8%	94.0%	94.9%
Jun	79.9%	91.0%	89.8%
Jul	79.4%	92.7%	89.0%
Aug	79.6%	93.1%	94.6%
Sep	78.6%	93.3%	93.3%
Oct	82.1%	96.1%	
Nov	78.2%	90.7%	
Dec	74.2%	96.1%	
Average	81.7%	90.6%	94.8%

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.⁸⁷ When offering into the regulation market, regulating resources must submit a cost-based offer and may submit a price-based offer (capped at \$100 per MW) by 14:15 the day before the operating day.⁸⁸

⁸⁷ See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 109 [Oct. 15, 2020].

⁸⁸ Id. at 3.2.2, at p 62.

Offers in the PJM Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (Δ MW of regulation movement) provided. The capability component for cost-based offers is not to exceed the increased fuel costs resulting from operating the regulating unit at a lower output level than its economically optimal output level, plus a \$12.00 per MW margin. The \$12.00 margin embeds market power in the regulation offers 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.⁸⁹

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.⁹⁰

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 10-42).⁹¹ Figure 10-19 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.⁹²

⁸⁹ See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 36 (Sept. 1, 2020).

⁹⁰ See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 109 (Oct. 15, 2020).

⁹¹ See "PJM Manual 28: Operating Agreement Accounting," § 4.1 Regulation Accounting Overview, Rev. 83 (Dec. 3, 2019).

⁹² See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 109 (Oct. 15, 2020).

Self-scheduled regulation comprised an average of 50.4 percent during ramp hours and 65.3 percent during nonramp hours in the first nine months of 2020.

Figure 10-19 Nonramp and ramp regulation levels: January 2019 through September 2020

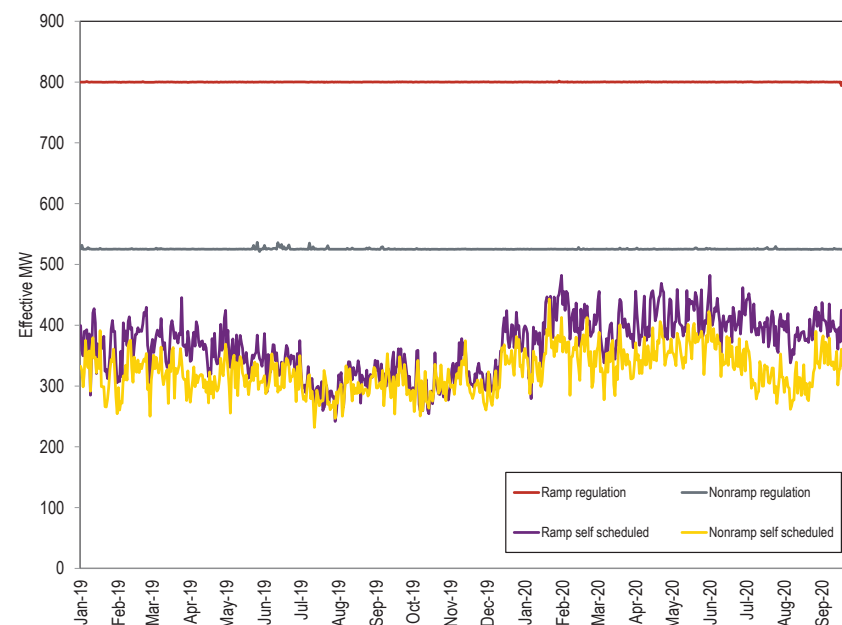


Table 10-41 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 49.6 percent of the total effective MW in September 2020) and a growing proportion of resources that self-schedule (25.0 percent of all self-scheduled effective MW in October 2012 and 75.8 percent of all self-scheduled effective MW in September 2020). In the first nine months of 2020, the average RegD percentage of total self-scheduled effective MW was 70.8 percent, an increase of 6.3 percent from the first nine months of 2019, when

the average was 64.5 percent. This increase in RegD self scheduling has led the increased amount of RegD cleared (Figure 10-12), and the decrease in the MBF (Figure 10-11).

Table 10-41 RegD self scheduled regulation by month: January 2018 through September 2020

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	RegD Percent of Total Self Scheduled Effective MW	RegD Percent of Total Effective MW
2019	Jan	223.0	303.6	345.8	674.0	64.5%	45.0%
2019	Feb	243.3	311.5	350.8	673.9	69.4%	46.2%
2019	Mar	240.9	314.2	347.0	647.6	69.4%	48.5%
2019	Apr	230.5	305.2	332.6	639.6	69.3%	47.7%
2019	May	213.2	297.2	330.9	639.9	64.4%	46.4%
2019	Jun	206.3	289.1	331.9	697.6	62.1%	41.4%
2019	Jul	188.5	290.3	285.9	703.1	65.9%	41.3%
2019	Aug	200.3	290.2	309.4	696.9	64.7%	41.6%
2019	Sep	198.9	269.4	312.2	639.8	63.7%	42.1%
2019	Oct	181.1	263.7	295.1	642.2	61.4%	41.1%
2019	Nov	192.6	255.2	313.1	639.9	61.5%	39.9%
2019	Dec	233.3	278.3	344.9	674.0	67.6%	41.3%
2019 Average		212.7	289.0	325.0	664.0	65.3%	43.6%
2020	Jan	253.3	311.9	376.5	674.0	67.3%	46.3%
2020	Feb	263.6	333.5	385.3	674.0	68.4%	49.5%
2020	Mar	257.9	319.9	358.9	639.9	71.9%	50.0%
2020	Apr	267.2	318.1	382.9	639.7	69.8%	49.7%
2020	May	274.6	312.2	388.5	639.8	70.7%	48.8%
2020	Jun	281.8	335.1	390.5	696.7	72.2%	48.1%
2020	Jul	252.6	343.3	369.3	697.1	68.4%	49.2%
2020	Aug	258.7	341.0	357.2	697.0	72.4%	48.9%
2020	Sep	275.4	317.2	363.3	639.6	75.8%	49.6%
Average		265.0	350.2	374.7	666.4	70.8%	48.9%

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 the first nine months of 2020, 46.7 percent was purchased in the PJM market, 48.3 percent was self scheduled, and 5.0 percent was purchased bilaterally (Table 10-42). Table 10-43 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for January through September,

2012 to 2020. Table 10-42 and Table 10-43 are based on settled (purchased) MW.

Table 10-42 Regulation sources: spot market, self scheduled, bilateral purchases: January 2019 through September 2020

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)
2019	Jan	190,256.0	50.0%	170,091.0	44.7%	20,426.0	5.4%	380,773.0
2019	Feb	173,403.6	50.4%	154,652.2	45.0%	15,841.0	4.6%	343,896.8
2019	Mar	176,012.6	48.1%	175,580.7	47.9%	14,679.0	4.0%	366,272.3
2019	Apr	170,454.4	49.1%	158,313.1	45.6%	18,133.0	5.2%	346,900.4
2019	May	165,667.4	46.4%	166,367.6	46.6%	25,305.0	7.1%	357,340.1
2019	Jun	210,077.0	54.5%	155,567.8	40.3%	19,950.0	5.2%	385,594.8
2019	Jul	249,225.2	61.9%	134,210.8	33.3%	19,405.5	4.8%	402,841.5
2019	Aug	232,920.9	58.3%	146,362.4	36.6%	20,246.5	5.1%	399,529.8
2019	Sep	187,018.5	53.2%	144,562.1	41.1%	20,200.0	5.7%	351,780.6
2019	Oct	208,324.1	56.1%	146,362.4	39.4%	16,859.0	4.5%	371,545.5
2019	Nov	194,713.4	54.0%	150,835.9	41.8%	14,924.5	4.1%	360,473.7
2019	Dec	209,273.2	53.8%	164,379.1	42.3%	15,323.0	3.9%	388,975.3
Total		2,367,346.1	53.1%	1,867,285.3	41.9%	221,292.5	5.0%	4,455,923.9
2020	Jan	179,061.4	46.2%	190,434.8	49.1%	18,166.0	4.7%	387,662.1
2020	Feb	160,674.9	43.8%	185,702.6	50.6%	20,815.5	5.7%	367,193.0
2020	Mar	175,560.8	46.5%	181,566.1	48.1%	20,266.0	5.4%	377,392.8
2020	Apr	154,642.4	42.4%	187,819.3	51.5%	22,195.5	6.1%	364,657.2
2020	May	167,682.0	44.2%	191,949.3	50.5%	20,125.5	5.3%	379,756.8
2020	Jun	192,336.9	49.3%	178,239.7	45.7%	19,479.5	5.0%	390,056.1
2020	Jul	189,098.3	46.4%	198,595.7	48.7%	19,997.5	4.9%	407,691.5
2020	Aug	207,948.6	51.1%	181,392.4	44.6%	17,756.0	4.4%	407,097.0
2020	Sep	181,955.4	49.6%	171,428.3	46.7%	13,358.0	3.6%	366,741.7
Total		1,608,960.6	46.7%	1,667,128.2	48.3%	172,159.5	5.0%	3,448,248.3

Table 10-43 Regulation sources: January through September, 2012 through 2020

Year (Jan-Sep)	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	5,110,747.9	79.7%	1,122,671.9	17.5%	180,121.0	2.8%	6,413,540.8
2013	2,528,830.3	60.8%	1,478,608.5	35.5%	152,328.5	3.7%	4,159,767.3
2014	1,836,488.7	51.8%	1,543,266.0	43.5%	166,857.0	4.7%	3,546,611.7
2015	1,897,225.7	54.7%	1,380,004.7	39.8%	193,529.1	5.6%	3,470,759.5
2016	1,672,795.5	47.8%	1,598,231.6	45.7%	226,803.5	6.5%	3,497,830.6
2017	1,849,333.5	54.1%	1,372,996.2	40.2%	196,759.5	5.8%	3,419,089.2
2018	2,124,551.1	61.8%	1,135,540.8	33.0%	178,593.5	5.2%	3,438,685.4
2019	1,755,035.5	52.6%	1,405,707.9	42.2%	174,186.0	5.2%	3,334,929.4
2020	1,608,960.6	46.7%	1,667,128.2	48.3%	172,159.5	5.0%	3,448,248.3

In the first nine months of 2020, DR provided an average of 12.6 MW of regulation per hour during ramp hours (17.0 MW of regulation per hour during ramp hours in the first nine months of 2019), and an average of 9.2 MW of regulation per hour during nonramp hours (14.3 MW of regulation per hour during nonramp hours in the first nine months of 2019). Generating units supplied an average of 690.7 MW of regulation per hour during ramp hours in the first nine months of 2020 (706.8 MW of regulation per hour during ramp hours in the first nine months of 2019), and an average of 480.6 MW per hour during nonramp hours in the first nine months of 2020 (454.0 MW of regulation per hour during nonramp hours in the first nine months of 2019).

Market Performance

Price

Table 10-47 shows the regulation price and regulation cost per MW for January through September, 2009 through 2020. The weighted average RMCP for the first nine months of 2020 was \$12.59 per MW. This is a decrease of \$2.38 per MW, or 15.9 percent, from the weighted average RMCP of \$14.97 per MW in the first nine months of 2019. This decrease in the regulation clearing price was the result of a decrease in energy prices in the first nine months of 2020 and the related decrease in the opportunity cost component of RMCP.

Figure 10-20 shows the capability price, performance price, and the opportunity cost component for the PJM Regulation Market on a performance adjusted MW basis. The regulation clearing price is determined based on the marginal unit's total offer (RCP + RPP + PJM calculated LOC). Then the maximum performance offer price (RPP) of any of the cleared units is used to set the marginal performance clearing price for the purposes of settlements. The difference between the marginal total clearing price and the highest performance clearing price (RMPCP) is the marginal capability clearing price (RMCCP). The capability price presented here is equal to the clearing price, minus the maximum cleared performance offer price. This data is based on actual five minute interval operational data.

Figure 10-20 illustrates the components of the regulation market clearing price. Each section represents the contribution of the lost opportunity cost (green area), capability price (blue area), and performance price (orange area), to the total price. From this figure, it is clear that the lost opportunity cost is the predominant component of the total clearing price.

Figure 10-20 Regulation market clearing price components (Dollars per MW): January through September, 2020

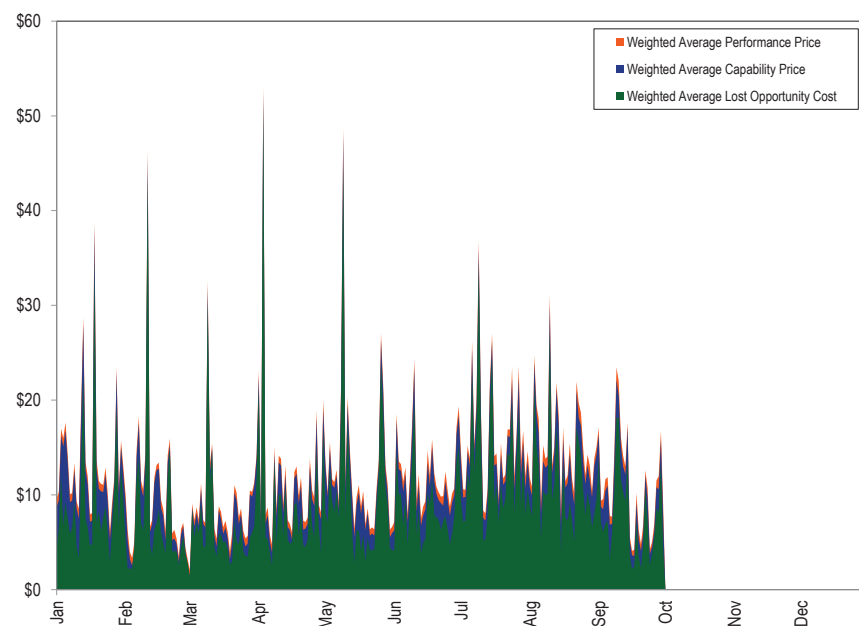


Table 10-44 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-19 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-44 PJM regulation market monthly component of price (Dollars per MW): January through September, 2020

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	\$12.89	\$0.81	\$13.70
Feb	\$9.44	\$0.68	\$10.12
Mar	\$8.41	\$0.65	\$9.06
Apr	\$11.33	\$0.77	\$12.10
May	\$12.28	\$0.69	\$12.97
Jun	\$11.42	\$0.89	\$12.31
Jul	\$15.24	\$0.90	\$16.14
Aug	\$14.33	\$1.03	\$15.36
Sep	\$9.99	\$0.89	\$10.88
Average	\$11.77	\$0.82	\$12.59

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly average regulation price and regulation cost are shown in Table 10-45. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges in the first nine months of 2020 was \$53.7 million, compared to \$63.9 million in the first nine months of 2019.

Table 10-45 Total regulation charges: January 2019 through September 2020

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges (\$)	Weighted Average Regulation Market Price (\$/MW)	Cost of Regulation (\$/MW)	Price as Percent of Cost
2019	Jan	380,773.0	\$7,272,344	\$14.71	\$19.10	77.0%
2019	Feb	343,896.8	\$5,651,921	\$12.30	\$16.43	74.9%
2019	Mar	366,272.3	\$7,204,760	\$15.00	\$19.67	76.3%
2019	Apr	346,900.4	\$7,528,065	\$16.96	\$21.70	78.2%
2019	May	357,340.1	\$6,116,384	\$12.90	\$17.12	75.4%
2019	Jun	385,594.8	\$5,752,677	\$11.37	\$14.92	76.2%
2019	Jul	402,841.5	\$8,187,698	\$16.16	\$20.32	79.5%
2019	Aug	399,529.8	\$7,358,409	\$14.62	\$18.42	79.4%
2019	Sep	351,780.6	\$8,806,206	\$20.91	\$25.03	83.5%
2019	Oct	371,545.5	\$11,481,407	\$25.70	\$30.90	83.2%
2019	Nov	360,473.7	\$7,991,507	\$19.12	\$22.17	86.2%
2019	Dec	388,975.3	\$7,195,341	\$15.85	\$18.50	85.7%
Yearly		4,455,923.9	\$90,506,378	\$16.27	\$20.31	80.1%
2020	Jan	387,662.1	\$6,493,789	\$13.70	\$16.75	81.8%
2020	Feb	367,193.0	\$4,630,253	\$10.12	\$12.61	80.3%
2020	Mar	377,392.8	\$4,619,257	\$9.06	\$12.24	74.0%
2020	Apr	364,657.2	\$5,646,138	\$12.10	\$15.48	78.1%
2020	May	379,756.8	\$6,078,957	\$12.97	\$16.01	81.0%
2020	Jun	390,056.1	\$6,072,212	\$12.31	\$15.57	79.1%
2020	Jul	407,691.5	\$7,730,514	\$16.14	\$18.96	85.1%
2020	Aug	407,097.0	\$7,565,597	\$15.36	\$18.58	82.7%
2020	Sep	366,741.7	\$4,909,050	\$10.88	\$13.39	81.3%
Average		3,448,248.3	\$53,745,767	\$12.59	\$15.59	80.8%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-46. Total scheduled regulation is based on settled performance adjusted MW. In the first nine months of 2020, the average total cost of regulation was \$15.59 per MW, 18.6 percent lower than \$19.15 in the first nine months of 2019. In the first nine months of 2020, the monthly average capability component cost of regulation was \$12.18, 13.6 percent lower than \$14.10 in the first nine months of 2019. In the first

nine months of 2020, the monthly average performance component cost of regulation was \$1.64, 42.6 percent lower than \$2.87 in the first nine months of 2019. The reduction of the average total cost in the first nine months of 2020 versus the first nine months of 2019, was primarily a result of lower LOC values due to lower prices in the energy market.

Table 10-46 Components of regulation cost: January 2019 through September 2020

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability (\$/MW)	Cost of Regulation Performance (\$/MW)	Opportunity Cost (\$/MW)	Total Cost (\$/MW)
2019	Jan	380,773.0	\$13.91	\$2.68	\$2.51	\$19.10
	Feb	343,896.8	\$11.51	\$2.67	\$2.26	\$16.43
	Mar	366,272.3	\$14.33	\$2.63	\$2.71	\$19.67
	Apr	346,900.4	\$16.18	\$2.65	\$2.88	\$21.70
	May	357,340.1	\$12.27	\$2.46	\$2.39	\$17.12
	Jun	385,594.8	\$10.35	\$3.10	\$1.47	\$14.92
	Jul	402,841.5	\$15.06	\$3.19	\$2.07	\$20.32
	Aug	399,529.8	\$13.59	\$3.31	\$1.52	\$18.42
	Sep	351,780.6	\$20.01	\$2.98	\$2.04	\$25.03
	Oct	371,545.5	\$24.61	\$3.49	\$2.81	\$30.90
	Nov	360,473.7	\$18.75	\$1.62	\$1.80	\$22.17
	Dec	388,975.3	\$15.42	\$1.78	\$1.29	\$18.50
Yearly		4,455,923.9	\$15.47	\$2.72	\$2.12	\$20.31
2020	Jan	387,662.1	\$13.32	\$1.80	\$1.63	\$16.75
	Feb	367,193.0	\$9.90	\$1.35	\$1.36	\$12.61
	Mar	377,392.8	\$8.71	\$1.46	\$2.07	\$12.24
	Apr	364,657.2	\$11.68	\$1.77	\$2.03	\$15.48
	May	379,756.8	\$12.66	\$1.39	\$1.95	\$16.01
	Jun	390,056.1	\$11.74	\$1.94	\$1.88	\$15.57
	Jul	407,691.5	\$15.75	\$1.54	\$1.67	\$18.96
	Aug	407,097.0	\$14.80	\$2.01	\$1.78	\$18.58
	Sep	366,741.7	\$10.42	\$1.49	\$1.47	\$13.39
Average		3,448,248.3	\$12.18	\$1.64	\$1.76	\$15.59

Table 10-47 provides a comparison of the average price and cost for PJM regulation. The ratio of regulation market price to the cost of regulation in the first nine months of 2020 was 80.8 percent, a 3.4 percent increase from 78.1 percent in the first nine months of 2019.

Table 10-47 Comparison of average price and cost for PJM regulation: January through September, 2009 through 2020

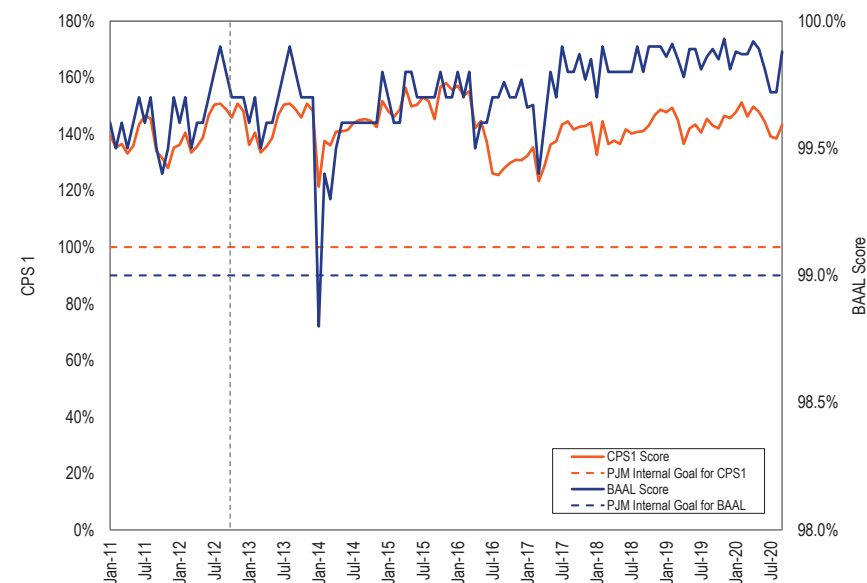
Year (Jan-Sep)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	\$24.94	\$7.34	340.0%
2010	\$19.47	\$15.06	129.3%
2011	\$17.04	\$15.66	108.8%
2012	\$15.16	\$5.91	256.4%
2013	\$33.29	\$38.49	86.5%
2014	\$50.19	\$60.94	82.4%
2015	\$35.56	\$43.00	82.7%
2016	\$16.52	\$18.99	87.0%
2017	\$15.70	\$21.70	72.4%
2018	\$28.21	\$35.06	80.5%
2019	\$14.97	\$19.15	78.1%
2020	\$12.59	\$15.59	80.8%

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-21 for every month from January 2011 through September 2020 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.⁹³ 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.

⁹³ See 2019 State of the Market Report for PJM, Appendix F: Ancillary Services.

Figure 10-21 PJM monthly CPS1 and BAAL performance: January 2011 through September 2020



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.⁹⁴ ⁹⁵ 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.

On February 1, 2019, PJM issued an incremental RFP for additional black start service in the BGE Zone. The RFP is a two stage process. Level one submissions

were due February 25, 2019. On March 8, 2019, PJM notified participants if a level two response would be requested. Level two bidders were requested by PJM to provide their detailed proposals by May 1, 2019. After the reviews were completed, none of the proposals were selected.

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 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.⁹⁶

In the first nine months of 2020, total black start charges were \$49.300 million, an increase of \$0.894 million (1.8 percent) from the same nine month period in 2019. Operating reserve charges for black start service decreased from \$0.175 million in the first nine months of 2019 to \$0.160 million in the first nine months of 2020. Table 10-48 shows total revenue requirement charges in the first nine months of 2010 through 2020. 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.

⁹⁴ See PJM, "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).

⁹⁵ RFPs issued can be found on the PJM website. See PJM. <<http://www.pjm.com/markets-and-operations/ancillary-services.aspx>>.

⁹⁶ OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).

Table 10-48 Black start revenue requirement charges: January through September, 2010 through 2020

Jan-Sep	Revenue Requirement Charges	Operating Reserve Charges	Total
2010	\$8,527,000	\$0	\$8,527,000
2011	\$9,996,898	\$0	\$9,996,898
2012	\$13,288,491	\$0	\$13,288,491
2013	\$15,728,447	\$68,903,357	\$84,631,804
2014	\$18,395,320	\$26,661,658	\$45,056,978
2015	\$39,718,855	\$5,070,944	\$44,789,799
2016	\$51,565,656	\$180,265	\$51,745,921
2017	\$52,422,434	\$186,752	\$52,609,186
2018	\$48,938,203	\$152,720	\$49,090,923
2019	\$48,231,346	\$175,400	\$48,406,746
2020	\$49,140,656	\$159,707	\$49,300,363

Black start zonal charges in the first nine months of 2020 ranged from \$0.04 per MW-day in the DLCO Zone (total charges were \$32,721) to \$3.95 per MW-day in the PENELEC Zone (total charges were \$3,260,274). For each zone, Table 10-49 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 \$1.08 per MW-day of reserve capacity during the first nine months of 2020.

Table 10-49 Black start zonal charges: January through September, 2019 and 2020⁹⁷

Zone	Jan-Sep 2019					Jan-Sep 2020				
	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW)	Black Start Rate (\$/MW-day)	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW)	Black Start Rate (\$/MW-day)
AECO	\$2,028,149.33	\$8,011.40	\$2,036,160.73	2,591	\$2.88	\$1,926,537.52	\$6,897.98	\$1,933,435.50	2,737	\$2.58
AEP	\$12,971,807.13	\$45,019.51	\$13,016,826.64	22,739	\$2.10	\$12,942,796.74	\$24,094.67	\$12,966,891.41	22,498	\$2.10
APS	\$2,922,052.35	\$1,102.36	\$2,923,154.71	9,342	\$1.15	\$2,866,141.17	\$1,158.85	\$2,867,300.02	9,596	\$1.09
ATSI	\$3,979,965.19	\$1,482.43	\$3,981,447.62	12,825	\$1.14	\$4,177,998.52	\$8,482.88	\$4,186,481.40	12,567	\$1.22
BGE	\$283,259.58	\$955.70	\$284,215.28	6,627	\$0.16	\$127,034.94	\$627.95	\$127,662.89	6,706	\$0.07
ComEd	\$3,156,492.99	\$12,469.93	\$3,168,962.92	21,349	\$0.54	\$5,885,976.76	\$11,261.74	\$5,897,238.50	20,949	\$1.03
DAY	\$157,663.45	\$1,176.13	\$158,839.58	3,337	\$0.17	\$163,532.19	\$14,119.98	\$177,652.17	3,259	\$0.20
DEOK	\$264,062.25	\$0.00	\$264,062.25	5,195	\$0.19	\$266,887.45	\$12,764	\$279,651.01	5,052	\$0.20
DLCO	\$33,657.14	\$0.00	\$33,657.14	2,795	\$0.04	\$32,721.34	\$0	\$32,721.34	2,662	\$0.04
Dominion	\$2,659,767.66	\$19,300.00	\$2,679,067.66	21,232	\$0.46	\$3,584,339.37	\$20,790.76	\$3,605,130.13	19,931	\$0.66
DPL	\$1,663,278.37	\$12,448.10	\$1,675,726.47	4,002	\$1.53	\$1,624,805.05	\$13,361.10	\$1,638,166.15	4,098	\$1.46
EKPC	\$250,756.86	\$1,964.45	\$252,721.31	3,431	\$0.27	\$245,425.32	\$1,640.67	\$247,065.99	3,074	\$0.29
JCPL	\$5,073,428.22	\$7,185.65	\$5,080,613.87	5,977	\$3.11	\$2,559,373.06	\$3,058.30	\$2,562,431.36	6,057	\$1.54
Met-Ed	\$344,956.70	\$31,386.46	\$376,343.16	3,028	\$0.46	\$301,701.49	\$9,841.90	\$311,543.39	2,986	\$0.38
OVEC	\$0	\$0	\$0	NA	NA	\$0	\$0	\$0	NA	NA
PECO	\$1,016,447.73	\$3,169.06	\$1,019,616.79	8,608	\$0.43	\$1,037,308.66	\$1,261.21	\$1,038,569.87	8,428	\$0.45
PENELEC	\$3,297,980.78	\$1,284.48	\$3,299,265.26	2,997	\$4.03	\$3,251,322.83	\$8,951.54	\$3,260,274.37	3,015	\$3.95
Pepco	\$1,846,793.47	\$8,759.17	\$1,855,552.64	6,412	\$1.06	\$1,475,262.40	\$6,494.85	\$1,481,757.25	6,191	\$0.87
PPL	\$837,500.24	\$7,278.63	\$844,778.87	7,681	\$0.40	\$2,112,492.37	\$4,965.00	\$2,117,457.37	7,939	\$0.97
PSEG	\$3,136,784.70	\$4,526.46	\$3,141,311.16	9,978	\$1.15	\$2,096,712.05	\$2,350.27	\$2,099,062.32	9,753	\$0.79
RECO	\$0	\$0	\$0	NA	NA	\$0	\$0	\$0	NA	NA
(Imp/Exp/Wheels)	\$2,306,542.31	\$7,879.71	\$2,314,422.02	8,067	\$1.05	\$2,462,287.19	\$7,583.77	\$2,469,870.96	8,338	\$1.08
Total	\$48,231,346.45	\$175,399.63	\$48,406,746.08	168,213	\$1.05	\$49,140,656.42	\$159,706.98	\$49,300,363.40	165,834	\$1.08

⁹⁷ Peak load for each zone is used to calculate the black start rate per MW day.

Table 10-50 provides a revenue requirement estimate by zone for the 2020/2021, 2021/2022 and 2022/2023 Delivery Years.⁹⁸ 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 10-50 Black start zonal revenue requirement estimate: 2020/2021 through 2022/2023 delivery years

Zone	2020 / 2021 Revenue Requirement	2021 / 2022 Revenue Requirement	2022 / 2023 Revenue Requirement
AECO	\$2,750,000	\$2,150,000	\$2,100,000
AEP	\$20,700,000	\$21,650,000	\$21,450,000
APS	\$5,050,000	\$10,300,000	\$10,300,000
ATSI	\$5,900,000	\$5,900,000	\$5,900,000
BGE	\$50,000	\$100,000	\$100,000
ComEd	\$9,800,000	\$9,950,000	\$9,300,000
DAY	\$250,000	\$300,000	\$250,000
DEOK	\$400,000	\$450,000	\$350,000
DLCO	\$400,000	\$2,100,000	\$2,100,000
Dominion	\$5,650,000	\$5,750,000	\$5,500,000
DPL	\$2,250,000	\$1,350,000	\$1,250,000
EKPC	\$350,000	\$400,000	\$300,000
JCPL	\$850,000	\$900,000	\$800,000
Met-Ed	\$400,000	\$550,000	\$450,000
OVEC	\$0	\$0	\$0
PECO	\$1,550,000	\$1,700,000	\$1,450,000
PENELEC	\$4,550,000	\$4,650,000	\$4,550,000
Pepco	\$700,000	\$350,000	\$350,000
PPL	\$4,750,000	\$5,250,000	\$5,200,000
PSEG	\$1,750,000	\$1,850,000	\$1,750,000
RECO	\$0	\$0	\$0
Total	\$68,100,000	\$75,650,000	\$73,450,000

CRF Issues

The capital recovery factor (CRF) defines the revenue requirement of black start units. The CRF is a rate, which when multiplied by the investment, provides for a return on and of capital over a defined time period. CRFs are calculated using a standard financial model that accounts for the weighted average cost of capital and its components, including depreciation and taxes. For example, a five year CRF will allow the recovery of 100 percent of the investment plus a return and associated taxes over five years. The PJM CRF table was created in 2007 as part of the new RPM capacity market design and incorporated in Attachment DD to the PJM OATT (Table 10-51). The CRF table provided for the accelerated return of incremental investment in capacity resources based on concerns about the fact that some old coal units would be making substantial investments related to pollution control. The CRF values were later added to the black start rules. The CRF table includes assumptions about tax rates that

⁹⁸ The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

are no longer correct. The CRF values are significantly too high as a result. The PJM tariff tables including CRF values should have been changed for both black start and the capacity market when the tax laws changed in 2017.

Table 10-51 Existing CRF table for black start units

Age of Black Start Unit (Years)	Term of Black Start Unit Commitment (Years)	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

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

The tax code changed significantly in December 2017. The PJM CRF table did not change to reflect these changes. As a result, CRF values have overcompensated black start units since the changes to the tax code. The new depreciation rules allow for a more accelerated depreciation and therefore lower taxes. The tax code also reduced the corporate tax rate to 21 percent which also reduces taxes.

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

Table 10-52, the MMU proposed CRF table, includes CRF values based on the new tax code. The second column is the cost recovery period and not the commitment period.

Table 10-52 MMU Proposed CRF table for black start units

Age of Black Start Unit (Years)	Black Start Cost Recovery Period (Years)	Levelized CRF
1 to 5	20	0.096
6 to 10	15	0.111
11 to 15	10	0.144
16+	5	0.246

Overcompensation amounts vary with the project investment and the CRF recovery period (Table 10-53). For a new black start unit with an investment cost of \$21M, the overcompensation is \$12,180,000 over the 20 year recovery period. For a new black start unit with an investment of \$21M, the overcompensation is \$12,285,000 over the five year recovery period.

Table 10-53 Lifetime recovery of black start units with old and MMU proposed CRF

Example	Old CRF Rate	New CRF Rate	Project Investment	Old CRF Lifetime Recovery	New CRF Lifetime Recovery	Lifetime Difference
1	0.125	0.096	\$9,000,000	\$22,500,000	\$17,280,000	\$5,220,000
2	0.125	0.096	\$15,000,000	\$37,500,000	\$28,800,000	\$8,700,000
3	0.125	0.096	\$21,000,000	\$52,500,000	\$40,320,000	\$12,180,000
1	0.146	0.111	\$9,000,000	\$19,710,000	\$14,985,000	\$4,725,000
2	0.146	0.111	\$15,000,000	\$32,850,000	\$24,975,000	\$7,875,000
3	0.146	0.111	\$21,000,000	\$45,990,000	\$34,965,000	\$11,025,000
1	0.198	0.144	\$9,000,000	\$17,820,000	\$12,960,000	\$4,860,000
2	0.198	0.144	\$15,000,000	\$29,700,000	\$21,600,000	\$8,100,000
3	0.198	0.144	\$21,000,000	\$41,580,000	\$30,240,000	\$11,340,000
1	0.363	0.246	\$9,000,000	\$16,335,000	\$11,070,000	\$5,265,000
2	0.363	0.246	\$15,000,000	\$27,225,000	\$18,450,000	\$8,775,000
3	0.363	0.246	\$21,000,000	\$38,115,000	\$25,830,000	\$12,285,000

Table 10-54 shows the total excess payments to black start units that will result if the CRF issue is not addressed. The table includes the excess payments for units in service prior to the 2017 tax law change and excess payments for units in service after the 2017 tax law change. For the pre 2017 units, the CRF

rates were changed to reflect only the change in the tax rate, and for the post 2017 units, the CRF rates were changed to reflect both the change in the tax rate and the change in the tax depreciation treatment.

Table 10-54 Lifetime Difference of black start units with old and MMU proposed CRF

Years	Existing Annual Revenue Requirement Total	New Annual Revenue Requirement Total	Difference Per Year Total	Lifetime Difference Total
Pre 2017 units	\$57,686,377	\$51,326,744	\$6,359,633	\$32,307,265
Post 2017 Units	\$28,479,043	\$19,840,359	\$8,638,684	\$64,020,531
Total	\$86,165,420	\$71,167,103	\$14,998,317	\$96,327,797

For the future, the CRF should be updated at least annually to reflect current interest rates and changes in federal or state taxes, including depreciation treatment and tax rates. Existing black start resources constructed prior to the new tax law and to which the new tax law depreciation rules did not apply should use a CRF calculated using the depreciation rules applicable to the investment in the resources, the current tax rate and the current interest rate.

NERC – CIP

Currently, no black start units have requested new or additional black start NERC – CIP Capital Costs.⁹⁹

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 10-22 illustrates that the size of the oil tank does not change with the addition of the black start unit. Figure 10-23 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.

⁹⁹ 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 10–22 Oil tank MTSL not changed from addition of black start generator

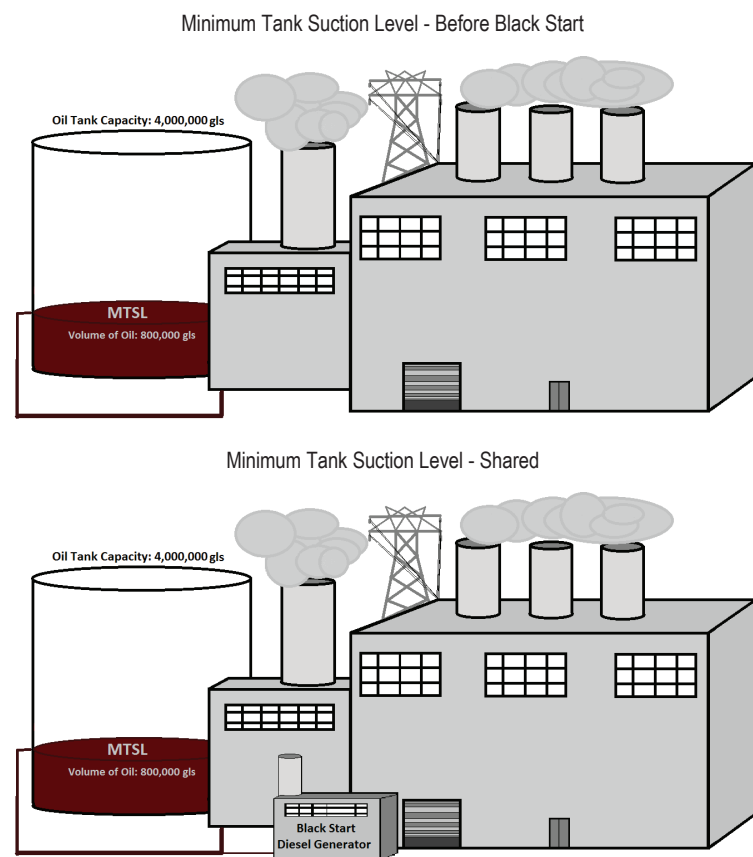
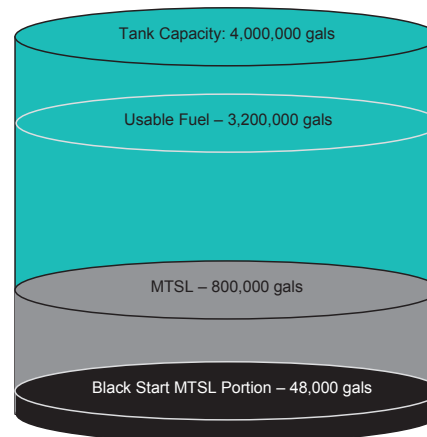


Figure 10–23 Oil tank black start MTSL portion



Reactive Power Service and Capability

Suppliers of reactive power are compensated separately for reactive power service and reactive capability. Compensation for reactive power service is determined based on real-time lost opportunity costs. Compensation for reactive capability is 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.¹⁰⁰

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

¹⁰⁰ See "PJM Manual 27: Open Access Transmission Tariff Accounting," § 3.2 Reactive Supply and Voltage Control Credits, Rev. 93, (Aug. 31, 2020).

compensators and capacitor banks).¹⁰¹ PJM in its role as the independent RTO and transmission provider determines the reactive capability it needs from all sources in order to reliably operate the grid. PJM, as part of its Interconnection Agreement, requires that all resources over 20 MW be able to operate at a power factor of 0.90 lagging to 0.95 leading throughout their entire operating range. This requirement ensures that even under extreme conditions every generator will be able to operate within the voltage schedule assigned to them either by PJM or their local transmission organization. Reactive power helps maintain appropriate voltages on the transmission system and must be sourced locally. Generators not modelled in the Bulk Electric System (BES) or connected at the subtransmission level (under 100kV line) will generally not be called on by PJM for reactive power service. Such generators may however, at present, schedule reactive power tests and enter test results into eDART and be compensated.¹⁰²

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements which are posted monthly on the PJM website.¹⁰³ 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 daily average point to point transmission reservations.^{104 105}

In 2016, the FERC began to reexamine its policies on reactive compensation.¹⁰⁶ 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.¹⁰⁷ The continued use of fleet rates rather than unit specific rates is also an issue.

¹⁰¹ OATT Schedule 2.

¹⁰² See "PJM Manual 3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA)," para 2.2 Model Information and Data Requirements, Rev. 18 (Dec. 5, 2019).

¹⁰³ 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).

¹⁰⁴ OATT Schedule 2.

¹⁰⁵ See "PJM Manual 27: Open Access Transmission Tariff Accounting," § 3.3 Reactive Supply and Voltage Control Charges, Rev. 93S (Aug. 1, 2020).

¹⁰⁶ 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).

¹⁰⁷ See 88 FERC ¶ 61,141 (1999).

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.¹⁰⁸ 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.¹⁰⁹ The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.¹¹⁰ 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.

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 organized markets. Increased reliance on markets for the recovery of reactive capability costs would promote efficiency and consistency. Customers, market administrators

¹⁰⁸ 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.").

¹⁰⁹ 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).

¹¹⁰ Order No. 827, 155 FERC ¶ 61,277 (2016); see also 151 FERC ¶ 61,097 at P 28 (2015).

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

Reactive compensation must be integrated into PJM's competitive market design. Reactive capability rates recover through cost of service rates exactly the same investment that capacity markets price at market based rates.

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 only go to the generating units that specifically support PJM grid operations and are fully subject to PJM dispatch, are based on capability that PJM needs to maintain system stability and do not constitute double recovery.

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 The only FERC proceeding that has provided an opportunity for the MMU to raise its concerns at hearing has been *Panda Stonewall LLC*.¹¹² The initial decision issued in that case sidesteps the issues identified by the MMU.¹¹³ These issues must be squarely addressed for PJM to have an even minimally satisfactory market design related to compensating investment in reactive capability that cannot be differentiated from investment in capacity.

Power Factor Capped at PJM Determined Level of Need

Under the *AEP* method, units must establish their MVAR rating based on “the capability of the generators to produce VARs.”¹¹⁴ Typically this has meant reliance on manufacturers’ specified nameplate power factor.¹¹⁵ More recently, the Commission has, in the *Wabash* Orders, required that “reactive power

revenue requirement filings must include reactive power test reports.”¹¹⁶ 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.¹¹⁷

The Commission has identified a significant issue. 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. However, power ratings, whether based on nameplate or testing, do not establish MVAR capability that is properly relevant to reactive capability rates in PJM. PJM determines the level of reactive capability it needs in its role as the independent RTO and transmission provider. Generation owners should not be permitted through uncoordinated reactive capability rates to substitute their assessment for PJM's.

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.¹¹⁸ 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 PJM required power factor value is the only value reasonably included in reactive capability rates because that is what PJM has determined it needs from each generator. Generators should not be permitted to make investment decisions that unnecessarily increase the cost of reactive capability. Individual owners have a conflict of interest concerning such decisions and are not

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 See Docket No. EL17-1821.

113 167 FERC ¶ 63,010 (April 26, 2019).

114 *AEP* *mimeo* at 31.

115 See, e.g., *id.*

116 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29 (*Wabash* Orders).

117 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.”).

118 See *supra* footnote 27.

authorized under the OATT to change PJM's determinations on the required power factor.

Reactive capability rates should not be confused with compensation for operating to provide reactive power at PJM's direction. 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.

Offset Cap on Reactive Capability Rates

In addition to effectively capping the appropriate level of the power factor, the PJM market rules also effectively cap the appropriate level of reactive capability rates overall.

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 included in the offset is not part of net CONE.¹¹⁹ 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.

The revenue offset is defined as a fixed number in the OATT and is currently set equal at \$2,199/MW-year.¹²⁰ This 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 PJM market rules explicitly account for recovery of reactive revenues of \$2,199 per MW-year. Reactive capability rates up to that level do not result in double recovery. Reactive capability rates above that level do result in double recovery because costs that would support a rate exceeding \$2,199 per MW-year continue to be recoverable in the PJM Capacity Market.

The \$2,199 offset is a simple rule that established a just and reasonable reconciliation of different regulatory approaches in the same market design. The offset assumes a defined level of revenues are received under cost of service rates and nets them from the parameters used in the capacity market. Those parameters define the operation of the market so that just and reasonable capacity prices are established. Reactive rates cannot be just and reasonable if they do not account for the market design in which PJM units operate.

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.¹²¹ 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 these issues through participation in proceedings at FERC concerning reactive capability rates for PJM units.¹²²

¹¹⁹ See OATT Attachment DD § 5.10(a)(iv).

¹²⁰ See OATT Attachment DD § 5.10(a)(v).

¹²¹ See OATT Attachment DD §§ 6.4, 6.8(d).
¹²² The MMUs has to date participated in nearly 150 reactive matters. 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.

Losses

The estimated capability costs also include estimated heating losses relative to MVAR output.¹²³ Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.¹²⁴ 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 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.

Fleet Rates

Cost of service rates are established under Schedule 2 of the OATT and may cover rates for single units or a fleet of units.¹²⁵ 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.¹²⁶ 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.¹²⁷

Fleet rates create confusion about what revenue is properly attributable to each unit in the fleet. Reactive rates should be stated separately for each unit, even if multiple plants or units are considered in a single proceeding. The MMU filed with the Commission to require unit specific rates when PJM proposed limited reforms that could have corrected the oversight and compliance problems

¹²³ 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).

¹²⁴ 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.

¹²⁵ See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).

¹²⁶ See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.

¹²⁷ *Id.*

posed by fleet rates.¹²⁸ But PJM rules require fleet owners only to submit informational filings when a reactive unit is transferred or deactivated.¹²⁹ The current rules do not require a rate filing, which would place the burden of proof on the company and allow for cost review.¹³⁰

The MMU also raised issues related to fleet rates in a settlement establishing a fleet rate without specifying the actual portion of the fleet rate attributable to each unit in the fleet.¹³¹ The approach could prevent or inhibit an appropriate adjustment of the fleet requirement if a unit receiving an unspecified portion of such requirement is deactivated or transferred because third parties without access to cost information would bear the burden of proof in a complaint proceeding.¹³² The MMU also explained that the approach makes it impossible to calculate cost-based offers from such units in the PJM Capacity Market. The settlement was approved over the MMU's objection on the grounds that the tariff does not prohibit fleet rates.¹³³

The MMU recommends that fleet rates be eliminated and that compensation be based on unit specific costs and rates.

Reactive Costs

In the first nine months of 2020, total reactive charges were \$266.0 million, a 6.2 percent increase from the \$250.6 million for the first nine months of 2019. Reactive capability charges increased from \$250.1 million in the first nine months of 2019 to \$265.6 million in the first nine months of 2020 and reactive service charges decreased from \$0.466 million in the first nine months of 2019 to \$0.412 million in the first nine months of 2020. All \$4.12 million in the first nine months of 2020 were paid for reactive service provided by 15 units in 124 hours.

Table 10-55 shows reactive service charges in the first nine months of 2019 and the first nine months of 2020, reactive capability charges and total charges. Reactive service charges show charges to each zone for reactive

¹²⁸ 151 FERC ¶ 61,224 at P 29 (2015).

¹²⁹ OATT Schedule 2.

¹³⁰ *Id.*

¹³¹ See Letter Opposing Settlement, Docket No ER06-554 et al. (June 14, 2017).

¹³² *Id.*

¹³³ 162 FERC ¶ 61,029 (2018).

service provided and not credits to plants in each zone. Reactive capability charges show charges to each zone for reactive capability.

Table 10-55 Reactive service charges and reactive capability charges by zone: January through September, 2019 and 2020

Zone	Jan-Sep 2019			Jan-Sep 2020		
	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
AECO	\$0	\$3,220,440	\$3,220,440	\$0	\$3,213,247	\$3,213,247
AEP	\$16,330	\$35,169,292	\$35,185,622	\$0	\$36,490,059	\$36,490,059
APS	\$14,903	\$11,282,129	\$11,297,032	\$0	\$13,060,933	\$13,060,933
ATSI	\$697	\$19,114,377	\$19,115,073	\$0	\$18,965,684	\$18,965,684
BGE	\$0	\$5,390,946	\$5,390,946	\$0	\$5,254,704	\$5,254,704
ComEd	\$0	\$27,240,093	\$27,240,093	\$0	\$30,188,033	\$30,188,033
DAY	\$0	\$2,112,619	\$2,112,619	\$0	\$2,107,900	\$2,107,900
DEOK	\$0	\$7,156,674	\$7,156,674	\$0	\$7,140,689	\$7,140,689
Dominion	\$182,436	\$28,791,280	\$28,973,716	\$0	\$30,058,725	\$30,058,725
DPL	\$112,469	\$7,372,780	\$7,485,250	\$10,538	\$7,924,044	\$7,934,581
DLCO	\$0	\$428,142	\$428,142	\$0	\$427,185	\$427,185
EKPC	\$0	\$1,635,666	\$1,635,666	\$45,499	\$1,632,013	\$1,677,512
JCPL	\$0	\$5,495,701	\$5,495,701	\$171,332	\$5,619,768	\$5,791,100
Met-Ed	\$1,093	\$3,776,068	\$3,777,161	\$4,631	\$4,638,623	\$4,643,254
OVEC	\$0	\$0	\$0	\$0	\$0	\$0
PECO	\$0	\$14,511,950	\$14,511,950	\$0	\$15,796,212	\$15,796,212
PENELEC	\$137,908	\$9,655,174	\$9,793,082	\$0	\$13,281,589	\$13,281,589
Pepco	\$0	\$8,354,253	\$8,354,253	\$0	\$8,236,634	\$8,236,634
PPL	\$0	\$26,060,684	\$26,060,684	\$180,337	\$26,496,380	\$26,676,717
PSEG	\$0	\$20,589,440	\$20,589,440	\$0	\$20,955,661	\$20,955,661
RECO	\$0	\$0	\$0	\$0	\$0	\$0
(Imp/Exp/Wheels)	\$0	\$12,768,881	\$12,768,881	\$0	\$14,118,796	\$14,118,796
Total	\$465,836	\$250,126,590	\$250,592,426	\$412,336	\$265,606,877	\$266,019,213

Table 10-56 shows the units which have received reactive service credits for the first nine months of 2020.

Table 10-56 Reactive service credits by plant: January through September, 2020

Jan - Sep 2020		
Zone	Plant	Reactive Service Credits
DPL	DPL COMM CHESAPEAKE - NEW CHURCH 2 CT	\$10,508
DPL	DPL BAYVIEW 2 D	\$16
DPL	DPL BAYVIEW 1 D	\$13
EKPC	EKPC COOPER 1 F	\$27,194
EKPC	EKPC COOPER 2 F	\$18,305
JCPL	JC WOODBRIDGE 1 CC	\$55,470
JCPL	JC WOODBRIDGE 2 CC	\$55,464
JCPL	JC LAKEWOOD NUG F	\$28,471
JCPL	JC LAKEWOOD 2 CT	\$17,359
JCPL	JC LAKEWOOD 1 CT	\$14,567
METED	ME MOUNTAIN 1 CT	\$4,631
PPL	PL HAZELTON 4 CT	\$108,584
PPL	PL HARWOOD 1-2 CT	\$36,103
PPL	PL HAZELTON 3 CT	\$29,560
PPL	PL HAZELTON 2 CT	\$6,090
Total		\$412,336

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.¹³⁴ 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.¹³⁵

¹³⁴ 157 FERC ¶ 61,122 (2016).

¹³⁵ See 164 FERC ¶ 61,224 (2018).

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

Frequency Control Definition

There are four distinct types of frequency control, distinguished by response timeframe and operational nature: Inertial Response, Primary Frequency Response, Secondary Frequency Control, 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 15 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.

VACAR Reserve Sharing Agreement

The VACAR Reserve Sharing Agreement (VRSA) is a combination of agreements among the entities in the VACAR subregion including Dominion. VACAR is a subregion of the SERC Reliability Corporation (SERC) region.¹³⁶ The agreement requires that each entity maintain primary reserves to meet the VACAR contingency reserve commitment (VACAR reserves) and deploy such reserves in the case of an emergency (e.g. loss of a unit in VACAR).¹³⁷ Dominion is the only party in the VRSA in PJM.

PJM procures Day-Ahead Scheduling Reserves (DASR) for the PJM region, including Dominion. The DASR requirement is calculated daily and it is equal to the peak load forecast for the ReliabilityFirst region (RFC) and EKPC times the sum of the forced outage rate and the load forecast error plus Dominion's share of the VACAR contingency reserve commitment. All units in PJM that meet the DASR operating parameter requirements are eligible to meet the DASR requirement.¹³⁸ There is no requirement that a specific amount of DASR be located in Dominion. Equation 10-1 shows the DASR requirement calculation.¹³⁹

Equation 10-1: DASR Requirement Formula.

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

PJM procures synchronized reserves and primary reserves for the PJM region, including Dominion. The synchronized reserve and primary reserve requirements are equal to the largest single contingency and 150 percent of the largest contingency. The requirement is procured separately for the RTO and the MidAtlantic Dominion area (MAD) when the largest contingency

¹³⁶ Duke Energy Progress, Duke Energy Carolinas, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas.

¹³⁷ See SERC Regional Criteria, Contingency Reserve Policy, NERC Reliability Standard BAL-002 at 10-11.

¹³⁸ DASR can be provided by units that do not clear the Day-Ahead Energy Market and can start within 30 minutes or by units that clear the Day-Ahead Energy Market and can ramp up within 30 minutes.

¹³⁹ During cold weather alerts and hot weather alerts, the DASR requirement is increased to procure additional reserves.

is located outside of MAD. All units in PJM that meet the synchronized or primary reserve operating parameter requirements are eligible to meet the synchronized and primary requirements as long as PJM does not deselect them.

The VRSA is not a public agreement. PJM is not a party to the VRSA.

PJM is expected to implement its ORDC proposal on May 1, 2022. One of the features of this proposal is that all reserve MW available in the system will be assigned and priced. Under the ORDC, it will not be possible for Dominion to hold reserves to meet the VRSA without double counting the reserves in PJM or withholding such reserves from PJM. After the implementation of the ORDC proposal, it will not be possible for Dominion to meet the VRSA and meet the PJM reserve rules.

Recommendations

The Market Monitor recommends that the details of VACAR Reserve Sharing Agreement (VRSA), including any responsibilities assigned to PJM, be made public.

The Market Monitor recommends that PJM make public the amount of reserves procured by Dominion to meet the VRSA.

The Market Monitor recommends that this agreement be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to other agreements between PJM and other bordering areas.

Congestion and Marginal Losses

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.¹ The difference is congestion.² As a result, congestion belongs to load and should be returned to load. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.³

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus 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 and the use of a load-weighted reference bus. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

SMP is the incremental price of energy for the system, given the current dispatch, at the load-weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load-weighted reference bus. The load-weighted reference bus is not a fixed location but varies with the distribution of load at system load buses. For SMP, energy means the component of LMP not associated with a binding transmission constraint. SMP is the system energy price.

CLMP is the incremental price of meeting load at each bus when a transmission constraint is binding, based on the shadow price associated with the relief of a binding transmission constraint in the security constrained optimization. (There can be multiple binding transmission constraints.) CLMPs are positive or negative depending on location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system CLMPs will be zero. This means that CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion. CLMP is a component of LMP at a bus that indicates whether the LMP at that bus is higher or lower than the system marginal load weighted average price for energy (SMP) due to binding

transmission constraints. The relative values of SMP and CLMP are arbitrary and depend on the 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 total system wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.⁴ The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the single higher price for all the energy used, including energy from low cost and energy from high cost generation, while generators are each paid the price at their individual bus. Congestion is the difference between what load pays based on the single higher price at load buses and what generators receive based on the lower prices at the individual generator buses due to binding transmission constraints.

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 CLMP charges plus net explicit CLMP charges plus net inadvertent CLMP charges. The net implicit CLMP charges are the implicit withdrawal CLMP charges less implicit injection CLMP credits.

¹ Withdrawals are generically referred to as load and injections are generically referred to as generation, unless specified otherwise.

² The difference in losses is not part of congestion.

³ PJM billing examples can be found in *2019 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

⁴ This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

The same point applies to total system energy costs and total marginal loss costs in the same way. As with congestion, total system energy costs are more precisely termed net system energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.⁵

Local congestion is the congestion paid by load at a specific bus or set of buses and is calculated on a constraint specific basis. Local congestion is the sum of the total CLMP charges to load at the defined set of buses minus the sum of the total CLMP credits received by all generation that supplied that load, given the set of all binding transmission constraints, regardless of location. Local congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load. Local congestion fully reflects the least cost security constrained system solution and the LMPs that result from that solution.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by \$23.0 million or 5.5 percent, from \$419.1 million in the first nine months of 2019 to \$396.1 million in the first nine months of 2020.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by \$8.9 million or 1.7 percent, from \$511.4 million in the first nine months of 2019 to \$502.5 million in the first nine months of 2020.

⁵ The total congestion and marginal losses for 2020 were calculated as of October 8, 2020, and are subject to change, based on continued PJM billing updates.

- **Balancing Congestion.** Negative balancing congestion costs increased by \$14.0 million or 15.1 percent, from -\$92.3 million in the first nine months of 2019 to -\$106.3 million in the first nine months of 2020. Negative balancing explicit charges increased by \$6.9 million, from -\$59.4 million in the first nine months of 2019 to -\$66.3 million in the first nine months of 2020.
- **Real-Time Congestion.** Real-time congestion costs increased by \$44.6 million or 8.6 percent, from \$517.3 million in the first nine months of 2019 to \$561.9 million in the first nine months of 2020.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2020 ranged from \$16.0 million in April to \$81.7 million in July.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Bagley – Graceton Line, the Conastone – Graceton Line, the Conastone – Peach Bottom Line, the Harwood – Susquehanna Line, and the Three Mile Island Transformer.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first nine months of 2020. The number of congestion event hours in the day-ahead energy market was about four times the number of congestion event hours in the real-time energy market.
Day-ahead congestion frequency decreased by 20.7 percent from 78,155 congestion event hours in the first nine months of 2019 to 61,957 congestion event hours in the first nine months of 2020.
Real-time congestion frequency increased by 23.5 percent from 13,495 congestion event hours in the first nine months of 2019 to 16,662 congestion event hours in the first nine months of 2020.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities except interfaces. The congestion event hours on the PA Central Interface increased from 43 hours in the first nine months of 2019 to 1,402 hours in the first nine months of 2020.

The Bagley – Graceton Line was the largest contributor to congestion costs in the first nine months of 2020. With \$56.2 million in total congestion costs, it accounted for 14.2 percent of the total PJM congestion costs in the first nine months of 2020.

- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** CT Price Setting Logic caused -\$0.4 million of day-ahead congestion in the first nine months of 2020 and -\$1.6 million of balancing congestion in the first nine months of 2020. None of the closed loop interfaces was binding in the first nine months of 2020 or 2019.
- **Zonal Congestion.** AEP had the largest zonal congestion costs among all control zones in the first nine months of 2020. AEP had \$72.0 million in zonal congestion costs, comprised of \$89.2 million in zonal day-ahead congestion costs and -\$17.2 million in zonal balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by \$153.5 million or 30.5 percent, from \$502.7 million in the first nine months of 2019 to \$349.2 million in the first nine months of 2020. The loss MWh in PJM decreased by 789.9 GWh or 6.8 percent, from 11,600.8 GWh in the first nine months of 2019 to 10,810.9 GWh in the first nine months of 2020. The loss component of real-time LMP in the first nine months of 2020 was \$0.01, compared to \$0.02 in the first nine months of 2019.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first nine months of 2020 ranged from \$22.5 million in April to \$67.0 million in July.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by \$151.1 million or 27.8 percent, from \$542.6 million in the first nine months of 2019 to \$391.5 million in the first nine months of 2020.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by \$2.4 million or 5.9 percent, from -\$39.9 million in the first nine months of 2019 to -\$42.3 million in the first nine months of 2020.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in the first nine months of 2020 by \$47.9 million or 29.6 percent, from

\$162.1 million in the first nine months of 2019, to \$114.2 million in the first nine months of 2020.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs increased by \$105.3 million or 31.0 percent, from -\$339.3 million in the first nine months of 2019 to -\$234.0 million in the first nine months of 2020.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs increased by \$104.0 million or 25.5 percent, from -\$407.6 million in the first nine months of 2019 to -\$303.6 million in the first nine months of 2020.
- **Balancing System Energy Costs.** Balancing system energy costs decreased by \$0.3 million or 0.5 percent, from \$68.0 million in the first nine months of 2019 to \$67.7 million in the first nine months of 2020.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first nine months of 2020 ranged from -\$42.5 million in July to -\$15.9 million in April.

Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and 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 the first nine months of 2020 was lower than congestion in the first nine months of any year from 2008 through 2019. This was the combined result of weather conditions and demand reductions due to COVID-19.

The monthly total congestion costs ranged from \$16.0 million in April to \$81.7 million in July in the first nine months of 2020.

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.⁶

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all congestion revenues. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first four months of the 2020/2021 planning period, using the rules effective for each planning period, was 75.0 percent. Load has been underpaid by \$2.2 billion from the 2011/2012 planning period through the first four months of the 2020/2021 planning period.

Issues

Closed Loop Interfaces and CT Pricing Logic

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 of 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.⁷ The objective of making inflexible resources marginal is to

⁶ 162 FERC ¶ 61,139 (2018).

⁷ The constrained side means the higher priced side with a positive CLMP created by the constraint.

artificially 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.

Failure to model the same constraints in the day-ahead and real-time markets 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. Unlike constraints that restrict the use of lower cost output in the system solution, the closed loop interface and CT price setting logic constraints are forcing the use of the relatively high cost resource. The sign of the shadow price of this artificial constraint in the optimization solution, unlike normal security constraints in a least cost dispatch optimization, is therefore positive because relaxing this constraint will cause system costs to go up, not down. Increasing the limit (relaxing) for a closed loop interface or CT price setting logic constraint requires an increase in the output from the high cost unit from within the artificially constrained area, and a decrease in output from low price generation from outside the artificially constrained area. This means that increasing the limit of a closed loop interface or CT price setting logic constraint causes a net increase in incremental cost for any increase in the flow limit of the constraint and a positive, rather than the usual negative, shadow price for the modeled transmission constraint.

The nature of the closed loop interface or CT price setting logic constraint is that more power is produced than consumed in the artificial closed loop or constrained area than would result without the closed loop. This means that there are more high CLMP generation credits than high CLMP load charges associated with the constrained area within the closed loop interface or CT price setting logic constraint. The rest of the system receives power from the closed loop/constrained area, the lower cost generators outside the closed loop/constrained area are backed down and prices are lower outside the loop than they would have been without the closed loop. While all of the generation within the artificially constrained area is paid the higher CLMP in the form of generation credits, a smaller amount of load (in some cases no load) pays this higher CLMP in the form of load charges within the loop. The residual energy is delivered and paid for at a lower CLMP outside the closed loop/constrained area. 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 that uneconomic generation costs that would otherwise be collected as uplift are being realized as negative congestion. In the day-ahead market this reduces the total congestion dollars that are available to FTR holders. In the balancing market these costs are allocated directly to load as negative balancing rather than to deviations as uplift charges.

Balancing Congestion Cost Calculation Logic Change

Effective April 1, 2018, PJM made a significant change to the calculation and allocation of balancing congestion costs.⁸

Prior to April 1, 2018, balancing implicit CLMP charges 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, at the time of the introduction of five minute settlements, PJM modified the calculation so that zonal and aggregate balancing implicit CLMP charges are now determined by netting the bus specific hourly deviations across every bus in a zone or subzonal aggregate and pricing the resulting

deviation in zone or aggregate total deviations at the zonal or aggregate congestion price in the real-time energy market. As a result, the allocation of balancing implicit congestion was reduced for MW deviations associated with load and virtual bids that settle at zones and aggregates.

Another result of the new rules was to increase negative balancing charges billed to load on a load ratio basis. While total load deviations and associated balancing charges at load aggregates were reduced by netting, the rules for determining balancing CLMP credits and charges to all other balancing MW deviations at all other bus or aggregates have not changed. This means that the new rules resulted in a decrease in total balancing implicit charges while having no effect on the calculation of total balancing implicit credits. The net result has been an increase in negative balancing congestion costs, which is the difference between balancing CLMP charges from deviations at aggregates and zones (reduced due to the rule change) and bus specific balancing CLMP credits (not been affected by the rule change). This has caused an increase in total negative balancing charges.

The netting of zonal and aggregate deviations decreased the allocation of balancing charges to load deviations and increased total negative balancing congestion. Negative balancing congestion is assigned to load and exports on a load ratio basis as the result of a FERC order.

Table 11-1 shows the total balancing implicit CLMP charges that would have resulted from applying the pre and post April 1, 2018, settlement rules for the first nine months of 2017 through 2020. Table 11-1 also shows the actual total balancing implicit CLMP charges for the first nine months of 2017 through 2020 based on the methods in place at the time. Table 11-1 shows that the April 1, 2018, settlement rule, if applied to the first nine months of 2017 through 2020, would have caused negative balancing congestion costs to increase. Table 11-1 shows that the post April 1, 2018, settlement rule caused negative total balancing implicit charges to increase by \$6.5 million (19.5 percent) in the first nine months of 2020.

⁸ See PJM, "Manual 28: Operating Agreement Accounting," Rev. 83 (Dec. 3, 2019).

Table 11-1 Total balancing implicit CLMP charge (Dollars (Millions)) (old method and new method): January through September, 2017 through 2020

Balancing Implicit CLMP Charges (\$ Million)										
Old Method			New Method			Actual			Change Between New and Old	
(Jan - Sep)	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	
2017	\$12.4	\$32.8	(\$20.3)	\$8.5	\$32.7	(\$24.3)	\$12.4	\$32.8	(\$20.3)	(\$3.9)
2018	\$21.7	\$50.5	(\$28.8)	\$6.8	\$47.8	(\$41.0)	\$18.2	\$50.1	(\$31.9)	(\$12.1)
2019	\$14.4	\$41.0	(\$26.6)	\$6.2	\$39.2	(\$33.0)	\$6.2	\$39.2	(\$33.0)	(\$6.4)
2020	(\$0.9)	\$32.6	(\$33.5)	(\$8.8)	\$31.3	(\$40.0)	(\$8.8)	\$31.3	(\$40.0)	(\$6.5)

The differences in results between the old method and the new method result from the use of zonal CLMP and zonal net deviations in place of the use of bus specific CLMPs and bus specific deviations.

When the total day-ahead factor weighted real-time bus CLMP is lower than real-time zonal CLMP, the balancing implicit CLMP charges will be lower using the new method. When the total day-ahead factor weighted real-time bus CLMP is higher than real-time zonal CLMP, the balancing implicit CLMP charges will be higher using the new method. Table 11-2 presents three cases to explain the calculation. The day-ahead load factor or real-time load factor for an aggregate equals the load at each bus divided by the total aggregate load.

Case 1 (Table 11-2) shows the case in which the total day-ahead factor weighted real-time bus CLMP (\$1.1) is less than the real-time zonal CLMP (\$1.6). The total balancing implicit CLMP charges using the new method (-\$4.2) are lower than under the old method (\$1.8).

Case 2 (Table 11-2) shows the case in which the total day-ahead factor weighted real-time bus CLMP (\$1.9) is larger than the real-time zonal CLMP (\$1.5). The total balancing implicit CLMP charges using the new method (\$2.0) are higher than under the old method (-\$1.2).

Case 3 (Table 11-2) shows that the total day-ahead factor weighted real-time bus CLMP (\$1.6) is equal to the real-time zonal CLMP (\$1.6). The total balancing implicit CLMP charges using the new method (-\$4.2) are equal under the old method (-\$4.2).

Table 11–2 Example of balancing implicit CLMP charge calculation under old method and new method

										Balancing Implicit Withdrawal Charges	
Case 1	Real-Time CLMP	Real-Time Load	Real-Time Load Factor	Real-Time CLMP * Real-Time Load Factor	Day-Ahead Load Factor	Real-Time CLMP * Day-Ahead Load Factor	Day-Ahead Load	Balancing Load		Old Method	New Method
Bus A	\$1.0	4.0	0.4	\$0.4	0.9	\$0.9	10.8	(6.8)		(\$6.80)	
Bus B	\$2.0	6.0	0.6	\$1.2	0.1	\$0.2	1.2	4.8		\$9.60	
Zonal		10.0		\$1.6		\$1.1	12.0			\$2.8	(\$3.20)
Balancing Implicit Injection Credits										\$1.0	\$1.0
Balancing Implicit Congestion Charges										\$1.8	(\$4.2)
Case 2											
Bus A	\$1.0	5.0	0.5	\$0.5	0.1	\$0.1	0.8	4.2		\$4.20	
Bus B	\$2.0	5.0	0.5	\$1.0	0.9	\$1.8	7.2	(2.2)		(\$4.40)	
Zonal		10.0		\$1.5		\$1.9	8.0			(\$0.2)	\$3.00
Balancing Implicit Injection Credits										\$1.0	\$1.0
Balancing Implicit Congestion Charges										(\$1.2)	\$2.0
Case 3											
Bus A	\$1.0	4.0	0.4	\$0.4	0.4	\$0.4	4.8	(0.8)		(\$0.80)	
Bus B	\$2.0	6.0	0.6	\$1.2	0.6	\$1.2	7.2	(1.2)		(\$2.40)	
Zonal		10.0		\$1.6		\$1.6	12.0			(\$3.2)	(\$3.20)
Balancing Implicit Injection Credits										\$1.0	\$1.0
Balancing Implicit Congestion Charges										(\$4.2)	(\$4.2)

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 does affect the components of LMP. With a distributed load reference bus, the energy component of LMP is a load-weighted system price. No congestion or losses are included in the load-weighted reference bus price.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus can be disaggregated into three components: the system marginal price (SMP), marginal loss component (MLMP), and congestion component (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of system energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.⁹ The first derivative of total losses with respect to the power flow is marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available,

⁹ For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

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.¹⁰ 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 by withdrawals (load) in the transmission constrained area and the total revenue received by injections (generation) to meet the withdrawals (load) in the transmission constrained area, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-3 shows the PJM real-time, load-weighted, average LMP components for January through September, 2008 through 2020.¹¹

The real-time, load-weighted, average LMP decreased \$6.38 or 23.1 percent from \$27.60 in the first nine months of 2019 to \$21.22 in the first nine months of 2020. The real-time, load-weighted, average congestion component was \$0.02 in the first nine months of 2019 and \$0.02 in the first nine months of 2020. The real-time, load-weighted, average loss component in the first nine months of 2020 was \$0.01 compared to \$0.02 in the first nine months of 2019. The real-time, load-weighted, average system energy component decreased by \$6.38 or 23.1 percent from \$27.56 in the first nine months of 2019 to \$21.19 in the first nine months of 2020.

¹⁰ 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.

¹¹ The PJM real-time, load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the real-time energy market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load-weighted prices. This after the fact adjustment means that the real-time energy market energy component of LMP (SMP) and the PJM real-time, load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM wide real-time, load-weighted average LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP. Without these adjustments, the congestion component of system average LMP would be zero.

Table 11-3 PJM real-time, load-weighted, average LMP components (Dollars per MWh): January through September, 2008 through 2020¹²

(Jan - Sep)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	\$77.27	\$77.15	\$0.07	\$0.05
2009	\$39.57	\$39.49	\$0.04	\$0.03
2010	\$49.91	\$49.81	\$0.06	\$0.04
2011	\$49.48	\$49.40	\$0.05	\$0.03
2012	\$35.02	\$34.97	\$0.04	\$0.01
2013	\$39.75	\$39.72	\$0.01	\$0.02
2014	\$58.60	\$58.61	(\$0.03)	\$0.02
2015	\$38.94	\$38.89	\$0.03	\$0.02
2016	\$29.32	\$29.27	\$0.04	\$0.02
2017	\$30.36	\$30.32	\$0.02	\$0.01
2018	\$39.43	\$39.37	\$0.04	\$0.02
2019	\$27.60	\$27.56	\$0.02	\$0.02
2020	\$21.22	\$21.19	\$0.02	\$0.01

Table 11-4 shows the PJM day-ahead, load-weighted, average LMP components for the first nine months of 2008 through 2020.¹³ The day-ahead, load-weighted, average LMP decreased \$6.75, or 24.4 percent, from \$27.70 in the first nine months of 2019 to \$20.95 in the first nine months of 2020. The day-ahead, load-weighted, average congestion component decreased \$0.01 from \$0.08 in the first nine months of 2019 to \$0.07 in the first nine months of 2020. The day-ahead, load-weighted, average loss component was -\$0.01 in the first nine months of 2019 and -\$0.01 in the first nine months of 2020. The day-ahead, load-weighted, average energy component decreased \$6.75, or 24.4 percent, from \$27.63 in the first nine months of 2019 to \$20.88 in the first nine months of 2020.

¹² 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.

¹³ 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 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September, 2008 through 2020

(Jan - Sep)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	\$75.96	\$76.30	(\$0.09)	(\$0.24)
2009	\$39.35	\$39.50	(\$0.05)	(\$0.10)
2010	\$49.12	\$49.05	\$0.11	(\$0.03)
2011	\$48.34	\$48.55	(\$0.05)	(\$0.16)
2012	\$34.29	\$34.19	\$0.12	(\$0.02)
2013	\$39.49	\$39.35	\$0.14	(\$0.00)
2014	\$59.08	\$58.84	\$0.26	(\$0.01)
2015	\$39.51	\$39.25	\$0.28	(\$0.02)
2016	\$29.69	\$29.54	\$0.17	(\$0.01)
2017	\$30.26	\$30.24	\$0.04	(\$0.02)
2018	\$38.71	\$38.60	\$0.12	(\$0.01)
2019	\$27.70	\$27.63	\$0.08	(\$0.01)
2020	\$20.95	\$20.88	\$0.07	(\$0.01)

Table 11-5 shows the PJM real-time, load-weighted, average LMP by constrained and unconstrained hours.

Table 11-5 PJM real-time, load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): January 2019 through September 2020

	2019		2020	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	\$33.75	\$21.61	\$22.30	\$15.73
Feb	\$28.99	\$23.33	\$19.56	\$17.12
Mar	\$30.81	\$24.22	\$18.28	\$16.13
Apr	\$27.04	\$24.43	\$17.63	\$17.39
May	\$24.92	\$20.27	\$18.81	\$12.20
Jun	\$24.94	\$19.28	\$21.64	\$14.18
Jul	\$32.29	\$20.04	\$28.58	\$15.77
Aug	\$24.63	\$21.02	\$26.01	\$17.43
Sep	\$29.79	\$17.03	\$19.94	\$12.31
Oct	\$27.97	\$23.45		
Nov	\$28.54	\$19.94		
Dec	\$24.37	\$16.20		
Avg	\$28.33	\$21.07	\$21.89	\$15.73

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-6 for the first nine months of 2019 and 2020. In the first nine months of 2020, BGE had the highest real-time congestion component of all control zones, \$3.08, and AECO had the lowest real-time congestion component, -\$2.38.

Table 11-6 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September, 2019 and 2020

	2019 (Jan - Sep)				2020 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	\$25.95	\$27.57	(\$1.94)	\$0.31	\$19.26	\$21.61	(\$2.38)	\$0.03
AEP	\$28.19	\$27.50	\$0.80	(\$0.11)	\$21.65	\$21.02	\$0.52	\$0.11
APS	\$28.02	\$27.61	\$0.39	\$0.03	\$22.01	\$21.05	\$1.03	(\$0.07)
ATSI	\$28.12	\$27.40	\$0.33	\$0.38	\$22.37	\$21.14	\$0.84	\$0.40
BGE	\$31.03	\$27.80	\$2.34	\$0.90	\$24.97	\$21.36	\$3.08	\$0.53
ComEd	\$25.20	\$27.38	(\$1.28)	(\$0.89)	\$19.87	\$21.21	(\$0.96)	(\$0.39)
DAY	\$29.32	\$27.60	\$0.81	\$0.91	\$22.63	\$21.22	\$0.45	\$0.97
DEOK	\$28.23	\$27.52	\$0.83	(\$0.13)	\$21.71	\$21.20	\$0.36	\$0.15
DLCO	\$27.79	\$27.41	\$0.44	(\$0.06)	\$22.85	\$21.28	\$1.61	(\$0.05)
Dominion	\$29.16	\$27.69	\$1.23	\$0.24	\$22.16	\$21.20	\$0.97	(\$0.02)
DPL	\$29.26	\$27.89	\$0.70	\$0.68	\$22.17	\$21.41	\$0.49	\$0.26
EKPC	\$28.07	\$28.01	\$0.35	(\$0.29)	\$21.53	\$21.17	\$0.32	\$0.04
JCPL	\$26.10	\$27.81	(\$1.92)	\$0.22	\$19.73	\$21.71	(\$1.98)	\$0.00
Met-Ed	\$26.92	\$27.59	(\$0.57)	(\$0.11)	\$20.65	\$21.17	(\$0.30)	(\$0.23)
OVEC	\$26.33	\$26.76	\$0.35	(\$0.77)	\$19.98	\$20.01	\$0.29	(\$0.32)
PECO	\$25.67	\$27.56	(\$1.84)	(\$0.05)	\$18.64	\$21.24	(\$2.34)	(\$0.26)
PENELEC	\$26.56	\$27.36	(\$0.78)	(\$0.01)	\$20.48	\$20.88	(\$0.28)	(\$0.12)
Pepco	\$29.79	\$27.73	\$1.50	\$0.56	\$22.77	\$21.31	\$1.24	\$0.22
PPL	\$25.21	\$27.62	(\$2.06)	(\$0.35)	\$18.63	\$21.03	(\$1.99)	(\$0.41)
PSEG	\$26.06	\$27.42	(\$1.47)	\$0.11	\$19.13	\$21.28	(\$2.07)	(\$0.07)
RECO	\$26.37	\$27.68	(\$1.41)	\$0.09	\$20.05	\$21.78	(\$1.76)	\$0.02
PJM	\$27.60	\$27.56	\$0.02	\$0.02	\$21.22	\$21.19	\$0.02	\$0.01

The day-ahead components of LMP for each control zone are presented in Table 11-7 for the first nine months of 2019 and 2020. In the first nine months of 2020, BGE had the highest day-ahead congestion component of all control zones, \$3.11, and AECO had the lowest day-ahead congestion component, -\$2.35.

Table 11–7 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through September, 2019 and 2020

	2019 (Jan – Sep)				2020 (Jan – Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	\$25.76	\$27.65	(\$2.09)	\$0.21	\$18.88	\$21.27	(\$2.35)	(\$0.04)
AEP	\$28.23	\$27.68	\$0.65	(\$0.10)	\$21.46	\$20.76	\$0.61	\$0.08
APS	\$28.22	\$27.67	\$0.54	\$0.01	\$21.51	\$20.77	\$0.79	(\$0.05)
ATSI	\$28.42	\$27.48	\$0.53	\$0.40	\$21.59	\$20.80	\$0.51	\$0.29
BGE	\$31.38	\$27.82	\$2.79	\$0.77	\$24.66	\$21.04	\$3.11	\$0.52
ComEd	\$25.35	\$27.40	(\$1.28)	(\$0.76)	\$19.81	\$20.84	(\$0.72)	(\$0.31)
DAY	\$29.43	\$27.66	\$0.89	\$0.88	\$22.64	\$20.92	\$0.77	\$0.95
DEOK	\$28.77	\$27.66	\$1.17	(\$0.07)	\$21.93	\$20.95	\$0.80	\$0.19
DLCO	\$28.02	\$27.47	\$0.63	(\$0.08)	\$22.24	\$21.00	\$1.28	(\$0.03)
Dominion	\$29.70	\$27.81	\$1.71	\$0.18	\$22.13	\$20.90	\$1.25	(\$0.02)
DPL	\$28.73	\$28.04	\$0.18	\$0.51	\$20.86	\$21.21	(\$0.60)	\$0.24
EKPC	\$28.11	\$28.20	\$0.32	(\$0.41)	\$21.67	\$21.16	\$0.58	(\$0.07)
JCPL	\$25.75	\$27.75	(\$2.14)	\$0.13	\$18.96	\$21.28	(\$2.26)	(\$0.06)
Met-Ed	\$26.35	\$27.64	(\$1.05)	(\$0.24)	\$19.96	\$20.91	(\$0.65)	(\$0.30)
OVEC	\$29.70	\$29.41	\$0.99	(\$0.70)	\$21.04	\$20.75	\$0.64	(\$0.35)
PECO	\$25.19	\$27.58	(\$2.21)	(\$0.17)	\$18.35	\$20.89	(\$2.20)	(\$0.34)
PENELEC	\$27.38	\$27.82	(\$0.50)	\$0.06	\$20.70	\$20.99	(\$0.29)	\$0.01
Pepco	\$30.33	\$27.85	\$1.96	\$0.52	\$22.83	\$21.12	\$1.43	\$0.28
PPL	\$25.05	\$27.67	(\$2.15)	(\$0.47)	\$18.35	\$20.71	(\$1.85)	(\$0.51)
PSEG	\$25.94	\$27.53	(\$1.65)	\$0.06	\$18.78	\$20.94	(\$2.04)	(\$0.12)
RECO	\$26.78	\$27.89	(\$1.19)	\$0.08	\$19.73	\$21.48	(\$1.72)	(\$0.03)
PJM	\$27.70	\$27.63	\$0.08	(\$0.01)	\$20.95	\$20.88	\$0.07	(\$0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-8 for the first nine months of 2019 and 2020.¹⁴

Table 11-8 Hub real-time, average LMP components (Dollars per MWh): January through September, 2019 and 2020

	2019 (Jan – Sep)				2020 (Jan – Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	\$25.73	\$26.26	\$0.26	(\$0.79)	\$19.76	\$19.92	\$0.24	(\$0.39)
AEP-DAY Hub	\$26.86	\$26.26	\$0.74	(\$0.14)	\$20.59	\$19.92	\$0.58	\$0.10
ATSI Gen Hub	\$26.50	\$26.26	\$0.33	(\$0.10)	\$20.51	\$19.92	\$0.53	\$0.06
Chicago Gen Hub	\$23.68	\$26.26	(\$1.41)	(\$1.17)	\$18.20	\$19.92	(\$1.11)	(\$0.61)
Chicago Hub	\$24.14	\$26.26	(\$1.33)	(\$0.79)	\$18.57	\$19.92	(\$1.01)	(\$0.33)
Dominion Hub	\$27.22	\$26.26	\$0.96	\$0.00	\$20.31	\$19.92	\$0.59	(\$0.20)
Eastern Hub	\$26.31	\$26.26	(\$0.46)	\$0.51	\$19.51	\$19.92	(\$0.57)	\$0.16
N Illinois Hub	\$23.98	\$26.26	(\$1.34)	(\$0.94)	\$18.49	\$19.92	(\$0.99)	(\$0.44)
New Jersey Hub	\$24.71	\$26.26	(\$1.64)	\$0.09	\$18.00	\$19.92	(\$1.82)	(\$0.10)
Ohio Hub	\$26.98	\$26.26	\$0.81	(\$0.10)	\$20.68	\$19.92	\$0.60	\$0.16
West Interface Hub	\$26.55	\$26.26	\$0.52	(\$0.23)	\$20.27	\$19.92	\$0.48	(\$0.14)
Western Hub	\$26.58	\$26.26	\$0.36	(\$0.05)	\$20.16	\$19.92	\$0.37	(\$0.13)

The day-ahead components of LMP for each hub are presented in Table 11-9 for the first nine months of 2019 and 2020.

Table 11-9 Hub day-ahead, average LMP components (Dollars per MWh): January through September, 2019 and 2020

	2019 (Jan – Sep)				2020 (Jan – Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	\$25.88	\$26.36	\$0.28	(\$0.76)	\$19.69	\$19.68	\$0.37	(\$0.37)
AEP-DAY Hub	\$26.89	\$26.36	\$0.65	(\$0.12)	\$20.43	\$19.68	\$0.65	\$0.09
ATSI Gen Hub	\$26.88	\$26.36	\$0.54	(\$0.02)	\$20.17	\$19.68	\$0.47	\$0.01
Chicago Gen Hub	\$23.94	\$26.36	(\$1.38)	(\$1.04)	\$18.23	\$19.68	(\$0.92)	(\$0.53)
Chicago Hub	\$24.37	\$26.36	(\$1.32)	(\$0.66)	\$18.66	\$19.68	(\$0.78)	(\$0.24)
Dominion Hub	\$27.61	\$26.36	\$1.33	(\$0.08)	\$20.20	\$19.68	\$0.74	(\$0.23)
Eastern Hub	\$26.14	\$26.36	(\$0.63)	\$0.41	\$18.81	\$19.68	(\$1.01)	\$0.14
N Illinois Hub	\$24.19	\$26.36	(\$1.33)	(\$0.83)	\$18.53	\$19.68	(\$0.78)	(\$0.37)
New Jersey Hub	\$24.62	\$26.36	(\$1.79)	\$0.05	\$17.64	\$19.68	(\$1.91)	(\$0.13)
Ohio Hub	\$26.95	\$26.36	\$0.67	(\$0.08)	\$20.46	\$19.68	\$0.66	\$0.12
West Interface Hub	\$26.93	\$26.36	\$0.77	(\$0.20)	\$20.11	\$19.68	\$0.58	(\$0.15)
Western Hub	\$26.95	\$26.36	\$0.62	(\$0.02)	\$20.24	\$19.68	\$0.59	(\$0.03)

¹⁴ The real-time components of LMP are the simple average of the hourly components for each hub. Some hubs include only generation buses and do not include load buses. The real-time components of LMP were previously reported as the real-time, load-weighted, average of the hourly components of LMP.

Congestion

Congestion Accounting

Total congestion costs equal net implicit CLMP charges, plus net explicit CLMP charges, plus net inadvertent CLMP charges. Implicit CLMP charges equal implicit withdrawal charges less implicit injection credits. Explicit CLMP charges are the net CLMP charges associated with the injection credits and withdrawal charges for point to point energy transactions. Inadvertent CLMP charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs. Congestion occurs in the day-ahead and real-time energy markets.¹⁵ Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the real-time energy market.

Implicit CLMP charges are the CLMP charges calculated for energy injected or withdrawn at a location. The explicit CLMP charges are the CLMP charges calculated for transactions with a defined source and a sink. For example, implicit CLMP charges are calculated for network load and explicit CLMP charges are calculated for up to congestion transactions (UTCs). Inadvertent CLMP charges are CLMP charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour.

CLMP charges and CLMP credits are calculated for both the day-ahead and balancing energy markets.

- **Day-Ahead Implicit Withdrawal CLMP Charges.** Day-ahead implicit withdrawal charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit withdrawal charges are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.

¹⁵ 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.

- **Day-Ahead Implicit Injection CLMP Credits.** Day-ahead implicit injection credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions.¹⁶ Day-ahead implicit injection credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.
- **Balancing Implicit Withdrawal CLMP Charges.** Balancing implicit withdrawal charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit withdrawal charges are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Balancing Implicit Injection CLMP Credits.** Balancing implicit injection credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit injection credits are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Explicit CLMP Charges.** Explicit CLMP charges are the net CLMP costs associated with point to point energy transactions. Day-ahead explicit CLMP charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing explicit CLMP charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit CLMP charges are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent CLMP Charges.** Inadvertent CLMP charges are charges resulting from the differences between the net actual energy flow and

¹⁶ Internal bilateral transactions are included in the tariff definitions of Market Participant Energy Injections and Market Participant Energy Withdrawals. The purchase part of an internal bilateral transaction is an injection to the buyer and the sale part of an internal bilateral transaction is a withdrawal to the seller. The tariff (Attachment K) also says market participants will be charged implicit CLMP charges for all Market Participant Energy Withdrawals and will be credited implicit CLMP credits for all Market Participant Energy Injections. The seller of an internal bilateral transaction will be charged implicit CLMP charges at the source and the buyer of an internal bilateral transaction will be credited implicit CLMP credits at the sink. Internal bilateral transaction CLMP credits and charges sum to zero, as the IBT is merely a transfer of ownership injection and withdrawal MW and associated charges and credits between participants, meaning that the sum of all MW and all credits and all charges with and without IBTs are the same.

the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent CLMP charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.¹⁷

The congestion calculation equations are in Table 11-10.

Table 11-10 Congestion calculations

Congestion Category	Calculation
Day-Ahead Implicit Withdrawal CLMP Charges	Day-Ahead Demand MWh * Day-Ahead CLMP
Day-Ahead Implicit Injection CLMP Credits	Day-Ahead Supply MWh * Day-Ahead CLMP
Day-Ahead Explicit CLMP Charges	Day-Ahead Transaction MW * (Day-Ahead Sink CLMP - Day-Ahead Source CLMP)
Day-Ahead Total Congestion Costs	Day-Ahead Implicit Withdrawal CLMP Charges - Day-Ahead Implicit Injection CLMP Credits + Day-Ahead Explicit CLMP Charges
Balancing Implicit Withdrawal CLMP Charges	Balancing Demand MWh * Real-Time CLMP
Balancing Implicit Injection CLMP Credits	Balancing Supply MWh * Real-Time CLMP
Balancing Explicit CLMP Costs	Balancing Transaction MW * (Real-Time Sink CLMP - Real-Time Source CLMP)
Balancing Total Congestion Costs	Balancing Implicit Withdrawal CLMP Charges - Balancing Implicit Injection CLMP Credits + Balancing Explicit CLMP Costs
Total Congestion Costs	Day-Ahead Total Congestion Costs + Balancing Total Congestion Costs

MWh Category	Definition
Day-Ahead Demand MWh	Cleared Demand, Decrement Bids, Energy Sale Transactions
Day-Ahead Supply MWh	Cleared Generation, Increment Bids, Energy Purchase Transactions
Real-Time Demand MWh	Load and Energy Sale Transactions
Real-Time Supply MWh	Generation and Energy Purchase Transactions
Balancing Demand MWh	Real-Time Demand MWh - Day-Ahead Demand MWh
Balancing Supply MWh	Real-Time Supply MWh - Day-Ahead Supply MWh

PJM billing items include Day-Ahead Transmission Congestion Charges, Day-Ahead Transmission Congestion Credits, Balancing Transmission Congestion Charges, and Balancing Transmission Congestion Credits. Those line items are calculated for each PJM member. The congestion bill shows the CLMP charges or credits collected from the PJM market participants. However, the sum of an individual customer's CLMP credits or charges on the customer's bill is not a measure of the congestion paid by that customer.

The congestion paid by a customer is the difference between what the customer paid for energy and what all network sources of that energy were paid to serve that customer. A load customer's congestion bill, in contrast, merely indicates whether the LMP they paid for their withdrawals is higher or lower than the system energy price due to transmission constraints. The customer's bill is correct, but the bill does not measure congestion paid by the customer, only how much the customer was charged and credited for their MW positions. The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints.

Zonal congestion is calculated on a constraint by constraint basis. The congestion calculations are the total difference between what the zonal load pays in CLMP charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation. Congestion costs can be both positive and negative and CLMP charges and CLMP credits can be both positive and negative. CLMP charges, positive or negative, are paid by withdrawals and CLMP credits, positive or negative, are paid to injections.

Total congestion costs (the sum of charges and credits), when positive, measure the net congestion payment by a participant group and when negative, measure the net congestion credit paid to a participant group. Explicit CLMP charges, when positive, measure the congestion payment to a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit CLMP charges are calculated for up to congestion transactions (UTCs).

¹⁷ PJM Operating Agreement Schedule 1 §3.7.

The accounting definitions can be misleading. Load pays congestion. Congestion is the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

The CLMP is calculated with respect to the LMP at the system reference bus, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor 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.¹⁸

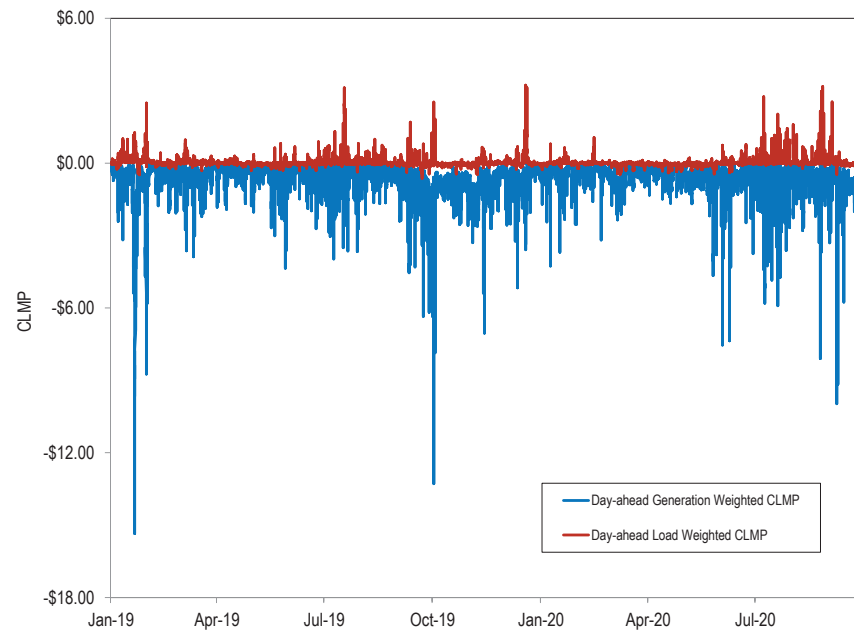
Load-weighted LMP components are calculated relative to a load-weighted, average LMP. At the load-weighted reference bus, which represents the load center of the system, the LMP includes no congestion or loss components, by definition. The load-weighted, average CLMP across all load buses, calculated relative to that reference bus, is equal to, or very close to, zero, with non-zero results caused by state estimator error and after the fact meter updates. The sum of load related CLMP charges is logically zero and the small differences are the result of accounting issues. A positive CLMP at a load bus indicates that the load at that bus has a total energy price higher than the average LMP, due to transmission constraints. A negative CLMP at a load bus indicates that the load at that bus has a total energy price lower than the average LMP, due to transmission constraints. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security

¹⁸ 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>.

constrained economic dispatch which accounts for transmission constraints and marginal losses. Due to transmission constraints, the average generation weighted CLMP for generation resources is lower than the LMP at the load-weighted reference bus price. Calculated relative to the load reference bus which has a CLMP of zero, this means that the average of the generation bus CLMPs is negative. This means that total generation CLMP credits are negative.

Figure 11-1 shows the weighted average CLMPs of generation and load in the day-ahead market. Figure 11-1 shows that in January 2019 through September 2020, day-ahead generation weighted CLMPs were generally negative and day-ahead load-weighted CLMPs were generally positive. Figure 11-1 also shows that in January 2019 through September 2020, load paid more for energy as a result of transmission constraints than generation was paid to provide that energy. Figure 11-1 shows that CLMP charges to load are slightly positive and total CLMP credits to generation are generally negative. Total CLMP load payments are higher than total CLMP generation credits. The difference in load payments and generation credits (load charges minus generation credits) is congestion (Table 11-13 and Table 11-14).

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead, load-weighted CLMPs: January 2019 through September 2020



Total Congestion

Total congestion costs in PJM in the first nine months of 2020 were \$396.1 million, comprised of implicit withdrawal charges of \$130.6 million, implicit injection credits of -\$276.0 million and explicit charges of -\$10.4 million. Total congestion costs in the first nine months of 2020 were lower than total congestion costs in the first nine months of any year from 2008 through 2019. Total congestion is the difference between that withdrawals (load) pay for energy and what injections (generation) pay for energy due to binding transmission constraints.

Table 11-11 shows total congestion for the first nine months of 2008 through 2020. Total congestion costs in Table 11-11 include congestion associated with

PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.^{19 20}

Table 11-11 Total PJM congestion costs (Dollars (Millions)): January through September, 2008 through 2020

Congestion Costs (Millions)				Percent of PJM
(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Billing
2008	\$1,778	NA	\$26,979	6.6%
2009	\$544	(69.4%)	\$19,927	2.7%
2010	\$1,134	108.7%	\$26,249	4.3%
2011	\$875	(22.9%)	\$28,836	3.0%
2012	\$425	(51.4%)	\$22,119	1.9%
2013	\$510	19.9%	\$25,153	2.0%
2014	\$1,705	234.6%	\$40,770	4.2%
2015	\$1,143	(33.0%)	\$33,710	3.4%
2016	\$822	(28.1%)	\$29,490	2.8%
2017	\$455	(44.6%)	\$29,510	1.5%
2018	\$1,116	145.1%	\$37,950	2.9%
2019	\$419	(62.5%)	\$29,980	1.4%
2020	\$396	(5.5%)	\$25,010	1.6%

CLMP charges and credits are not in and of themselves congestion. CLMP charges and credits are adjustments to energy charges and credits reflecting marginal energy price differences caused by binding system constraints. Congestion is the sum of all congestion related charges and credits. In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of the market for any particular day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

¹⁹ See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, LLC," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <<http://www.pjm.com/documents/agreements.aspx>>.

²⁰ 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 11-12 shows total congestion by day-ahead and balancing component for the first nine months of 2008 through 2020.

Table 11-12 Total PJM CLMP credits and charges by accounting category by market (Dollars (Millions)): January through September, 2008 through 2020

(Jan – Sep)	CLMP Credits and Charges (Millions)									
	Day-Ahead					Balancing				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Congestion Costs
2008	\$1,126.9	(\$971.2)	\$152.8	\$2,250.9	(\$204.9)	\$90.5	(\$177.3)	(\$472.7)	\$0.0	\$1,778.2
2009	\$245.7	(\$385.0)	\$73.8	\$704.6	(\$35.1)	\$4.1	(\$121.9)	(\$161.0)	\$0.0	\$543.6
2010	\$301.7	(\$932.7)	\$69.5	\$1,303.9	(\$11.5)	\$39.3	(\$118.7)	(\$169.6)	(\$0.0)	\$1,134.3
2011	\$389.3	(\$628.2)	\$45.6	\$1,063.2	\$52.7	\$92.6	(\$148.4)	(\$188.3)	\$0.0	\$874.9
2012	\$106.6	(\$409.8)	\$86.7	\$603.2	(\$3.3)	\$37.1	(\$137.6)	(\$178.0)	\$0.0	\$425.2
2013	\$227.1	(\$452.6)	\$121.6	\$801.4	\$6.8	\$112.2	(\$186.4)	(\$291.8)	\$0.0	\$509.6
2014	\$505.4	(\$1,497.8)	(\$38.5)	\$1,964.6	\$73.1	\$224.4	(\$107.9)	(\$259.2)	\$0.0	\$1,705.4
2015	\$539.3	(\$783.2)	\$24.6	\$1,347.1	\$11.4	\$69.9	(\$145.6)	(\$204.1)	\$0.0	\$1,143.0
2016	\$313.0	(\$529.0)	\$35.7	\$877.8	\$1.9	\$20.0	(\$37.3)	(\$55.5)	(\$0.0)	\$822.2
2017	\$105.1	(\$375.1)	\$2.3	\$482.5	\$12.5	\$32.9	(\$6.7)	(\$27.1)	\$0.0	\$455.4
2018	\$249.0	(\$931.9)	(\$29.3)	\$1,151.7	\$18.2	\$50.1	(\$3.6)	(\$35.5)	\$0.0	\$1,116.2
2019	\$178.3	(\$295.2)	\$37.9	\$511.4	\$6.2	\$39.2	(\$59.4)	(\$92.3)	\$0.0	\$419.1
2020	\$139.3	(\$307.2)	\$55.9	\$502.5	(\$8.8)	\$31.3	(\$66.3)	(\$106.3)	\$0.0	\$396.1

Charges and Credits versus Congestion: Virtual Transactions, Load and Generation

In PJM's two settlement system, there is a day ahead market and a real-time, balancing market, that make up a market day.

In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of each market day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Unlike virtual bids, physical load and generation have net MW at the close of a market day's day ahead and balancing settlement.

Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP.

The residual difference between total load charges (day-ahead and balancing) and generation credits (day-ahead and balancing) after virtual bids have settled their day-ahead and balancing positions is congestion. That is, congestion is the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to binding transmission constraints, after virtual bids are settled at the end of the market day. Load is the source of the net surplus after generation is paid and virtuals are settled at the end of the market day. Load pays congestion.

Table 11-13 and Table 11-14 show the total CLMP charges and credits for each transaction type in the first nine months of 2020 and 2019. Table 11-13 shows that in the first nine months of 2020 DECs paid \$13.2 million in CLMP charges in the day-ahead market, were paid \$19.3 million in CLMP credits in the balancing energy market, resulting in a net payment of \$6.1 million in total CLMP credits. In the first nine months of 2020, INCs paid \$13.5 million in CLMP charges in the day-ahead market, were paid \$24.6 million in CLMP credits in the balancing energy market resulting in a net payment of \$11.1 million in total CLMP credits. In the first nine months of 2020, up to congestion (UTCs) paid \$52.8 million in CLMP charges in the day-ahead market, were paid \$65.9 million in CLMP credits in the balancing market resulting in a total payment of \$13.2 million in total CLMP credits.

Table 11–13 Total PJM CLMP credits and charges by transaction type by market (Dollars (Millions)): January through September, 2020

Transaction Type	CLMP Credits and Charges (Millions)									
	Day-Ahead					Balancing				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	\$13.2	\$0.0	\$0.0	\$13.2	(\$19.3)	\$0.0	\$0.0	(\$19.3)	\$0.0	(\$6.1)
Demand	\$28.6	\$0.0	\$0.0	\$28.6	\$18.7	\$0.0	\$0.0	\$18.7	\$0.0	\$47.3
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	\$1.5	\$1.5	\$0.0	\$0.0	(\$0.4)	(\$0.4)	\$0.0	\$1.1
Explicit Congestion and Loss Only	\$0.0	\$0.0	\$0.1	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1
Export	(\$24.5)	\$0.0	(\$0.3)	(\$24.8)	(\$6.7)	\$0.0	\$0.3	(\$6.4)	\$0.0	(\$31.2)
Generation	\$0.0	(\$417.4)	\$0.0	\$417.4	\$0.0	\$9.6	\$0.0	(\$9.6)	\$0.0	\$407.7
Import	\$0.0	(\$0.3)	\$0.0	\$0.3	\$0.0	(\$1.5)	(\$0.0)	\$1.5	\$0.0	\$1.7
INC	\$0.0	(\$13.5)	\$0.0	\$13.5	\$0.0	\$24.6	\$0.0	(\$24.6)	\$0.0	(\$11.1)
Internal Bilateral	\$122.0	\$123.9	\$1.9	\$0.0	(\$1.1)	(\$1.1)	\$0.0	\$0.0	\$0.0	\$0.0
Up to Congestion	\$0.0	\$0.0	\$52.8	\$52.8	\$0.0	\$0.0	(\$65.9)	(\$65.9)	\$0.0	(\$13.2)
Wheel In	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.4)	(\$0.3)	\$0.1	\$0.0	\$0.1
Wheel Out	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.4)	\$0.0	\$0.0	(\$0.4)	\$0.0	(\$0.4)
Total	\$139.3	(\$307.2)	\$55.9	\$502.5	(\$8.8)	\$31.3	(\$66.3)	(\$106.3)	\$0.0	\$396.1

Table 11–14 Total PJM CLMP credits and charges by transaction type by market (Dollars (Millions)): January through September, 2019

Transaction Type	CLMP Credits and Charges (Millions)									
	Day-Ahead					Balancing				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	\$11.6	\$0.0	\$0.0	\$11.6	(\$11.1)	\$0.0	\$0.0	(\$11.1)	\$0.0	\$0.5
Demand	\$38.9	\$0.0	\$0.0	\$38.9	\$20.1	\$0.0	\$0.0	\$20.1	\$0.0	\$59.0
Demand Response	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Explicit Congestion Only	\$0.0	\$0.0	\$0.8	\$0.8	\$0.0	\$0.0	(\$0.1)	(\$0.1)	\$0.0	\$0.7
Explicit Congestion and Loss Only	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Export	(\$19.6)	\$0.0	(\$0.3)	(\$19.9)	(\$2.3)	\$0.0	(\$0.2)	(\$2.5)	\$0.0	(\$22.3)
Generation	\$0.0	(\$431.3)	\$0.0	\$431.3	\$0.0	\$22.5	\$0.0	(\$22.5)	\$0.0	\$408.8
Import	\$0.0	\$0.5	\$0.0	(\$0.5)	\$0.0	(\$3.1)	(\$0.2)	\$2.8	\$0.0	\$2.4
INC	\$0.0	(\$11.7)	\$0.0	\$11.7	\$0.0	\$20.2	\$0.0	(\$20.2)	\$0.0	(\$8.6)
Internal Bilateral	\$147.4	\$147.4	(\$0.0)	(\$0.0)	(\$0.5)	(\$0.5)	\$0.0	(\$0.0)	\$0.0	(\$0.0)
Up to Congestion	\$0.0	\$0.0	\$37.4	\$37.4	\$0.0	\$0.0	(\$58.6)	(\$58.6)	\$0.0	(\$21.2)
Wheel In	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.3)	(\$0.2)	\$0.0	(\$0.2)
Wheel Out	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$0.0)
Total	\$178.3	(\$295.2)	\$37.9	\$511.4	\$6.2	\$39.2	(\$59.4)	(\$92.3)	\$0.0	\$419.1

Table 11-15 shows the change in total CLMP credits and charges incurred by transaction type from the first nine months of 2019 to the first nine months of 2020. Total negative CLMP credits incurred by generation decreased by \$1.1 million, and total CLMP charges incurred by demand decreased by \$11.7 million. The total CLMP credits to up to congestion transactions (UTCs) decreased from \$21.2 million in the first nine months of 2019 to \$13.2 million in the first nine months of 2020. Total day-ahead CLMP charges to UTCs increased by \$15.4 million from \$37.4 million in the first nine months of 2019 to \$52.8 million in the first nine months of 2020. Over the same period balancing CLMP credits to UTCs increased by \$7.3 million, from \$58.6 million in the first nine months of 2019 to \$65.9 million in the first nine months of 2020.

Table 11-15 Change in total PJM CLMP credits and charges by transaction type by market (Dollars (Millions)): January through September, 2019 to 2020

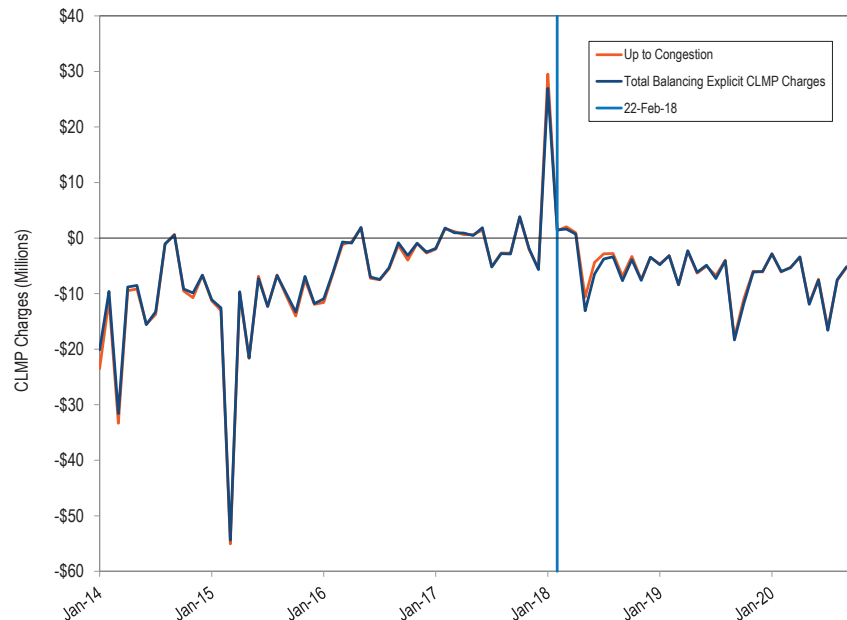
Change in CLMP Credits and Charges (Millions)										
Transaction Type	Day-Ahead				Balancing					Grand Total
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	
DEC	\$1.6	\$0.0	\$0.0	\$1.6	(\$8.2)	\$0.0	\$0.0	(\$8.2)	\$0.0	(\$6.7)
Demand	(\$10.2)	\$0.0	\$0.0	(\$10.2)	(\$1.4)	\$0.0	\$0.0	(\$1.4)	\$0.0	(\$11.7)
Demand Response	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Explicit Congestion Only	\$0.0	\$0.0	\$0.6	\$0.6	\$0.0	\$0.0	(\$0.2)	(\$0.2)	\$0.0	\$0.4
Explicit Congestion and Loss Only	\$0.0	\$0.0	\$0.1	\$0.1	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.0	\$0.1
Export	(\$4.9)	\$0.0	(\$0.0)	(\$4.9)	(\$4.4)	\$0.0	\$0.4	(\$4.0)	\$0.0	(\$8.9)
Generation	\$0.0	\$14.0	\$0.0	\$14.0	\$0.0	(\$12.9)	\$0.0	\$12.9	\$0.0	(\$1.1)
Import	\$0.0	(\$0.8)	\$0.0	\$0.8	\$0.0	\$1.6	\$0.2	(\$1.4)	\$0.0	(\$0.6)
INC	\$0.0	(\$1.8)	\$0.0	\$1.8	\$0.0	\$4.3	\$0.0	(\$4.3)	\$0.0	(\$2.5)
Internal Bilateral	(\$25.4)	(\$23.5)	\$2.0	\$0.0	(\$0.6)	(\$0.6)	\$0.0	\$0.0	\$0.0	\$0.0
Up to Congestion	\$0.0	\$0.0	\$15.4	\$15.4	\$0.0	\$0.0	(\$7.3)	(\$7.3)	\$0.0	\$8.1
Wheel In	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.3)	\$0.0	\$0.3	\$0.0	\$0.3
Wheel Out	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.3)	\$0.0	\$0.0	(\$0.3)	\$0.0	(\$0.3)
Total	(\$39.0)	(\$12.1)	\$18.0	(\$8.9)	(\$15.0)	(\$7.9)	(\$6.9)	(\$14.0)	\$0.0	(\$22.9)

UTCs and Negative Balancing Explicit CLMP Charges

Figure 11-2 shows the change in up to congestion balancing explicit CLMP charges from January 2014 through September 2020. Figure 11-2 shows that UTCs account for almost all balancing explicit CLMP charges in PJM. As shown in Figure 11-2, UTCs are generally paid balancing CLMP credits, which take the form of negative balancing CLMP charges being allocated to UTC positions. In the first nine months of 2020, 99.4 percent (-\$65.9 million out of -\$66.3 million) of negative balancing explicit CLMP charges was incurred by UTCs and 0.6 percent (-\$0.4 out of -\$66.3 million) was incurred by Explicit Congestion Only, Export and Wheel In transactions (Table 11-13). The vertical line in the graph shows the date, February 22, 2018 when the FERC order that limited UTC trading to hubs, residual metered load, and interfaces was effective.²¹

²¹ For additional information about the FERC order, see the 2019 State of the Market Report for PJM, Appendix F: Congestion and Marginal Losses.

Figure 11-2 Monthly balancing explicit CLMP charges incurred by up to congestion: January 2014 through September 2020



Balancing congestion is caused by settling real-time deviations from day-ahead positions at real-time prices. Whether balancing congestion is positive or negative depends on the differences between the day-ahead and real-time market models including modeled constraints, the transfer capability (line limits) of the modeled constraints and the differences in deviations between day-ahead and real-time flows that result. The deviations are priced at the real-time LMPs.

For example, one source of negative balancing congestion is that the PJM system has less transmission transfer capability in the real-time market than in the day-ahead market. In order to reduce processing time in the presence of large number of virtual bids and offers, PJM only enforces or models a subset of its physical transmission limits in the day-ahead market. Transmission constraints not modeled in the day-ahead market have unlimited transfer

capability in the day-ahead market model. The reduction in transmission capability in the real-time market requires the use of more high cost generation and the use of less low cost generation to serve load, which means a decrease in congestion.²² The reduction in real-time congestion compared to day-ahead congestion creates negative balancing congestion.

As a day-ahead spread bid, UTCs can take advantage of and profit from LMP differences caused by modeling differences between the day-ahead and real-time market. UTCs clear between source and sink points with little or no price differences in the day-ahead market, and settle the resulting deviations at higher real-time price differences in the real-time market. The result is negative balancing congestion caused by and paid to UTCs in the form of CLMP credits. This is an example of false arbitrage because the UTCs cannot cause prices to converge and the profits to decrease. As a result of the FERC order requiring load to pay balancing congestion, load is responsible for paying the balancing congestion caused by UTCs.²³

Table 11-17 provides an example of how UTCs can profit from differences in day-ahead and real-time models and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of \$1.00 and Generation at B has a price of \$6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than \$1.

As a result of the fact that the transmission capability between A and B is unlimited in the day-ahead market, all of load at A and B can be met with the \$1 generation at bus A. The constraint between A and B does not bind in 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

²² As the amount of low cost generation decreases and the amount of high cost generation increases, the difference between load payments to generation and the payments received by generators goes down. High cost generation receives what load pays.

²³ 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

clears. The UTC causes a 200 MW injection at A and 200 MW withdrawal at B, creating 200 MW of flow between bus A and bus B. The 300 MW of combined flow from generation at A and UTC injections at A to the load and UTC sink at B does not exceed the DA modeled limit between A and B. This means that all 200 MW of the UTC injection at A and 200 MW of withdrawal at B can clear without forcing a price spread between A and B. Total day-ahead congestion, which is the difference between CLMP charges and credits, is zero. There is no price difference between the two nodes and every MW of injection and every MW of withdrawal at bus A and bus B settles at the same price.

In the real-time market, the transmission line between bus A and bus B has a 50 MW limit. The UTC does not physically exist in the real-time market and therefore has deviations at Bus A (-200 MW) and at Bus B (+200 MW). The UTC must buy at bus A at the real-time price and sell at bus B at the real-time price to settle its deviations. The load at A (100 MW) and B (100 MW) does not change, so there are no load deviations. With only 50 MW of transmission capability between A and B, the generation at A cannot be used to meet total load on the system. Generation from A meets the load at A (100 MW) and can supply only 50 MW of the 100 MW of load at B. Due to the binding constraint between A and B, the remaining 50 MW of load at B must be met with local generation at B at a cost of \$6 and the price at A remains \$1.

The UTC must buy 200 MW at A at the real-time price of \$1 and sell 200 MW at B at the real-time price of \$6. The UTC pays \$200 at A and is paid \$1,200 at B. The result is a net payment to the UTC of \$1,000 in balancing credits.

Table 11-16 shows the balancing credits and charges associated with the real-time deviations in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative \$1,250. Total CLMP credits (payments) to generation and the UTC exceed the total charges collected from load. The negative balancing congestion that results is paid by the load under the FERC order.²⁴

²⁴ 153 FERC ¶ 61,180.

The UTC did not and could not contribute to price convergence between the day-ahead and real-time market and did not and could not improve efficiency in system dispatch or commitment. The UTC took advantage of the modeling differences between the day-ahead and real-time markets. The UTC did significantly increase payments by load. Load was required to pay the UTC \$1,000 in negative balancing, over and above the costs of generation that was needed to meet real-time load. The differences in modeling would have resulted in \$250 in negative balancing congestion if there had been no UTCs.

Table 11-16 Example of UTC causing and profiting from negative balancing congestion

Prices	Bus A	Transfer Capability (Line Limit MW)	Bus B	
LMP DA	\$1.00	9,999	\$1.00	
LMP RT	\$1.00	50	\$6.00	
Day-Ahead MW	Bus A		Bus B	Total MW
Day-Ahead Generation	200		0	200
Day-Ahead Load	(100)		(100)	(200)
Day-Ahead UTC (+/-)	200		(200)	0
Total MW	300		(300)	0
Day-Ahead Credits and Charges	Bus A		Bus B	Total Day-Ahead Congestion
Total DA Gen Credits	\$200.00		\$0.00	
Total DA Load Charges	\$100.00		\$100.00	
Total DA UTC Credits	\$200.00		(\$200.00)	
Total DA Credits	\$300.00		(\$300.00)	\$0.00
Total Day-Ahead Congestion (Charges - Credits)				\$0.00
Balancing Deviation MW	Bus A		Bus B	Total Deviations
RT GEN Deviations	(50)		50	
RT Load Deviations	0		0	
DA UTC (+/-)	(200)		200	
Total Deviations	(250)		250	0
Balancing Credits and Charges	Bus A		Bus B	Balancing Congestion Credits
Total BA Gen Credits	(\$50.00)		\$300.00	\$250.00
Total BA Load Charges	\$0.00		\$0.00	
Total BA UTC Credits	(\$200.00)		\$1,200.00	\$1,000.00
Total BA Credits	(\$250.00)		\$1,500.00	\$1,250.00
Total Balancing Congestion (Charges - Credits)				(\$1,250.00)

Zonal Congestion

Zonal congestion is calculated on a constraint specific basis. Local congestion is the difference between what withdrawals (load) pay for energy and

what injections (generation) are paid for energy due to individual binding transmission constraints. Local congestion includes all energy charges or credits incurred to serve zonal load. Local congestion calculations account for the total difference between what the zonal load pays in CLMP charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Local congestion is calculated on a constraint specific basis. This constraint based congestion is the total congestion payments by withdrawals (load) at the buses within a defined area minus total CLMP credits received by all injections (generation) that supplied that load, given the transmission constraints, regardless of location. 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.

On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation.

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load CLMP charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation CLMP credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

Constraint specific CLMPs are determined relative to a reference bus, where there is no congestion and no losses. For purposes of allocating the congestion of an individual constraint, the reference bus for each constraint calculation

is moved to the point that is just upstream of the constraint (the bus with the greatest negative price effect from the constraint), allowing any positive price effects of the constraint to be reflected as a positive CLMP.

In order to define the load that is actually paying congestion (withdrawal payments in excess of injection credits), constraint specific congestion is appropriately assigned to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the CLMP charges collected from that load due to that constraint. The congestion collected from each load bus due to a constraint is equal to the CLMP caused by that constraint times the MW of load at that load bus. This calculation is done for both day-ahead congestion and balancing congestion.

Table 11-17 shows the day-ahead and balancing congestion by zone for the first nine months of 2020. AEP had the largest zonal congestion costs among all control zones in the first nine months of 2020. AEP had \$72.0 million in zonal congestion costs, comprised of \$89.2 million in zonal day-ahead congestion costs and -\$17.2 million in zonal balancing congestion costs. The Bagley – Graceton Line, the East Elkhart – Mottville Tap Line, the Conastone – Graceton Line, the Conastone – Peach Bottom Line, the Three Mile Island Transformer contributed \$24.3 million, or 33.8 percent of the AEP zonal congestion costs.

Table 11-18 shows the congestion costs by zone for the first nine months of 2019.

Table 11-17 Day-ahead and balancing congestion by zone (Dollars (Millions)): January through September, 2020

CLMP Credits and Charges (Millions)									
Control Zone	Day-Ahead				Balancing				Congestion Costs
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	
AECO	\$1.2	(\$3.4)	\$0.6	\$5.2	(\$0.1)	\$0.4	(\$0.8)	(\$1.3)	\$3.9
AEP	\$18.9	(\$59.3)	\$11.0	\$89.2	(\$0.8)	\$5.4	(\$11.1)	(\$17.2)	\$72.0
APS	\$14.9	(\$17.4)	\$2.7	\$35.0	(\$0.1)	\$2.2	(\$4.1)	(\$6.5)	\$28.5
ATSI	\$8.7	(\$28.9)	\$4.5	\$42.1	(\$0.3)	\$3.2	(\$5.2)	(\$8.7)	\$33.4
BGE	\$6.8	(\$11.3)	\$1.5	\$19.6	(\$0.1)	\$1.3	(\$2.5)	(\$4.0)	\$15.6
ComEd	(\$0.2)	(\$52.2)	\$11.4	\$63.4	(\$0.3)	\$4.2	(\$7.0)	(\$11.4)	\$52.1
DAY	\$1.0	(\$7.8)	\$1.3	\$10.1	(\$0.1)	\$0.7	(\$1.4)	(\$2.2)	\$7.9
DEOK	\$2.1	(\$10.9)	\$1.8	\$14.8	(\$0.1)	\$1.1	(\$2.2)	(\$3.4)	\$11.4
DLCO	\$0.4	(\$5.5)	\$0.7	\$6.6	(\$0.0)	\$0.7	(\$1.2)	(\$1.9)	\$4.7
Dominion	\$24.3	(\$33.9)	\$5.0	\$63.2	(\$4.4)	\$2.7	(\$8.9)	(\$16.1)	\$47.1
DPL	\$17.4	(\$2.9)	\$2.2	\$22.6	(\$0.4)	\$0.9	(\$1.7)	(\$3.0)	\$19.6
EKPC	\$1.0	(\$5.5)	\$1.0	\$7.6	(\$0.1)	\$0.5	(\$1.2)	(\$1.7)	\$5.9
EXT	\$0.6	(\$0.1)	\$0.1	\$0.8	(\$0.1)	(\$0.1)	(\$1.1)	(\$1.1)	(\$0.3)
JCPL	\$2.7	(\$8.4)	\$1.1	\$12.2	(\$0.1)	\$0.9	(\$2.0)	(\$3.0)	\$9.2
Met-Ed	\$9.1	(\$4.3)	\$1.0	\$14.4	(\$0.7)	\$0.8	(\$1.8)	(\$3.3)	\$11.2
OVEC	(\$0.0)	(\$0.0)	\$0.5	\$0.5	(\$0.0)	\$0.0	(\$0.1)	(\$0.1)	\$0.4
PECO	\$2.8	(\$14.8)	\$1.8	\$19.4	(\$0.2)	\$1.4	(\$3.1)	(\$4.8)	\$14.6
PENELEC	\$8.2	(\$3.3)	\$0.9	\$12.4	(\$0.3)	\$0.6	(\$1.4)	(\$2.3)	\$10.1
Pepco	\$5.6	(\$9.2)	\$1.4	\$16.2	(\$0.1)	\$1.2	(\$2.3)	(\$3.6)	\$12.6
PPL	\$7.8	(\$12.7)	\$2.9	\$23.4	(\$0.2)	\$1.5	(\$3.2)	(\$4.9)	\$18.4
PSEG	\$6.0	(\$14.8)	\$2.2	\$22.9	(\$0.2)	\$1.7	(\$3.6)	(\$5.5)	\$17.4
RECO	\$0.2	(\$0.5)	\$0.1	\$0.9	(\$0.0)	\$0.1	(\$0.3)	(\$0.4)	\$0.5
Total	\$139.3	(\$307.2)	\$55.9	\$502.5	(\$8.8)	\$31.3	(\$66.3)	(\$106.3)	\$396.1

Table 11-18 Day-ahead and balancing congestion by zone (Dollars (Millions)): January through September, 2019

CLMP Credits and Charges (Millions)									
Control Zone	Day-Ahead				Balancing				Congestion Costs
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	
AECO	\$3.2	(\$3.2)	\$0.7	\$7.0	\$0.1	\$0.5	(\$0.8)	(\$1.1)	\$5.9
AEP	\$34.9	(\$44.6)	\$7.2	\$86.7	\$1.0	\$6.5	(\$9.6)	(\$15.1)	\$71.6
APS	\$14.6	(\$17.4)	\$1.6	\$33.6	\$0.5	\$2.4	(\$3.5)	(\$5.4)	\$28.2
ATSI	\$11.9	(\$22.4)	\$2.4	\$36.8	\$0.5	\$3.0	(\$4.9)	(\$7.4)	\$29.4
BGE	\$8.0	(\$10.4)	\$0.8	\$19.1	\$0.1	\$1.8	(\$2.4)	(\$4.0)	\$15.1
ComEd	\$14.7	(\$43.9)	\$9.3	\$67.8	\$1.2	\$5.0	(\$5.6)	(\$9.3)	\$58.5
DAY	\$3.7	(\$5.5)	\$0.8	\$10.1	\$0.2	\$0.9	(\$1.4)	(\$2.1)	\$8.0
DEOK	\$7.0	(\$8.1)	\$1.3	\$16.4	\$0.3	\$1.3	(\$2.2)	(\$3.3)	\$13.1
DLCO	\$1.9	(\$3.3)	\$0.3	\$5.6	\$0.1	\$0.6	(\$1.0)	(\$1.5)	\$4.1
Dominion	\$21.7	(\$35.2)	\$2.7	\$59.6	\$1.1	\$5.2	(\$7.5)	(\$11.6)	\$48.1
DPL	\$15.0	(\$8.0)	\$2.1	\$25.0	(\$0.0)	\$0.9	(\$1.7)	(\$2.5)	\$22.5
EKPC	\$3.1	(\$4.1)	\$0.6	\$7.8	\$0.1	\$0.6	(\$1.0)	(\$1.5)	\$6.3
EXT	\$0.2	(\$0.0)	\$0.1	\$0.4	(\$0.3)	\$0.3	(\$2.4)	(\$3.0)	(\$2.7)
JCPL	\$3.5	(\$10.2)	\$0.8	\$14.5	\$0.2	\$1.1	(\$1.7)	(\$2.6)	\$11.9
Met-Ed	\$3.9	(\$6.6)	\$0.5	\$11.1	(\$0.1)	\$0.8	(\$1.3)	(\$2.2)	\$8.9
OVEC	(\$0.0)	\$0.0	\$0.2	\$0.2	\$0.0	\$0.0	\$0.1	\$0.1	\$0.3
PECO	\$3.5	(\$17.6)	\$1.1	\$22.3	\$0.4	\$1.9	(\$3.0)	(\$4.5)	\$17.7
PENELEC	\$5.8	(\$6.5)	\$0.7	\$13.0	(\$0.0)	\$0.9	(\$1.2)	(\$2.0)	\$11.0
Pepco	\$7.1	(\$9.2)	\$0.7	\$17.0	\$0.3	\$1.5	(\$2.1)	(\$3.4)	\$13.6
PPL	\$7.5	(\$18.2)	\$2.1	\$27.9	\$0.3	\$1.8	(\$2.8)	(\$4.4)	\$23.5
PSEG	\$6.9	(\$20.0)	\$1.6	\$28.5	\$0.2	\$2.2	(\$3.1)	(\$5.0)	\$23.4
RECO	\$0.3	(\$0.7)	\$0.2	\$1.2	(\$0.0)	\$0.1	(\$0.4)	(\$0.5)	\$0.7
Total	\$178.3	(\$295.2)	\$37.9	\$511.4	\$6.2	\$39.2	(\$59.4)	(\$92.3)	\$419.1

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. In the first nine months of 2020, the total congestion costs associated with the special cases were \$5.1 million or 1.3 percent of the total congestion costs. Table 11-17 and Table 11-18 include congestion allocations from these special case constraints.

There are five 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 interfaces (closed loop interfaces); 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 CLMP charges and calculated congestion costs including rounding errors (unclassified).

Table 11-19 and Table 11-20 show the allocation of total congestion by each special case allocation method, congestion allocated by the standard method and total allocation by zone. Closed loop interfaces and CT pricing logic generally result in negative congestion on a constraint specific basis. PJM's use of both the

closed loop interfaces and CT Pricing Logic forces the affected resource bus LMP to match the marginal offer of the resource. This causes higher CLMP payments to the affected generation than the CLMP load charges to any affected load, resulting in negative congestion associated with the constraint. None of the closed loop interfaces were binding in the first nine months of 2019 and 2020.

Table 11-19 Day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): January through September, 2020

Congestion Costs (Millions)																		
Day-Ahead								Balancing								Grand Total	Special Cases Total	Percent of Special Cases
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total				
AECO	(\$0.0)	\$0.0	\$0.0	\$0.0	(\$0.1)	\$5.2	\$5.2	\$0.0	(\$0.0)	\$0.0	(\$0.0)	\$0.0	(\$1.3)	(\$1.3)	\$3.9	(\$0.1)	(1.7%)	
AEP	\$0.0	(\$0.2)	\$0.0	\$0.2	\$0.5	\$88.7	\$89.2	(\$0.0)	(\$0.6)	\$0.0	(\$0.0)	(\$0.4)	(\$16.2)	(\$17.2)	\$72.0	(\$0.5)	(0.7%)	
APS	\$0.0	\$0.0	\$0.0	\$0.2	\$0.1	\$34.7	\$35.0	(\$0.0)	(\$0.0)	\$0.0	\$0.0	\$0.0	(\$6.5)	(\$6.5)	\$28.5	\$0.3	1.2%	
ATSI	\$0.0	\$0.1	\$0.0	\$0.0	\$0.1	\$41.8	\$42.1	\$0.0	(\$0.2)	\$0.0	\$0.0	\$0.2	(\$8.7)	(\$8.7)	\$33.4	\$0.3	0.9%	
BGE	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$19.6	\$19.6	(\$0.0)	(\$0.0)	\$0.0	\$0.0	\$0.0	(\$4.0)	(\$4.0)	\$15.6	\$0.0	0.1%	
ComEd	\$0.0	(\$0.1)	\$0.0	\$2.5	\$0.5	\$60.6	\$63.4	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$11.4)	(\$11.4)	\$52.1	\$2.9	5.5%	
DAY	\$0.0	(\$0.1)	\$0.0	(\$0.0)	\$0.1	\$10.0	\$10.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$2.2)	(\$2.2)	\$7.9	\$0.1	1.4%	
DEOK	\$0.0	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$14.9	\$14.8	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$3.5)	(\$3.4)	\$11.4	\$0.0	0.1%	
DLCO	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.1	\$6.6	\$6.6	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$1.9)	(\$1.9)	\$4.7	\$0.1	1.8%	
Dominion	\$0.0	\$0.0	\$0.0	\$1.4	\$0.1	\$61.7	\$63.2	(\$0.0)	(\$0.1)	\$0.0	(\$0.3)	\$0.0	(\$15.8)	(\$16.1)	\$47.1	\$1.2	2.5%	
DPL	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.1)	\$22.7	\$22.6	\$0.0	(\$0.1)	\$0.0	\$0.0	\$0.0	(\$3.0)	(\$3.0)	\$19.6	(\$0.1)	(0.6%)	
EKPC	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$7.6	\$7.6	\$0.0	(\$0.1)	\$0.0	(\$0.0)	(\$0.0)	(\$1.6)	(\$1.7)	\$5.9	(\$0.1)	(1.4%)	
EXT	\$0.0	(\$0.2)	\$0.0	\$1.0	\$0.0	\$0.0	\$0.8	\$0.0	(\$0.6)	\$0.0	(\$0.0)	(\$0.5)	\$0.0	(\$1.1)	(\$0.3)	(\$0.3)	100.0%	
JCPL	(\$0.0)	\$0.1	\$0.0	\$0.0	(\$0.1)	\$12.2	\$12.2	\$0.0	(\$0.1)	\$0.0	\$0.0	\$0.0	(\$2.9)	(\$3.0)	\$9.2	(\$0.1)	(0.7%)	
Met-Ed	\$0.0	\$0.0	\$0.0	\$0.5	\$0.0	\$13.9	\$14.4	(\$0.0)	(\$0.0)	\$0.0	(\$0.4)	(\$0.1)	(\$2.8)	(\$3.3)	\$11.2	(\$0.0)	(0.3%)	
OVEC	\$0.0	\$0.0	\$0.0	\$0.5	(\$0.0)	\$0.0	\$0.5	\$0.0	(\$0.0)	\$0.0	\$0.0	(\$0.0)	(\$0.0)	(\$0.1)	\$0.4	\$0.5	103.7%	
PECO	(\$0.0)	(\$0.1)	\$0.0	\$0.0	\$0.5	\$19.0	\$19.4	\$0.0	\$0.1	\$0.0	(\$0.0)	(\$0.0)	(\$4.9)	(\$4.8)	\$14.6	\$0.5	3.3%	
PENELEC	\$0.0	(\$0.1)	\$0.0	\$0.0	\$0.4	\$12.1	\$12.4	(\$0.0)	(\$0.0)	\$0.0	(\$0.0)	\$0.0	(\$2.3)	(\$2.3)	\$10.1	\$0.3	3.4%	
Pepco	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$16.2	\$16.2	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$3.6)	(\$3.6)	\$12.6	\$0.0	0.2%	
PPL	\$0.0	(\$0.2)	\$0.0	\$0.0	\$0.2	\$23.3	\$23.4	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$5.0)	(\$4.9)	\$18.4	\$0.1	0.5%	
PSEG	(\$0.0)	\$0.1	\$0.0	\$0.0	\$0.1	\$22.8	\$22.9	\$0.0	(\$0.1)	\$0.0	\$0.0	(\$0.0)	(\$5.5)	(\$5.5)	\$17.4	\$0.0	0.3%	
RECO	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.8	\$0.9	\$0.0	(\$0.2)	\$0.0	\$0.0	(\$0.0)	(\$0.2)	(\$0.4)	\$0.5	(\$0.1)	(26.5%)	
Total	\$0.0	(\$0.4)	\$0.0	\$6.3	\$2.3	\$494.3	\$502.5	(\$0.0)	(\$1.6)	\$0.0	(\$0.8)	(\$0.7)	(\$103.2)	(\$106.3)	\$396.1	\$5.1	1.3%	

Table 11–20 Day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): January through September, 2019

Congestion Costs (Millions)																		
Day-Ahead								Balancing								Grand Total	Special Cases Total	Percent of Special Cases
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total				
AECO	(\$0.0)	\$0.0	\$0.0	\$0.0	\$0.0	\$7.0	\$7.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$1.1)	(\$1.1)	\$5.9	\$0.0	0.0%	
AEP	\$0.0	(\$0.0)	\$0.0	\$2.0	(\$0.0)	\$84.8	\$86.7	(\$0.0)	(\$0.6)	\$0.0	\$0.0	(\$0.2)	(\$14.3)	(\$15.1)	\$71.6	\$1.1	1.6%	
APS	\$0.0	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$33.6	\$33.6	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.0	(\$5.4)	(\$5.4)	\$28.2	\$0.0	0.1%	
ATSI	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$36.7	\$36.8	\$0.0	(\$0.3)	\$0.0	\$0.0	(\$0.0)	(\$7.1)	(\$7.4)	\$29.4	(\$0.3)	(0.9%)	
BGE	\$0.0	(\$0.0)	\$0.0	\$0.1	\$0.0	\$19.0	\$19.1	(\$0.0)	(\$0.0)	\$0.0	\$0.0	\$0.0	(\$4.0)	(\$4.0)	\$15.1	\$0.1	0.8%	
ComEd	\$0.0	(\$0.0)	\$0.0	\$1.6	(\$0.0)	\$66.3	\$67.8	(\$0.0)	(\$0.7)	\$0.0	(\$0.0)	(\$0.0)	(\$8.7)	(\$9.3)	\$58.5	\$0.9	1.5%	
DAY	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$10.1	\$10.1	\$0.0	(\$0.1)	\$0.0	\$0.0	\$0.0	(\$2.0)	(\$2.1)	\$8.0	(\$0.1)	(1.2%)	
DEOK	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$16.4	\$16.4	\$0.0	(\$0.1)	\$0.0	(\$0.0)	(\$0.0)	(\$3.2)	(\$3.3)	\$13.1	(\$0.1)	(0.7%)	
DLCO	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.0	\$5.6	\$5.6	\$0.0	(\$0.0)	\$0.0	\$0.0	(\$0.0)	(\$1.5)	(\$1.5)	\$4.1	(\$0.0)	(0.7%)	
Dominion	\$0.0	\$0.0	\$0.0	\$0.1	\$0.0	\$59.6	\$59.6	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$0.1)	(\$11.6)	(\$11.6)	\$48.1	\$0.1	0.1%	
DPL	\$0.0	(\$0.0)	\$0.0	\$0.1	\$0.0	\$25.0	\$25.0	(\$0.0)	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$2.5)	(\$2.5)	\$22.5	\$0.0	0.1%	
EKPC	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$7.8	\$7.8	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.0	(\$1.5)	(\$1.5)	\$6.3	(\$0.0)	(0.0%)	
EXT	\$0.0	(\$0.1)	\$0.0	\$0.3	\$0.1	\$0.0	\$0.4	(\$0.0)	(\$2.8)	\$0.0	(\$0.0)	(\$0.2)	\$0.0	(\$3.0)	(\$2.7)	(\$2.7)	100.0%	
JCPL	(\$0.0)	(\$0.0)	\$0.0	\$0.0	\$0.0	\$14.5	\$14.5	\$0.0	(\$0.1)	\$0.0	(\$0.0)	\$0.0	(\$2.5)	(\$2.6)	\$11.9	(\$0.1)	(0.9%)	
Met-Ed	\$0.0	\$0.0	\$0.0	\$0.6	(\$0.0)	\$10.5	\$11.1	\$0.0	\$0.0	\$0.0	(\$0.1)	(\$0.0)	(\$2.1)	(\$2.2)	\$8.9	\$0.5	5.4%	
OVEC	\$0.0	(\$0.0)	\$0.0	\$0.2	(\$0.0)	\$0.0	\$0.2	\$0.0	\$0.1	\$0.0	\$0.0	\$0.0	(\$0.0)	\$0.1	\$0.3	\$0.3	104.6%	
PECO	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	\$22.2	\$22.3	\$0.0	(\$0.1)	\$0.0	(\$0.0)	(\$0.0)	(\$4.4)	(\$4.5)	\$17.7	(\$0.0)	(0.1%)	
PENELEC	\$0.0	(\$0.1)	\$0.0	\$0.2	(\$0.0)	\$12.9	\$13.0	\$0.0	\$0.0	\$0.0	(\$0.1)	\$0.0	(\$2.0)	(\$2.0)	\$11.0	\$0.1	0.6%	
Pepco	\$0.0	(\$0.0)	\$0.0	(\$0.0)	\$0.0	\$17.0	\$17.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.0)	(\$3.4)	(\$3.4)	\$13.6	\$0.0	0.1%	
PPL	\$0.0	(\$0.0)	\$0.0	\$0.1	(\$0.0)	\$27.8	\$27.9	(\$0.0)	(\$0.1)	\$0.0	\$0.0	\$0.0	(\$4.3)	(\$4.4)	\$23.5	(\$0.0)	(0.1%)	
PSEG	(\$0.0)	\$0.1	\$0.0	\$0.0	(\$0.0)	\$28.4	\$28.5	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.0	(\$5.0)	(\$5.0)	\$23.4	\$0.1	0.3%	
RECO	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$1.2	\$1.2	\$0.0	(\$0.3)	\$0.0	\$0.0	(\$0.0)	(\$0.2)	(\$0.5)	\$0.7	(\$0.3)	(36.6%)	
Total	\$0.0	(\$0.2)	\$0.0	\$5.3	\$0.1	\$506.2	\$511.4	(\$0.0)	(\$5.0)	\$0.0	(\$0.2)	(\$0.5)	(\$86.7)	(\$92.3)	\$419.1	(\$0.4)	(0.1%)	

Monthly Congestion

Table 11-21 shows day-ahead, balancing and inadvertent congestion costs by month for January 2019 through September 2020. Compared to 2019, the total congestion cost in 2020 decreased in January through May due to the combined effects of the COVID-19 related load reduction and milder weather in the first part of 2020, but increased in June through September of 2020 as prices increased. Components of this increase included an increase in day-ahead negative implicit injection credits incurred by generation in June through August, and an increase in balancing explicit charges incurred by up to congestion transactions (UTCs) in September.

Table 11-21 Monthly PJM congestion costs by market (Dollars (Millions)):
January 2019 through September 2020

	Congestion Costs (Millions)							
	2019				2020			
	Day-Ahead	Inadvertent	Balancing	Charges	Day-Ahead	Inadvertent	Balancing	Charges
				Total				Total
Jan	\$120.7	(\$20.6)	\$0.0	\$100.2	\$43.3	(\$5.6)	\$0.0	\$37.6
Feb	\$36.4	(\$5.5)	\$0.0	\$30.9	\$28.7	(\$7.0)	(\$0.0)	\$21.7
Mar	\$45.0	(\$12.2)	\$0.0	\$32.8	\$31.4	(\$5.6)	(\$0.0)	\$25.8
Apr	\$25.4	(\$3.2)	\$0.0	\$22.2	\$24.2	(\$8.2)	\$0.0	\$16.0
May	\$47.5	(\$9.5)	(\$0.0)	\$38.0	\$46.1	(\$19.5)	\$0.0	\$26.6
Jun	\$36.4	(\$6.5)	\$0.0	\$29.9	\$62.8	(\$10.7)	\$0.0	\$52.0
Jul	\$75.1	(\$6.5)	\$0.0	\$68.5	\$105.6	(\$23.8)	\$0.0	\$81.7
Aug	\$40.2	(\$5.0)	(\$0.0)	\$35.2	\$82.5	(\$14.0)	(\$0.0)	\$68.5
Sep	\$84.6	(\$23.4)	(\$0.0)	\$61.2	\$78.1	(\$11.9)	\$0.0	\$66.1
Oct	\$72.5	(\$13.5)	(\$0.0)	\$59.0				
Nov	\$67.0	(\$16.2)	(\$0.0)	\$50.8				
Dec	\$63.0	(\$8.6)	\$0.0	\$54.5				
Total	\$714.0	(\$130.7)	\$0.0	\$583.3	\$502.5	(\$106.3)	\$0.0	\$396.1

Figure 11-3 shows PJM monthly total congestion cost for January 2008 through September 2020.

Figure 11-3 PJM monthly total congestion cost (Dollars (Millions)): January 2008 through September 2020

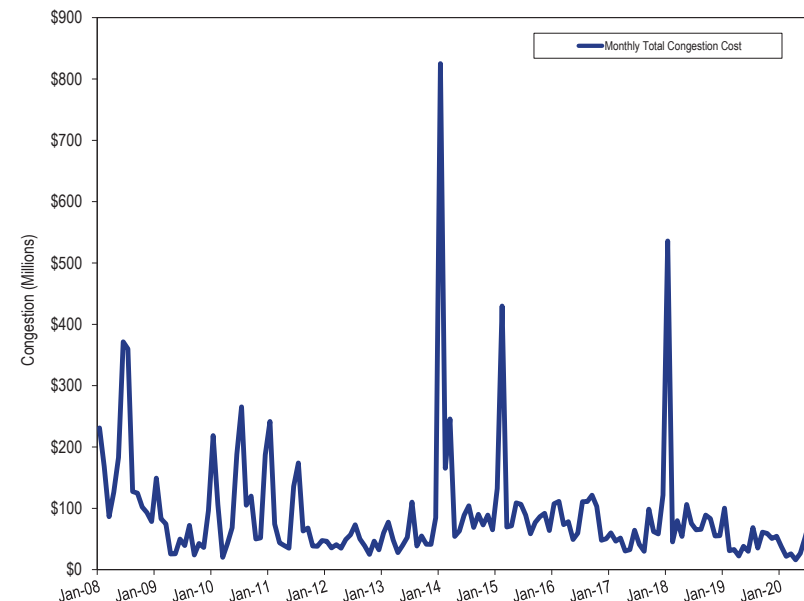


Table 11-22 shows monthly total CLMP credits and charges for each virtual transaction type in the first nine months of 2019 and 2020. Virtual transaction CLMP charges, when positive, are the total CLMP charges to the virtual transactions and when negative, are the total CLMP credits to the virtual transactions. The negative totals in Table 11-22 show that virtuals were paid, in net, CLMP credits in the first nine months of 2020 and 2019. In the first nine months of 2020, 43.3 percent of the total credits to virtuals went to UTCs, compared to 72.5 percent in the first nine months of 2019.

Table 11–22 Monthly PJM CLMP charges by virtual transaction type and by market (Dollars (Millions)): January 2019 through September 2020

CLMP Credits and Charges (Millions)										
Year	DEC			INC			Up to Congestion			Grand Total
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	
2019 Jan	\$3.5	(\$4.0)	(\$0.6)	\$1.2	(\$3.6)	(\$2.4)	\$5.1	(\$4.6)	\$0.5	(\$2.5)
Feb	\$0.8	(\$1.4)	(\$0.6)	\$1.0	(\$1.1)	(\$0.1)	\$2.0	(\$3.2)	(\$1.2)	(\$1.8)
Mar	\$0.7	(\$1.5)	(\$0.7)	\$1.4	(\$2.3)	(\$0.8)	\$4.0	(\$8.4)	(\$4.4)	(\$6.0)
Apr	\$0.6	(\$0.1)	\$0.5	\$1.1	(\$1.4)	(\$0.3)	\$2.8	(\$2.3)	\$0.5	\$0.7
May	\$0.4	(\$0.0)	\$0.4	\$2.4	(\$3.0)	(\$0.6)	\$5.4	(\$6.3)	(\$0.9)	(\$1.2)
Jun	\$0.8	(\$0.6)	\$0.2	\$1.2	(\$1.3)	(\$0.2)	\$3.3	(\$5.0)	(\$1.7)	(\$1.7)
Jul	\$2.2	(\$0.7)	\$1.5	\$0.4	(\$2.0)	(\$1.6)	\$4.1	(\$6.8)	(\$2.6)	(\$2.8)
Aug	\$1.1	(\$0.9)	\$0.2	\$0.1	(\$0.3)	(\$0.2)	\$2.9	(\$4.0)	(\$1.1)	(\$1.1)
Sep	\$1.6	(\$2.0)	(\$0.3)	\$3.0	(\$5.2)	(\$2.3)	\$7.7	(\$17.9)	(\$10.3)	(\$12.9)
Oct	\$1.2	(\$2.3)	(\$1.1)	\$3.0	(\$5.0)	(\$2.0)	\$6.3	(\$10.9)	(\$4.6)	(\$7.7)
Nov	\$0.9	(\$3.1)	(\$2.1)	\$0.6	(\$2.5)	(\$2.0)	\$6.5	(\$5.9)	\$0.5	(\$3.5)
Dec	\$1.1	(\$0.8)	\$0.3	\$0.3	(\$0.4)	(\$0.1)	\$4.0	(\$6.1)	(\$2.1)	(\$1.9)
Total	\$14.8	(\$17.3)	(\$2.4)	\$15.5	(\$28.2)	(\$12.7)	\$54.2	(\$81.6)	(\$27.4)	(\$42.5)
2020 Jan	\$0.2	(\$0.6)	(\$0.4)	\$1.4	(\$1.8)	(\$0.4)	\$3.7	(\$2.9)	\$0.8	(\$0.0)
Feb	\$0.2	(\$0.2)	(\$0.1)	\$1.3	(\$1.5)	(\$0.1)	\$4.8	(\$6.1)	(\$1.3)	(\$1.5)
Mar	(\$0.8)	(\$0.1)	(\$0.9)	\$1.3	(\$1.6)	(\$0.2)	\$4.8	(\$5.3)	(\$0.5)	(\$1.6)
Apr	(\$0.6)	\$0.8	\$0.2	\$1.9	(\$5.0)	(\$3.0)	\$2.7	(\$3.4)	(\$0.7)	(\$3.5)
May	\$0.6	(\$0.6)	\$0.0	\$2.7	(\$5.1)	(\$2.4)	\$7.3	(\$11.7)	(\$4.4)	(\$6.8)
Jun	\$1.0	(\$1.6)	(\$0.6)	\$1.7	(\$2.8)	(\$1.2)	\$7.7	(\$7.4)	\$0.3	(\$1.5)
Jul	\$5.1	(\$3.7)	\$1.4	\$0.9	(\$3.5)	(\$2.6)	\$9.1	(\$16.2)	(\$7.1)	(\$8.3)
Aug	\$5.1	(\$7.4)	(\$2.4)	\$0.6	(\$1.9)	(\$1.3)	\$5.8	(\$7.6)	(\$1.8)	(\$5.5)
Sep	\$2.5	(\$5.9)	(\$3.4)	\$1.7	(\$1.5)	\$0.1	\$6.9	(\$5.3)	\$1.6	(\$1.7)
Total	\$13.2	(\$19.3)	(\$6.1)	\$13.5	(\$24.6)	(\$11.1)	\$52.8	(\$65.9)	(\$13.2)	(\$30.4)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. If two facilities are constrained during an hour the result is one constrained hour and two congestion event hours. Constraints are often simultaneous, so the number of congestion event hours usually exceeds the number of constrained hours and the number of congestion event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion.

In the first nine months of 2020, there were 61,957 day-ahead, congestion event hours compared to 78,155 day-ahead congestion event hours in the first nine months of 2019. Of the day-ahead congestion event hours in the first nine months of 2020, only 7,875 (12.7 percent) were also constrained in the real-time energy market (Table 11–25). In the first nine months of 2020, there were 16,662 real-time, congestion event hours compared to 13,495 real-time, congestion

event hours in the first nine months of 2019. Of the real-time congestion event hours in the first nine months of 2020, 7,969 (47.8 percent) were also constrained in the day-ahead energy market (Table 11-26).

The top five constraints by congestion costs contributed \$140.2 million, or 35.4 percent, of the total PJM congestion costs in the first nine months of 2020. The top five constraints were the Bagley – Graceton Line, the Conastone – Graceton Line, the Conastone – Peach Bottom Line, the Harwood – Susquehanna Line and the Three Mile Island Transformer.

Several of the top constraints by congestion costs are located in the BGE Zone in the first nine months of 2019 and 2020 (Figure 11-4). The PA Central Interface remains a top constraint by congestion costs, along with the Bagley – Graceton Line, in the first nine months of 2020. The PA Central Reactive Transfer Interface is a reactive transfer interface in northeastern Pennsylvania that was made effective on October 1, 2018. The PA Central Reactive Interface was created to limit power flows from specific gas fired generation units in the PPL Zone that contribute to voltage issues on the 500 kV system, especially when there are transmission outages in the area, and that cannot be controlled by the modeled thermal limits of the transmission facilities in the area.²⁵

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on all types of facilities except interfaces. Interfaces increased from 661 day-ahead, congestion event hours in the first nine months of 2019 to 1,735 day-ahead congestion event hours in the first nine months of 2020. Of 1,735 congestion event hours, 80.8 percent (1,402 hours of 1,735 hours) were on the PA Central Interface.

Real-time, congestion event hours increased on all types of facilities except flowgates in the first nine months of 2020. Interfaces increased from 130 real-time, congestion event hours in the first nine months of 2019 to 1,285 real-time congestion event hours in the first nine months of 2020. Of 1,285 congestion event hours, 93.1 percent (1,196 hours of 1,285 hours) was incurred on the PA Central Interface.

²⁵ See “PA Central Reactive Transfer Interface,” presented at the PJM Operating Committee Meeting (September 11, 2018) <<https://www.pjm.com/-/media/committees-groups/committees/oc/20180911/20180911-item-22-pa-central-transfer-interface-review.ashx>>.

Day-ahead congestion costs decreased on all types of facilities except lines and transformers in the first nine months of 2020 compared to the first nine months of 2019. Day-ahead negative implicit injection credits decreased on all types of facilities except lines and transformers in the first nine months of 2020 compared to the first nine months of 2019.

Negative balancing congestion costs decreased on flowgates and transformers and increased on interfaces and lines in the first nine months of 2020 compared to the first nine months of 2019 (Table 11-24). Table 11-23 provides congestion event hour subtotals and congestion cost subtotals comparing the first nine months of 2020 results by facility type: line, transformer, interface, flowgate and unclassified facilities.^{26 27}

²⁶ Unclassified are congestion costs related to nontransmission facility constraints in the day-ahead energy market and any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors. Nontransmission facility constraints include day-ahead market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

²⁷ The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Table 11-23 Congestion summary (By facility type): January through September, 2020

CLMP Credits and Charges (Millions)												
Type	Day-Ahead				Balancing				Event Hours			
	Implicit	Implicit	Explicit	Total	Implicit	Implicit	Explicit	Total	Congestion	Day-Ahead	Real-Time	
	Withdrawal	Injection			Charges	Charges						Credits
Flowgate	(\$20.5)	(\$59.0)	\$14.2	\$52.8	(\$1.2)	\$4.2	(\$34.2)	(\$39.7)	\$13.1	5,073	3,181	
Interface	\$2.4	(\$14.7)	\$1.1	\$18.3	\$0.1	\$2.3	(\$1.9)	(\$4.0)	\$14.3	1,735	1,285	
Line	\$137.2	(\$169.3)	\$31.9	\$338.4	(\$8.3)	\$15.3	(\$22.3)	(\$45.9)	\$292.5	43,775	9,863	
Transformer	\$12.8	(\$50.4)	\$7.2	\$70.4	(\$1.5)	\$6.2	(\$4.6)	(\$12.4)	\$58.0	9,343	1,817	
Other	\$7.5	(\$11.7)	\$1.1	\$20.3	\$2.0	\$3.2	(\$2.5)	(\$3.6)	\$16.6	2,031	516	
Unclassified	(\$0.1)	(\$2.1)	\$0.3	\$2.3	\$0.1	(\$0.0)	(\$0.8)	(\$0.7)	\$1.6	NA	NA	
Total	\$139.3	(\$307.2)	\$55.9	\$502.5	(\$8.8)	\$31.3	(\$66.3)	(\$106.3)	\$396.1	61,957	16,662	

Table 11-24 Congestion summary (By facility type): January through September, 2019

CLMP Credits and Charges (Millions)											
Day-Ahead					Balancing					Event Hours	
Type	Implicit Withdrawal	Implicit Injection	Explicit Charges	Total	Implicit Withdrawal	Implicit Injection	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
	Charges	Credits			Charges	Credits					
Flowgate	(\$16.1)	(\$65.5)	\$5.2	\$54.6	\$2.8	\$6.7	(\$38.5)	(\$42.5)	\$12.1	8,152	3,984
Interface	\$7.3	(\$32.9)	\$0.2	\$40.4	\$1.1	\$4.1	\$0.7	(\$2.3)	\$38.0	661	130
Line	\$154.8	(\$140.1)	\$26.7	\$321.6	\$3.7	\$16.6	(\$16.5)	(\$29.4)	\$292.2	50,609	7,518
Transformer	\$23.2	(\$38.9)	\$4.4	\$66.5	(\$2.1)	\$7.2	(\$3.3)	(\$12.6)	\$53.9	15,358	967
Other	\$9.1	(\$17.7)	\$1.4	\$28.2	\$0.6	\$4.4	(\$1.3)	(\$5.1)	\$23.2	3,375	896
Unclassified	\$0.1	(\$0.0)	\$0.0	\$0.1	\$0.1	\$0.1	(\$0.5)	(\$0.5)	(\$0.4)	NA	NA
Total	\$178.3	(\$295.2)	\$37.9	\$511.4	\$6.2	\$39.2	(\$59.4)	(\$92.3)	\$419.1	78,155	13,495

Table 11-25 and Table 11-26 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the day-ahead energy market, the number of hours during which the facility is also constrained in the real-time energy market are presented in Table 11-25. In the first nine months of 2020, there were 61,957 congestion event hours in the day-ahead energy market. Of those day-ahead congestion event hours, only 7,875 (12.7 percent) were also constrained in the real-time energy market. In the first nine months of 2019, of the 78,155 day-ahead congestion event hours, only 5,943 (7.6 percent) were binding in the real-time energy market.²⁸

Among the hours for which a facility was constrained in the real-time energy market, the number of hours during which the facility was also constrained in the day-ahead energy market are presented in Table 11-26. In the first nine months of 2020, of the 16,662 congestion event hours in the real-time energy market, 7,969 (47.8 percent) were also constrained in the day-ahead energy market. In the first nine months of 2019, of the 13,495 real-time congestion event hours, 6,146 (45.5 percent) were also in the day-ahead energy market.

²⁸ Constraints are mapped to transmission facilities. In the day-ahead energy market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the day-ahead energy market. Similarly in the real-time market a facility may account for more than one constraint-hour within a given hour.

Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first nine months of 2020. The number of congestion event hours in the day-ahead energy market was about four times the number of congestion event hours in the real-time energy market.

In the real-time market, PJM has the capability to model and monitor almost all PJM transmission facilities. In the day-ahead market, PJM can model and monitor only a portion of PJM transmission facilities. This difference in modeling is the basis of false arbitrage and the source of significant virtual profits. While more constraints are modeled and monitored in the PJM real-time market than the day-ahead market, there is significantly more network flow in the day-ahead market than in the real-time market as a result of virtual bids and offers. Virtual bids and offers also contribute to day-ahead market flows that do not align with realized real-time physical flows. The number of congestion event hours in the day-ahead energy market was about four times the number of congestion event hours in the real-time energy market, despite the fact that only a portion of PJM transmission facilities are modeled in the day-ahead market.

Table 11-25 Congestion event hours (day-ahead against real-time): January through September, 2019 and 2020

Congestion Event Hours						
Type	2019 (Jan - Sep)			2020 (Jan - Sep)		
	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Interface	661	27	4.1%	1,735	1,016	58.6%
Transformer	15,358	486	3.2%	9,343	1,043	11.2%
Flowgate	8,152	997	12.2%	5,073	987	19.5%
Line	50,609	3,897	7.7%	43,775	4,581	10.5%
Other	3,375	536	15.9%	2,031	248	12.2%
Total	78,155	5,943	7.6%	61,957	7,875	12.7%

Table 11-26 Congestion event hours (real-time against day-ahead): January through September, 2019 and 2020

Congestion Event Hours						
Type	2019 (Jan - Sep)			2020 (Jan - Sep)		
	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Interface	130	31	23.8%	1,285	1,053	81.9%
Transformer	967	484	50.1%	1,817	1,067	58.7%
Flowgate	3,984	1,008	25.3%	3,181	989	31.1%
Line	7,518	4,070	54.1%	9,863	4,611	46.8%
Other	896	553	61.7%	516	249	48.3%
Total	13,495	6,146	45.5%	16,662	7,969	47.8%

Table 11-27 shows congestion costs by facility voltage class for the first nine months of 2020. Congestion costs in the first nine months of 2020 decreased for all facilities except 230 kV, 161 kV, 138 kV and 115 kV facilities compared to the first nine months of 2019.

Table 11-27 Congestion summary (By facility voltage): January through September, 2020

CLMP Credits and Charges (Millions)											
Voltage (kV)	Day-Ahead				Balancing				Event Hours		
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
765	(\$0.0)	(\$0.1)	\$0.2	\$0.3	\$0.0	\$0.0	\$0.0	\$0.0	\$0.3	43	0
500	\$26.9	(\$55.8)	\$4.4	\$87.1	\$0.0	\$9.6	(\$5.7)	(\$15.3)	\$71.7	4,896	2,514
345	(\$5.4)	(\$31.8)	\$9.7	\$36.2	\$0.3	\$1.6	(\$8.4)	(\$9.8)	\$26.4	6,596	672
230	\$93.2	(\$89.6)	\$9.4	\$192.2	\$1.5	\$8.0	(\$3.4)	(\$9.8)	\$182.4	15,459	5,162
161	(\$10.7)	(\$30.9)	\$5.3	\$25.5	\$0.0	\$3.1	(\$13.5)	(\$16.6)	\$8.8	2,260	1,564
138	(\$12.9)	(\$109.9)	\$23.7	\$120.7	(\$4.3)	\$10.4	(\$32.7)	(\$47.4)	\$73.3	18,279	4,159
115	\$37.8	\$12.1	\$1.0	\$26.7	(\$6.2)	(\$1.4)	(\$1.4)	(\$6.2)	\$20.5	6,163	2,328
69	\$10.6	\$1.1	\$2.0	\$11.5	(\$0.2)	(\$0.1)	(\$0.3)	(\$0.4)	\$11.1	8,174	263
34	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	3	0
13.8	(\$0.0)	(\$0.1)	\$0.0	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	75	0
4.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	9	0
Unclassified	(\$0.1)	(\$2.1)	\$0.3	\$2.3	\$0.1	(\$0.0)	(\$0.8)	(\$0.7)	\$1.6	NA	NA
Total	\$139.3	(\$307.2)	\$55.9	\$502.5	(\$8.8)	\$31.3	(\$66.3)	(\$106.3)	\$396.1	61,957	16,662

Table 11-28 Congestion summary (By facility voltage): January through September, 2019

CLMP Credits and Charges (Millions)											
Voltage (kV)	Day-Ahead				Balancing				Event Hours		
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Congestion Costs	Day-Ahead	Real-Time
765	(\$0.1)	(\$0.7)	\$0.6	\$1.3	(\$0.1)	\$0.2	(\$0.2)	(\$0.5)	\$0.7	175	46
500	\$95.1	(\$40.0)	\$0.4	\$135.5	\$5.1	\$10.6	(\$0.8)	(\$6.3)	\$129.2	4,811	3,023
345	(\$1.5)	(\$53.7)	\$9.0	\$61.2	\$0.7	\$2.4	(\$11.8)	(\$13.5)	\$47.7	8,841	1,058
230	\$48.2	(\$88.1)	\$4.9	\$141.2	(\$1.9)	\$10.9	(\$5.6)	(\$18.3)	\$122.9	11,527	2,874
212	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	117	0
161	(\$0.3)	(\$5.3)	(\$0.2)	\$4.9	(\$0.1)	\$0.2	(\$0.0)	(\$0.3)	\$4.5	1,183	262
138	\$15.2	(\$83.4)	\$18.8	\$117.3	\$2.1	\$7.4	(\$39.0)	(\$44.3)	\$73.0	25,445	4,817
115	\$7.7	(\$18.0)	\$0.7	\$26.4	(\$0.2)	\$6.0	(\$1.0)	(\$7.2)	\$19.2	6,958	884
69	\$13.4	(\$6.1)	\$3.6	\$23.1	\$0.5	\$1.4	(\$0.4)	(\$1.3)	\$21.7	16,849	531
35	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	17	0
34	\$0.4	\$0.1	\$0.0	\$0.4	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	1,338	0
13	\$0.1	\$0.0	\$0.0	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.1	561	0
12	\$0.1	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	333	0
Unclassified	\$0.1	(\$0.0)	\$0.0	\$0.1	\$0.1	\$0.1	(\$0.5)	(\$0.5)	(\$0.4)	NA	NA
Total	\$178.3	(\$295.2)	\$37.9	\$511.4	\$6.2	\$39.2	(\$59.4)	(\$92.3)	\$419.1	78,155	13,495

Constraint Frequency

Table 11-29 lists the constraints for the first nine months of 2019 and 2020 that were most frequently binding and Table 11-30 shows the constraints which experienced the largest change in congestion event hours from the first nine months of 2019 to the first nine months of 2020. In Table 11-29, constraints are presented in descending order of total day-ahead event hours and real-time event hours for the first nine months of 2020. In Table 11-30, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from the first nine months of 2019 to the first nine months of 2020.

Table 11-29 Top 25 constraints with frequent occurrence: January through September, 2019 and 2020

No.	Constraint	Type	Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
			(Jan - Sep)			(Jan - Sep)			(Jan - Sep)			(Jan - Sep)		
			2019	2020	Change	2019	2020	Change	2019	2020	Change	2019	2020	Change
1	Bagley - Graceton	Line	709	3,055	2,346	92	1,409	1,317	10.8%	46%	36%	1%	21%	20%
2	PA Central	Interface	43	1,402	1,359	87	1,196	1,109	1%	21%	21%	1%	18%	17%
3	Easton - Emuni	Line	3,383	2,422	(961)	9	9	0	52%	37%	(15%)	0%	0%	(0%)
4	Lenox - North Meshoppen	Line	425	1,174	749	352	1,162	810	6%	18%	11%	5%	18%	12%
5	DoeX530	Transformer	1,170	2,206	1,036	0	0	0	18%	34%	16%	0%	0%	0%
6	Mountain	Transformer	875	1,767	892	0	0	0	13%	27%	14%	0%	0%	0%
7	Sub 85 - Sub 18	Flowgate	0	1,004	1,004	0	667	667	0%	15%	15%	0%	10%	10%
8	Sayreville - Sayreville	Line	286	1,648	1,362	0	0	0	4%	25%	21%	0%	0%	0%
9	Logtown - North Delphos	Line	494	955	461	3	462	459	8%	15%	7%	0%	7%	7%
10	Three Mile Island	Transformer	68	893	825	26	462	436	1%	14%	13%	0%	7%	7%
11	Harwood - Susquehanna	Line	99	1,000	901	19	334	315	2%	15%	14%	0%	5%	5%
12	Monroe - Vineland	Line	3,803	1,168	(2,635)	97	69	(28)	58%	18%	(40%)	1%	1%	(0%)
13	Conastone - Peach Bottom	Line	3,870	1,178	(2,692)	2,576	23	(2,553)	59%	18%	(41%)	39%	0%	(39%)
14	New Carisle - Pletcher	Line	24	1,085	1,061	0	110	110	0%	17%	16%	0%	2%	2%
15	Nottingham	Other	340	773	433	129	284	155	5%	12%	7%	2%	4%	2%
16	Paradise - BR Tap	Flowgate	0	576	576	40	411	371	0%	9%	9%	1%	6%	6%
17	Graceton - Safe Harbor	Line	1,292	619	(673)	440	363	(77)	20%	9%	(10%)	7%	6%	(1%)
18	Gardners - Texas Eastern	Line	1,383	817	(566)	105	63	(42)	21%	12%	(9%)	2%	1%	(1%)
19	Yukon	Transformer	27	512	485	24	333	309	0%	8%	7%	0%	5%	5%
20	East Towanda - Hillside	Line	598	397	(201)	342	438	96	9%	6%	(3%)	5%	7%	1%
21	Cedar Grove Sub - Roseland	Line	238	773	535	16	59	43	4%	12%	8%	0%	1%	1%
22	Quad Cities	Transformer	507	799	292	0	0	0	8%	12%	4%	0%	0%	0%
23	Trenton - College Crn	Line	76	785	709	0	0	0	1%	12%	11%	0%	0%	0%
24	Grant - Greentown	Line	696	765	69	3	0	(3)	11%	12%	1%	0%	0%	(0%)
25	Easton - East Muni	Line	0	713	713	0	0	0	0%	11%	11%	0%	0%	0%

Table 11-30 Top 25 constraints with largest year to year change in occurrence: January through September, 2019 and 2020

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
			(Jan - Sep)			(Jan - Sep)			(Jan - Sep)			(Jan - Sep)		
No.	Constraint	Type	2019	2020	Change	2019	2020	Change	2019	2020	Change	2019	2020	Change
1	Conastone - Peach Bottom	Line	3,870	1,178	(2,692)	2,576	23	(2,553)	59%	18%	(41%)	39%	0%	(39%)
2	Bagley - Graceton	Line	709	3,055	2,346	92	1,409	1,317	11%	46%	36%	1%	21%	20%
3	Monroe - Vineland	Line	3,803	1,168	(2,635)	97	69	(28)	58%	18%	(40%)	1%	1%	(0%)
4	Berwick - Koonsville	Line	2,875	352	(2,523)	32	1	(31)	44%	5%	(39%)	0%	0%	(0%)
5	PA Central	Interface	43	1,402	1,359	87	1,196	1,109	1%	21%	21%	1%	18%	17%
6	Sub 85 - Sub 18	Flowgate	0	1,004	1,004	0	667	667	0%	15%	15%	0%	10%	10%
7	Lenox - North Meshoppen	Line	425	1,174	749	352	1,162	810	6%	18%	11%	5%	18%	12%
8	Face Rock	Other	1,956	665	(1,291)	290	44	(246)	30%	10%	(20%)	4%	1%	(4%)
9	Marblehead	Flowgate	1,105	25	(1,080)	474	28	(446)	17%	0%	(16%)	7%	0%	(7%)
10	Marquis - Dept of Energy	Line	1,494	0	(1,494)	0	0	0	23%	0%	(23%)	0%	0%	0%
11	Roxana - Praxair	Flowgate	984	0	(984)	457	0	(457)	15%	0%	(15%)	7%	0%	(7%)
12	Sayreville - Sayreville	Line	286	1,648	1,362	0	0	0	4%	25%	21%	0%	0%	0%
13	Three Mile Island	Transformer	68	893	825	26	462	436	1%	14%	13%	0%	7%	7%
14	Harwood - Susquehanna	Line	99	1,000	901	19	334	315	2%	15%	14%	0%	5%	5%
15	New Carlisle - Pletcher	Line	24	1,085	1,061	0	110	110	0%	17%	16%	0%	2%	2%
16	DoeX530	Transformer	1,170	2,206	1,036	0	0	0	18%	34%	16%	0%	0%	0%
17	Easton - Emuni	Line	3,383	2,422	(961)	9	9	0	52%	37%	(15%)	0%	0%	(0%)
18	Paradise - BR Tap	Flowgate	0	576	576	40	411	371	0%	9%	9%	1%	6%	6%
19	Logtown - North Delphos	Line	494	955	461	3	462	459	8%	15%	7%	0%	7%	7%
20	Mountain	Transformer	875	1,767	892	0	0	0	13%	27%	14%	0%	0%	0%
21	New Carlisle - Olive	Line	883	1	(882)	0	0	0	13%	0%	(13%)	0%	0%	0%
22	Munster	Flowgate	709	0	(709)	170	0	(170)	11%	0%	(11%)	3%	0%	(3%)
23	Cedar Creek - Red Lion	Line	766	2	(764)	57	0	(57)	12%	0%	(12%)	1%	0%	(1%)
24	Siegfried	Transformer	560	53	(507)	310	3	(307)	9%	1%	(8%)	5%	0%	(5%)
25	Yukon	Transformer	27	512	485	24	333	309	0%	8%	7%	0%	5%	5%

Constraint Costs

Table 11-31 and Table 11-32 show the top constraints affecting congestion costs by facility for the first nine months of 2020 and 2019. The Bagley – Graceton Line was the largest contributor to congestion costs in the first nine months of 2020, with \$56.2 million in total congestion costs and 14.2 percent of the total PJM congestion costs in the first nine months of 2020.

Table 11-31 Top 25 constraints affecting PJM congestion costs (By facility): January through September, 2020²⁹

CLMP Credits and Charges (Millions)													
Day-Ahead								Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Bagley - Graceton	Line	BGE	\$49.2	(\$5.5)	\$2.9	\$57.6	\$1.1	\$3.6	\$1.2	(\$1.3)	\$56.2	14.2%
2	Conastone - Graceton	Line	BGE	\$8.0	(\$17.4)	\$0.3	\$25.7	\$0.2	(\$0.7)	(\$0.1)	\$0.8	\$26.5	6.7%
3	Conastone - Peach Bottom	Line	500	\$18.8	(\$1.1)	\$0.5	\$20.5	(\$0.0)	(\$0.1)	\$0.0	\$0.1	\$20.6	5.2%
4	Harwood - Susquehanna	Line	PPL	\$1.3	(\$17.5)	\$0.6	\$19.5	(\$0.2)	\$0.4	(\$0.3)	(\$0.9)	\$18.6	4.7%
5	Three Mile Island	Transformer	500	\$10.1	(\$7.6)	\$1.1	\$18.8	\$0.6	\$0.5	(\$0.5)	(\$0.5)	\$18.4	4.6%
6	Yukon	Transformer	500	(\$6.4)	(\$27.2)	\$1.3	\$22.1	(\$0.8)	\$5.3	(\$2.6)	(\$8.8)	\$13.3	3.4%
7	Pleasant View - Ashburn	Line	Dominion	\$10.8	(\$2.5)	(\$0.1)	\$13.1	\$0.4	\$0.8	(\$0.2)	(\$0.6)	\$12.5	3.2%
8	PA Central	Interface	500	\$1.1	(\$13.0)	\$0.8	\$14.9	\$0.3	\$1.7	(\$1.3)	(\$2.7)	\$12.2	3.1%
9	Smithton - Yukon	Line	APS	(\$4.8)	(\$14.1)	\$1.2	\$10.6	\$0.2	\$0.4	(\$0.3)	(\$0.5)	\$10.2	2.6%
10	Coolspring - Milford	Line	DPL	\$1.5	(\$7.9)	\$0.3	\$9.7	(\$1.5)	(\$0.2)	(\$0.3)	(\$1.6)	\$8.1	2.0%
11	Braidwood - East Frankfort	Line	ComEd	(\$0.2)	(\$7.8)	\$0.4	\$8.0	(\$0.0)	\$0.0	(\$0.3)	(\$0.3)	\$7.7	1.9%
12	Pruntytown	Other	APS	(\$1.5)	(\$7.8)	(\$0.5)	\$5.8	\$0.0	(\$0.0)	\$0.3	\$0.3	\$6.1	1.5%
13	Cumberland - Juniata	Line	PPL	(\$1.8)	(\$7.7)	\$0.4	\$6.4	(\$0.1)	(\$0.4)	(\$1.0)	(\$0.7)	\$5.7	1.4%
14	Logtown - North Delphos	Line	AEP	(\$15.3)	(\$25.2)	\$2.1	\$11.9	\$0.0	\$3.5	(\$3.3)	(\$6.8)	\$5.2	1.3%
15	Paradise - BR Tap	Flowgate	MISO	(\$3.4)	(\$8.4)	(\$0.2)	\$4.8	\$0.0	(\$0.0)	(\$0.2)	(\$0.2)	\$4.6	1.2%
16	Nottingham	Other	PECO	\$5.1	\$1.4	\$0.7	\$4.4	\$0.0	\$0.0	\$0.0	\$0.0	\$4.4	1.1%
17	Loretto - Vienna	Line	DPL	\$5.3	\$1.4	\$0.4	\$4.3	(\$0.1)	(\$0.2)	(\$0.1)	\$0.0	\$4.3	1.1%
18	Ashburn - Cochran Mill	Line	Dominion	\$2.2	(\$1.9)	(\$0.2)	\$3.9	\$0.2	\$0.2	\$0.4	\$0.4	\$4.3	1.1%
19	Gardners - Texas Eastern	Line	Met-Ed	\$3.4	(\$0.7)	\$0.4	\$4.4	(\$0.3)	(\$0.1)	(\$0.0)	(\$0.2)	\$4.2	1.1%
20	Graceton - Safe Harbor	Line	BGE	\$3.9	\$0.4	\$0.5	\$4.0	\$0.1	(\$0.1)	(\$0.1)	\$0.1	\$4.1	1.0%
21	Maple - Long Plant Tap	Flowgate	MISO	(\$0.7)	(\$1.9)	\$1.3	\$2.6	(\$1.3)	\$0.4	(\$5.0)	(\$6.6)	(\$4.1)	(1.0%)
22	Plymouth Meeting - Whitpain	Line	PECO	(\$0.1)	(\$3.8)	\$0.1	\$3.8	\$0.2	\$0.2	\$0.1	\$0.1	\$3.9	1.0%
23	Mohomet - ChampTP	Flowgate	MISO	(\$0.6)	(\$3.9)	\$1.9	\$5.3	(\$0.1)	(\$0.4)	(\$1.9)	(\$1.7)	\$3.6	0.9%
24	Grant - Greentown	Line	AEP	(\$1.0)	(\$3.0)	\$1.5	\$3.5	\$0.0	\$0.0	\$0.0	\$0.0	\$3.5	0.9%
25	Seward - Towanda	Line	PENELEC	\$15.2	\$11.9	\$0.0	\$3.3	\$0.0	\$0.0	\$0.0	\$0.0	\$3.3	0.8%
Top 25 Total				\$100.3	(\$170.7)	\$17.9	\$288.9	(\$1.1)	\$14.8	(\$15.6)	(\$31.6)	\$257.3	65.0%
All Other Constraints				\$39.1	(\$136.5)	\$38.0	\$213.6	(\$7.6)	\$16.4	(\$50.7)	(\$74.8)	\$138.8	35.0%
Total				\$139.3	(\$307.2)	\$55.9	\$502.5	(\$8.8)	\$31.3	(\$66.3)	(\$106.3)	\$396.1	100.0%

²⁹ All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11–32 Top 25 constraints affecting PJM congestion costs (By facility): January through September, 2019³⁰

CLMP Credits and Charges (Millions)													
No.	Constraint	Type	Location	Day-Ahead				Balancing				Congestion Costs	Percent of Total PJM Congestion Costs
				Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total		
1	Conastone – Peach Bottom	Line	500	\$81.5	(\$1.7)	\$0.1	\$83.3	\$3.7	\$5.4	\$1.6	(\$0.1)	\$83.3	19.9%
2	Coolspring – Milford	Line	DPL	(\$0.6)	(\$16.2)	\$0.2	\$15.9	(\$0.1)	(\$0.6)	(\$0.7)	(\$0.2)	\$15.7	3.7%
3	Tanners Creek – Miami Fort	Flowgate	MISO	(\$5.9)	(\$20.5)	\$0.3	\$14.9	\$0.0	\$0.0	\$0.0	\$0.0	\$14.9	3.6%
4	Siegfried	Transformer	PPL	\$6.8	(\$13.7)	\$0.4	\$20.9	(\$1.6)	\$5.2	(\$0.1)	(\$6.8)	\$14.1	3.4%
5	AP South	Interface	500	\$8.4	(\$5.5)	(\$0.2)	\$13.7	\$0.2	\$0.1	\$0.1	\$0.1	\$13.8	3.3%
6	East	Interface	500	(\$5.9)	(\$20.3)	\$0.1	\$14.5	\$0.9	\$4.0	\$0.9	(\$2.2)	\$12.3	2.9%
7	Roxana – Praxair	Flowgate	MISO	(\$1.1)	(\$2.7)	\$2.1	\$3.7	\$2.6	\$3.4	(\$13.8)	(\$14.6)	(\$10.9)	(2.6%)
8	Graceton – Safe Harbor	Line	BGE	\$11.4	\$0.7	\$0.1	\$10.9	\$0.4	\$0.9	\$0.2	(\$0.2)	\$10.6	2.5%
9	Conastone – Northwest	Line	BGE	\$7.0	(\$3.0)	\$0.4	\$10.4	\$0.0	(\$0.0)	(\$0.3)	(\$0.3)	\$10.1	2.4%
10	Cedar Creek – Red Lion	Line	DPL	\$1.6	(\$7.8)	\$0.9	\$10.3	(\$0.8)	(\$0.6)	(\$0.7)	(\$1.0)	\$9.3	2.2%
11	Face Rock	Other	PPL	(\$0.0)	(\$9.6)	\$0.7	\$10.2	\$1.0	\$1.7	(\$0.3)	(\$1.0)	\$9.3	2.2%
12	Bagley – Graceton	Line	BGE	\$5.9	(\$2.0)	\$0.1	\$8.1	\$0.2	\$0.5	\$0.4	\$0.0	\$8.1	1.9%
13	CPL – DOM	Interface	500	\$3.5	(\$4.2)	\$0.1	\$7.8	\$0.0	\$0.0	\$0.0	\$0.0	\$7.8	1.9%
14	Palisades – Argenta	Flowgate	MISO	(\$0.3)	(\$7.3)	\$0.6	\$7.6	\$0.1	(\$0.3)	(\$0.6)	(\$0.3)	\$7.3	1.7%
15	Pleasant View – Ashburn	Line	Dominion	\$5.7	(\$1.2)	\$0.3	\$7.3	\$0.4	\$0.9	(\$0.2)	(\$0.7)	\$6.5	1.6%
16	Greentown	Flowgate	MISO	(\$0.2)	(\$1.7)	(\$0.1)	\$1.5	(\$0.6)	\$0.9	(\$6.2)	(\$7.7)	(\$6.1)	(1.5%)
17	Conastone	Other	500	\$5.7	(\$0.5)	\$0.1	\$6.2	(\$0.3)	\$0.6	\$0.3	(\$0.6)	\$5.6	1.3%
18	Gardners – Texas Eastern	Line	Met-Ed	(\$0.5)	(\$6.7)	\$0.2	\$6.4	(\$0.8)	\$0.2	(\$0.4)	(\$1.5)	\$5.0	1.2%
19	Smithton – Yukon	Line	APS	(\$2.6)	(\$7.1)	\$0.3	\$4.8	\$0.9	\$0.2	(\$0.7)	(\$0.1)	\$4.8	1.1%
20	Tanners Creek – Miami Fort	Line	AEP	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.2)	\$0.7	(\$3.6)	(\$4.6)	(\$4.6)	(1.1%)
21	Cedar Grove Sub – Roseland	Line	PSEG	(\$0.0)	(\$4.8)	(\$0.3)	\$4.5	(\$0.0)	\$0.1	\$0.0	(\$0.1)	\$4.4	1.0%
22	Riverside	Line	BGE	\$0.4	(\$4.0)	\$0.1	\$4.5	\$0.2	\$0.2	(\$0.2)	(\$0.2)	\$4.4	1.0%
23	Preston – Tanyard	Line	DPL	\$4.7	\$1.3	\$0.6	\$4.0	\$0.0	(\$0.0)	(\$0.0)	\$0.0	\$4.0	1.0%
24	Blooming Grove – Paupack	Line	PPL	\$1.4	(\$2.6)	\$0.0	\$3.9	\$0.0	\$0.0	\$0.0	\$0.0	\$3.9	0.9%
25	Cloverdale	Transformer	AEP	\$1.5	(\$1.8)	\$0.3	\$3.6	\$0.0	(\$0.2)	(\$0.1)	\$0.1	\$3.7	0.9%
Top 25 Total				\$128.3	(\$143.2)	\$7.6	\$279.0	\$6.2	\$23.5	(\$24.5)	(\$41.8)	\$237.2	56.6%
All Other Constraints				\$50.1	(\$152.0)	\$30.3	\$232.4	(\$0.0)	\$15.6	(\$34.9)	(\$50.6)	\$181.8	43.4%
Total				\$178.3	(\$295.2)	\$37.9	\$511.4	\$6.2	\$39.2	(\$59.4)	(\$92.3)	\$419.1	100.0%

³⁰ 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 11-4 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in the first nine months of 2020. Three of the top 10 constraints are located in the BGE Zone: the Bagley - Graceton Line, the Conastone - Graceton Line and the Conastone - Peach Bottom Line. Multiple constraints in the BGE Control Zone have been in the top 10 constraints by total congestion costs since 2016.

Figure 11-4 Location of the top 10 constraints by PJM total congestion costs: January through September, 2020

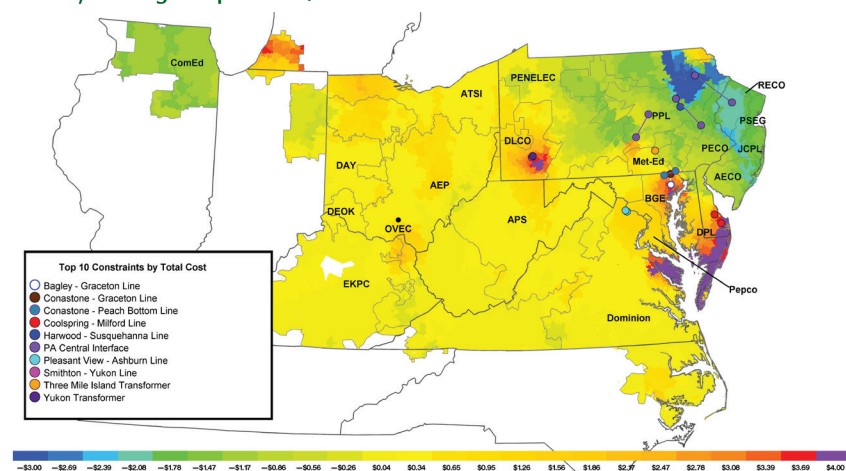


Figure 11-5 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time, load-weighted, average CLMP in the first nine months of 2020.

Figure 11-5 Location of top 10 constraints by balancing congestion costs: January through September, 2020

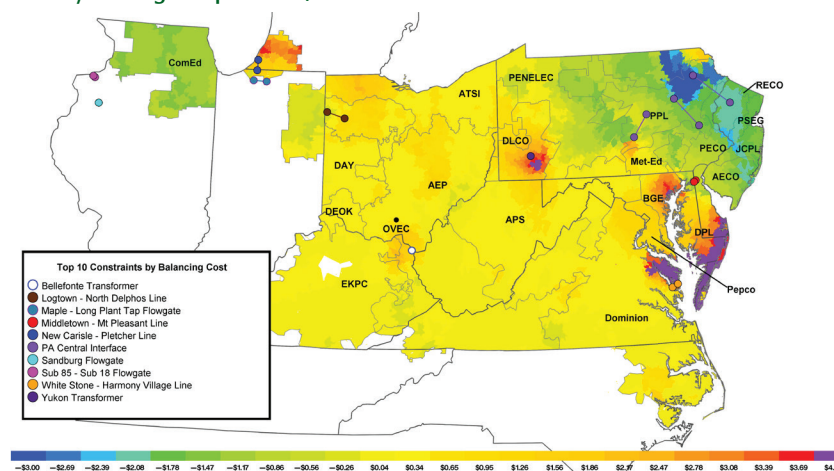
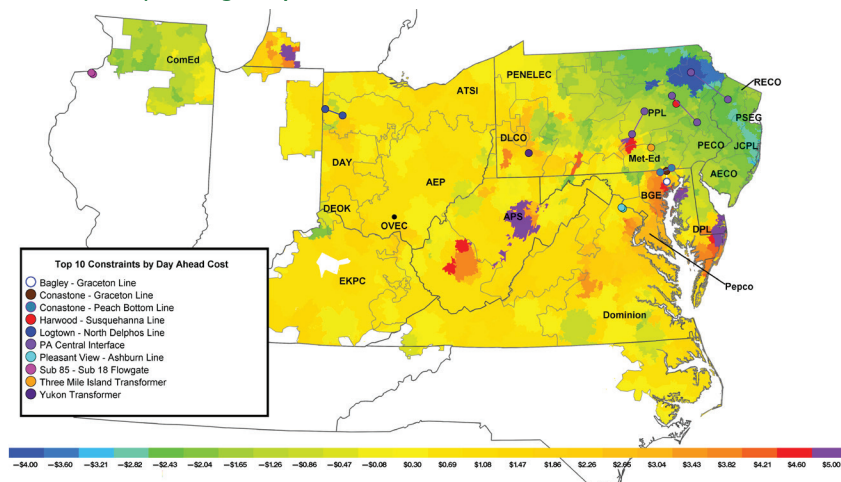


Figure 11-6 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead, load-weighted, average CLMP in the first nine months of 2020.

Figure 11-6 Location of the top 10 constraints by PJM day-ahead congestion costs: January through September, 2020

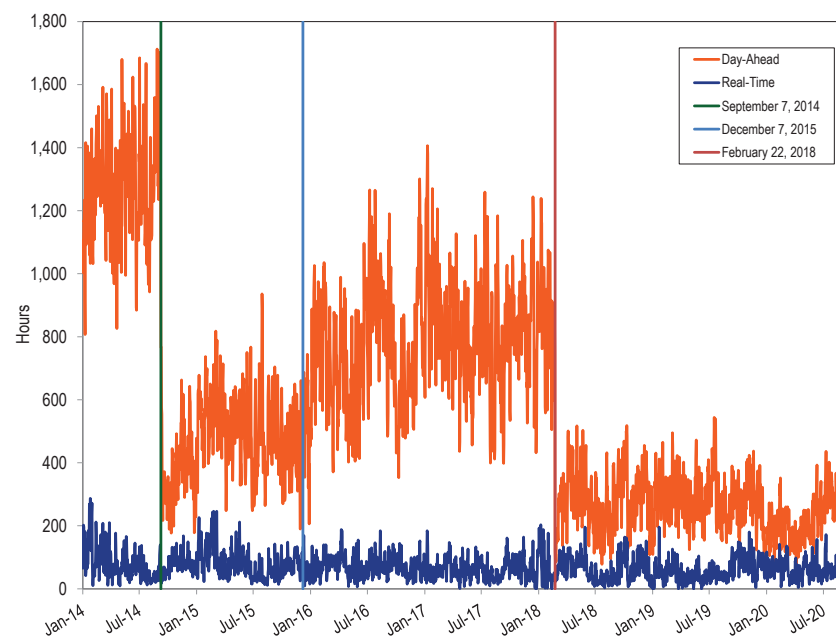


Congestion Event Summary: Impact of Changes in UTC Volumes

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 the first nine months of 2020, the average hourly cleared UTC MW decreased, compared to the first nine months of 2019. Day-ahead congestion event hours decreased by 20.7 percent from 78,155 congestion event hours in the first nine months of 2019 to 61,957 congestion event hours in the first nine months of 2020 (Table 11-25).

Figure 11-7 shows the daily day-ahead and real-time congestion event hours for January 2014 through September 2020.

Figure 11-7 Daily congestion event hours: January 2014 through September 2020



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 withdrawal loss charges minus injection loss credits, plus explicit loss charges, incurred in both the day-ahead energy market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal implicit marginal loss charges plus explicit marginal loss charges plus net inadvertent loss charges. Implicit marginal loss charges equal withdrawal loss charges minus injection loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.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 withdrawal loss charges and injection loss 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. Withdrawal loss charges, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Injection 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 marginal loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total system energy costs and net residual market adjustments that is allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.³³

- **Day-Ahead Implicit Withdrawal Loss Charges.** Day-ahead implicit withdrawal loss charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit

³¹ PJM Operating Agreement Schedule 1 §3.7.

³² *Id.*

³³ See PJM, "Manual 28: Operating Agreement Accounting," Rev. 83 (Dec. 3, 2019).

withdrawal loss charges are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.

- **Day-Ahead Implicit Injection Loss Credits.** Day-ahead implicit injection loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead implicit injection 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 Implicit Withdrawal Loss Charges.** Balancing implicit withdrawal loss charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit withdrawal loss charges are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Implicit Injection Loss Credits.** Balancing implicit injection 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 implicit injection loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Charges.** Explicit loss charges are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative,

where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load plus export ratio basis.³⁴

Total Marginal Loss Cost

The total marginal loss cost in PJM for the first nine months of 2020 was \$349.2 million, which was comprised of implicit withdrawal loss charges of -\$25.8 million, implicit injection loss credits of -\$387.4 million, explicit loss charges of -\$12.4 million and inadvertent loss charges of \$0.0 million (Table 11-34). The total marginal loss cost in the first nine months of 2020 was lower than the total marginal loss cost in the first nine months of any year from 2008 through 2019.

Monthly marginal loss costs in the first nine months of 2020 ranged from \$22.5 million in April to \$67.0 million in July. Total marginal loss surplus decreased in the first nine months of 2020 by \$47.9 million or 29.6 percent from \$162.1 million in the first nine months of 2019 to \$114.2 million in the first nine months of 2020.

³⁴ PJM Operating Agreement Schedule 1 §3.7.

Table 11-33 shows the total marginal loss component costs and the total PJM billing for the first nine months of 2008 through 2020.

Table 11-33 Total PJM loss component costs (Dollars (Millions)): January through September, 2008 through 2020³⁵

(Jan - Sep)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	\$2,049	NA	\$26,979	7.6%
2009	\$992	(51.6%)	\$19,927	5.0%
2010	\$1,259	26.9%	\$26,249	4.8%
2011	\$1,153	(8.5%)	\$28,836	4.0%
2012	\$758	(34.3%)	\$22,119	3.4%
2013	\$797	5.2%	\$25,153	3.2%
2014	\$1,243	56.0%	\$40,770	3.0%
2015	\$830	(33.3%)	\$33,710	2.5%
2016	\$542	(34.7%)	\$29,490	1.8%
2017	\$501	(7.5%)	\$29,510	1.7%
2018	\$757	51.1%	\$37,950	2.0%
2019	\$503	(33.6%)	\$29,980	1.7%
2020	\$349	(30.5%)	\$25,010	1.4%

Table 11-34 shows PJM total marginal loss costs by accounting category for the first nine months of 2008 through 2020. Table 11-35 shows PJM total marginal loss costs by accounting category by market for the first nine months of 2008 through 2020.

Table 11-34 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through September, 2008 through 2020

(Jan - Sep)	Marginal Loss Costs (Millions)				Total
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	
2008	(\$210.3)	(\$2,185.9)	\$73.3	\$0.0	\$2,048.9
2009	(\$62.0)	(\$1,028.3)	\$26.1	\$0.0	\$992.4
2010	(\$73.8)	(\$1,301.6)	\$31.5	(\$0.0)	\$1,259.3
2011	(\$138.8)	(\$1,277.7)	\$13.7	\$0.0	\$1,152.6
2012	(\$17.3)	(\$790.0)	(\$15.1)	\$0.0	\$757.6
2013	(\$3.3)	(\$834.4)	(\$34.1)	(\$0.0)	\$797.0
2014	(\$47.6)	(\$1,343.7)	(\$52.9)	\$0.0	\$1,243.1
2015	(\$26.1)	(\$872.8)	(\$16.9)	\$0.0	\$829.8
2016	(\$41.7)	(\$605.4)	(\$21.8)	(\$0.0)	\$541.9
2017	(\$38.6)	(\$568.1)	(\$28.4)	\$0.0	\$501.0
2018	(\$32.7)	(\$798.6)	(\$8.9)	\$0.0	\$757.0
2019	(\$35.5)	(\$550.1)	(\$12.0)	\$0.0	\$502.7
2020	(\$25.8)	(\$387.4)	(\$12.4)	\$0.0	\$349.2

³⁵ The loss costs include net inadvertent charges.

Table 11-35 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January through September, 2008 through 2020

(Jan – Sep)	Marginal Loss Costs (Millions)								
	Day-Ahead				Balancing				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges
2008	(\$132.3)	(\$2,133.4)	\$100.8	\$2,101.8	(\$77.9)	(\$52.5)	(\$27.4)	(\$52.9)	\$0.0
2009	(\$65.9)	(\$1,025.7)	\$53.2	\$1,013.0	\$3.9	(\$2.6)	(\$27.1)	(\$20.6)	\$0.0
2010	(\$94.4)	(\$1,307.1)	\$61.5	\$1,274.2	\$20.6	\$5.6	(\$30.0)	(\$14.9)	(\$0.0)
2011	(\$174.3)	(\$1,313.6)	\$51.7	\$1,191.1	\$35.5	\$36.0	(\$38.0)	(\$38.5)	\$0.0
2012	(\$42.2)	(\$805.6)	\$12.7	\$776.0	\$24.9	\$15.6	(\$27.8)	(\$18.5)	\$0.0
2013	(\$30.3)	(\$857.9)	\$44.0	\$871.6	\$27.0	\$23.5	(\$78.1)	(\$74.6)	(\$0.0)
2014	(\$95.5)	(\$1,380.8)	\$62.7	\$1,347.9	\$47.9	\$37.1	(\$115.6)	(\$104.8)	\$0.0
2015	(\$47.0)	(\$883.1)	\$24.7	\$860.8	\$20.9	\$10.3	(\$41.6)	(\$31.0)	\$0.0
2016	(\$48.4)	(\$606.0)	\$37.8	\$595.4	\$6.6	\$0.5	(\$59.5)	(\$53.4)	(\$0.0)
2017	(\$45.9)	(\$568.9)	\$43.1	\$566.0	\$7.3	\$0.8	(\$71.5)	(\$65.0)	\$0.0
2018	(\$38.5)	(\$790.8)	\$28.6	\$780.9	\$5.8	(\$7.8)	(\$37.5)	(\$23.9)	\$0.0
2019	(\$37.4)	(\$547.8)	\$32.2	\$542.6	\$1.9	(\$2.3)	(\$44.2)	(\$39.9)	\$0.0
2020	(\$27.8)	(\$388.8)	\$30.5	\$391.5	\$2.0	\$1.4	(\$42.9)	(\$42.3)	\$0.0

Table 11-36 and Table 11-37 show the total loss costs for each transaction type in the first nine months of 2020 and 2019. In the first nine months of 2020, generation paid loss costs of \$371.5 million, 106.4 percent of total loss costs. In the first nine months of 2019, generation paid loss costs of \$529.5 million, 105.3 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 the first nine months of 2020, DEC's were paid \$1.6 million in loss credits in the day-ahead market, paid \$3.1 million in loss charges in the balancing energy market and paid \$1.5 million in total loss payments. In the first nine months of 2020, INC's paid \$5.7 million in loss charges in the day-ahead market, were paid \$6.6 million in loss credits in the balancing energy market and were paid \$0.9 million in total loss credits. In the first nine months of 2020, up to congestion paid \$30.5 million in loss charges in the day-ahead market, were paid \$43.1 million in loss credits in the balancing energy market and received \$12.6 million in total loss credits.

Table 11-36 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through September, 2020

Transaction Type	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	(\$1.6)	\$0.0	\$0.0	(\$1.6)	\$3.1	\$0.0	\$0.0	\$3.1	\$0.0	\$1.5
Demand	(\$2.9)	\$0.0	\$0.0	(\$2.9)	\$3.4	\$0.0	\$0.0	\$3.4	\$0.0	\$0.5
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	(\$0.3)	(\$0.3)	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.0	(\$0.3)
Export	(\$8.4)	\$0.0	\$0.0	(\$8.4)	(\$3.7)	\$0.0	\$0.2	(\$3.5)	\$0.0	(\$11.9)
Generation	\$0.0	(\$368.0)	\$0.0	\$368.0	\$0.0	(\$3.5)	\$0.0	\$3.5	\$0.0	\$371.5
Import	\$0.0	(\$0.5)	\$0.0	\$0.5	\$0.0	(\$0.9)	(\$0.0)	\$0.9	\$0.0	\$1.4
INC	\$0.0	(\$5.7)	\$0.0	\$5.7	\$0.0	\$6.6	\$0.0	(\$6.6)	\$0.0	(\$0.9)
Internal Bilateral	(\$15.0)	(\$14.7)	\$0.3	\$0.0	(\$0.7)	\$0.0	(\$0.0)	\$0.0	\$0.0	(\$0.0)
Up to Congestion	\$0.0	\$0.0	\$30.5	\$30.5	\$0.0	\$0.0	(\$43.1)	(\$43.1)	\$0.0	(\$12.6)
Wheel In	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total	(\$27.8)	(\$388.8)	\$30.5	\$391.5	\$2.0	\$1.4	(\$42.9)	(\$42.3)	\$0.0	\$349.2

Table 11-37 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through September, 2019

Transaction Type	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	(\$3.9)	\$0.0	\$0.0	(\$3.9)	\$5.2	\$0.0	\$0.0	\$5.2	\$0.0	\$1.2
Demand	(\$4.6)	\$0.0	\$0.0	(\$4.6)	\$4.9	\$0.0	\$0.0	\$4.9	\$0.0	\$0.4
Demand Response	(\$0.0)	\$0.0	\$0.0	(\$0.0)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Explicit Congestion and Loss Only	\$0.0	\$0.0	(\$0.4)	(\$0.4)	\$0.0	\$0.0	(\$0.0)	(\$0.0)	\$0.0	(\$0.5)
Export	(\$13.2)	\$0.0	(\$0.0)	(\$13.2)	(\$7.5)	\$0.0	\$0.3	(\$7.2)	\$0.0	(\$20.4)
Generation	\$0.0	(\$523.1)	\$0.0	\$523.1	\$0.0	(\$6.4)	\$0.0	\$6.4	\$0.0	\$529.5
Import	\$0.0	(\$1.4)	\$0.0	\$1.4	\$0.0	(\$4.4)	(\$0.1)	\$4.4	\$0.0	\$5.8
INC	\$0.0	(\$7.8)	\$0.0	\$7.8	\$0.0	\$9.2	\$0.0	(\$9.2)	\$0.0	(\$1.4)
Internal Bilateral	(\$15.7)	(\$15.5)	\$0.1	(\$0.0)	(\$0.7)	\$0.0	(\$0.0)	\$0.0	\$0.0	(\$0.0)
Up to Congestion	\$0.0	\$0.0	\$32.5	\$32.5	\$0.0	\$0.0	(\$44.2)	(\$44.2)	\$0.0	(\$11.7)
Wheel In	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	(\$0.2)	(\$0.2)	\$0.0	(\$0.2)
Total	(\$37.4)	(\$547.8)	\$32.2	\$542.6	\$1.9	(\$2.3)	(\$44.2)	(\$39.9)	\$0.0	\$502.7

Monthly Marginal Loss Costs

Table 11-38 shows a monthly summary of marginal loss costs by market type for January 2019 through September 2020.

Table 11-38 Monthly marginal loss costs by market (Millions): January 2019 through September 2020

	Marginal Loss Costs (Millions)							
	2019				2020			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	\$92.3	(\$5.8)	\$0.0	\$86.5	\$49.8	(\$5.3)	(\$0.0)	\$44.5
Feb	\$57.2	(\$3.3)	\$0.0	\$53.9	\$39.8	(\$4.6)	(\$0.0)	\$35.2
Mar	\$70.5	(\$7.0)	\$0.0	\$63.5	\$32.4	(\$3.5)	(\$0.0)	\$28.8
Apr	\$42.7	(\$3.9)	\$0.0	\$38.8	\$25.9	(\$3.4)	(\$0.0)	\$22.5
May	\$45.2	(\$3.9)	(\$0.0)	\$41.3	\$30.4	(\$4.8)	\$0.0	\$25.7
Jun	\$43.9	(\$2.8)	(\$0.0)	\$41.1	\$41.0	(\$4.3)	\$0.0	\$36.7
Jul	\$77.3	(\$3.5)	\$0.0	\$73.8	\$73.2	(\$6.1)	\$0.0	\$67.0
Aug	\$60.6	(\$4.4)	(\$0.0)	\$56.3	\$59.8	(\$5.8)	(\$0.0)	\$54.0
Sep	\$53.0	(\$5.4)	(\$0.0)	\$47.6	\$39.1	(\$4.4)	\$0.0	\$34.8
Oct	\$42.6	(\$3.6)	(\$0.0)	\$39.0				
Nov	\$58.2	(\$6.0)	(\$0.0)	\$52.2				
Dec	\$53.1	(\$4.9)	(\$0.0)	\$48.1				
Total	\$696.5	(\$54.5)	(\$0.0)	\$642.0	\$391.5	(\$42.3)	\$0.0	\$349.2

Figure 11-8 shows PJM monthly marginal loss costs for January 2008 through September 2020.

Figure 11-8 PJM monthly marginal loss costs (Dollars (Millions)): January 2008 through September 2020

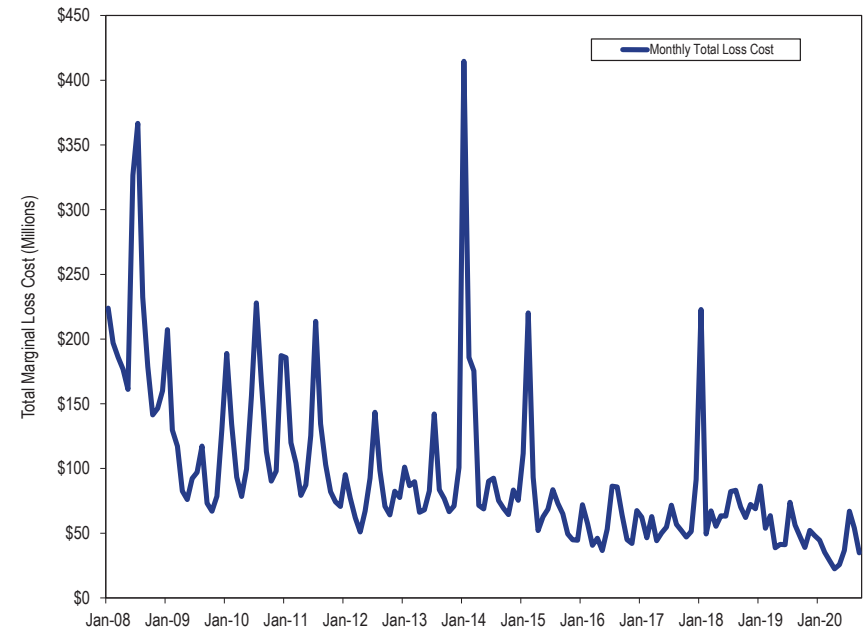


Table 11-39 shows the monthly total loss costs for each virtual transaction type in January 2019 through September 2020.

Table 11-39 Monthly PJM loss charges by virtual transaction type and by market (Dollars (Millions)): January 2019 through September 2020

Marginal Loss Charges (Millions)										
DEC			INC			Up to Congestion				
Year	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2019 Jan	(\$0.2)	\$0.4	\$0.2	\$1.1	(\$1.4)	(\$0.3)	\$5.4	(\$6.5)	(\$1.1)	(\$1.2)
Feb	(\$0.4)	\$0.3	(\$0.1)	\$0.8	(\$1.0)	(\$0.3)	\$3.1	(\$4.4)	(\$1.3)	(\$1.6)
Mar	(\$0.2)	\$0.2	\$0.0	\$1.4	(\$1.5)	(\$0.1)	\$6.0	(\$6.9)	(\$0.9)	(\$1.0)
Apr	(\$0.3)	\$0.3	\$0.0	\$0.7	(\$0.8)	(\$0.1)	\$3.3	(\$4.1)	(\$0.8)	(\$0.9)
May	(\$0.7)	\$0.9	\$0.2	\$0.9	(\$0.8)	\$0.0	\$3.2	(\$4.2)	(\$0.9)	(\$0.7)
Jun	(\$0.5)	\$0.7	\$0.2	\$0.6	(\$0.7)	(\$0.1)	\$1.8	(\$3.4)	(\$1.6)	(\$1.5)
Jul	(\$0.7)	\$1.0	\$0.3	\$0.9	(\$1.1)	(\$0.2)	\$3.3	(\$4.8)	(\$1.4)	(\$1.4)
Aug	(\$0.5)	\$0.5	\$0.0	\$0.6	(\$0.6)	(\$0.0)	\$3.2	(\$4.5)	(\$1.3)	(\$1.3)
Sep	(\$0.5)	\$0.9	\$0.4	\$0.9	(\$1.2)	(\$0.4)	\$3.1	(\$5.5)	(\$2.3)	(\$2.3)
Oct	(\$0.2)	\$0.4	\$0.2	\$0.8	(\$1.2)	(\$0.3)	\$2.5	(\$3.8)	(\$1.3)	(\$1.5)
Nov	(\$0.3)	\$0.4	\$0.1	\$1.2	(\$1.3)	(\$0.2)	\$4.6	(\$6.3)	(\$1.7)	(\$1.8)
Dec	(\$0.1)	\$0.1	\$0.1	\$0.7	(\$1.0)	(\$0.2)	\$4.1	(\$5.7)	(\$1.6)	(\$1.8)
Total	(\$4.5)	\$6.1	\$1.6	\$10.5	(\$12.7)	(\$2.2)	\$43.7	(\$60.1)	(\$16.4)	(\$17.0)
2020 Jan	(\$0.1)	\$0.1	(\$0.0)	\$0.7	(\$0.9)	(\$0.2)	\$3.7	(\$5.2)	(\$1.5)	(\$1.7)
Feb	(\$0.1)	\$0.2	\$0.0	\$0.6	(\$0.8)	(\$0.2)	\$3.2	(\$4.4)	(\$1.2)	(\$1.3)
Mar	(\$0.3)	\$0.4	\$0.1	\$0.6	(\$0.7)	(\$0.1)	\$2.5	(\$3.7)	(\$1.2)	(\$1.3)
Apr	(\$0.2)	\$0.4	\$0.1	\$0.6	(\$0.7)	(\$0.1)	\$2.3	(\$3.5)	(\$1.2)	(\$1.1)
May	(\$0.1)	\$0.2	\$0.1	\$0.8	(\$0.8)	\$0.0	\$3.7	(\$4.8)	(\$1.1)	(\$0.9)
Jun	(\$0.2)	\$0.5	\$0.2	\$0.5	(\$0.6)	(\$0.1)	\$3.1	(\$4.6)	(\$1.4)	(\$1.3)
Jul	(\$0.3)	\$0.8	\$0.4	\$0.9	(\$0.9)	(\$0.0)	\$5.1	(\$6.5)	(\$1.4)	(\$1.0)
Aug	(\$0.1)	\$0.4	\$0.3	\$0.6	(\$0.7)	(\$0.1)	\$4.1	(\$6.2)	(\$2.2)	(\$2.0)
Sep	(\$0.1)	\$0.2	\$0.2	\$0.5	(\$0.6)	(\$0.1)	\$2.8	(\$4.2)	(\$1.4)	(\$1.4)
Total	(\$1.6)	\$3.1	\$1.5	\$5.7	(\$6.6)	(\$0.9)	\$30.5	(\$43.1)	(\$12.6)	(\$12.0)

Marginal Loss Costs and Loss Credits

Total marginal loss surplus is calculated by adding the total system energy costs, the total marginal loss costs and net residual market adjustments. The total system energy costs are equal to the net implicit energy charges (implicit withdrawal charges minus implicit injection credits) plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss charges (implicit withdrawal loss charges less implicit injection loss credits) plus net explicit loss charges plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more injection credits than withdrawal charges in every hour. Total system energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus

real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-40 shows the total system energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for the first nine months of 2008 through 2020. The total marginal loss surplus decreased \$47.9 million in the first nine months of 2020 from the first nine months of 2019.

Table 11-40 Marginal loss surplus (Dollars (Millions)): January through September, 2008 through 2020³⁶

Marginal Loss Surplus (Millions)						
Net Residual Market Adjustment						
(Jan – Sep)	System Energy Costs	Marginal Loss Costs	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total
2008	(\$976.0)	\$2,048.9	\$0.0	\$0.0	\$0.0	\$1,073.0
2009	(\$484.6)	\$992.4	(\$0.0)	(\$0.4)	(\$0.1)	\$508.3
2010	(\$618.6)	\$1,259.3	\$0.0	(\$0.6)	(\$0.1)	\$641.5
2011	(\$651.3)	\$1,152.6	\$0.1	\$1.3	(\$0.0)	\$500.1
2012	(\$442.6)	\$757.6	\$0.1	(\$0.7)	\$0.0	\$315.7
2013	(\$527.2)	\$797.0	\$0.0	\$1.7	\$0.0	\$268.0
2014	(\$833.9)	\$1,243.1	(\$0.0)	\$5.1	\$0.1	\$404.1
2015	(\$536.5)	\$829.8	(\$0.3)	\$4.7	(\$0.1)	\$288.3
2016	(\$358.3)	\$541.9	\$0.0	\$2.8	(\$0.2)	\$181.0
2017	(\$344.0)	\$501.0	\$0.0	\$0.7	(\$0.1)	\$156.5
2018	(\$498.7)	\$757.0	(\$0.0)	\$1.9	(\$0.1)	\$256.4
2019	(\$339.3)	\$502.7	(\$0.0)	\$1.3	(\$0.1)	\$162.1
2020	(\$234.0)	\$349.2	(\$0.0)	\$1.1	(\$0.1)	\$114.2

System Energy Costs Energy Accounting

The system energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The system energy cost is based on the day-ahead and real-time energy components of LMP. Total system energy costs, analogous to total congestion costs or total loss costs, are equal to

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.

the withdrawal energy charges minus injection energy credits, incurred in both the day-ahead energy market and the balancing energy market, plus net inadvertent energy charges. Total system energy costs can be more accurately thought of as net system energy costs.

Total System Energy Costs

The total system energy cost for the first nine months of 2020 was -\$234.0 million, which was comprised of implicit withdrawal energy charges of \$17,364.8 million, implicit injection energy credits of \$17,600.7 million, explicit energy charges of \$0.0 million and inadvertent energy charges of \$1.9 million. The monthly system energy costs for the first nine months of 2020 ranged from -\$42.5 million in July to -\$15.9 million in April.

Table 11-41 shows total system energy costs and total PJM billing, for the first nine months of 2008 through 2020.

Table 11-41 Total PJM system energy costs (Dollars (Millions)): January through September, 2008 through 2020³⁷

(Jan – Sep)	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	(\$976)	NA	\$26,979	(3.6%)
2009	(\$485)	(50.3%)	\$19,927	(2.4%)
2010	(\$619)	27.6%	\$26,249	(2.4%)
2011	(\$651)	5.3%	\$28,836	(2.3%)
2012	(\$443)	(32.0%)	\$22,119	(2.0%)
2013	(\$527)	19.1%	\$25,153	(2.1%)
2014	(\$834)	58.2%	\$40,770	(2.0%)
2015	(\$537)	(35.7%)	\$33,710	(1.6%)
2016	(\$358)	(33.2%)	\$29,490	(1.2%)
2017	(\$344)	(4.0%)	\$29,510	(1.2%)
2018	(\$499)	45.0%	\$37,950	(1.3%)
2019	(\$339)	(32.0%)	\$29,980	(1.1%)
2020	(\$234)	(31.0%)	\$25,010	(0.9%)

System energy costs for the first nine months of 2008 through 2020 are shown in Table 11-42 and Table 11-43. Table 11-42 shows PJM system energy costs by accounting category and Table 11-43 shows PJM system energy costs by market category.

³⁷ The system energy costs include net inadvertent charges.

Table 11-42 Total PJM system energy costs by accounting category (Dollars (Millions)): January through September, 2008 through 2020

(Jan – Sep)	System Energy Costs (Millions)				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	\$91,391.9	\$92,368.9	\$0.0	\$1.0	(\$976.0)
2009	\$32,472.4	\$32,960.8	\$0.0	\$3.8	(\$484.6)
2010	\$41,562.3	\$42,169.5	\$0.0	(\$11.4)	(\$618.6)
2011	\$38,515.2	\$39,193.0	\$0.0	\$26.5	(\$651.3)
2012	\$28,303.5	\$28,754.0	\$0.0	\$7.9	(\$442.6)
2013	\$32,756.8	\$33,279.9	\$0.0	(\$4.2)	(\$527.2)
2014	\$50,415.3	\$51,245.6	\$0.0	(\$3.6)	(\$833.9)
2015	\$33,772.7	\$34,311.9	\$0.0	\$2.6	(\$536.5)
2016	\$25,858.3	\$26,213.7	\$0.0	(\$2.9)	(\$358.3)
2017	\$26,082.1	\$26,430.6	\$0.0	\$4.5	(\$344.0)
2018	\$33,871.7	\$34,376.1	\$0.0	\$5.7	(\$498.7)
2019	\$23,696.4	\$24,035.9	\$0.0	\$0.2	(\$339.3)
2020	\$17,364.8	\$17,600.7	\$0.0	\$1.9	(\$234.0)

Table 11-43 Total PJM system energy costs by market category (Dollars (Millions)): January through September, 2008 through 2020

(Jan – Sep)	System Energy Costs (Millions)									
	Day-Ahead					Balancing				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	\$67,568.7	\$68,653.8	\$0.0	(\$1,085.1)	\$23,823.2	\$23,715.1	\$0.0	\$108.1	\$1.0	(\$976.0)
2009	\$32,628.0	\$33,162.4	\$0.0	(\$534.4)	(\$155.6)	(\$201.6)	\$0.0	\$45.9	\$3.8	(\$484.6)
2010	\$41,665.6	\$42,289.1	\$0.0	(\$623.5)	(\$103.4)	(\$119.7)	\$0.0	\$16.3	(\$11.4)	(\$618.6)
2011	\$38,908.1	\$39,530.7	\$0.0	(\$622.6)	(\$392.9)	(\$337.7)	\$0.0	(\$55.3)	\$26.5	(\$651.3)
2012	\$28,423.3	\$28,853.1	\$0.0	(\$429.8)	(\$119.9)	(\$99.2)	\$0.0	(\$20.7)	\$7.9	(\$442.6)
2013	\$32,797.0	\$33,398.3	\$0.0	(\$601.3)	(\$40.2)	(\$118.4)	\$0.0	\$78.2	(\$4.2)	(\$527.2)
2014	\$50,428.5	\$51,603.0	\$0.0	(\$1,174.5)	(\$13.2)	(\$357.4)	\$0.0	\$344.2	(\$3.6)	(\$833.9)
2015	\$33,910.7	\$34,549.7	\$0.0	(\$639.0)	(\$138.0)	(\$237.8)	\$0.0	\$99.8	\$2.6	(\$536.5)
2016	\$25,986.4	\$26,469.9	\$0.0	(\$483.5)	(\$128.1)	(\$256.2)	\$0.0	\$128.1	(\$2.9)	(\$358.3)
2017	\$26,360.1	\$26,844.5	\$0.0	(\$484.4)	(\$278.0)	(\$413.9)	\$0.0	\$135.9	\$4.5	(\$344.0)
2018	\$33,957.1	\$34,508.6	\$0.0	(\$551.4)	(\$85.4)	(\$132.5)	\$0.0	\$47.1	\$5.7	(\$498.7)
2019	\$24,004.0	\$24,411.6	\$0.0	(\$407.6)	(\$307.7)	(\$375.7)	\$0.0	\$68.0	\$0.2	(\$339.3)
2020	\$17,564.2	\$17,867.8	\$0.0	(\$303.6)	(\$199.4)	(\$267.1)	\$0.0	\$67.7	\$1.9	(\$234.0)

Table 11-44 and Table 11-45 show the total system energy costs for each transaction type in the first nine months of 2020 and 2019. In the first nine months of 2020, generation was paid \$12,633.6 million and demand paid \$11,801.1 million in net energy payment. In the first nine months of 2019, generation was paid \$17,268.8 million and demand paid \$16,283.8 million in net energy payment.

Table 11-44 Total PJM system energy costs by transaction type by market (Dollars (Millions)): January through September, 2020

System Energy Costs (Millions)									
Transaction Type	Day-Ahead				Balancing				Grand Total
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	
DEC	\$607.9	\$0.0	\$0.0	\$607.9	(\$620.5)	\$0.0	\$0.0	(\$620.5)	(\$12.7)
Demand	\$11,671.7	\$0.0	\$0.0	\$11,671.7	\$129.4	\$0.0	\$0.0	\$129.4	\$11,801.1
Demand Response	(\$0.2)	\$0.0	\$0.0	(\$0.2)	\$0.2	\$0.0	\$0.0	\$0.2	\$0.0
Export	\$441.7	\$0.0	\$0.0	\$441.7	\$250.3	\$0.0	\$0.0	\$250.3	\$691.9
Generation	\$0.0	\$12,674.0	\$0.0	(\$12,674.0)	\$0.0	(\$40.4)	\$0.0	\$40.4	(\$12,633.6)
Import	\$0.0	\$23.4	\$0.0	(\$23.4)	\$0.0	\$60.8	\$0.0	(\$60.8)	(\$84.2)
INC	\$0.0	\$327.3	\$0.0	(\$327.3)	\$0.0	(\$328.7)	\$0.0	\$328.7	\$1.4
Internal Bilateral	\$4,843.1	\$4,843.1	\$0.0	\$0.0	\$20.1	\$20.1	\$0.0	\$0.0	\$0.0
Wheel In	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$21.2	\$0.0	(\$21.2)	(\$21.2)
Wheel Out	\$0.0	\$0.0	\$0.0	\$0.0	\$21.2	\$0.0	\$0.0	\$21.2	\$21.2
Total	\$17,564.2	\$17,867.8	\$0.0	(\$303.6)	(\$199.4)	(\$267.1)	\$0.0	\$67.7	(\$235.9)

Table 11-45 Total PJM system energy costs by transaction type by market (Dollars (Millions)): January through September, 2019

System Energy Costs (Millions)									
Transaction Type	Day-Ahead				Balancing				Grand Total
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	
DEC	\$742.3	\$0.0	\$0.0	\$742.3	(\$744.1)	\$0.0	\$0.0	(\$744.1)	(\$1.8)
Demand	\$16,219.3	\$0.0	\$0.0	\$16,219.3	\$64.5	\$0.0	\$0.0	\$64.5	\$16,283.8
Demand Response	(\$0.6)	\$0.0	\$0.0	(\$0.6)	\$0.6	\$0.0	\$0.0	\$0.6	(\$0.0)
Export	\$513.0	\$0.0	\$0.0	\$513.0	\$337.8	\$0.0	\$0.0	\$337.8	\$850.8
Generation	\$0.0	\$17,308.3	\$0.0	(\$17,308.3)	\$0.0	(\$39.5)	\$0.0	\$39.5	(\$17,268.8)
Import	\$0.0	\$59.5	\$0.0	(\$59.5)	\$0.0	\$139.5	\$0.0	(\$139.5)	(\$199.0)
INC	\$0.0	\$513.8	\$0.0	(\$513.8)	\$0.0	(\$509.2)	\$0.0	\$509.2	(\$4.6)
Internal Bilateral	\$6,530.0	\$6,530.0	\$0.0	(\$0.0)	\$17.8	\$17.8	\$0.0	(\$0.0)	(\$0.0)
Wheel In	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$15.7	\$0.0	(\$15.7)	(\$15.7)
Wheel Out	\$0.0	\$0.0	\$0.0	\$0.0	\$15.7	\$0.0	\$0.0	\$15.7	\$15.7
Total	\$24,004.0	\$24,411.6	\$0.0	(\$407.6)	(\$307.7)	(\$375.7)	\$0.0	\$68.0	(\$339.5)

Monthly System Energy Costs

Table 11-46 shows a monthly summary of system energy costs by market type for January 2019 through September 2020. Total balancing system energy costs in the first nine months of 2020 decreased from the first nine months of 2019. Monthly total system energy costs in the first nine months of 2020 ranged from -\$42.5 million in July to -\$15.9 million in April.

Table 11-46 Monthly system energy costs by market type (Dollars (Millions)):
January 2019 through September 2020

System Energy Costs (Millions)								
2019				2020				
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	(\$69.5)	\$9.8	\$0.4	(\$59.3)	(\$40.0)	\$9.4	(\$0.1)	(\$30.7)
Feb	(\$42.8)	\$6.9	\$0.5	(\$35.4)	(\$30.7)	\$6.8	(\$0.3)	(\$24.2)
Mar	(\$54.2)	\$12.3	\$0.2	(\$41.6)	(\$25.5)	\$5.2	(\$0.1)	(\$20.4)
Apr	(\$34.2)	\$8.1	\$0.4	(\$25.7)	(\$21.1)	\$5.2	(\$0.0)	(\$15.9)
May	(\$34.5)	\$6.6	(\$0.1)	(\$28.0)	(\$25.4)	\$6.9	\$0.4	(\$18.1)
Jun	(\$32.8)	\$4.2	(\$0.2)	(\$28.8)	(\$32.8)	\$7.6	\$0.6	(\$24.6)
Jul	(\$54.7)	\$6.3	\$0.1	(\$48.3)	(\$52.4)	\$9.0	\$0.9	(\$42.5)
Aug	(\$44.3)	\$8.2	(\$0.6)	(\$36.7)	(\$44.9)	\$9.9	(\$0.2)	(\$35.1)
Sep	(\$40.7)	\$5.8	(\$0.5)	(\$35.4)	(\$30.7)	\$7.6	\$0.6	(\$22.5)
Oct	(\$33.6)	\$7.4	(\$0.6)	(\$26.8)				
Nov	(\$45.9)	\$10.3	(\$0.8)	(\$36.4)				
Dec	(\$41.5)	\$9.1	(\$0.3)	(\$32.7)				
Total	(\$528.6)	\$94.9	(\$1.5)	(\$435.2)	(\$303.6)	\$67.7	\$1.9	(\$234.0)

Figure 11-9 shows PJM monthly system energy costs for January 2008 through September 2020.

Figure 11-9 PJM monthly system energy costs (Millions): January 2008 through September 2020

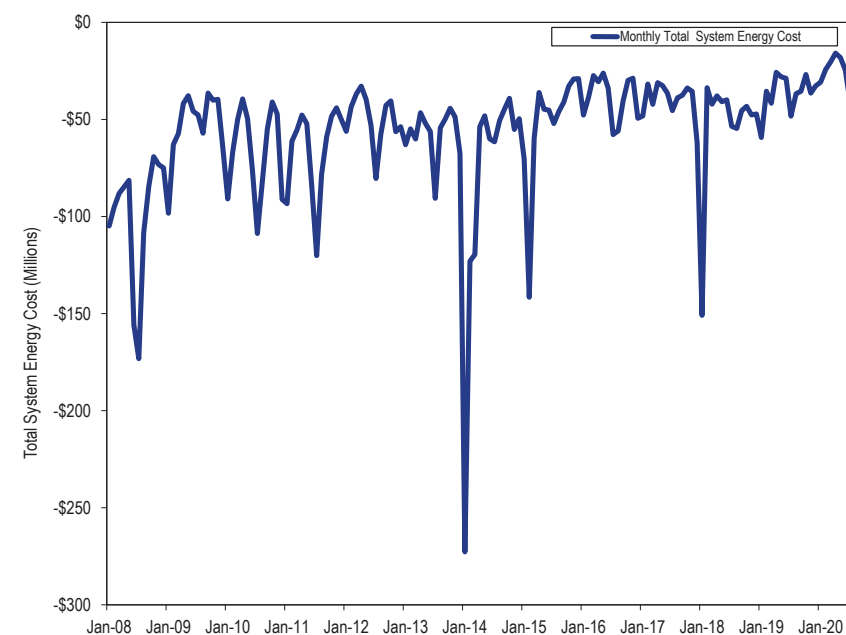


Table 11-47 shows the monthly total system energy costs for each virtual transaction type in the first nine months of 2020 and year of 2019. In the first nine months of 2020, DECs paid \$607.9 million in energy charges in the day-ahead market, were paid \$620.5 million in energy credits in the balancing energy market and were paid \$12.7 million in total energy credits. In the first nine months of 2020, INCs were paid \$327.3 million in energy credits in the day-ahead market, paid \$328.7 million in energy charges in the balancing market and paid \$1.4 million in total energy charges. In the first nine months of 2019, DECs paid \$742.3 million in energy charges in the day-ahead market, were paid \$744.1 million in energy credits in the balancing energy market and

were paid \$1.8 million in total energy credits. In the first nine months of 2019, INCs were paid \$513.8 million in energy credits in the day-ahead market, paid \$509.2 million in energy charges in the balancing energy market and were paid \$4.6 million in total energy credits. The system energy costs are zero for UTCs because the system energy costs for UTCs equal the difference in the energy component between source and sink and the energy component is the same at all buses.

Table 11-47 Monthly PJM energy charges by virtual transaction type and by market (Dollars (Millions)): January 2019 through September 2020

Energy Charges (Millions)								
DEC				INC				Grand Total
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	
2019	Jan	\$104.4	(\$97.7)	\$6.7	(\$71.7)	\$67.1	(\$4.6)	\$2.1
	Feb	\$64.0	(\$66.8)	(\$2.8)	(\$52.5)	\$54.0	\$1.6	(\$1.2)
	Mar	\$76.6	(\$77.4)	(\$0.8)	(\$66.7)	\$65.4	(\$1.2)	(\$2.0)
	Apr	\$60.3	(\$59.7)	\$0.6	(\$59.0)	\$58.5	(\$0.5)	\$0.1
	May	\$81.9	(\$79.1)	\$2.9	(\$56.1)	\$53.9	(\$2.2)	\$0.6
	Jun	\$75.8	(\$75.3)	\$0.4	(\$47.1)	\$46.5	(\$0.6)	(\$0.2)
	Jul	\$105.6	(\$106.1)	(\$0.5)	(\$60.7)	\$61.7	\$1.0	\$0.5
	Aug	\$72.4	(\$69.7)	\$2.7	(\$49.2)	\$46.0	(\$3.2)	(\$0.5)
	Sep	\$101.3	(\$112.4)	(\$11.0)	(\$50.9)	\$56.2	\$5.3	(\$5.7)
	Oct	\$62.6	(\$75.9)	(\$13.3)	(\$57.5)	\$63.2	\$5.7	(\$7.6)
	Nov	\$59.6	(\$58.8)	\$0.8	(\$70.8)	\$68.7	(\$2.1)	(\$1.3)
	Dec	\$52.7	(\$53.3)	(\$0.5)	(\$43.0)	\$42.6	(\$0.4)	(\$0.9)
Total		\$917.1	(\$932.0)	(\$14.8)	(\$685.1)	\$683.7	(\$1.4)	(\$16.2)
2020	Jan	\$44.4	(\$43.3)	\$1.0	(\$44.0)	\$43.2	(\$0.8)	\$0.2
	Feb	\$43.0	(\$42.4)	\$0.6	(\$34.5)	\$33.5	(\$1.0)	(\$0.3)
	Mar	\$43.9	(\$44.0)	(\$0.1)	(\$32.1)	\$31.7	(\$0.4)	(\$0.5)
	Apr	\$42.4	(\$43.8)	(\$1.4)	(\$32.4)	\$33.6	\$1.2	(\$0.2)
	May	\$59.9	(\$62.4)	(\$2.5)	(\$34.7)	\$35.2	\$0.5	(\$2.0)
	Jun	\$79.9	(\$83.8)	(\$3.9)	(\$32.4)	\$33.2	\$0.8	(\$3.1)
	Jul	\$116.8	(\$119.2)	(\$2.4)	(\$48.7)	\$49.9	\$1.2	(\$1.2)
	Aug	\$99.9	(\$105.4)	(\$5.5)	(\$35.0)	\$35.7	\$0.7	(\$4.8)
	Sep	\$77.6	(\$76.2)	\$1.4	(\$33.4)	\$32.6	(\$0.8)	\$0.6
	Total	\$607.9	(\$620.5)	(\$12.7)	(\$327.3)	\$328.7	\$1.4	(\$11.3)

Generation and Transmission Planning¹

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of September 30, 2020, PJM had a total installed capacity of 196,832.0 MW, of which 50,230.8 MW (25.5 percent) are coal fired steam units, 50,563.6 MW (25.7 percent) are combined cycle units and 33,452.6 MW (17.0 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 196,832.0 MW of installed capacity, 71,577.4 MW (36.4 percent) are from units older than 40 years, of which 36,939.4 MW (51.6 percent) are coal fired steam units, 532.0 MW (0.7 percent) are combined cycle units and 16,184.6 MW (22.6 percent) are nuclear units.

Generation Retirements²

- There are 43,787.4 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 31,846.2 MW (72.7 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost natural gas.
- In the first nine months of 2020, 2,469.0 MW of generation retired. The largest generator that retired in the first nine months of 2020 was the 337.0 MW Conesville 4 coal fired steam unit located in the AEP Zone. Of the 2,469.0 MW of generation that retired, 776.8 MW (31.5 percent) were located in the AEP Zone.
- As of September 30, 2020, there are 4,556.0 MW of generation that have requested retirement after September 30, 2020, of which 1,907.5 MW (41.9

percent) are located in the Dominion Zone. Of the Dominion generation requesting retirement, 1,121.5 MW (58.8 percent) are coal fired steam units.

Generation Queue³

- There were 126,818.9 MW in generation queues, in the status of active, under construction or suspended, at the end of 2019. In the first nine months of 2020, the AF2 and AG1 queue windows closed. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On September 30, 2020, there were 148,361.6 MW in generation queues, in the status of active, under construction or suspended, an increase of 21,542.7 MW (17.0 percent) from the end of 2019.⁴
- As of September 30, 2020, 5,367 projects, representing 624,142.5 MW, have entered the queue process since its inception in 1998. Of those, 932 projects, representing 71,856.6 MW, went into service. Of the projects that entered the queue process, 2,916 projects, representing 403,924.3 MW (64.7 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.
- As of September 30, 2020, 148,361.6 MW were in generation request queues in the status of active, under construction or suspended. Based on historical completion rates, 38,864.3 MW of new generation in the queue are expected to go into service.

¹ Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.

² See PJM. Planning. "Generator Deactivations," (Accessed on September 30, 2020) <<http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>>.

³ See PJM. Planning. "New Services Queue," (Accessed on September 30, 2020) <<https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>>.

⁴ The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. PJM's benefit/cost analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through September 30, 2020, PJM has completed four market efficiency cycles under Order No. 1000.⁵

PJM MISO Interregional Market Efficiency Process (IMEP)

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

PJM MISO Targeted Market Efficiency Process (TMEP)

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

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance

criteria, as determined by PJM."⁶ Supplemental projects are exempt from the competitive planning process.

- The average number of supplemental projects in each expected in service year increased by 735.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 167 for years 2008 through 2020 (post Order 890).
- The process for designating projects as supplemental projects should be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build the project, or used to effectively replace the RTEP process.

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. Some Transmission Owners include end of life transmission projects in their Transmission Owner Form 715 Planning Criteria. These projects were exempt from the competitive planning process.⁷ On August 30, 2019, the Commission issued an Order Instituting Section 206 Proceeding that removed the proposal window exemption for Form No. 715 Planning Criteria.⁸
- End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project.

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, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for

⁵ See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

⁶ See PJM, "Transmission Construction Status," (Accessed on September 30, 2020) <<http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>>.

⁷ See PJM, Operating Agreement, Schedule 6 § 1.5.8(o).

⁸ 168 FERC ¶ 61,132 at P 13 (2019).

authorization.⁹ In the first nine months of 2020, the PJM Board approved a net change of \$770.4 million in upgrades. As of September 30, 2020, the PJM Board has approved \$38.4 billion in system enhancements since 1999.

Transmission Competition

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

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of September 30, 2020, no QTUs have cleared a BRA.

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.¹⁰

- There were 6,856 transmission outage requests submitted in the first four months of 2020/2021 planning period. Of the requested outages, 75.2 percent of the requested outages were planned for less than or equal to five days and 11.4 percent of requested outages were planned for greater than 30 days. Of the requested outages, 46.8 percent were late according to the rules in PJM's Manual 3.

Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.¹¹ (Priority: Low. First reported 2013. Status: Partially adopted, 2012.)
- 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. First reported 2018. Status: Adopted, 2019.)

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.)

¹⁰ See PJM. "PJM Manual 03: Transmission Operations," Rev. 57 (May 29, 2020).

¹¹ 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>.

⁹ Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

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

Transmission Competition

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

and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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: Adopted 2020.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. New recommendation. Status: Not adopted.)

Cost Allocation

- 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.¹² (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

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

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled 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

¹² See the 2015 State of the Market Report for PJM, Volume 2, Section 12: Generation and Transmission Planning, at p. 463, Cost Allocation Issues.

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

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current benefit/cost analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The MMU recommends that the market efficiency process be eliminated.

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 nonincumbent 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 nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. 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 asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for of a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

If it is retained, 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 definition of benefits should also be reevaluated.

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.

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.¹³ As of September 30, 2020, PJM had an installed capacity of 196,832.0 MW, of which 50,230.8 MW (25.5 percent) are coal fired steam units, 50,563.6 MW (25.7 percent) are combined cycle units and 33,452.6 MW (17.0 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, external units and uses nameplate values for solar and wind resources.

The AEP Zone has the most installed capacity of any PJM zone. Of the 196,832.0 MW of PJM installed capacity, 31,020.1 MW (15.8 percent) are in the AEP Zone, of which 13,463.0 MW (43.4 percent) are coal fired steam units, 6,990.0 MW (22.5 percent) are combined cycle units and 2,071.0 MW (6.7 percent) are nuclear units.

¹³ The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 12-1 Existing PJM capacity: September 30, 2020 (By zone and unit type (MW))¹⁴

Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
AECO	0.0	901.9	544.7	26.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	8.9	61.8	0.0	0.0	458.9	0.0	0.0	0.0	7.5	0.0	2,015.2
AEP	6.0	6,990.0	4,108.2	16.2	4.8	0.0	66.0	420.9	2,071.0	0.0	0.0	20.4	14.7	0.0	0.0	13,463.0	738.0	0.0	50.0	3,050.9	0.0	31,020.1
APS	80.4	2,179.0	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	29.6	0.0	18.3	99.4	0.0	0.0	5,299.0	0.0	0.0	0.0	875.1	0.0	9,935.3
ATSI	0.0	3,495.5	958.0	629.0	6.4	0.0	0.0	0.0	2,134.0	0.0	18.5	46.1	0.0	0.0	0.0	2,264.0	325.0	0.0	0.0	0.0	0.0	9,876.5
BGE	0.0	0.0	267.6	228.8	0.0	0.0	0.0	0.4	1,716.0	0.0	0.0	4.2	1.1	0.0	0.0	1,578.0	143.5	397.0	57.0	0.0	0.0	4,393.6
ComEd	148.5	2,621.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	38.3	9.0	0.0	0.0	3,840.1	1,326.0	0.0	0.0	4,490.7	0.0	29,846.7
DAY	0.0	0.0	897.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	932.6
DEOK	20.0	522.2	598.0	56.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	0.0	0.0	0.0	1,857.0	47.0	0.0	0.0	0.0	0.0	3,217.0
DLCO	0.0	244.0	0.0	15.0	0.0	0.0	0.0	6.3	1,777.0	0.0	0.0	0.0	0.0	0.0	0.0	565.0	0.0	0.0	0.0	0.0	0.0	2,607.3
Dominion	0.0	9,099.6	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	39.0	106.4	1,708.3	0.0	0.0	3,852.6	35.0	1,586.0	368.4	587.0	0.0	28,654.6
DPL	0.0	1,742.5	978.2	478.2	0.0	30.0	0.0	0.0	0.0	0.0	88.0	14.1	300.4	0.0	0.0	410.0	812.0	153.0	70.0	0.0	0.0	5,076.4
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	0.0	2,597.0
JCPL	40.0	2,427.5	531.1	225.6	0.0	0.4	400.0	0.0	0.0	0.0	0.0	14.1	369.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,008.2
Met-Ed	0.0	2,646.0	2.0	398.5	0.0	0.0	0.0	19.0	0.0	0.0	0.0	33.4	0.0	0.0	0.0	115.0	0.0	0.0	60.0	0.0	0.0	3,273.9
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	0.0	0.0	2,388.8	0.0	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	4,089.0	0.0	828.0	0.0	0.0	1,070.0	572.0	4,546.8	0.0	2.0	0.9	3.0	0.0	0.0	0.0	762.0	0.0	103.0	0.0	0.0	11,976.7
PENELEC	28.4	1,900.0	350.5	57.0	0.0	0.0	513.0	77.8	0.0	120.1	28.0	17.8	13.5	0.0	0.0	6,053.5	610.0	0.0	42.0	1,100.4	0.0	10,912.0
Pepco	0.0	1,736.5	764.2	308.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.1	2.5	0.0	0.0	1,896.0	1,164.1	0.0	52.0	0.0	0.0	5,934.4
PPL	20.0	5,558.5	252.0	185.5	20.6	0.0	0.0	706.6	2,520.0	12.0	5.0	14.7	35.0	0.0	0.0	2,547.9	2,449.0	0.0	29.0	216.5	0.0	14,572.3
PSEG	7.7	4,410.3	1,039.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	9.0	224.6	0.0	0.0	0.0	3.0	0.0	179.1	0.0	0.0	9,370.8
XIC	0.0	0.0	858.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	4,222.7
Total	351.0	50,563.6	24,655.7	3,934.4	43.8	32.0	5,052.0	3,040.6	33,452.6	161.7	218.5	362.4	2,843.8	0.0	0.0	50,230.8	8,414.6	2,136.0	1,010.5	10,328.1	0.0	196,832.0

¹⁴ The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction.

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most installed capacity of any PJM state. Of the 196,832.0 MW of installed capacity, 48,157.9 MW (24.5 percent) are in Pennsylvania, of which 9,281.4 MW (19.3 percent) are coal fired steam units, 17,616.5 MW (36.6 percent) are combined cycle units and 8,843.8 MW (18.4 percent) are nuclear units.

Table 12-2 Existing PJM capacity: September 30, 2020 (By state and unit type (MW))

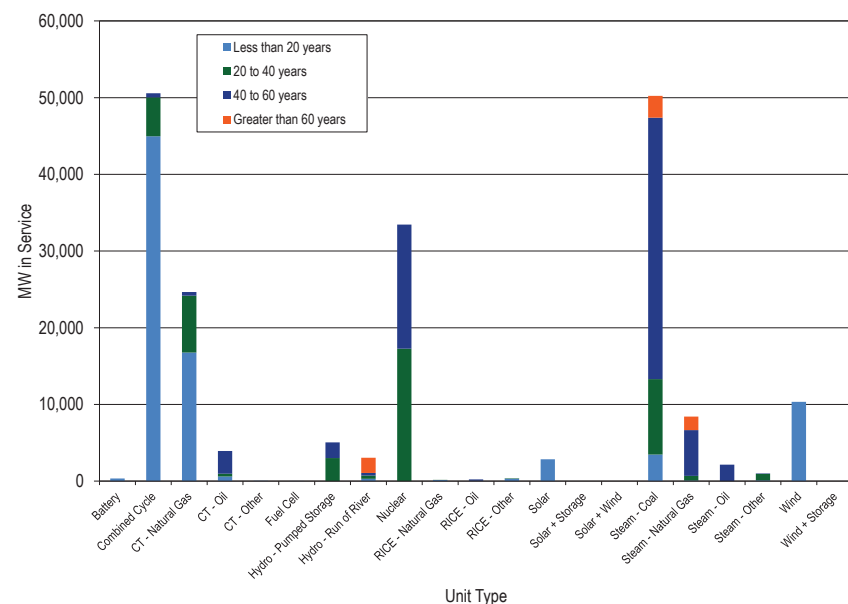
State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	19.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.5
DE	0.0	742.5	325.5	116.3	0.0	30.0	0.0	0.0	0.0	0.0	0.0	8.1	0.0	0.0	0.0	410.0	812.0	0.0	70.0	0.0	0.0	2,514.4
IL	148.5	2,621.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	38.3	9.0	0.0	0.0	3,840.1	1,326.0	0.0	0.0	4,490.7	0.0	29,846.7
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	0.0	0.0	3,923.8	0.0	0.0	0.0	2,153.2	0.0	8,374.9
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	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	0.0	3,719.1
MD	20.0	2,717.0	1,684.5	552.7	0.0	0.0	0.0	0.4	1,716.0	0.0	76.0	21.3	313.4	0.0	0.0	3,654.0	1,307.6	550.0	109.0	295.0	0.0	13,016.9
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	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	661.5	0.0	0.0	0.0	0.0	0.0	0.0	208.0	0.0	1,367.5
NJ	47.7	7,739.7	2,115.0	251.6	0.0	2.0	400.0	5.0	3,493.0	0.0	4.0	32.0	655.8	0.0	0.0	458.9	3.0	0.0	179.1	7.5	0.0	15,394.2
OH	24.0	6,972.7	4,201.2	701.2	6.4	0.0	0.0	200.0	2,134.0	0.0	47.0	50.9	1.1	0.0	0.0	9,689.0	47.0	0.0	0.0	897.7	0.0	24,972.2
PA	49.9	17,616.5	1,491.9	1,484.0	20.6	0.0	1,583.0	1,445.7	8,843.8	161.7	40.5	85.1	91.5	0.0	0.0	9,281.4	4,146.0	0.0	234.0	1,582.3	0.0	48,157.9
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
VA	0.0	8,934.6	4,172.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	33.0	112.4	1,076.8	0.0	0.0	2,847.6	495.0	1,586.0	368.4	12.0	0.0	27,351.9
WV	60.9	0.0	1,073.9	11.0	0.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	20.0	0.0	0.0	12,484.0	0.0	0.0	0.0	681.7	0.0	14,528.8
XIC	0.0	0.0	858.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	4,222.7
Total	351.0	50,563.6	24,655.7	3,934.4	43.8	32.0	5,052.0	3,040.6	33,452.6	161.7	218.5	362.4	2,843.8	0.0	0.0	50,230.8	8,414.6	2,136.0	1,010.5	10,328.1	0.0	196,832.0

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of September 30, 2020. Of the 196,832.0 MW of installed capacity, 71,577.4 MW (36.4 percent) are from units older than 40 years, of which 36,939.4 MW (51.6 percent) are coal fired steam units, 532.0 MW (0.7 percent) are combined cycle units and 16,184.6 MW (22.6 percent) are nuclear units.

Table 12-3 PJM capacity (MW) by unit type and age (years): September 30, 2020

Age (years)	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Less than 20	351.0	44,971.7	16,772.6	604.5	43.8	32.0	0.0	297.2	0.0	149.7	20.0	301.0	2,843.8	0.0	0.0	3,475.0	82.0	0.0	97.4	10,328.1	0.0	80,369.7
20 to 40	0.0	5,059.9	7,413.4	355.5	0.0	0.0	3,003.0	427.2	17,268.0	12.0	25.0	61.4	0.0	0.0	0.0	9,816.4	600.0	0.0	843.1	0.0	0.0	44,884.9
40 to 60	0.0	532.0	469.7	2,974.4	0.0	0.0	2,049.0	340.0	16,184.6	0.0	173.5	0.0	0.0	0.0	0.0	34,086.6	5,971.1	2,136.0	70.0	0.0	0.0	64,986.9
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	0.0	0.0	2,852.8	1,761.5	0.0	0.0	0.0	0.0	6,590.5
Total	351.0	50,563.6	24,655.7	3,934.4	43.8	32.0	5,052.0	3,040.6	33,452.6	161.7	218.5	362.4	2,843.8	0.0	0.0	50,230.8	8,414.6	2,136.0	1,010.5	10,328.1	0.0	196,832.0

Figure 12-1 PJM capacity (MW) by age (years): September 30, 2020



Generation Retirements^{15 16}

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.¹⁷ 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.¹⁸

Rules that preserve the Capacity Interconnection Rights (CIRs) associated with retired units, and with the conversion from Capacity Performance (CP) to energy only status, impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and they can be further extended, at no cost, if assigned to a new project in the interconnection queue at the same point of interconnection.¹⁹ 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.²⁰ The MMU recognized the progress made in this rule change, but it did not fully address the issues. The MMU recommends that the question of whether CIRs should persist after the retirement of a unit, or conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.²¹

¹⁵ See PJM. Planning. "Generator Deactivations," (Accessed on September 30, 2020) <<http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>>.

¹⁶ Generation retirements reported in this section do not include external units. Therefore, retirement totals reported in this section may not match totals reported elsewhere in this report where external units are included.

¹⁷ See OATT Section V and Attachment M-Appendix § IV.

¹⁸ See PJM. "Explaining Power Plant Retirements in PJM," at <<http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>>.

¹⁹ See OATT § 230.3.3.

²⁰ See PJM Interconnection, LLC, Docket No. ER12-1177 (Feb. 29, 2012).

²¹ See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

Generation Retirements 2011 through 2024

Table 12-4 shows that as of September 30, 2020, there are 43,787.4 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 31,846.2 MW (72.7 percent) are coal fired steam units. Retirements are primarily a result of the inability of coal and other units to compete with efficient combined cycle units burning low cost gas.

Table 12-4 Summary of PJM unit retirements by unit type (MW): 2011 through 2024

	Battery	CT - Combined Cycle	Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar + Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind + Wind	Wind + Storage	Total
Retirements 2011	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	0.0	543.0	522.5	0.0	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,907.9	0.0	548.0	16.0	0.0	0.0	6,961.9
Retirements 2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	7.0	0.0	0.0	0.0	2,589.9	82.0	166.0	8.0	0.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	0.0	0.0	2,239.0	158.0	0.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	856.2	2.0	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	0.0	9,262.7
Retirements 2016	0.0	0.0	0.0	65.0	6.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	0.0	0.0	243.0	74.0	0.0	0.0	0.0	0.0	400.4
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	2,038.0	34.0	0.0	0.0	0.0	0.0	2,112.8
Retirements 2018	1.0	425.0	0.0	38.0	1.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	0.0	0.0	3,186.5	996.0	148.0	108.0	0.0	0.0	5,542.7
Retirements 2019	0.0	0.0	346.8	51.4	6.4	0.0	0.0	0.0	805.0	0.0	0.0	15.9	0.0	0.0	0.0	4,113.8	97.0	10.0	10.0	0.0	0.0	5,456.3
Retirements 2020	0.0	0.0	232.5	24.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	0.0	0.0	0.0	2,131.8	0.0	0.0	60.0	0.0	0.0	2,469.0
Planned Retirements (October 2020 and later)	0.0	0.0	80.0	0.0	0.0	0.0	0.0	0.0	1,786.5	0.0	13.0	0.0	0.0	0.0	0.0	1,788.5	102.0	786.0	0.0	0.0	0.0	4,556.0
Total	41.0	425.0	2,364.3	1,824.9	22.0	0.0	0.5	0.0	3,206.0	0.0	57.1	64.5	0.0	0.0	0.0	31,846.2	2,065.5	1,658.0	202.0	10.4	0.0	43,787.4

Table 12-5 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2024, while Table 12-6 shows these retirements by state. Of the 43,787.4 MW of units that has been, or are planned to be, retired between 2011 and 2024, 31,846.2 MW (72.7 percent) are coal fired steam units. These coal fired steam units have an average age of 52.8 years and an average size of 188.4 MW. Over half of the retiring coal fired steam units, 56.3 percent, are located in Ohio or Pennsylvania.

Table 12-5 Retirements by unit type: 2011 through 2024

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	115	26.8	34.7	4,211.2	9.6%
Natural Gas	60	39.4	40.9	2,364.3	5.4%
Oil	49	37.2	44.1	1,824.9	4.2%
Other	6	3.7	19.2	22.0	0.1%
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	4	801.5	49.1	3,206.0	7.3%
RICE	28	4.5	28.7	121.6	0.3%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	11	5.2	46.1	57.1	0.1%
Other	17	3.8	11.3	64.5	0.1%
Solar	0	0	0	0	0.0%
Solar + Storage	0	0	0	0	0.0%
Solar + Wind	0	0	0	0	0.0%
Steam	200	152.1	46.1	35,771.7	81.7%
Coal	169	188.4	52.8	31,846.2	72.7%
Natural Gas	18	114.8	60.8	2,065.5	4.7%
Oil	6	276.3	45.7	1,658.0	3.8%
Other	7	28.9	25.1	202.0	0.5%
Wind	1	10.4	15.6	10.4	0.0%
Wind + Storage	0	0	0	0	0.0%
Total	353	124.0	46.2	43,787.4	100.0%

Table 12-6 Retirements (MW) by unit type and state: 2011 through 2024

State	CT - Combined		Natural Gas	CT - Oil		CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas			Solar	Solar + Storage	Solar + Wind	Steam - Natural Gas			Steam - Oil	Steam - Other	Wind + Storage		Total
	Battery	Cycle									Natural Gas	Oil	Other											
DC	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0	0.0	0.0	0.0	0.0	788.0
DE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.0	136.0	0.0	0.0	0.0	0.0	0.0	390.0
IL	0.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	0.0	1,786.5	0.0	0.0	12.5	0.0	0.0	0.0	1,624.0	0.0	0.0	0.0	0.0	0.0	0.0	3,719.0
IN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0
KY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0
MD	0.0	0.0	347.5	104.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	1,839.0	171.0	0.0	0.0	0.0	0.0	0.0	2,463.9
NC	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.5	0.0	0.0	0.0	0.0	0.0	0.0	355.5
NJ	0.0	158.0	1,590.0	1,040.2	6.4	0.0	0.5	0.0	0.0	614.5	0.0	8.0	19.5	0.0	0.0	0.0	1,543.0	932.5	148.0	10.0	0.0	0.0	0.0	6,070.6
OH	40.0	0.0	0.0	286.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	5.4	0.0	0.0	0.0	0.0	13,179.4	0.0	0.0	0.0	0.0	0.0	0.0	13,543.1
PA	1.0	0.0	50.8	44.0	14.0	0.0	0.0	0.0	0.0	805.0	0.0	13.9	18.0	0.0	0.0	0.0	4,734.3	283.0	176.0	109.0	10.4	0.0	0.0	6,259.4
VA	0.0	267.0	80.0	79.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9	8.4	0.0	0.0	0.0	3,680.0	543.0	786.0	83.0	0.0	0.0	0.0	5,530.0
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	0.0	0.0	0.0	2,691.0	0.0	0.0	0.0	0.0	0.0	0.0	2,691.0
Total	41.0	425.0	2,364.3	1,824.9	22.0	0.0	0.5	0.0	0.0	3,206.0	0.0	57.1	64.5	0.0	0.0	0.0	31,846.2	2,065.5	1,658.0	202.0	10.4	0.0	0.0	43,787.4

Figure 12-2 is a map of unit retirements between 2011 and 2024, with a mapping to unit names in Table 12-7.

Figure 12-2 Map of PJM unit retirements: 2011 through 2024

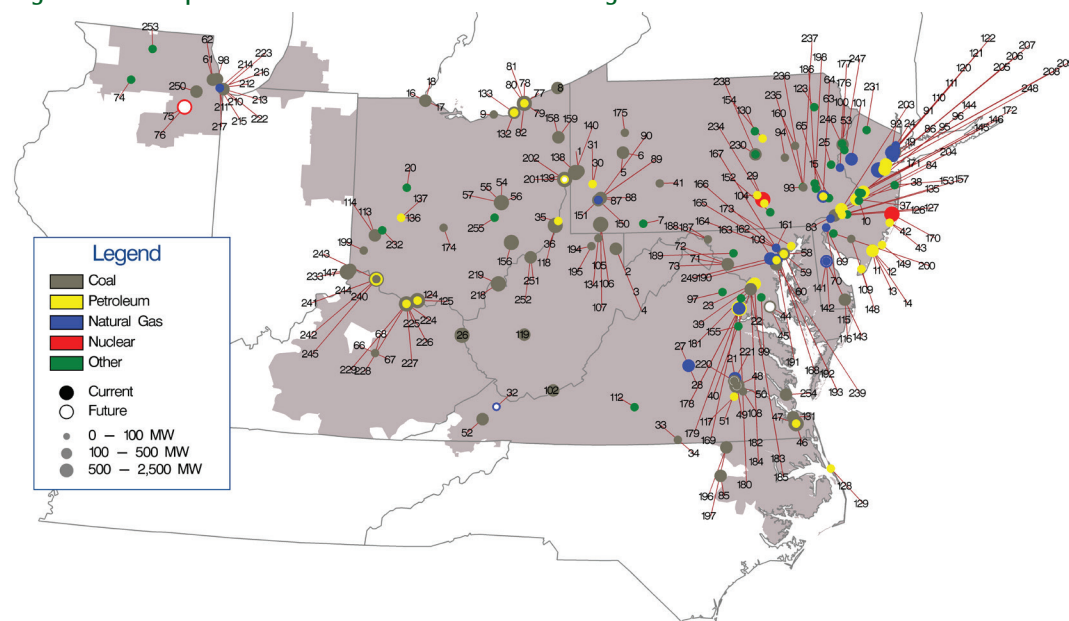


Table 12–7 Unit identification for map of PJM unit retirements: 2011 through 2024

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AES Beaver Valley	56	Conesville 5	111	Hudson 2	166	Notch Cliff GT6	221	Spruance NUG2 (Rich 3-4)
2	Albright 1	57	Conesville 6	112	Hurt NUG	167	Notch Cliff GT7	222	State Line 3
3	Albright 2	58	Crane 1	113	Hutchings 1-3, 5-6	168	Notch Cliff GT8	223	State Line 4
4	Albright 3	59	Crane 2	114	Hutchings 4	169	Ocoquan 1 LF	224	Stuart 1
5	Armstrong 1	60	Crane GT1	115	Indian River 1	170	Oyster Creek	225	Stuart 2
6	Armstrong 2	61	Crawford 7	116	Indian River 3	171	Pennsbury Generator Landfill 1	226	Stuart 3
7	Arnold (Green Mtn. Wind Farm	62	Crawford 8	117	Ingenco Petersburg	172	Pennsbury Generator Landfill 2	227	Stuart 4
8	Ashtabula 5	63	Cromby 1	118	Kammer 1-3	173	Perryman 2	228	Stuart Diesels 1-4
9	Avon Lake 7	64	Cromby 2	119	Kanawha River 1-2	174	Picway 5	229	Stuart Diesels 1-4
10	BC Landfill	65	Cromby D	120	Kearny 10	175	Piney Creek NUG	230	Sunbury 1-4
11	BL England 1	66	Dale 1-2	121	Kearny 11	176	Portland 1	231	Sussex County LF
12	BL England 2	67	Dale 3	122	Kearny 9	177	Portland 2	232	Tait Battery
13	BL England 3	68	Dale 4	123	Keystone Recovery (Units 1 - 7)	178	Possum Point 3	233	Tanners Creek 1-4
14	BL England Diesel Units 1-4	69	Deepwater 1	124	Killen 2	179	Possum Point 4	234	Three Mile Island Unit 1
15	Barbados AES Battery	70	Deepwater 6	125	Killen CT	180	Possum Point 5	235	Titus 1
16	Bay Shore 2	71	Dickerson Unit 1	126	Kimberly Clark Generator	181	Potomac River 1	236	Titus 2
17	Bay Shore 3	72	Dickerson Unit 2	127	Kinsley Landfill	182	Potomac River 2	237	Titus 3
18	Bay Shore 4	73	Dickerson Unit 3	128	Kitty Hawk GT 1	183	Potomac River 3	238	Viking Energy NUG
19	Bayonne Cogen Plant (CC)	74	Dixon Lee Landfill Generator	129	Kitty Hawk GT 2	184	Potomac River 4	239	Wagner 2
20	Bellefontaine Landfill Generating Station	75	Dresden 2	130	Koppers Co. IPP	185	Potomac River 5	240	Walter C Beckjord 1
21	Bellemeade	76	Dresden 3	131	Lake Kingman	186	Pottstown LF (Moser)	241	Walter C Beckjord 2
22	Benning 15	77	Eastlake 1	132	Lake Shore 18	187	R Paul Smith 3	242	Walter C Beckjord 3
23	Benning 16	78	Eastlake 2	133	Lake Shore EMD	188	R Paul Smith 4	243	Walter C Beckjord 4
24	Bergen 3	79	Eastlake 3	134	MEA NUG (WVU)	189	Reichs Ford Road Landfill Generator	244	Walter C Beckjord 5-6
25	Bethlehem Renewable Energy Generator (Landfill)	80	Eastlake 4	135	MH50 Markus Hook Co-gen	190	Riverside 4	245	Walter C Beckjord GT 1-4
26	Big Sandy 2	81	Eastlake 5	136	Mad River CIs A	191	Riverside 6	246	Warren County Landfill
27	Bremo 3	82	Eastlake 6	137	Mad River CIs B	192	Riverside 7	247	Warren County NUG
28	Bremo 4	83	Eddystone 1	138	Mansfield 1	193	Riverside 8	248	Werner 1-4
29	Brunner Island Diesels	84	Eddystone 2	139	Mansfield 2	194	Riversville 5	249	Westport 5
30	Brunot Island 1B	85	Edgecomb NUG (Rocky 1-2)	140	Mansfield 3	195	Riversville 6	250	Will County 3
31	Brunot Island 1C	86	Edison 1-3	141	McKee 1	196	Roanoke Valley 1	251	Willow Island 1
32	Buchanan 1-2	87	Elrama 1	142	McKee 2	197	Roanoke Valley 2	252	Willow Island 2
33	Buggs Island 1 (Mecklenberg)	88	Elrama 2	143	McKee 3	198	Rolling Hills Landfill Generator	253	Winnebago Landfill
34	Buggs Island 2 (Mecklenberg)	89	Elrama 3	144	Mercer 1	199	SMART Paper	254	Yorktown 1-2
35	Burger 3	90	Elrama 4	145	Mercer 2	200	Salem County LF	255	Zanesville Landfill
36	Burger EMD	91	Essex 10-11	146	Mercer 3	201	Sammis 1-4		
37	Burlington 8,11	92	Essex 12	147	Miami Fort 6	202	Sammis Diesel		
38	Burlington 9	93	Evergreen Power United Corstack	148	Middle 1-3	203	Schuylkill 1		
39	Buzzard Point East Banks 1,2,4-8	94	FRACKVILLE WHEELABRATOR 1	149	Missouri Ave B,C,D	204	Schuylkill Diesel		
40	Buzzard Point West Banks 1-9	95	Fairless Hills Landfill A	150	Mitchell 2	205	Sewaren 1		
41	Cambria CoGen	96	Fairless Hills Landfill B	151	Mitchell 3	206	Sewaren 2		
42	Cedar 1	97	Fauquier County Landfill	152	Modern Power Landfill NUG	207	Sewaren 3		
43	Cedar 2	98	Fisk Street 19	153	Monmouth NUG landfill	208	Sewaren 4		
44	Chalk Point Unit 1	99	GUDE Landfill	154	Montour ATG	209	Sewaren 6		
45	Chalk Point Unit 2	100	Gilbert 1-4	155	Morris Landfill Generator	210	Southeast Chicago CT11		
46	Chesapeake 1-4	101	Glen Gardner 1-8	156	Muskingum River 1-5	211	Southeast Chicago CT12		
47	Chesapeake 7-10	102	Glen Lyn 5-6	157	National Park 1	212	Southeast Chicago CT5		
48	Chesterfield 3	103	Gould Street Generation Station	158	Niles 1	213	Southeast Chicago CT6		
49	Chesterfield 4	104	Harrisburg 4 CT	159	Niles 2	214	Southeast Chicago CT7		
50	Chesterfield 5	105	Hatfield's Ferry 1	160	Northeastern Power NEPCO	215	Southeast Chicago CT8		
51	Chesterfield 6	106	Hatfield's Ferry 2	161	Notch Cliff GT1	216	Southeast Chicago GT10		
52	Clinch River 3	107	Hatfield's Ferry 3	162	Notch Cliff GT2	217	Southeast Chicago GT9		
53	Columbia Dam Hydro	108	Hopewell James River Cogeneration	163	Notch Cliff GT3	218	Sporn 1-4		
54	Conesville 3	109	Howard Down 10	164	Notch Cliff GT4	219	Sporn 5		
55	Conesville 4	110	Hudson 1	165	Notch Cliff GT5	220	Spruance NUG1 (Rich 1-2)		

Current Year Generation Retirements

Table 12-8 shows that in the first nine months of 2020, 2,469.0 MW of generation retired. The largest generator that retired in the first nine months of 2020 was the 337.0 MW Conesville 4 coal fired steam unit located in the AEP Zone. Of the 2,469.0 MW of generation that retired, 776.8 MW (31.5 percent) were located in the AEP Zone.

Table 12-8 Unit deactivations: January through September, 2020

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
Avenue Capital Group LLC	Eastlake 6	24.0	CT-Oil	ATSI	46.2	18-Feb-20
Exelon Corporation	Notch Cliff GT5	14.6	CT-Natural_Gas	BGE	50.8	01-Mar-20
Exelon Corporation	Notch Cliff GT6	15.6	CT-Natural_Gas	BGE	50.8	01-Mar-20
Exelon Corporation	Notch Cliff GT7	14.5	CT-Natural_Gas	BGE	50.8	01-Mar-20
Exelon Corporation	Notch Cliff GT8	16.0	CT-Natural_Gas	BGE	50.8	01-Mar-20
Macquarie Group Limited	FRACKVILLE WHEELABRATOR 1	43.0	Steam-Coal	PPL	31.5	01-Mar-20
American Electric Power Company, Inc.	Conesville 4	337.0	Steam-Coal	AEP	47.0	01-Jun-20
Avenue Capital Group LLC	Sammis 1-4	160.0	Steam-Coal	ATSI	57.6	01-Jun-20
Avenue Capital Group LLC	Sammis 1-4	160.0	Steam-Coal	ATSI	59.0	01-Jun-20
Avenue Capital Group LLC	Sammis 1-4	160.0	Steam-Coal	ATSI	60.0	01-Jun-20
Avenue Capital Group LLC	Sammis 1-4	160.0	Steam-Coal	ATSI	60.9	01-Jun-20
Exelon Corporation	Fairless Hills Landfill A	30.0	Steam-Other	PECO	32.4	01-Jun-20
Exelon Corporation	Fairless Hills Landfill B	30.0	Steam-Other	PECO	32.4	01-Jun-20
Exelon Corporation	Notch Cliff GT1	14.0	CT-Natural_Gas	BGE	51.0	01-Jun-20
Exelon Corporation	Notch Cliff GT2	14.0	CT-Natural_Gas	BGE	51.0	01-Jun-20
Exelon Corporation	Notch Cliff GT3	14.0	CT-Natural_Gas	BGE	51.0	01-Jun-20
Exelon Corporation	Notch Cliff GT4	14.0	CT-Natural_Gas	BGE	51.0	01-Jun-20
Exelon Corporation	Pennsbury Generator Landfill 1	3.0	CT-Other	PECO	24.4	01-Jun-20
Exelon Corporation	Pennsbury Generator Landfill 2	3.0	CT-Other	PECO	24.4	01-Jun-20
Exelon Corporation	Westport 5	115.8	CT-Natural_Gas	BGE	51.4	01-Jun-20
Riverstone Holdings LLC	Wagner 2	135.0	Steam-Coal	BGE	61.5	01-Jun-20
South Jersey Industries, Inc.	BC Landfill	6.0	RICE-Other	PSEG	12.6	01-Jun-20
South Jersey Industries, Inc.	Salem County LF	1.7	RICE-Other	AECO	11.5	01-Jun-20
South Jersey Industries, Inc.	Sussex County LF	2.0	RICE-Other	JCPL	9.0	01-Jun-20
The AES Corporation	Conesville 4	127.8	Steam-Coal	AEP	47.0	01-Jun-20
United Energy Corporation	Keystone Recovery (Units 1 - 7)	5.0	RICE-Other	PPL	24.3	01-Jun-20
Vistra Energy Corp	Conesville 4	312.0	Steam-Coal	AEP	47.0	01-Jun-20
GenOn Energy, Inc.	Dickerson Unit 1	179.0	Steam-Coal	Pepco	61.2	13-Aug-20
GenOn Energy, Inc.	Dickerson Unit 2	179.0	Steam-Coal	Pepco	60.4	13-Aug-20
GenOn Energy, Inc.	Dickerson Unit 3	179.0	Steam-Coal	Pepco	58.5	13-Aug-20
Total		2,469.0				

Planned Generation Retirements

Table 12-9 shows that, as of September 30, 2020, there are 4,556.0 MW of generation that have requested retirement after September 30, 2020, of which 1,907.5 MW (41.9 percent) are located in the Dominion Zone. Of the Dominion generation requesting retirement, 1,121.5 MW (58.8 percent) are coal fired steam units.

Table 12-9 Planned retirement of PJM units: September 30, 2020

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
Ares Management LP	Spruance NUG1 (aka Spruance 1 Rich 1-2)	115.5	Steam-Coal	Dominion	12-Jan-21
Dominion Resources, Inc.	Possum Point 5	786.0	Steam-Oil	Dominion	31-May-21
GenOn Energy, Inc.	Chalk Point Unit 1	331.0	Steam-Coal	Pepco	01-Jun-21
GenOn Energy, Inc.	Chalk Point Unit 2	336.0	Steam-Coal	Pepco	01-Jun-21
City of Dover	McKee 3	102.0	Steam-Natural Gas	DPL	01-Jun-21
Avenue Capital Group LLC	Sammis Diesel	13.0	RICE-Oil	ATSI	01-Jun-21
Exelon Corporation	Dresden 2	883.5	Nuclear	ComEd	01-Nov-21
Exelon Corporation	Dresden 3	903.0	Nuclear	ComEd	01-Nov-21
Dominion Resources, Inc.	Chesterfield 5	336.0	Steam-Coal	Dominion	31-May-23
Dominion Resources, Inc.	Chesterfield 6	670.0	Steam-Coal	Dominion	31-May-23
LS Power Equity Partners, LP.	Buchanan 1-2	80.0	CT-Natural Gas	AEP	01-Jun-23
Total		4,556.0			

Generation Queue²²

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.²³ 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 one year. Queues C through T were open for six months. Starting in February 2008, Queues U through Y1 were open for three months. In May 2012, the duration of the queue period was reset to six months, starting with Queue Y2. Queue AF2 opened on October 1, 2019 and closed on March 31, 2020. Queue AG1 opened on April 1, 2020 and closed on September 30, 2020.

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.²⁴ 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.²⁵

The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result.²⁶ The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition from new generation investments are not created.

²² The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

²³ See OATT Parts IV & VI.

²⁴ See PJM, "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 13 (August 23, 2018).

²⁵ PJM does not track the duration of suspensions or PJM termination of projects.

²⁶ See *PJM Interconnection, LLC*, Docket No. ER12-1177 (Feb. 29, 2012).

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. 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.

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 September 30, 2020, 148,361.6 MW were in generation request queues for construction through 2029. Although it is clear that not all generation in the queues will be built, PJM has added capacity steadily since markets were implemented on April 1, 1999.²⁷

There were 126,818.9 MW in generation queues, in the status of active, under construction or suspended, at the end of 2019. In the first nine months of 2020, the AF2 and AG1 queue windows closed. The AF2 queue window added 28,441.9 MW to the queue and the AG1 queue window added 7,849.3 MW to the queue. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On September 30, 2020, there were 148,361.6 MW in generation queues, in the status of active, under construction or suspended, an increase of 21,542.7 MW (17.0 percent). Table 12-11 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2019, and September 30, 2020, for ongoing projects, i.e. projects with the status active, under construction or suspended.²⁸

²⁷ See "PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf>.

²⁸ Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

Table 12-11 Queue comparison by expected completion year (MW): December 31, 2019 and September 30, 2020²⁹

Year	Year Change			
	As of 12/31/2019	As of 9/30/2020	MW	Percent
2008	0.0	0.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	0.0	0.0	0.0	0.0%
2012	16.1	16.1	0.0	0.0%
2013	20.0	20.0	0.0	0.0%
2014	0.0	0.0	0.0	0.0%
2015	1.3	1.3	0.0	0.0%
2016	120.9	120.9	0.0	0.0%
2017	1,172.8	1,046.6	(126.2)	(10.8%)
2018	3,315.2	2,520.6	(794.6)	(24.0%)
2019	10,917.9	9,001.4	(1,916.5)	(17.6%)
2020	15,507.4	13,734.0	(1,773.4)	(11.4%)
2021	29,315.7	33,463.3	4,147.5	14.1%
2022	34,459.5	42,429.4	7,969.9	23.1%
2023	11,134.0	27,093.8	15,959.8	143.3%
2024	6,887.3	10,942.0	4,054.7	58.9%
2025	3,676.9	3,726.9	50.0	1.4%
2026	1,325.2	2,645.2	1,320.0	99.6%
2027	800.1	800.1	0.0	0.0%
2028	0.0	0.0	0.0	0.0%
2029	800.1	800.1	0.0	0.0%
Total	119,470.4	148,361.6	28,891.2	24.2%

Table 12-12 shows the project status changes in more detail and how scheduled queue MW have changed between December 31, 2019, and September 30, 2020. For example, 34,243.7 MW entered the queue in the first nine months of 2020. Of those 34,243.7 MW, 5,352.5 MW have been withdrawn. Of the total 118,297.3 MW marked as active on December 31, 2019, 12,237.6 MW were withdrawn, 3,077.1 MW were suspended, 4,011.2 MW started construction, and 219.4 MW went into service by September 30, 2020. Analysis of projects that were suspended on December 31, 2019 show that 2,559.3 MW came out of suspension and are now active as of September 30, 2020.

Table 12-12 Change in project status (MW): December 31, 2019 to September 30, 2020

Status at 12/31/2019 (Entered during 2020)	Status at 9/30/2020					
	Total at 12/31/2019	Active	In Service	Under Construction	Suspended	Withdrawn
Active	118,297.3	98,752.0	219.4	4,011.2	3,077.1	12,237.6
In Service	68,964.2	0.0	68,964.2	0.0	0.0	0.0
Under Construction	9,082.2	0.0	2,473.0	6,609.2	0.0	0.0
Suspended	7,781.3	2,559.3	200.0	0.0	4,461.6	560.4
Withdrawn	385,773.8	0.0	0.0	0.0	0.0	385,773.8
Total	589,898.8	130,201.0	71,856.6	10,621.9	7,538.7	403,924.3

On September 30, 2020, 148,361.6 MW 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 130,201.0 MW in the status of Active on September 30, 2020, 13,563.6 MW (10.4 percent) were combined cycle projects. Of the 10,621.9 MW in the status of under construction, 6,698.1 MW (63.1 percent) were combined cycle projects. A significant amount of renewable hybrid projects (defined as solar + storage, solar + wind and wind + storage projects) have entered the queue in recent years. Of the 130,201.0 MW in the status of Active on September 30, 2020, 12,971.5 MW (10.0 percent) were renewable hybrid projects. Of the 10,621.9 MW in the status of under construction, 2.6 MW (0.02 percent) were renewable hybrid projects.

²⁹ Wind and solar capacity in Table 12-11 through Table 12-15 have not been adjusted to reflect derating.

Table 12-13 Current project status (MW) by unit type: September 30, 2020

	CT -		CT -		Hydro -		Hydro -		RICE -		RICE -		Steam -		Steam -		Steam -		Wind +			
	Battery	Combined Cycle	Natural Gas	CT - Oil	Other	Fuel Cell	Pumped Storage	Run of River	Nuclear	Natural Gas	RICE - Oil	Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Natural Gas	- Oil	Other	Wind	Storage	Total
Active	9,907.9	13,563.6	5,752.2	18.0	0.0	0.0	700.0	72.5	173.5	40.0	0.0	0.8	59,772.7	12,770.0	199.0	60.0	70.0	0.0	0.0	27,098.4	2.5	130,201.0
Suspended	32.5	5,601.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	19.9	0.0	0.0	1,011.5	0.0	0.0	0.0	0.0	0.0	0.0	737.6	106.3	7,538.7
Under Construction	0.0	6,698.1	384.5	13.0	0.0	3.0	0.0	22.7	44.0	1.3	4.0	0.0	2,070.3	2.6	0.0	36.0	0.0	0.0	0.0	1,342.4	0.0	10,621.9
Total	9,940.3	25,862.7	6,166.7	31.0	0.0	3.0	700.0	95.2	217.5	61.2	4.0	0.8	62,854.5	12,772.6	199.0	96.0	70.0	0.0	0.0	29,178.4	108.8	148,361.6

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units and renewable resources enter the queue and coal fired steam units retire. As of September 30, 2020, of the 148,361.6 MW in the generation request queues in the status of active, suspended or under construction, 32,160.6 MW (21.7 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 13,080.4 MW (8.8 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units) and 96.0 MW (0.1 percent) were coal fired steam projects.

As of September 30, 2020, there are 1,788.5 MW of coal fired steam units and 182.0 MW of natural gas units slated for deactivation between October 1, 2020, and December 31, 2024 (See Table 12-9). The ongoing replacement of coal fired steam units by natural gas units will continue to significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Table 12-14 shows the total MW in the status of active, in service, under construction, suspended, or withdrawn for each queue since the beginning of the RTEP process and the total MW that had been included in each queue. All items in queues A-R are either in service or have been withdrawn. As of September 30, 2020, there are 148,361.6 MW in queues that are not yet in service or withdrawn, of which 5.1 percent are suspended, 7.2 percent are under construction and 87.8 percent have not begun construction.

Table 12-14 Queue totals by status (MW): September 30, 2020³⁰

Queue	Under					Total
	Active	In Service	Construction	Suspended	Withdrawn	
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	0.0	0.0	8,129.2	10,528.0
O Expired 31-Jul-05	0.0	1,890.2	0.0	0.0	5,466.8	7,357.0
P Expired 31-Jan-06	0.0	3,290.3	0.0	0.0	5,320.5	8,610.8
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	11,385.7	14,533.6
R Expired 31-Jan-07	0.0	1,892.5	0.0	0.0	20,708.9	22,601.4
S Expired 31-Jul-07	70.0	3,543.5	0.0	0.0	12,396.5	16,010.0
T Expired 31-Jan-08	0.0	4,196.5	0.0	0.0	23,313.3	27,509.8
U1 Expired 30-Apr-08	0.0	218.9	0.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	0.0	327.5	450.0	0.0	16,218.6	16,996.1
U3 Expired 31-Oct-08	100.0	333.0	0.0	0.0	2,535.6	2,968.6
U4 Expired 31-Jan-09	0.0	85.2	0.0	200.0	4,745.0	5,030.2
V1 Expired 30-Apr-09	0.0	197.9	0.0	0.0	2,572.8	2,770.7
V2 Expired 31-Jul-09	0.0	989.9	16.1	0.0	3,625.1	4,631.1
V3 Expired 31-Oct-09	0.0	912.0	220.0	0.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	200.0	748.8	0.0	0.0	3,508.0	4,456.8
W1 Expired 30-Apr-10	0.0	567.4	0.0	0.0	5,139.5	5,706.9
W2 Expired 31-Jul-10	0.0	351.7	0.0	0.0	3,051.7	3,403.4
W3 Expired 31-Oct-10	0.0	508.7	22.7	0.0	8,673.2	9,204.6
W4 Expired 31-Jan-11	0.0	1,109.8	351.0	0.0	4,152.6	5,613.4
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	3,706.4	0.0	0.0	5,578.4	9,284.7
X3 Expired 31-Oct-11	894.0	89.2	20.0	0.0	6,771.9	7,775.1
X4 Expired 31-Jan-12	0.0	2,948.9	0.0	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	0.0	1,795.5	0.0	72.0	6,207.7	8,075.2
Y2 Expired 31-Oct-12	0.0	1,657.2	0.0	0.0	9,636.5	11,293.7
Y3 Expired 30-Apr-13	0.0	1,425.5	205.0	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	713.0	2,998.0	76.5	300.3	4,037.0	8,124.8
Z2 Expired 30-Apr-14	33.0	3,063.0	0.0	10.0	2,994.8	6,100.8
AA1 Expired 31-Oct-14	904.6	3,526.9	1,302.0	0.0	6,335.4	12,068.9
AA2 Expired 30-Apr-15	1,722.3	1,195.6	1,625.0	1,138.9	10,384.5	16,066.3
AB1 Expired 31-Oct-15	5,013.5	1,176.7	288.7	3,104.3	10,862.7	20,445.9

³⁰ Projects listed as partially in service are counted as in service for the purposes of this analysis.

Queue	Under					Total
	Active	In Service	Construction	Suspended	Withdrawn	
AB2 Expired 31-Mar-16	3,452.7	352.4	2,642.2	293.8	8,469.3	15,210.4
AC1 Expired 30-Sep-16	5,271.5	634.4	2,737.2	2,095.6	9,333.7	20,072.3
AC2 Expired 30-Apr-17	3,688.3	247.0	152.2	42.2	8,472.0	12,601.6
AD1 Expired 30-Sep-17	5,793.8	103.2	104.6	153.3	5,160.7	11,315.6
AD2 Expired 31-Mar-18	7,542.7	249.4	316.4	47.0	12,223.9	20,379.3
AE1 Expired 30-Sep-18	16,929.4	10.8	40.0	27.6	16,902.6	33,910.5
AE2 Expired 31-Mar-19	23,696.9	0.0	3.8	53.8	10,135.8	33,890.2
AF1 Expired 30-Sep-19	23,765.1	2.4	47.0	0.0	5,183.4	28,997.9
AF2 Expired 31-Mar-20	23,061.2	0.0	1.5	0.0	5,379.2	28,441.9
AG1 Expired 30-Sep-20	7,349.1	0.0	0.0	0.0	500.3	7,849.3
Total	130,201.0	71,856.6	10,621.9	7,538.7	403,924.3	624,142.5

Table 12-15 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of September 30, 2020, 148,361.6 MW were in generation request queues for construction through 2029. Table 12-15 also shows the planned retirements for each zone.

Table 12-15 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): September 30, 2020³¹

LDA	Zone	Battery	CT -			Fuel Cell	Pumped Storage	Hydro - Run of River	Hydro - Nuclear	RICE -			Solar Storage	Solar + Wind	Steam - Coal	Steam -			Wind Storage	Wind + Storage	Queue Capacity	Planned Retirements
			Natural Gas	CT - Oil	CT - Other					Natural Gas	RICE - Oil	RICE - Other				Natural Gas	Steam - Oil	Steam - Other				
EMAAC	AECO	793.0	7.6	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	423.1	0.0	0.0	0.0	0.0	0.0	3,441.6	0.0	4,895.3	0.0
	DPL	401.2	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,967.9	7.0	0.0	0.0	0.0	0.0	1,877.1	0.0	4,697.2	102.0
	JCPL	980.2	35.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	125.2	90.0	0.0	0.0	0.0	0.0	4,269.2	0.0	5,499.6	0.0
	PECO	20.0	102.0	29.0	0.0	0.0	0.0	0.0	44.0	0.0	4.0	0.0	29.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	228.8	0.0
	PSEG	862.0	882.6	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.2	22.6	0.0	0.0	0.0	0.0	0.0	0.0	2,499.4	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	3,056.4	1,478.2	934.0	0.0	0.0	0.0	0.0	44.0	0.0	4.0	0.0	2,603.2	112.6	0.0	0.0	0.0	0.0	9,587.9	0.0	17,820.3	102.0
SWMAAC	BGE	302.5	0.0	144.6	14.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	537.9	0.0
	Pepco	0.0	1,102.6	57.3	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	148.2	20.0	0.0	0.0	6.0	0.0	0.0	0.0	1,338.1	667.0
	SWMAAC Total	302.5	1,102.6	201.9	18.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	178.2	20.0	0.0	0.0	6.0	0.0	0.0	0.0	1,876.0	667.0
WMAAC	Met-Ed	141.2	75.0	13.5	7.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	918.3	138.9	0.0	0.0	0.0	0.0	0.0	0.0	1,294.4	0.0
	PENELEC	795.8	248.0	588.5	0.0	0.0	3.0	0.0	0.0	39.9	0.0	0.0	2,962.2	743.2	0.0	0.0	0.0	0.0	210.2	0.0	5,590.8	0.0
	PPL	270.0	106.6	0.0	0.0	0.0	0.0	700.0	0.0	100.0	0.0	0.0	1,689.7	190.0	0.0	0.0	0.0	0.0	514.9	90.0	3,661.1	0.0
	WMAAC Total	1,207.0	429.6	602.0	7.5	0.0	3.0	700.0	0.0	100.0	39.9	0.0	5,570.1	1,072.1	0.0	0.0	0.0	0.0	725.1	90.0	10,546.3	0.0
Non-MAAC	AEP	1,743.8	6,015.0	617.6	0.0	0.0	0.0	51.0	28.0	0.0	0.0	0.8	16,798.6	5,348.2	0.0	96.0	0.0	0.0	4,550.9	0.0	35,249.8	80.0
	APS	286.5	5,589.7	112.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	3,042.8	590.3	0.0	0.0	0.0	0.0	639.4	16.3	10,296.9	0.0
	ATSI	40.3	3,635.0	116.0	5.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,060.5	280.9	0.0	0.0	0.0	0.0	816.1	0.0	7,954.2	13.0
	ComEd	1,036.8	3,712.6	1,173.2	0.0	0.0	0.0	22.7	0.0	0.0	0.0	0.0	6,326.9	1,102.0	199.0	0.0	64.0	0.0	7,429.9	2.5	21,069.6	1,786.5
	DAY	109.9	1,150.0	43.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,184.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,487.5	0.0
	DEOK	72.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	709.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	782.1	0.0
	DLCO	0.0	0.0	222.9	0.0	0.0	0.0	0.0	21.5	0.0	0.0	0.0	54.2	37.5	0.0	0.0	0.0	0.0	0.0	0.0	336.1	0.0
	Dominion	2,030.8	2,750.0	2,143.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19,233.0	2,443.1	0.0	0.0	0.0	0.0	5,429.2	0.0	34,029.7	1,907.5
	EKPC	54.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,973.0	1,766.0	0.0	0.0	0.0	0.0	0.0	0.0	3,793.0	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	120.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.0	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	0.0
		Non-MAAC Total	5,374.4	22,852.3	4,428.8	5.5	0.0	0.0	95.2	28.0	20.0	0.0	0.8	54,503.0	11,567.9	199.0	96.0	64.0	0.0	18,865.4	18.8	118,119.0
	Total	9,940.3	25,862.7	6,166.7	31.0	0.0	3.0	700.0	95.2	217.5	61.2	4.0	62,854.5	12,772.6	199.0	96.0	70.0	0.0	29,178.4	108.8	148,361.6	4,556.0

Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of nameplate capacity until actual generation data are available. Beginning with Queue U, PJM derated wind resources to 13 percent of nameplate capacity until there was operational data to support a different conclusion. 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 29,178.4 MW of wind resources and 62,854.5 MW of solar resources, using the average derate factors, the 148,361.6 MW currently under construction, suspended or active in the queue would be reduced to 90,408.7 MW.

³¹ This data includes only projects with a status of active, under construction, or suspended.

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.³² 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 2,916 projects withdrawn as of September 30, 2020, 1,468 (50.3 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 2,916 projects withdrawn, 558 (19.1 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-16 Last milestone at time of withdrawal: January 1997 through September 2020

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	499	17.1%	81	868
Feasibility Study	969	33.2%	273	1,633
System Impact Study	591	20.3%	725	3,248
Facilities Study	299	10.3%	1,123	4,107
Construction Service Agreement (CSA) or beyond	558	19.1%	1,341	5,642
Total	2,916	100.0%		

³² See PJM, "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 48 (Oct. 1, 2020).

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 1,069 days, or 2.9 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 623 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-17 Project queue times by status (days): September 30, 2020³³

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	609	513	13	4,944
In-Service	1,069	786	0	5,306
Suspended	1,624	709	576	4,296
Under Construction	1,544	998	183	4,452
Withdrawn	623	730	0	5,642

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 1,519 projects in the queue as of September 30, 2020, 356 (23.4 percent) had a completed feasibility study and 364 (24.0 percent) had a completed construction service agreement.

Table 12-18 Project queue times by milestone (days): September 30, 2020

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	114	7.5%	75	180
Feasibility Study	356	23.4%	313	1,615
System Impact Study	652	42.9%	698	4,384
Facilities Study	33	2.2%	1,266	2,834
Construction Service Agreement (CSA) or beyond	364	24.0%	1,246	4,944
Total	1,519	100.0%		

³³ 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 12-19 shows the time spent in the queue by fuel type, and year the project entered the queue, for projects that are in service. The time from when a project enters the queue to the time the project goes in service has been decreasing across all fuel types. For example, for a battery project entering the queue in 2015, it was an average of 1,082 days from the time it entered the queue until it went in service, compared to only 293 days when entering the queue in 2018.

Table 12-19 Average time in queue (days) by fuel type and year submitted (In Service Projects): September 30, 2020³⁴

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Battery	983	609	417	692	789	1,082	941	383	293	504	
CC	1,310	1,551	1,578	1,386	1,106	841	746	702	309		
CT - Natural Gas	1,131	804	953	1,021	734	901	1,401	310	535	184	
CT - Oil	717		259								
CT - Other	729	634	954	1,248	718	360					
Fuel Cell						827	643				
Hydro - Pumped Storage						1,402					
Hydro - Run of River			1,325	614	332		580	426	606		
Nuclear	885	866		1,234							
RICE - Natural Gas			1,702	1,053	1,332	798		250			
RICE - Oil											
RICE - Other	638	1,385	1,479	241	627	622	491				
Solar	1,701	1,313	969	1,014	1,003	1,249	830	546	643	499	
Solar + Storage									553		
Solar + Wind											
Steam - Coal	745		513	1,010	583	853	677	647			
Steam - Natural Gas				1,182		421					
Steam - Oil											
Steam - Other	256	838	643								
Wind	2,802	2,711	1,750	1,270	1,494	1,463	1,131	1,254	561		
Wind + Storage											

³⁴ A blank cell in this table means that no project of that fuel type, that was submitted to the queue in that year, subsequently went in service.

Completion Rates

The probability of a project going into service increases as each step of the planning process is completed.

Table 12-20 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study (SIS), facilities study agreement (FSA) and construction service agreement (CSA) milestones as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone. For each unit type, the total MW in service was divided by the total energy MW entered in the queue. To calculate the completion rates for projects that reached the individual milestones, only those projects that reached a final status of withdrawn or in service were evaluated. For example, if a project was withdrawn after the completion of its SIS, but before the completion of the FSA, the totals would be included in the calculation of the SIS completion rate, but not in the calculation of the FSA or CSA completion rates. Similarly, if a project was withdrawn after the completion of its FSA, but before the completion of the CSA, the totals would be included in the calculation of the SIS and FSA completion rates, but not in the calculation of the CSA completion rate. The completion rates show that of all battery projects to ever enter the queue and complete the system impact study stage, 20.8 percent of the queued MW has gone into service. The completion rate for battery projects increases to 40.6 percent when battery projects complete the facility study agreement and further increases to 49.6 percent when battery projects complete the construction service agreement. Of all battery projects to enter the queue, only 1.9 percent of the queued MW has gone into service.

Table 12-20 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: January 1997 through September 2020

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	20.8%	40.6%	49.6%	1.9%
CC	33.2%	52.1%	83.9%	13.8%
CT - Natural Gas	75.7%	82.0%	85.6%	44.8%
CT - Oil	35.6%	60.2%	90.8%	25.4%
CT - Other	12.3%	18.6%	29.5%	10.7%
Fuel Cell	30.6%	31.6%	31.6%	43.6%
Hydro - Pumped Storage	100.0%	100.0%	100.0%	24.5%
Hydro - Run of River	43.2%	61.3%	68.9%	21.4%
Nuclear	35.0%	41.9%	51.1%	28.4%
RICE - Natural Gas	34.4%	47.6%	53.5%	26.4%
RICE - Oil	30.6%	55.9%	55.9%	23.8%
RICE - Other	89.0%	91.4%	92.0%	77.9%
Solar	14.5%	32.7%	41.5%	2.1%
Solar + Storage	0.2%	100.0%	100.0%	0.0%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.6%	25.4%	37.5%	6.2%
Steam - Natural Gas	90.4%	90.4%	90.4%	84.0%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	30.4%	39.9%	47.8%	27.4%
Wind	17.9%	33.8%	50.3%	8.2%
Wind + Storage	0.0%	0.0%	0.0%	0.0%

On September 30, 2020, 148,361.6 MW were in generation request queues in the status of active, under construction or suspended. Of the total 148,361.6 MW in the queue, 109,667.78 MW (73.9 percent) have reached at least the SIS milestone and 38,693.8 MW (26.1 percent) have not received a completed SIS. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the SIS, FSA or CSA milestone, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 38,864.3 MW of new generation in the queue are expected to go into service.

Table 12-21 shows the percent of all project MW, by unit type, to go in service by year submitted to the queue. Of all battery projects that entered the queue in 2010, 65.5 percent reached the status of in service by September 30, 2020. Of all battery projects that entered the queue in 2016, only 1.3 percent have reached the status of in service as of September 30, 2020.

Table 12-21 Percent of all projects (MW energy) to go in service by unit type and year submitted to the queue: September 30, 2020

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Battery	65.5%	8.3%	15.1%	43.9%	21.5%	7.7%	1.3%	4.1%	0.3%	0.0%	0.0%
CC	14.6%	24.5%	30.8%	34.9%	43.7%	3.6%	2.2%	1.8%	1.2%	0.0%	NA
CT - Natural Gas	100.0%	98.3%	89.7%	23.5%	32.0%	0.2%	4.7%	8.6%	2.5%	0.0%	0.0%
CT - Oil	100.0%	NA	1.2%	0.0%	0.0%	NA	NA	NA	0.0%	0.0%	0.0%
CT - Other	28.8%	27.1%	36.1%	100.0%	0.0%	100.0%	NA	0.0%	NA	NA	NA
Fuel Cell	NA	NA	NA	NA	NA	67.4%	12.5%	0.0%	NA	0.0%	NA
Hydro - Pumped Storage	NA	NA	NA	NA	NA	100.0%	NA	NA	0.0%	0.0%	NA
Hydro - Run of River	0.0%	0.0%	57.6%	49.6%	11.2%	NA	100.0%	26.8%	100.0%	0.0%	0.0%
Nuclear	15.5%	1.6%	0.0%	100.0%	NA	NA	0.0%	0.0%	0.0%	NA	0.0%
RICE - Natural Gas	NA	NA	100.0%	66.7%	5.4%	6.2%	0.0%	5.4%	NA	NA	NA
RICE - Oil	0.0%	0.0%	NA	NA	NA	0.0%	NA	NA	NA	NA	NA
RICE - Other	100.0%	100.0%	100.0%	100.0%	79.7%	25.5%	2.8%	0.0%	0.0%	NA	NA
Solar	10.7%	7.1%	16.9%	24.4%	30.7%	11.6%	3.0%	0.3%	0.1%	0.0%	0.0%
Solar + Storage	NA	NA	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Wind	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.0%
Steam - Coal	100.0%	0.0%	1.4%	68.4%	1.2%	23.4%	37.5%	100.0%	0.0%	0.0%	NA
Steam - Natural Gas	NA	NA	NA	100.0%	0.0%	100.0%	16.9%	100.0%	NA	NA	0.0%
Steam - Oil	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Steam - Other	0.5%	61.2%	16.6%	0.0%	0.0%	NA	NA	NA	NA	NA	NA
Wind	2.9%	3.4%	2.5%	5.0%	20.7%	12.5%	2.8%	2.4%	0.0%	0.0%	0.0%
Wind + Storage	NA	NA	NA	NA	NA	NA	0.0%	0.0%	NA	NA	NA
All	10.4%	18.9%	26.5%	32.1%	34.3%	6.5%	2.8%	1.5%	0.4%	0.0%	0.0%

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 12-22 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 2,715 projects entered from January 2015 through September 2020, 2,352 projects, 86.6 percent, were renewable. Of the 515 projects entered in the first nine months of 2020, 498 projects, 96.7 percent, were renewable.

Table 12-22 Number of projects entered in the queue: September 30, 2020

Year Entered	Fuel Group			Total
	Nuclear	Renewable	Traditional	
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	391	48	440
2019	0	647	50	697
2020	2	498	15	515
Total	72	3,766	1,529	5,367

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 89.5 percent of all projects in the queue and those projects account for 78.1 percent of the nameplate MW currently active, suspended or under construction in the queue as of September 30, 2020 (Table 12-23).

Table 12-23 Queue details by fuel group: September 30, 2020

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	7	0.5%	217.5	0.1%
Renewable	1,360	89.5%	115,851.7	78.1%
Traditional	152	10.0%	32,292.4	21.8%
Total	1,519	100.0%	148,361.6	100.0%

Queue Analysis by Unit Type and Project Classification

Table 12-24 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through September 30, 2020. As of September 30, 2020, 5,367 projects, representing 624,142.5 MW, have entered the queue process since its inception. Of those, 932 projects, representing 71,856.6 MW, went into service. Of the projects that entered the queue process, 2,916 projects, representing 403,924.3 MW (64.7 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 4,315 projects have been classified as new generation and 1,052 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 4,309 projects (80.3 percent) of all 5,367 generation queue projects to enter the queue since January 1, 1997.

Table 12-24 Status of all generation queue projects: January 1997 through September 2020

Project Status	Project Classification	Number of Projects																												
		CT - Natural		CT - Oil		Hydro - Pumped Storage		Hydro - Run of River		RICE - Natural		RICE - Oil		RICE - Other		Solar + Storage		Solar + Wind		Steam - Coal		Steam - Natural		Steam - Oil		Steam - Other		Wind + Storage		Total
		Battery	CC	Gas	CT - Oil	Other	Fuel Cell	Pumped Storage	River	Nuclear	Gas	Oil	Other	Solar	Storage	Wind	Coal	Gas	- Oil	Other	Wind	Storage								
In Service	New Generation	22	62	49	10	25	3	0	10	2	10	0	55	157	1	0	8	5	0	4	90	0	513							
	Upgrade	7	97	100	15	5	0	3	19	41	9	1	15	25	0	0	55	9	0	8	10	0	419							
Under Construction	New Generation	0	6	2	0	0	0	0	2	0	1	0	0	25	2	0	0	0	0	0	7	0	45							
	Upgrade	0	12	17	8	0	1	0	0	1	0	1	0	8	0	0	1	0	0	0	1	0	50							
Suspended	New Generation	4	5	0	0	0	0	0	0	0	1	0	0	28	0	0	0	0	0	0	6	1	45							
	Upgrade	1	3	1	0	0	0	0	0	0	0	0	0	5	0	0	0	0	0	0	0	1	11							
Withdrawn	New Generation	159	425	25	9	81	26	2	41	9	25	12	16	1,227	46	0	55	1	0	34	444	0	2,637							
	Upgrade	30	90	15	13	13	2	0	5	13	0	2	3	47	1	0	14	0	0	2	29	0	279							
Active	New Generation	111	17	12	1	0	0	2	2	0	2	0	0	721	127	1	0	0	0	79	0	1,075								
	Upgrade	60	23	29	2	0	0	0	1	6	0	0	1	131	15	0	4	3	0	0	17	1	293							
Total Projects	New Generation	296	515	88	20	106	29	4	55	11	39	12	71	2,158	176	1	63	6	0	38	626	1	4,315							
	Upgrade	98	225	162	38	18	3	3	25	61	9	4	19	216	16	0	74	12	0	10	57	2	1,052							

Table 12-25 shows the totals in Table 12-24 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, 76.0 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 20.0 percent of hydro run of river upgrades were withdrawn and 4.0 percent of hydro run of river upgrades are active in the queue.

Table 12-25 Status of all generation queue projects as a percent of total projects by classification: January 1997 through September 2020

Project Status	Project Classification	Percent of Projects																				Total	
		CT - Natural		CT - Oil		Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural		RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural	Steam - Oil	Steam - Other	Wind + Storage		
		Battery	CC	Gas	Oil	Other	Cell	Storage	Run	Nuclear	Natural	Gas	Oil	Other	Solar	Storage	Wind	Coal	Gas	Oil	Other		Storage
In Service	New Generation	7.4%	12.0%	55.7%	50.0%	23.6%	10.3%	0.0%	18.2%	18.2%	25.6%	0.0%	77.5%	7.3%	0.6%	0.0%	12.7%	83.3%	0.0%	10.5%	14.4%	0.0%	11.9%
	Upgrade	7.1%	43.1%	61.7%	39.5%	27.8%	0.0%	100.0%	76.0%	67.2%	100.0%	25.0%	78.9%	11.6%	0.0%	0.0%	74.3%	75.0%	0.0%	80.0%	17.5%	0.0%	39.8%
Under Construction	New Generation	0.0%	1.2%	2.3%	0.0%	0.0%	0.0%	0.0%	3.6%	0.0%	2.6%	0.0%	0.0%	1.2%	1.1%	0.0%	0.0%	0.0%	0.0%	1.1%	0.0%	1.0%	
	Upgrade	0.0%	5.3%	10.5%	21.1%	0.0%	33.3%	0.0%	0.0%	1.6%	0.0%	25.0%	0.0%	3.7%	0.0%	0.0%	1.4%	0.0%	0.0%	1.8%	0.0%	4.8%	
Suspended	New Generation	1.4%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	100.0%	1.0%	
	Upgrade	1.0%	1.3%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	1.0%	
Withdrawn	New Generation	53.7%	82.5%	28.4%	45.0%	76.4%	89.7%	50.0%	74.5%	81.8%	64.1%	100.0%	22.5%	56.9%	26.1%	0.0%	87.3%	16.7%	0.0%	89.5%	70.9%	0.0%	61.1%
	Upgrade	30.6%	40.0%	9.3%	34.2%	72.2%	66.7%	0.0%	20.0%	21.3%	0.0%	50.0%	15.8%	21.8%	6.3%	0.0%	18.9%	0.0%	0.0%	20.0%	50.9%	0.0%	26.5%
Active	New Generation	37.5%	3.3%	13.6%	5.0%	0.0%	0.0%	50.0%	3.6%	0.0%	5.1%	0.0%	0.0%	33.4%	72.2%	100.0%	0.0%	0.0%	0.0%	12.6%	0.0%	24.9%	
	Upgrade	61.2%	10.2%	17.9%	5.3%	0.0%	0.0%	0.0%	4.0%	9.8%	0.0%	0.0%	5.3%	60.6%	93.8%	0.0%	5.4%	25.0%	0.0%	0.0%	29.8%	50.0%	27.9%

Table 12-26 shows the total MW of projects in the PJM generation queue by unit type and project classification. For example, the 444 new generation wind projects that have been withdrawn from the queue as of September 30, 2020, (as shown in Table 12-24) constitute 77,087.8 MW. The 425 new generation combined cycle projects that have been withdrawn in the same time period constitute 210,974.2 MW.

Table 12-26 Status of all generation (MW) in the PJM generation queue: January 1997 through September 2020

Project Status	Project Classification	Project MW																					
		CT - Natural		CT - Oil		Fuel Cell	Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural		RICE - Oil	RICE - Other	Solar Storage	Solar + Wind	Steam - Coal	Steam - Natural		Steam - Oil	Steam - Other	Wind Storage	Wind + Total	
		Battery	CC	Gas	Gas					Gas	Gas						Gas	Gas					Gas
In Service	New Generation	221.4	33,703.0	6,666.5	676.5	151.3	1.9	0.0	371.5	1,639.0	156.4	0.0	440.1	1,993.4	1.1	0.0	1,343.0	723.0	0.0	60.9	9,272.2	0.0	57,421.3
	Upgrade	46.4	6,439.3	2,589.5	127.8	12.3	0.0	390.0	387.6	2,282.8	17.3	23.3	49.9	41.3	0.0	0.0	965.5	161.5	0.0	667.8	233.0	0.0	14,435.3
Under Construction	New Generation	0.0	5,446.9	245.0	0.0	0.0	0.0	0.0	22.7	0.0	1.3	0.0	0.0	1,817.1	2.6	0.0	0.0	0.0	0.0	0.0	1,342.4	0.0	8,878.0
	Upgrade	0.0	1,251.2	139.5	13.0	0.0	3.0	0.0	0.0	44.0	0.0	4.0	0.0	253.2	0.0	0.0	36.0	0.0	0.0	0.0	0.0	0.0	1,743.9
Suspended	New Generation	12.5	5,070.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.9	0.0	0.0	955.6	0.0	0.0	0.0	0.0	0.0	0.0	737.6	90.0	6,885.5
	Upgrade	20.0	531.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.3	653.2
Withdrawn	New Generation	3,134.1	210,974.2	2,782.5	1,721.0	1,244.2	5.5	500.0	2,007.2	8,161.0	420.0	63.9	88.6	36,872.9	6,007.1	0.0	33,511.6	27.0	0.0	1,050.9	77,087.8	0.0	385,659.4
	Upgrade	786.3	11,151.3	619.5	589.0	72.5	0.9	0.0	105.1	966.0	0.0	13.0	10.0	1,451.5	3.7	0.0	865.0	0.0	0.0	37.1	1,594.0	0.0	18,264.9
Active	New Generation	7,893.1	11,214.5	4,399.1	14.0	0.0	0.0	700.0	21.5	0.0	40.0	0.0	0.0	55,039.0	12,322.8	199.0	0.0	0.0	0.0	0.0	25,674.1	0.0	117,517.1
	Upgrade	2,014.7	2,349.1	1,353.1	4.0	0.0	0.0	0.0	51.0	173.5	0.0	0.0	0.8	4,733.7	447.2	0.0	60.0	70.0	0.0	0.0	1,424.3	2.5	12,683.9
Total Projects	New Generation	11,261.1	266,408.6	14,093.1	2,411.5	1,395.6	7.4	1,200.0	2,422.9	9,800.0	637.6	63.9	528.7	96,678.0	18,333.6	199.0	34,854.6	750.0	0.0	1,111.8	114,114.0	90.0	576,361.2
	Upgrade	2,867.4	21,721.9	4,731.6	733.8	84.8	3.9	390.0	543.7	3,466.3	17.3	40.3	60.7	6,535.6	450.9	0.0	1,926.5	231.5	0.0	704.9	3,251.3	18.8	47,781.2

Table 12-27 shows the MW totals in Table 12-26 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, 67.6 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and September 30, 2020.

Table 12-27 Status of all generation queue projects as percent of total MW in project classification: January 1997 through September 2020

		Percent of Total Projects by Classification																						
	Project	CT - Natural			CT - Oil			Hydro - Pumped	Hydro - Run of	RICE - Natural				Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural	Steam - Oil	Steam - Other	Wind + Storage	Wind + Total			
Project Status	Classification	Battery	CC	Gas	CT - Oil	Other	Fuel Cell	Storage	River	Nuclear	Natural	Gas	Oil	Other	Solar	Storage	Wind	Steam - Coal	Gas	- Oil	Other	Wind	Storage	Total
In Service	New Generation	2.0%	12.7%	47.3%	28.1%	10.8%	26.2%	0.0%	15.3%	16.7%	24.5%	0.0%	83.2%	2.1%	0.0%	0.0%	3.9%	96.4%	0.0%	5.5%	8.1%	0.0%	10.0%	
	Upgrade	1.6%	29.6%	54.7%	17.4%	14.5%	0.0%	100.0%	71.3%	65.9%	100.0%	57.8%	82.2%	0.6%	0.0%	0.0%	50.1%	69.8%	0.0%	94.7%	7.2%	0.0%	30.2%	
Under Construction	New Generation	0.0%	2.0%	1.7%	0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	0.2%	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%	0.0%	1.5%	
	Upgrade	0.0%	5.8%	2.9%	1.8%	0.0%	76.0%	0.0%	0.0%	1.3%	0.0%	9.9%	0.0%	3.9%	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	3.6%	
Suspended	New Generation	0.1%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.1%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	100.0%	1.2%	
	Upgrade	0.7%	2.4%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	86.7%	1.4%	
Withdrawn	New Generation	27.8%	79.2%	19.7%	71.4%	89.2%	73.8%	41.7%	82.8%	83.3%	65.9%	100.0%	16.8%	38.1%	32.8%	0.0%	96.1%	3.6%	0.0%	94.5%	67.6%	0.0%	66.9%	
	Upgrade	27.4%	51.3%	13.1%	80.3%	85.5%	24.0%	0.0%	19.3%	27.9%	0.0%	32.3%	16.5%	22.2%	0.8%	0.0%	44.9%	0.0%	0.0%	5.3%	49.0%	0.0%	38.2%	
Active	New Generation	70.1%	4.2%	31.2%	0.6%	0.0%	0.0%	58.3%	0.9%	0.0%	6.3%	0.0%	0.0%	56.9%	67.2%	100.0%	0.0%	0.0%	0.0%	0.0%	22.5%	0.0%	20.4%	
	Upgrade	70.3%	10.8%	28.6%	0.5%	0.0%	0.0%	0.0%	9.4%	5.0%	0.0%	0.0%	1.3%	72.4%	99.2%	0.0%	3.1%	30.2%	0.0%	0.0%	43.8%	13.3%	26.5%	

Table 12-28 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 81.2 percent of all new projects entering the generation queue have been combined cycle (18.2 percent), wind (19.5 percent) or solar projects (43.3 percent). Prior to 2015, no renewable hybrid units (solar + storage, solar + wind and wind + storage) entered the queue. In the time period from January 1, 2015 through September 30, 2020, 19,092.2 MW have entered the queue.

Table 12-28 Queue project MW by unit type and queue entry year: January 1997 through September 2020

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	4,148.0	321.0	315.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0	4,840.0
1998	0.0	7,006.0	1,775.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,781.0
1999	0.0	29,412.7	2,412.1	0.0	10.0	0.0	0.0	196.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	47.0	0.0	0.0	525.0	115.4	0.0	32,763.2
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	0.0	0.0	37.0	2.5	0.0	0.0	95.6	0.0	21,909.9
2001	0.0	25,411.7	264.0	0.0	0.0	0.0	0.0	107.0	90.0	0.0	0.0	15.6	0.0	0.0	0.0	1,244.6	10.0	0.0	0.0	252.9	0.0	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	0.0	0.0	1,895.0	0.0	0.0	0.0	790.9	0.0	7,486.9
2003	0.0	2,361.4	10.0	8.0	0.8	0.0	0.0	2.0	0.0	29.0	0.0	27.5	0.0	0.0	0.0	522.0	0.0	0.0	165.0	997.0	0.0	4,122.7
2004	0.0	3,610.0	43.3	20.0	49.1	0.0	0.0	0.0	1,911.0	0.0	35.5	17.5	0.0	0.0	0.0	1,187.0	0.0	0.0	0.0	1,614.7	0.0	8,488.1
2005	0.0	5,824.6	961.0	281.0	51.4	0.0	340.0	174.2	242.0	21.5	0.0	65.1	0.0	0.0	0.0	6,360.0	0.0	0.0	24.0	6,020.0	0.0	20,364.9
2006	0.0	4,188.1	454.3	607.5	73.1	0.0	0.0	159.0	6,894.0	0.0	0.0	93.0	0.0	0.0	0.0	9,586.0	0.0	0.0	258.5	7,650.7	0.0	29,964.2
2007	0.0	13,944.6	941.2	215.9	149.5	0.0	16.0	161.6	368.0	0.0	0.0	56.5	3.3	0.0	0.0	9,078.0	190.0	0.0	50.5	18,525.6	0.0	43,700.6
2008	121.0	26,001.0	129.7	1,113.0	488.8	0.0	0.0	1,254.5	105.0	6.0	0.0	32.0	66.3	0.0	0.0	1,198.0	0.0	0.0	192.3	11,016.1	0.0	41,723.7
2009	34.0	5,548.4	14.0	66.0	214.2	0.0	0.0	133.9	1,933.8	4.5	16.0	15.2	636.5	0.0	0.0	1,273.0	5.5	0.0	148.0	6,672.6	0.0	16,715.6
2010	72.4	9,185.4	176.0	7.9	117.3	0.0	0.0	132.6	426.0	0.0	2.4	57.8	3,672.6	0.0	0.0	64.0	0.0	0.0	173.5	9,848.4	0.0	23,936.3
2011	24.1	19,744.0	29.5	0.0	174.6	0.0	0.0	30.0	182.0	0.0	14.0	75.3	2,014.0	0.0	0.0	357.0	0.0	0.0	49.0	5,576.4	0.0	28,269.9
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	284.6	0.0	0.0	1,837.0	0.0	0.0	143.1	1,529.8	0.0	22,746.8
2013	217.4	10,493.1	1,201.8	5.0	11.2	0.0	0.0	89.4	102.0	59.7	0.0	1.6	231.7	0.0	0.0	158.0	40.0	0.0	44.7	1,407.9	0.0	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	1,590.0	0.0	0.0	1,730.5	27.0	0.0	43.1	1,689.7	0.0	19,099.0
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	2,922.9	2.0	0.0	47.0	606.5	0.0	0.0	2,160.6	0.0	35,553.0
2016	111.1	18,802.5	1,392.0	0.0	0.0	3.4	0.0	12.5	50.3	23.5	0.0	38.9	11,677.7	85.6	0.0	80.0	77.0	0.0	0.0	3,448.7	18.8	35,821.9
2017	24.6	5,477.6	701.0	0.0	4.1	2.7	0.0	20.5	39.1	97.1	0.0	33.8	13,454.7	424.9	0.0	14.0	17.0	0.0	0.0	5,342.0	90.0	25,743.2
2018	1,513.9	11,080.1	2,647.4	14.0	0.0	0.0	700.0	2.4	28.1	0.0	0.0	0.8	19,737.6	4,573.9	0.0	49.0	0.0	0.0	0.0	17,719.5	0.0	58,066.7
2019	5,843.2	3,332.5	1,572.1	13.0	0.0	3.0	500.0	99.0	0.0	0.0	0.0	0.0	27,037.0	9,997.6	0.0	11.0	0.0	0.0	0.0	11,585.4	0.0	59,993.8
2020	5,230.3	0.0	134.9	4.0	0.0	0.0	0.0	26.8	100.0	0.0	0.0	0.0	19,884.7	3,700.5	199.0	0.0	6.0	0.0	0.0	3,305.5	0.0	32,591.7
Total	14,128.5	288,130.5	18,824.7	3,145.3	1,480.3	11.3	1,590.0	2,966.6	13,266.3	654.9	104.2	589.4	103,213.6	18,784.4	199.0	36,781.1	981.5	0.0	1,816.7	117,365.3	108.8	624,142.5

Combined Cycle Project Analysis

Table 12-29 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2020, by zone. Of the 66 combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 36 projects (54.5 percent) are located in AEP, ComEd and APS.

Table 12-29 Status of all combined cycle queue projects by zone (number of projects): January 1997 through September 2020

Project Status	Project Classification	Number of Projects																					
		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	5	2	3	2	1	0	1	0	7	2	0	7	4	0	5	2	4	10	6	0	62
	Upgrade	3	12	7	4	0	4	0	0	0	15	5	0	6	3	0	10	4	3	7	14	0	97
Under Construction	New Generation	0	3	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	Upgrade	0	4	1	1	0	0	0	0	0	0	0	0	0	1	0	2	0	1	1	1	0	12
Suspended	New Generation	0	0	2	2	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	5
	Upgrade	0	0	1	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	3
Withdrawn	New Generation	23	19	43	13	8	14	0	1	2	17	17	3	26	25	0	43	40	33	42	54	2	425
	Upgrade	7	7	5	3	0	4	0	1	0	11	4	0	7	7	0	3	5	3	8	15	0	90
Active	New Generation	0	3	4	0	0	4	1	0	0	1	0	0	0	0	0	0	1	1	0	2	0	17
	Upgrade	1	2	7	1	0	3	0	0	0	2	0	0	0	0	0	1	2	2	2	0	0	23
Total Projects	New Generation	24	30	52	19	10	20	1	2	2	26	19	3	33	29	0	48	43	38	52	62	2	515
	Upgrade	11	25	21	9	0	11	0	1	0	28	10	0	14	11	0	16	11	9	18	30	0	225

Table 12-30 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997, through September 30, 2020, by zone. Of the 25,862.7 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 15,317.3 MW (59.2 percent) are located in AEP, ComEd and APS.

Table 12-30 Status of all combined cycle queue projects by zone (MW): January 1997 through September 2020

Project Status	Project Classification	Project MW																					
		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	650.0	3,545.0	1,455.0	2,599.0	140.0	600.0	0.0	20.0	0.0	5,828.6	319.2	0.0	1,665.8	2,557.0	0.0	2,665.0	1,900.0	1,560.0	5,750.0	2,448.5	0.0	33,703.0
	Upgrade	229.0	384.0	790.0	306.0	0.0	633.6	0.0	0.0	0.0	963.0	102.0	0.0	110.0	83.9	0.0	973.5	142.3	164.1	712.0	845.9	0.0	6,439.3
Under Construction	New Generation	0.0	2,579.0	515.0	1,152.0	0.0	1,200.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,446.9
	Upgrade	0.0	916.0	20.0	38.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	35.0	0.0	64.5	51.6	51.1	0.0	1,251.2
Suspended	New Generation	0.0	0.0	1,575.0	1,895.0	0.0	0.0	0.0	0.0	0.0	1,600.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,070.0
	Upgrade	0.0	0.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.0	0.0	35.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	531.0
Withdrawn	New Generation	8,542.4	12,509.5	20,122.1	8,641.0	3,122.1	10,142.0	0.0	134.5	665.0	11,261.0	5,436.4	991.8	13,562.6	13,001.0	0.0	23,340.0	15,951.0	20,414.2	18,917.7	24,213.1	6.9	210,974.2
	Upgrade	149.4	711.0	579.0	86.0	0.0	1,735.0	0.0	36.0	0.0	780.4	668.0	0.0	378.0	1,742.0	0.0	240.0	1,040.6	85.0	703.0	2,217.9	0.0	11,151.3
Active	New Generation	0.0	2,200.0	2,516.0	0.0	0.0	2,400.0	1,150.0	0.0	0.0	1,060.0	0.0	0.0	0.0	0.0	0.0	0.0	163.0	894.0	0.0	831.5	0.0	11,214.5
	Upgrade	7.6	320.0	918.7	550.0	0.0	111.7	0.0	0.0	0.0	90.0	0.0	0.0	0.0	0.0	0.0	67.0	85.0	144.1	55.0	0.0	0.0	2,349.1
Total Projects	New Generation	9,192.4	20,833.5	26,183.1	14,287.0	3,262.1	14,342.9	1,150.0	154.5	665.0	19,749.6	5,755.6	991.8	15,228.4	15,558.0	0.0	26,005.0	18,014.0	22,868.2	24,667.7	27,493.1	6.9	266,408.6
	Upgrade	386.0	2,331.0	2,352.7	980.0	0.0	2,480.3	0.0	36.0	0.0	1,833.4	1,221.0	0.0	523.0	1,900.9	0.0	1,315.5	1,267.9	457.7	1,521.6	3,114.9	0.0	21,721.9

Combustion Turbine – Natural Gas Project Analysis

Table 12-31 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2020, by zone. Of the 61 combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 22 projects (36.1 percent) are located in AEP, ComEd and APS.

Table 12-31 Status of all combustion turbine – natural gas generation queue projects by zone (number of projects): January 1997 through September 2020

Project Status	Project Classification	Number of Projects																					
		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	3	7	0	3	1	0	2	4	2	4	9	0	49
	Upgrade	4	8	7	1	0	11	5	0	0	26	7	0	4	1	0	3	2	3	4	14	0	100
Under Construction	New Generation	0	0	0	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	2
	Upgrade	0	0	1	2	0	4	0	0	0	0	0	0	1	4	0	0	5	0	0	0	0	17
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
	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	1	5	0	0	1	1	1	0	0	3	0	1	0	0	0	1	5	0	1	5	0	25
	Upgrade	2	1	1	1	0	2	2	0	1	3	0	0	0	1	0	0	1	0	0	0	0	15
Active	New Generation	1	1	0	0	1	1	0	0	1	3	0	0	0	0	0	1	2	0	0	1	0	12
	Upgrade	0	3	2	4	0	8	2	0	1	2	0	0	0	0	0	0	2	5	0	0	0	29
Total Projects	New Generation	7	6	6	0	5	3	1	0	2	9	7	1	3	1	0	4	11	2	5	15	0	88
	Upgrade	6	12	12	8	0	25	9	0	2	31	7	0	5	6	0	3	10	8	4	14	0	162

Table 12-32 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997, through September 30, 2020, by zone. Of the 6,166.7 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,902.8 MW (30.9 percent) are located within AEP, ComEd and APS.

Table 12-32 Status of all combustion turbine – natural gas queue projects by zone (MW): January 1997 through September 2020

Project Status	Project Classification	Project MW																					
		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	360.7	0.0	1,176.0	0.0	23.0	0.0	0.0	0.0	0.0	1,081.0	1,491.0	0.0	522.1	10.0	0.0	559.0	361.9	5.0	150.9	925.9	0.0	6,666.5
	Upgrade	43.7	190.0	187.7	40.0	0.0	323.0	60.0	0.0	0.0	887.7	86.0	0.0	200.0	34.1	0.0	13.0	25.0	32.0	252.3	215.0	0.0	2,589.5
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	245.0
	Upgrade	0.0	0.0	12.0	5.0	0.0	95.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.5	0.0	0.0	14.0	0.0	0.0	0.0	0.0	139.5
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0
Withdrawn	New Generation	7.5	989.5	0.0	0.0	9.0	10.0	104.0	0.0	0.0	102.2	0.0	73.0	0.0	0.0	0.0	0.5	326.8	0.0	19.9	1,140.1	0.0	2,782.5
	Upgrade	165.5	6.0	4.0	25.0	0.0	23.0	104.0	0.0	0.0	57.0	0.0	0.0	0.0	0.0	0.0	0.0	235.0	0.0	0.0	0.0	0.0	619.5
Active	New Generation	230.0	529.5	0.0	0.0	144.6	190.0	0.0	0.0	14.4	2,105.6	0.0	0.0	0.0	0.0	0.0	29.0	481.0	0.0	0.0	675.0	0.0	4,399.1
	Upgrade	0.0	88.1	70.0	111.0	0.0	848.2	43.5	0.0	3.5	38.0	0.0	0.0	0.0	0.0	0.0	0.0	93.5	57.3	0.0	0.0	0.0	1,353.1
Total Projects	New Generation	598.2	1,519.0	1,176.0	0.0	176.6	240.0	104.0	0.0	219.4	3,288.8	1,491.0	73.0	522.1	10.0	0.0	588.5	1,169.7	5.0	170.8	2,741.0	0.0	14,093.1
	Upgrade	209.2	284.1	303.7	181.0	0.0	1,289.2	207.5	0.0	3.5	982.7	86.0	0.0	200.0	47.6	0.0	13.0	367.5	89.3	252.3	215.0	0.0	4,731.6

Wind Project Analysis

Table 12-33 shows the status of all wind generation projects, by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2020, by zone. Of the 100 wind projects to achieve in service status, 61 projects (61.0 percent) are located in AEP, ComEd and APS. Of the 110 wind projects currently active, suspended or under construction in the PJM generation queue, 72 projects (65.5 percent) are located in AEP, ComEd and APS.

Table 12-33 Status of all wind generation queue projects by zone (number of projects): January 1997 through September 2020

		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	17	16	0	0	23	0	0	0	2	0	0	0	0	0	0	23	0	8	0	0	90
	Upgrade	0	0	1	0	0	4	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	10
Under Construction	New Generation	0	2	1	0	0	3	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	7
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	3	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	2	0	0	6
	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	18	105	45	8	0	107	15	0	0	21	11	1	2	0	0	0	64	0	46	1	0	444
	Upgrade	2	2	6	0	0	8	0	0	0	3	0	0	0	0	0	0	6	0	2	0	0	29
Active	New Generation	6	20	5	3	0	25	0	0	0	7	5	0	5	0	0	0	1	0	2	0	0	79
	Upgrade	0	1	2	0	0	9	0	0	0	0	3	0	1	0	0	0	1	0	0	0	0	17
Total Projects	New Generation	25	147	67	11	0	158	15	0	0	32	16	1	7	0	0	0	88	0	58	1	0	626
	Upgrade	2	3	10	0	0	21	0	0	0	3	3	0	1	0	0	0	12	0	2	0	0	57

Table 12-34 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997, through September 30, 2020, by zone. Of the 9,505.2 MW of wind generation to achieve the in service status, 7,875.2 MW (82.9 percent) are located within AEP, ComEd and APS. Of the 29,178.4 MW of wind generation currently active, suspended or under construction in the PJM generation queue, 12,620.1 MW (43.3 percent) are located in AEP, ComEd and APS.

Table 12-34 Status of all wind generation queue projects by zone (MW): January 1997 through September 2020

Project Status	Project	Project MW																				Total	
	Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG		RECO
In Service	New Generation	7.5	3,094.6	1,114.6	0.0	0.0	3,453.5	0.0	0.0	0.0	310.5	0.0	0.0	0.0	0.0	0.0	0.0	1,065.0	0.0	226.5	0.0	0.0	9,272.2
	Upgrade	0.0	0.0	5.0	0.0	0.0	207.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.5	0.0	0.0	0.0	0.0	233.0
Under Construction	New Generation	0.0	450.0	200.0	0.0	0.0	680.4	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,342.4
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	272.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	300.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	165.3	0.0	0.0	737.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	4,643.6	22,131.8	3,472.2	1,295.6	0.0	25,033.1	2,128.0	0.0	0.0	4,988.4	2,968.8	150.3	1,504.0	0.0	0.0	0.0	5,377.0	0.0	3,375.1	20.0	0.0	77,087.8
	Upgrade	5.0	370.0	100.0	0.0	0.0	755.7	0.0	0.0	0.0	114.0	0.0	0.0	0.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	1,594.0
Active	New Generation	3,441.6	3,812.2	420.0	816.1	0.0	6,448.8	0.0	0.0	0.0	5,116.9	1,399.8	0.0	3,759.2	0.0	0.0	0.0	109.9	0.0	349.6	0.0	0.0	25,674.1
	Upgrade	0.0	16.6	19.4	0.0	0.0	300.7	0.0	0.0	0.0	0.0	477.3	0.0	510.0	0.0	0.0	0.0	100.3	0.0	0.0	0.0	0.0	1,424.3
Total Projects	New Generation	8,092.7	29,760.6	5,206.8	2,111.7	0.0	35,615.8	2,128.0	0.0	0.0	10,728.1	4,368.6	150.3	5,263.2	0.0	0.0	0.0	6,551.9	0.0	4,116.5	20.0	0.0	114,114.0
	Upgrade	5.0	386.6	124.4	0.0	0.0	1,263.8	0.0	0.0	0.0	114.0	477.3	0.0	510.0	0.0	0.0	0.0	364.2	0.0	6.0	0.0	0.0	3,251.3

Solar Project Analysis

Table 12-35 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2020, by zone. Of the 182 solar projects to achieve in service status, 12 projects (6.6 percent) are located in AEP, ComEd and APS. Of the 918 solar projects currently active, suspended or under construction in the PJM generation queue, 303 projects (33.0 percent) are located in AEP, ComEd and APS.

Table 12-35 Status of all solar generation queue projects by zone (number of projects): January 1997 through September 2020

Project Status	Project Classification	Number of Projects																					
		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	8	4	7	0	1	1	1	0	0	25	11	0	50	0	0	1	1	1	2	44	0	157
	Upgrade	1	0	0	0	0	0	0	0	0	4	8	0	9	0	0	0	0	0	3	0	0	25
Under Construction	New Generation	0	2	1	0	0	0	0	1	0	15	2	0	1	0	0	0	0	0	0	3	0	25
	Upgrade	0	2	0	0	0	0	0	1	0	3	0	0	0	0	0	0	0	0	0	2	0	8
Suspended	New Generation	0	4	12	0	0	0	0	0	1	9	0	0	0	1	0	0	0	0	0	1	0	28
	Upgrade	0	0	0	0	0	0	0	0	1	1	0	0	1	2	0	0	0	0	0	0	0	5
Withdrawn	New Generation	179	107	76	16	14	38	19	14	1	207	132	9	191	20	1	9	45	18	43	88	0	1,227
	Upgrade	3	3	1	1	0	5	0	0	0	16	1	0	9	0	0	0	3	2	0	3	0	47
Active	New Generation	15	133	62	33	2	43	28	6	2	167	43	21	12	23	1	2	72	11	42	3	0	721
	Upgrade	1	26	13	7	0	5	6	2	0	45	6	1	2	3	0	0	7	0	5	2	0	131
Total Projects	New Generation	202	250	158	49	17	82	48	21	4	423	188	30	254	44	2	12	118	30	87	139	0	2,158
	Upgrade	5	31	14	8	0	10	6	3	1	69	15	1	21	5	0	0	10	2	8	7	0	216

Table 12-36 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997, through September 30, 2020, by zone. Of the 2,034.7 MW of solar generation to achieve in service status, 121.0 MW (5.9 percent) are located in AEP, ComEd and APS. Of the 62,854.5 MW of solar generation currently active, suspended or under construction in the PJM generation queue, 26,168.2 MW (41.6 percent) are located in AEP, ComEd and APS.

Table 12-36 Status of all solar generation queue projects by zone (MW): January 1997 through September 2020

Project Status	Project Classification	Project MW																					
		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	59.7	14.7	97.3	0.0	1.1	9.0	2.5	0.0	0.0	1,039.2	130.4	0.0	373.4	0.0	0.0	3.3	13.5	2.5	15.0	231.9	0.0	1,993.4
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.0	0.0	0.0	14.3	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	41.3
Under Construction	New Generation	0.0	80.0	10.0	0.0	0.0	0.0	0.0	125.0	0.0	1,394.6	170.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	17.5	0.0	1,817.1
	Upgrade	0.0	150.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	24.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	253.2
Suspended	New Generation	0.0	180.0	256.9	0.0	0.0	0.0	0.0	0.0	11.7	466.0	0.0	0.0	0.0	35.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	955.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.3	0.0	0.0	0.0	7.6	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55.9
Withdrawn	New Generation	2,002.1	7,093.5	1,861.2	1,053.3	112.3	2,498.8	1,093.9	429.4	20.0	12,326.6	1,935.4	527.9	1,594.8	641.0	78.0	78.4	1,971.8	208.7	811.6	534.2	0.0	36,872.9
	Upgrade	170.0	126.0	0.0	8.0	0.0	110.0	0.0	0.0	0.0	988.8	0.0	0.0	23.8	0.0	0.0	0.0	20.0	3.6	0.0	1.3	0.0	1,451.5
Active	New Generation	423.1	14,821.6	2,528.1	2,621.8	30.0	6,141.9	3,018.6	499.9	34.2	15,768.8	1,725.9	1,933.0	86.6	793.3	120.0	29.8	2,735.7	148.2	1,548.7	29.9	0.0	55,039.0
	Upgrade	0.0	1,567.0	247.8	438.7	0.0	185.0	165.5	10.0	0.0	1,579.2	72.0	40.0	11.0	50.0	0.0	0.0	226.5	0.0	141.0	0.0	0.0	4,733.7
Total Projects	New Generation	2,484.9	22,189.8	4,753.5	3,675.1	143.4	8,649.7	4,115.0	1,054.3	65.9	30,995.2	3,961.7	2,460.9	2,074.7	1,469.3	198.0	111.5	4,721.0	359.4	2,375.2	819.5	0.0	96,678.0
	Upgrade	170.0	1,843.0	247.8	446.7	0.0	295.0	165.5	85.0	8.3	2,609.4	72.0	40.0	56.7	90.0	0.0	0.0	246.5	3.6	151.0	5.1	0.0	6,535.6

Renewable Hybrid Project Analysis

Table 12-37 shows the status of all renewable hybrid generation projects (solar + storage, solar + wind and wind + storage) by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2020, by zone. Of the 148 renewable hybrid projects currently active, suspended or under construction in the PJM generation queue, 46 projects (31.1 percent) are located in AEP, ComEd and APS.

Table 12-37 Status of all renewable hybrid generation queue projects by zone (number of projects): January 1997 through September 2020

Project Status	Project Classification	Number of Projects																					
		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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	2
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1
	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	4	9	2	3	0	4	0	0	0	10	0	6	0	0	0	0	0	0	0	8	0	46
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1
Active	New Generation	0	20	14	6	0	5	0	0	2	28	0	13	2	9	0	0	10	1	17	1	0	128
	Upgrade	0	3	1	0	0	2	0	0	0	6	0	2	0	0	0	0	0	0	2	0	0	16
Total Projects	New Generation	4	29	16	9	0	9	0	0	2	38	0	19	2	9	0	0	10	1	18	12	0	178
	Upgrade	0	3	2	0	0	2	0	0	0	6	0	2	0	1	0	0	0	0	2	0	0	18

Table 12-38 shows the status of all renewable hybrid projects by MW that entered PJM generation queues from January 1, 1997, through September 30, 2020, by zone. Of the 13,080.4 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation queue, 7,258.2 MW (55.5 percent) are located in AEP, ComEd and APS.

Table 12-38 Status of all renewable hybrid generation queue projects by zone (MW): January 1997 through September 2020

Project Status	Project Classification	Project MW																					
		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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	1.1
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	0.0	2.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	90.0	0.0	0.0	90.0
	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	0.0	0.0	0.0	0.0	0.0	0.0	16.3
Withdrawn	New Generation	14.5	3,270.8	210.0	174.9	0.0	610.0	0.0	0.0	0.0	790.0	0.0	907.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.9	0.0	6,007.1
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7
Active	New Generation	0.0	5,205.0	590.3	280.9	0.0	1,281.0	0.0	0.0	37.5	2,349.1	0.0	1,666.0	90.0	138.9	0.0	0.0	743.2	20.0	100.0	20.0	0.0	12,521.8
	Upgrade	0.0	143.2	0.0	0.0	0.0	22.5	0.0	0.0	0.0	94.0	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	90.0	0.0	0.0	449.7
Total Projects	New Generation	14.5	8,475.8	800.3	455.8	0.0	1,891.0	0.0	0.0	37.5	3,139.1	0.0	2,573.0	90.0	138.9	0.0	0.0	743.2	20.0	190.0	53.5	0.0	18,622.6
	Upgrade	0.0	143.2	16.3	0.0	0.0	22.5	0.0	0.0	0.0	94.0	0.0	100.0	0.0	3.7	0.0	0.0	0.0	0.0	90.0	0.0	0.0	469.7

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.”³⁵ 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 nonincumbent transmission developer which is a competitor of the transmission owner. The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest.

Table 12-39 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 September 30, 2020, 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 154.5 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 624,142.5 MW that have entered the queue during the time period of January 1, 1997, through September 30, 2020, 67,167.2 MW (10.8 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 37,497.4 MW that entered the queue during the time period of January 1, 1997, through September 30, 2020, 14,287.3 MW (38.1 percent) have been submitted by PSEG or one of their affiliated companies.

³⁵ See OATT § 1 (Transmission Owner).

Table 12-39 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: September 30, 2020

Parent Company	Transmission Owner	Related to Developer	Number of Projects	MW by Unit Type																							
				CT -				Hydro -				RICE -				Solar +				Steam -				Wind +			
				Battery	CC	Natural Gas	CT - Oil	CT - Other	Fuel Cell	Pumped Storage	Run of River	Nuclear	Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Storage	Total		
AEP	AEP	Related	48	16.0	678.0	0.0	0.0	0.0	0.0	34.0	2.4	214.0	0.0	0.0	0.0	142.7	0.0	0.0	3,918.0	90.0	0.0	0.0	0.0	0.0	5,095.1		
		Unrelated	662	2,589.0	22,486.5	1,803.1	7.5	127.3	0.0	0.0	453.6	0.0	12.0	0.0	75.4	23,890.1	8,619.0	0.0	10,399.0	0.0	0.0	452.0	30,147.2	0.0	101,061.6		
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	0.0	0.0	1,347.5	0.0	0.0	0.0	0.0	0.0	1,427.0		
		Unrelated	82	204.9	1,150.0	273.5	0.0	1.9	0.0	0.0	0.0	0.0	0.0	0.0	10.0	4,259.0	0.0	0.0	0.0	0.0	0.0	0.0	2,128.0	0.0	8,027.3		
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	0.0	0.0	0.0		
		Unrelated	33	20.0	665.0	222.9	40.0	19.2	0.0	0.0	132.8	1,879.0	0.0	0.0	0.0	74.2	37.5	0.0	2,810.0	0.0	0.0	0.0	0.0	0.0	5,900.6		
Dominion	Dominion	Related	119	0.0	12,338.5	2,045.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0	1,941.0	17.0	0.0	301.0	0.0	0.0	4.0	2,786.0	0.0	21,877.2		
		Unrelated	662	2,370.0	9,244.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4	31,663.6	3,216.1	0.0	20.0	0.0	0.0	316.3	8,056.1	0.0	57,504.6		
Duke	DEOK	Related	10	27.3	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	106.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	169.7		
		Unrelated	32	140.4	154.5	0.0	0.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	1,032.9	0.0	0.0	120.0	0.0	0.0	0.0	0.0	0.0	1,564.6		
EKPC	EKPC	Related	2	0.0	821.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	821.8		
		Unrelated	58	74.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,500.9	2,673.0	0.0	0.0	0.0	0.0	0.0	150.3	0.0	5,641.5		
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	0.0	0.0	0.0	738.3		
		Unrelated	337	914.0	8,848.4	807.4	388.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3	2,646.6	14.5	0.0	15.0	5.5	0.0	10.0	8,097.7	0.0	21,787.9		
	BGE	Related	15	22.5	250.0	10.0	0.0	0.0	0.0	0.0	0.0	108.5	0.0	0.0	8.5	20.0	0.0	0.0	10.0	101.0	0.0	0.0	0.0	0.0	530.5		
		Unrelated	63	540.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0	123.4	0.0	0.0	0.0	2.5	0.0	25.0	0.0	0.0	7,302.9		
	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	0.0	0.0	0.0	1,194.0		
		Unrelated	429	1,558.3	16,823.2	1,529.2	42.0	65.2	0.0	0.0	22.7	0.0	35.0	0.0	67.7	8,935.7	1,712.0	199.0	1,926.0	91.0	0.0	90.0	36,879.6	2.5	69,979.1		
	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	0.0	0.0	0.0	1,723.4		
		Unrelated	324	569.7	5,611.6	1,226.0	600.9	42.6	0.0	0.0	0.0	0.0	0.0	0.0	84.6	4,026.3	0.0	0.0	653.0	15.0	0.0	65.0	4,845.9	0.0	17,740.6		
	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	0.0	0.0	7.0	0.0	0.0	0.0	0.0	0.0	7,809.3		
		Unrelated	85	25.3	20,355.5	596.5	2.0	15.0	0.0	0.0	0.0	0.0	0.0	17.0	3.7	111.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21,126.5		
	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	0.0	0.0	0.0		
		Unrelated	105	20.0	23,325.9	94.3	34.0	9.0	0.0	0.0	0.0	1,640.0	32.0	0.0	3.5	363.0	20.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	25,547.7		
FirstEnergy	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	0.0	0.0	1,710.0	0.0	0.0	0.0	0.0	0.0	3,163.0		
		Unrelated	451	682.4	27,082.8	1,479.7	0.0	84.4	0.0	0.0	623.3	0.0	140.0	53.8	25.4	5,001.3	800.3	0.0	4,092.0	0.0	0.0	184.4	5,331.2	16.3	45,597.2		
	ATSI	Related	6	0.0	1,678.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,694.0		
		Unrelated	133	96.4	13,589.0	181.0	10.5	166.4	0.0	0.0	0.0	0.0	59.7	0.0	6.9	4,121.8	455.8	0.0	0.0	16.5	0.0	0.0	2,111.7	0.0	20,815.7		
	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	0.0	0.0	0.0	32.0		
		Unrelated	410	1,462.0	15,751.4	722.1	0.0	4.8	0.6	0.0	1.6	0.0	0.6	0.0	12.8	2,119.4	90.0	0.0	0.0	0.0	0.0	30.0	5,773.2	0.0	25,968.5		
	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	0.0	0.0	0.0		
		Unrelated	149	355.9	17,458.9	57.6	1,204.4	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2	1,559.3	142.6	0.0	0.0	0.0	0.0	84.0	0.0	0.0	21,039.0		
	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	0.0	0.0	1,860.0	0.0	0.0	0.0	0.0	0.0	2,399.0		
		Unrelated	383	905.2	18,747.9	1,532.2	0.0	214.4	3.0	16.0	46.3	0.0	341.8	8.0	14.8	4,967.5	743.2	0.0	561.0	590.0	0.0	525.0	6,916.1	0.0	36,132.1		
OVEC	OVEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
		Unrelated	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	198.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	198.0		
PPL	PPL	Related	22	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	124.8	0.0	0.0	111.0	0.0	0.0	0.0	0.0	0.0	4,205.8		
		Unrelated	322	599.8	23,928.3	423.1	8.0	234.5	0.0	1,200.0	142.6	488.0	19.9	2.4	44.7	2,401.5	190.0	0.0	6,896.6	0.0	0.0	31.0	4,122.5	90.0	40,822.9		
PSEG	PSEG	Related	109	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	180.4	3.7	0.0	24.0	44.0	0.0	0.0	0.0	0.0	14,287.3		
		Unrelated	228	874.5	18,771.9	1,137.9	600.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7	644.2	49.9	0.0	0.0	20.0	0.0	0.0	20.0	0.0	23,210.1		
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	0.0	0.0	0.0		
		Unrelated	2	0.0	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.9		
Total		Related	415	125.8	40,946.4	4,272.8	189.5	0.0	0.0	374.0	396.4	5,886.3	0.0	0.0	68.5	2,573.4	20.7	0.0	9,288.5	235.0	0.0	4.0	2,786.0	0.0	67,167.2		
		Unrelated	4952	14,002.8	247,184.1	14,551.9	2,955.8	1,480.3	11.3	1,216.0	2,570.2	7,380.0	654.9	104.2	520.9	100,640.2	18,763.8	199.0	27,492.6	746.5	0.0	1,812.7	114,579.3	108.8	556,975.3		

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-40 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 September 30, 2020, by transmission owner and project status. Of the 46,840.4 combined cycle project MW that have achieved in service or under construction status during this time period, 9,279.6 MW (19.8 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 September 30, 2020, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-40 Relationship between project developer and transmission owner for all combined cycle project MW in PJM interconnection queue: September 30, 2020

Parent Company	Transmission Owner	Related to Developer	MW by Project Status					Total
			Active	In Service	Under Construction	Suspended	Withdrawn	
AEP	AEP	Related	0.0	678.0	0.0	0.0	0.0	678.0
		Unrelated	2,520.0	3,251.0	3,495.0	0.0	13,220.5	22,486.5
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	90.0	4,747.5	0.0	0.0	7,501.0	12,338.5
		Unrelated	1,060.0	2,044.1	0.0	1,600.0	4,540.4	9,244.5
Duke	DEOK	Related	0.0	0.0	0.0	0.0	36.0	36.0
		Unrelated	0.0	20.0	0.0	0.0	134.5	154.5
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	7.6	879.0	0.0	0.0	7,961.8	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	2,511.7	1,233.6	1,200.9	0.0	11,877.0	16,823.2
	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	3,638.5	35.0	0.0	16,615.0	20,355.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,038.1	1,724.1	64.5	0.0	20,499.2	23,325.9
FirstEnergy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0
		Unrelated	3,434.7	1,720.0	535.0	1,620.0	19,773.1	27,082.8
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0
		Unrelated	550.0	2,905.0	1,190.0	1,895.0	7,049.0	13,589.0
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	1,775.8	0.0	35.0	13,940.6	15,751.4
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	2,640.9	75.0	0.0	14,743.0	17,458.9
	PENELEC	Related	0.0	0.0	0.0	0.0	534.0	534.0
		Unrelated	248.0	2,042.3	0.0	0.0	16,457.6	18,747.9
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	55.0	5,862.0	51.6	0.0	17,959.7	23,928.3
PSEG	PSEG	Related	0.0	2,488.0	51.1	0.0	9,297.0	11,836.1
		Unrelated	831.5	806.4	0.0	0.0	17,134.0	18,771.9
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	6.9	6.9
Total		Related	90.0	9,228.5	51.1	0.0	31,576.8	40,946.4
		Unrelated	13,473.6	30,913.8	6,647.0	5,601.0	190,548.6	247,184.1

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-41 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 September 30, 2020, by transmission owner and project status. Of the 9,640.5 CT – natural gas project MW that have achieved in service or under construction status during this time period, 2,107.0 (21.9 percent) have been developed by Transmission Owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building CT – natural gas projects in their own service territory. Of the 2,956.0 MW that entered the queue during the time period of January 1, 1997, through September 30, 2020, 1,818.1 MW (61.5 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-41 Relationship between project developer and transmission owner for all CT – natural gas project MW in PJM interconnection queue: September 30, 2020

Parent Company	Transmission Owner	Related to Developer	MW by Project Status					Total
			Active	In Service	Under Construction	Suspended	Withdrawn	
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	617.6	190.0	0.0	0.0	995.5	1,803.1
AES	DAY	Related	0.0	38.0	0.0	0.0	0.0	38.0
		Unrelated	43.5	22.0	0.0	0.0	208.0	273.5
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	17.9	0.0	205.0	0.0	0.0	222.9
Dominion	Dominion	Related	1,176.0	786.0	0.0	0.0	83.7	2,045.7
		Unrelated	967.6	1,182.7	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	0.0	0.0	0.0	0.0	73.0	73.0
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	230.0	404.4	0.0	0.0	173.0	807.4
	BGE	Related	0.0	10.0	0.0	0.0	0.0	10.0
		Unrelated	144.6	13.0	0.0	0.0	9.0	166.6
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,038.2	323.0	135.0	0.0	33.0	1,529.2
	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	57.3	37.0	0.0	0.0	0.0	94.3
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	70.0	1,363.7	12.0	30.0	4.0	1,479.7
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	111.0	40.0	5.0	0.0	25.0	181.0
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	722.1	0.0	0.0	0.0	722.1
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	44.1	13.5	0.0	0.0	57.6
	PENELEC	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	574.5	381.9	14.0	0.0	561.8	1,532.2
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	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	675.0	228.9	0.0	0.0	234.0	1,137.9
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	1,176.0	2,107.0	0.0	0.0	989.8	4,272.8
		Unrelated	4,576.2	7,149.0	384.5	30.0	2,412.2	14,551.9

Wind Project Developer and Transmission Owner Relationships

Table 12-42 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 September 30, 2020, by transmission owner and project status. Of the 10,847.6 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 10,842.1 MW that entered the queue during the time period of January 1, 1997, through September 30, 2020, 2,786.0 MW (25.7 percent) have been submitted by Dominion or one of their affiliated companies.

Table 12-42 Relationship between project developer and transmission owner for all wind project MW in PJM interconnection queue: September 30, 2020

Parent Company	Transmission Owner	Related to Developer	MW by Project Status					Total
			Active	In Service	Under Construction	Suspended	Withdrawn	
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,828.9	3,094.6	450.0	272.0	22,501.8	30,147.2
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	2,128.0	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	2,640.0	0.0	12.0	0.0	134.0	2,786.0
		Unrelated	2,476.9	310.5	0.0	300.3	4,968.4	8,056.1
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	3,441.6	7.5	0.0	0.0	4,648.6	8,097.7
	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	6,749.5	3,661.0	680.4	0.0	25,788.7	36,879.6
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,877.1	0.0	0.0	0.0	2,968.8	4,845.9
	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
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	439.4	1,119.6	200.0	0.0	3,572.2	5,331.2
	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	4,269.2	0.0	0.0	0.0	1,504.0	5,773.2
	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	210.2	1,085.5	0.0	0.0	5,620.3	6,916.1
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	349.6	226.5	0.0	165.3	3,381.1	4,122.5
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	2,640.0	0.0	12.0	0.0	134.0	2,786.0
		Unrelated	24,458.4	9,505.2	1,330.4	737.6	78,547.8	114,579.3

Solar Project Developer and Transmission Owner Relationships

Table 12-43 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 September 30, 2020, by transmission owner and project status. Of the 4,105.0 solar project MW that have achieved in service or under construction status during this time period, 1,183.1 MW (28.8 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building solar projects in their own service territory. Of the 824.6 MW that entered the queue during the time period of January 1, 1997, through September 30, 2020, 180.4 MW (21.9 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-43 Relationship between project developer and transmission owner for all solar project MW in PJM interconnection queue: September 30, 2020

Parent Company	Transmission Owner	Related to Developer	MW by Project Status					Total
			Active	In Service	Under Construction	Suspended	Withdrawn	
AEP	AEP	Related	68.0	14.7	0.0	10.0	50.0	142.7
		Unrelated	16,320.6	0.0	230.0	170.0	7,169.5	23,890.1
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5
		Unrelated	3,184.1	2.5	0.0	0.0	1,072.4	4,259.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	34.2	0.0	0.0	20.0	20.0	74.2
Dominion	Dominion	Related	676.6	646.4	366.1	0.0	251.9	1,941.0
		Unrelated	16,671.4	409.8	1,052.9	466.0	13,063.5	31,663.6
Duke	DEOK	Related	50.0	0.0	0.0	0.0	56.4	106.4
		Unrelated	459.9	0.0	200.0	0.0	373.0	1,032.9
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,973.0	0.0	0.0	0.0	527.9	2,500.9
Exelon	AECO	Related	0.0	0.0	0.0	0.0	8.3	8.3
		Unrelated	423.1	59.7	0.0	0.0	2,163.9	2,646.6
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0
		Unrelated	30.0	1.1	0.0	0.0	92.3	123.4
	ComEd	Related	0.0	9.0	0.0	0.0	0.0	9.0
		Unrelated	6,326.9	0.0	0.0	0.0	2,608.8	8,935.7
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4
		Unrelated	1,797.9	123.0	170.0	0.0	1,935.4	4,026.3
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	29.8	3.3	0.0	0.0	78.4	111.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	148.2	2.5	0.0	0.0	212.3	363.0
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,775.9	97.3	10.0	256.9	1,861.2	5,001.3
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,060.5	0.0	0.0	0.0	1,061.3	4,121.8
	JCPL	Related	0.0	0.0	0.0	0.0	12.0	12.0
		Unrelated	97.6	387.7	20.0	7.6	1,606.6	2,119.4
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	843.3	0.0	0.0	75.0	641.0	1,559.3
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,962.2	13.5	0.0	0.0	1,991.8	4,967.5
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	120.0	0.0	0.0	0.0	78.0	198.0
PPL	PPL	Related	124.8	0.0	0.0	0.0	0.0	124.8
		Unrelated	1,564.9	25.0	0.0	0.0	811.6	2,401.5
PSEG	PSEG	Related	0.0	134.3	5.2	0.0	40.9	180.4
		Unrelated	29.9	97.6	16.1	6.0	494.6	644.2
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	919.4	811.8	371.3	10.0	461.0	2,573.4
		Unrelated	58,853.3	1,223.0	1,699.0	1,001.5	37,863.5	100,640.2

Renewable Hybrid Project Developer and Transmission Owner Relationships

Table 12-44 shows the relationship between the project developer and transmission owner for all renewable hybrid project MW that have entered the PJM generation queue from January 1, 1997, through September 30, 2020, by transmission owner and project status. Of the 3.7 renewable hybrid project MW that have achieved in service or under construction status during this time period, 3.7 MW (100.0 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 hybrid projects in their own service territory. Of the 53.6 MW that entered the queue during the time period of January 1, 1997, through September 30, 2020, 3.7 MW (6.9 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-44 Relationship between project developer and transmission owner for all hybrid project MW in PJM interconnection queue: September 30, 2020

Parent Company	Transmission Owner	Related to Developer	MW by Project Status					Total
			Active	In Service	Under Construction	Suspended	Withdrawn	
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,348.2	0.0	0.0	0.0	3,270.8	8,619.0
AES	DAY	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
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	37.5	0.0	0.0	0.0	0.0	37.5
Dominion	Dominion	Related	17.0	0.0	0.0	0.0	0.0	17.0
		Unrelated	2,426.1	0.0	0.0	0.0	790.0	3,216.1
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	1,766.0	0.0	0.0	0.0	907.0	2,673.0
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	14.5	14.5
	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	1,303.5	0.0	0.0	0.0	610.0	1,913.5
	DPL	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
	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	20.0	0.0	0.0	0.0	0.0	20.0
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	590.2	0.0	0.0	16.3	210.0	816.5
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	280.9	0.0	0.0	0.0	174.9	455.8
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	90.0	0.0	0.0	0.0	0.0	90.0
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	138.9	0.0	0.0	0.0	3.7	142.6
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	743.2	0.0	0.0	0.0	0.0	743.2
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	190.0	0.0	0.0	90.0	0.0	280.0
PSEG	PSEG	Related	0.0	1.1	2.6	0.0	0.0	3.7
		Unrelated	20.0	0.0	0.0	0.0	29.9	49.9
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	17.0	1.1	2.6	0.0	0.0	20.7
		Unrelated	12,954.5	0.0	0.0	106.3	6,010.8	19,071.6

Regional Transmission Expansion Plan (RTEP)³⁶

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.

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

³⁶ 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. 48 (October 1, 2020).

analyses.³⁷ PJM presents the RTEP market efficiency enhancements to the PJM Board, along with stakeholder input, for Board approval.

To be recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or expansion of the proposed project must reduce congestion on one or more constraints by at least one dollar, meet a benefit/cost ratio threshold of at least 1.25:1 and have an independent cost review, performed by PJM, if expected costs are over \$50 million. PJM provides the review of a project with a projected cost of over \$50 million using its own staff or outside consultants that are hired to assist in the review. PJM presents its findings to the TEAC where PJM's findings are reviewed by the stakeholders. While stakeholders can comment on the findings, PJM makes the final decision about what costs will be used for the purpose of calculating the Benefit/Cost ratio for the project. 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 concurrently with the long-term proposal window for reliability projects.³⁸

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. The 2013 window was open from August 12, 2013, through September 26, 2013. This window accepted proposals to address historical congestion on 25 identified flowgates. PJM received 17 proposals from six entities. One project was approved by the PJM Board.

³⁷ See PJM, "PJM Regional Transmission Expansion Plan: 2018," (February 28, 2019) <<https://www.pjm.com/-/media/library/reports-notices/2018-rtep/2018-rtep-book-1.ashx?la=en>>.

³⁸ 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>>.

The first market efficiency cycle conducted under Order 1000 was performed during the 2014/2015 RTEP long term window. The 2014/2015 long term window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. PJM received 93 proposals from 19 entities. Thirteen projects were approved by the PJM Board.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. The 2016/2017 long term window was open from November 1, 2016, through February 28, 2017. This window accepted proposals to address historical congestion on four identified flowgates. PJM received 96 proposals from 20 entities. Four projects were approved by the PJM Board.

PJM also held an addendum 2016/2017 long term window. This 2016/2017 1A long term window was open from September 14, 2017, through September 28, 2017. This window accepted proposals to address historical congestion on one identified flowgate. PJM received three proposals from two entities. One project was approved by the PJM Board.

The fourth market efficiency cycle was performed for the 2018/2019 RTEP long term window. The 2018/2019 long term window was open from November 2, 2018, through March 15, 2019. This window accepted proposals to address historical congestion on one internal and three interregional flowgates. PJM received 33 proposals from 10 entities. One project was approved by the PJM Board to address the historical congestion on the internal flowgate, and one project was approved by the PJM Board to address the historical congestion on one of the interregional flowgates.³⁹

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.

³⁹ No proposals effectively resolved the congestion on two of the three identified interregional market efficiency flowgates. One proposal received provisional approval by the PJM Board, pending approval by the MISO Board.

The total benefit of a project is calculated as the sum of the net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. PJM measures benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments and in system capacity costs in the capacity market, but does not weight increases and decreases in benefits equally. The method for calculating energy market benefits and reliability pricing model benefits depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kv.

The energy market benefit analysis uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution, including total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in energy production costs and load energy payments.

The definition of the energy benefit analysis depends on whether the project is regional or subregional. For a regional project, the energy benefit for each modeled year is equal to 50 percent of the change in system wide total system energy production costs with and without the project plus 50 percent of the change in zonal load payments with and without the project, including only those zones where the project reduced the load payments. For subregional projects, the calculation of benefits for each modeled year ignores any impact on system wide energy production costs and is instead based only the change in zonal load energy payments with and without the project, but including only those zones where the project reduced the load energy payments.

In both the regional and subregional analysis, changes in zonal load energy payments are netted against changes in the estimated value of any Auction Revenue Rights (ARR) that sink in that zone for purposes of determining whether a zone benefits from a proposed RTEP project. Estimated ARR credits are calculated for each simulated year using the most recent planning year's

actual ARR MW combined with FTR prices assumed to be equal to the market simulation's CLMP differences between ARR source and sink points. The value of the ARR rights with and without the RTEP project is evaluated based on changes in modeled CLMPs on the latest allocation of ARR rights. ARR MW allocations are not adjusted to reflect any potential changes in ARR allocations which may be allowed by the RTEP upgrade and the value of the ARRs are assumed to match the forecasted CLMP differences on the ARR paths.

The Reliability Pricing Model (RPM) Benefit analysis is conducted using the RPM solution software, with and without the proposed RTEP project, using a set of estimated capacity offers.

The definition of the benefit in the RPM benefit analysis depends on whether the project is regional or subregional. For a regional project, the RPM benefit for each modeled year is equal to 50 percent of the change in system wide total system capacity payments with and without the project plus 50 percent of the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments. For subregional projects, the reliability pricing model benefits for each modeled year ignores any impact on system wide total capacity payments and is equal to the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments.

The difference in the benefits calculation used in the regional and subregional cost benefit threshold tests is related to how the direct costs of the transmission projects are allocated for approved regional and subregional projects. The costs of an approved regional project are allocated so that 50 percent of the total costs are allocated on a system wide load ratio share basis and the remaining 50 percent of the total costs are allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits. The costs of an approved subregional project are allocated so that the total costs of the project is allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits.

There are significant issues with PJM's benefit/cost analysis. The current rules governing benefit/cost analysis of competing transmission projects do not accurately measure the relative costs and benefits of transmission projects. The current rules do not account for the fact that the benefits of projects are uncertain and highly sensitive to the modeling assumptions used. The current rules explicitly ignore the increased zonal load costs that a project may create. The current rules do not account for the fact that the project costs are nonbinding estimates, are not subject to cost caps and may significantly exceed the estimated costs. These flaws have contributed to PJM approving market efficiency projects with forecasted benefits that do not exceed the forecasted costs.

The recent introduction of storage as transmission assets (SATA) raises a number of additional concerns about PJM's benefit/cost analysis. PJM's benefit/cost analysis uses a 15 year forecast for purposes of evaluating benefits and costs of traditional transmission assets with an expected useful life of 50 years or more. Using the same 15 year horizon does not make sense for SATA resources with an expected useful life of 10 years or less, depending on use. Using a 15 year benefit horizon will exaggerate the forecasted benefit stream relative to the stream of benefits that could be produced over the expected useful life relative to traditional transmission assets. Further, the rules for how to account for the actual, and forecasted, revenues and charges for operating the SATA to provide transmission load relief have not been established. Without clear rules on how to allocated operational revenues and costs it is impossible to develop forecasted benefits and/or costs of a SATA project.

The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. The MMU recommends that the market efficiency process be eliminated.

The Transource Project

The Transource Project (Project 9A) is an example of a PJM approved market efficiency project that passed PJM's 1.25 benefit/cost threshold test despite having benefits, if accurately calculated, that were less than forecasted costs. This project also illustrates the risks of ignoring potential cost increases given that the costs included in the benefit/cost calculation are nonbinding estimates. The Transource Project was proposed in PJM's 2014/2015 RTEP long term window. PJM's 2014/2015 RTEP long term window was the first market efficiency cycle under Order 1000. The 2014/2015 long term window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. The AP South Interface was one of the 12 identified flow gates listed in the 2014/15 RTEP Long Term Proposal Window Problem Statement.

A total of 41 market efficiency projects were proposed to address congestion on the AP South Transmission Interface. Transource Energy LLC, together with Dominion High Voltage, submitted a proposal referenced by PJM as Project 9A (or IEC or the Transource project) to address AP South related congestion.

Project 9A was considered a subregional project based on its voltage level, meaning that changes in forecasted system costs were not considered for purposes of estimating the benefit/cost ratios. Instead, only reductions in zonal load costs were considered as a benefit of the project. Any increases in zonal load costs were ignored in the analysis.

The initial study had a benefit to cost ratio of 2.48, with a capital cost of \$340.6 million. The sum of the positive (energy cost reductions) effects was \$1,188.07 million. The sum of negative effects (energy cost increases) was \$851.67 million. The net actual benefit of the project in the study was therefore \$336.40 million, not the \$1,188.07 used in the study. Using the total benefits (positive and negative) to compare to the net present value of costs, the benefit to cost ratio was 0.70, not 2.48. The project should have been rejected on those grounds.

Subsequent studies of the 9A project have reduced its benefit/cost ratio as a result of increased costs, decreased congestion on the AP South Interface since 2014 and a reduction in peak load forecasts since 2015. The most recent study produced by PJM in 2019 using simulations for years 2017, 2021, 2024 and 2027 had a benefit cost ratio of 2.10 with a capital cost of \$383.63 million. The sum of the positive (energy cost reductions) effects was \$855.19 million, a reduction of \$322 million (28.0 percent) from the initial study. The sum of negative effects (energy cost increases) was \$827.34 million, a reduction of \$27.86 million (3.3 percent) from the results of the initial study. The net actual benefit of the project in the 2019 study was \$27.85 million, not the \$1,188.07 from the initial study. Using the total benefits (positive and negative) to compare to the net present value of costs in the 2019 analysis, the benefit to cost ratio was 0.07, not 2.10. The project should have been rejected on those grounds.

PJM MISO Interregional Market Efficiency Process (IMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion. To qualify as an IMEP project, the project must be evaluated in a joint study process, qualify as an economic transmission enhancement in both PJM and MISO transmission expansion models and meet specific IMEP cost benefit criteria.⁴⁰ The allocation of costs to each RTO for IMEPs will be in proportion to the benefits received.

While the IMEP process is a joint effort, PJM and MISO perform their own analysis of benefits to their own system and each uses a different modeling approach and a different metric for determining the benefits of a proposed project. PJM makes use of the benefit/cost analysis used for its own internal market efficiency projects which will, by definition, overstate project benefits

⁴⁰ See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <<http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>>.

by ignoring areas where energy costs are increased. MISO, on the other hand, measures benefits as changes in projected system wide production cost caused by the project. The use of different approaches to measuring benefits is an issue when studying potential benefits of projects in a joint effort, and when using the defined benefits to allocate the costs of IMEP projects to each RTO. PJM's approach will overallocate the costs of IMEP projects to PJM members.

PJM and MISO conducted a two year interregional market efficiency project study in 2018/2019 and included the investigation of forward looking congestion on three market to market flowgates. Proposals were received during the 2018/2019 long term window, which was open from November 2, 2018, through March 15, 2019. PJM and MISO received 10 proposals from seven entities. As a result of this analysis, the RTOs recommended one IMEP project.⁴¹ The approved project has an in service cost of \$24.7 million and a PJM benefit/cost ratio of 2.63. The PJM board approved the recommended project in December 2019. The MISO board approved the recommended project in September 2020.

PJM and MISO are currently in the first year of the two year 2020/2021 IMEP cycle. The RTOs are currently coordinating the development of their regional models. Final constraint identification is currently targeted for the fourth quarter of 2020.

PJM MISO Targeted Market Efficiency Process (TMEP)

PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects. The TMEP process operates on a 12 month study schedule. To qualify as a TMEP project, the project must have an estimated in service date by the third summer peak season from the year the project was approved, have an estimated cost of less than \$20 million and meet specific TMEP cost benefit criteria.⁴² The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.⁴³

⁴¹ Analysis showed that no projects met the B/C criteria on two of the identified flowgates.

⁴² See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, LLC," (December 11, 2008) <<http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>>.

⁴³ See *PJM Interconnection, LLC*, Docket No. ER17-729-000 (December 30, 2016).

On November 2, 2017, PJM submitted a compliance filing including additional revisions to the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process.⁴⁴

The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and included the investigation of historical congestion on an initial set of 50 market to market flowgates. The causes of congestion on these flowgates were analyzed. If the historical congestion was a result of outages, or if the congestion was expected to be mitigated by planned upgrades already included in the PJM RTEP or MISO MTEP, then the flowgate was eliminated from consideration in the TMEP process. As a result of this analysis, potential short term upgrades were identified for 13 of the initial 50 flowgates. PJM and MISO conducted a market efficiency and power flow analysis to determine the potential to eliminate the identified congestion on the 13 flowgates. As a result of this analysis, the RTOs recommended five TMEP projects. The five projects address \$59.0 million in historical congestion, with a TMEP benefit of \$99.6 million. The projects have a total cost of \$20.0 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.⁴⁵

The second Targeted Market Efficiency Process analysis occurred in 2018 and included the investigation of historical congestion on an initial set of 61 market to market flowgates. The causes of congestion on these flowgates were analyzed. If the historical congestion was a result of outages, or if the congestion was expected to be mitigated by planned upgrades already included in the PJM RTEP or MISO MTEP, then the flowgate was eliminated from consideration in the TMEP process. As a result of this analysis, potential short term upgrades were identified for 20 of the initial 61 flowgates. PJM and MISO conducted a market efficiency and power flow analysis to determine the potential to eliminate the identified congestion on the 20 flowgates. As a result of this analysis, the RTOs recommended two TMEP projects. The two projects address \$25.0 million in historical congestion, with a TMEP benefit of

⁴⁴ See *PJM Interconnection, LLC*, Docket No. ER17-718-000, et al. (November 2, 2017).

⁴⁵ See PJM, "MISO PJM IPSAC," (January 12, 2018) <<http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>>.

\$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.⁴⁶

With only one additional year of historical information, and the fact that many of the same constraints were evaluated in the 2018 TMEP process, PJM and MISO did not conduct a TMEP study in 2019.

As a result of decreases in M2M congestion and the addition of transmission upgrades already in process that affect the top congested historical M2M flowgates, PJM and MISO did not conduct a TMEP study in 2020.

Supplemental Transmission Projects

Supplemental projects are asserted to be “transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM.”⁴⁷ Attachment M-3 of the PJM OATT defines the process that Transmission Owners (TO) must follow in adding Supplemental Projects in their local plan. The M-3 Process requires proposed Supplemental Projects to be presented in a manner that is transparent and allows the opportunity for PJM Stakeholders to provide input and comments.

The M-3 Process requires TOs to present the criteria, assumptions and models that they will use to plan and identify Supplemental Projects on a yearly basis. These planning assumptions, while presented by each TO individually, generally identify the same criteria for Supplemental Projects. Specifically the criteria identified for Supplemental Projects are very broad and include: equipment material condition, performance and risk, operational flexibility and efficiency, infrastructure resilience, customer service or other, as well as asset management.

While the identification of the criteria violations and solutions are reviewed, and stakeholders have the opportunity to comment, the solution that is submitted in the Local Plan is the Transmission Owner’s decision. PJM conducts a do no harm analysis to ensure the Supplemental Projects do not negatively affect the reliability of the system. Supplemental Projects are ultimately included in PJM’s Regional Transmission Expansion Plan and are allocated 100 percent to the zone in which the transmission facilities are located. Supplemental Projects may displace projects that would have otherwise been implemented through the RTEP process.

Supplemental projects are currently exempt from the Order No. 1000 competitive process. 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 baseline and supplemental projects by expected in service year. FERC Order No. 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order No. 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order No. 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 12-45 and Table 12-46 because PJM did not track or report such projects. There has been a significant increase in supplemental projects coincident with the implementation of Order No. 890 starting in 2008 and the competitive planning process introduced by FERC Order No. 1000 starting in 2011.

⁴⁶ See PJM, “MISO PJM IPSAC,” (January 18, 2019) <<https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>>.

⁴⁷ See PJM, Planning, “Transmission Construction Status,” (Accessed on September 30, 2020) <<http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>>.

Figure 12-3 Cost estimate of baseline and supplemental projects by expected in service year: 1998 through 2020

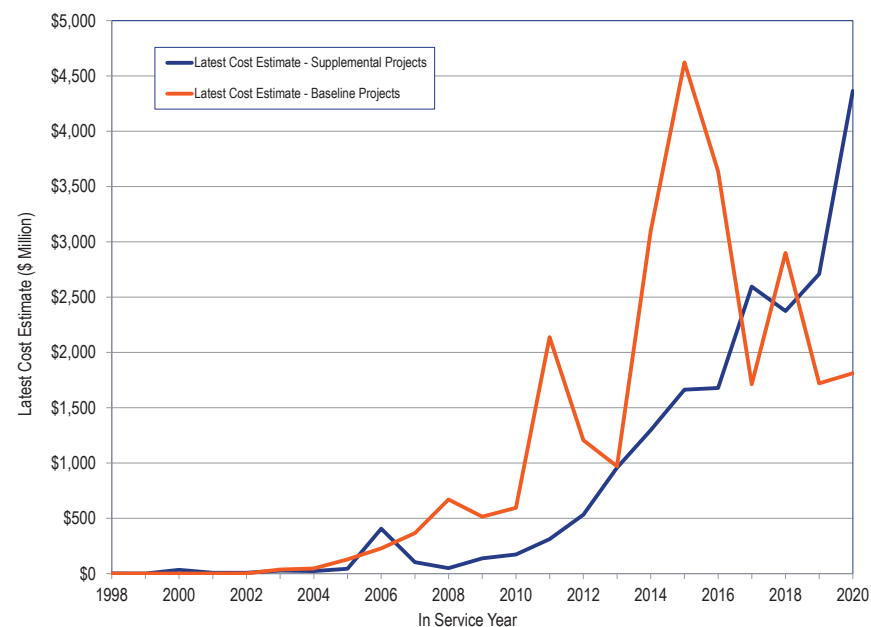


Table 12-45 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 735.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 167 for years 2008 through 2020 (post Order 890).

Table 12-45 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	4	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	2	0	0	0	0	16
2004	5	0	10	0	0	10	0	0	0	0	12	0	2	0	0	0	0	0	0	2	0	41
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	2	1	5	0	4	5	0	0	4	0	7	0	0	0	0	0	2	0	1	6	0	37
2008	4	0	15	0	1	6	0	0	1	7	4	0	0	1	0	0	0	0	3	1	0	43
2009	3	1	6	0	1	8	0	0	3	3	5	0	0	0	0	5	1	0	1	2	0	39
2010	0	6	7	0	3	4	0	0	6	3	0	0	1	2	0	2	0	0	3	5	0	42
2011	0	8	8	0	0	2	0	0	5	2	0	0	1	0	0	4	0	0	6	4	0	40
2012	0	5	6	4	1	2	0	7	3	16	1	0	2	0	0	1	0	0	5	11	0	64
2013	5	21	4	5	0	11	0	6	4	13	1	0	1	1	0	1	0	1	14	19	0	107
2014	3	32	2	8	2	14	0	5	6	18	3	2	2	0	0	1	2	0	9	18	0	127
2015	4	16	2	9	1	37	0	8	4	17	5	4	2	0	0	1	0	4	7	24	0	145
2016	6	17	4	17	0	26	0	6	2	13	4	2	0	1	0	3	2	3	12	30	0	148
2017	8	107	3	26	1	23	0	3	8	31	11	5	0	3	0	0	3	1	23	44	0	300
2018	10	143	3	13	1	20	0	14	3	22	6	4	0	0	0	2	0	1	20	26	0	288
2019	3	160	4	30	7	14	3	16	1	32	8	5	7	22	0	1	15	1	13	26	0	368
2020	5	156	7	55	8	12	7	17	2	23	3	5	21	30	0	0	69	0	16	26	0	462
2021	2	222	1	36	2	4	4	13	0	23	3	6	9	72	5	5	61	0	34	23	0	525
2022	5	189	3	16	2	4	2	2	1	12	7	0	0	17	0	4	27	3	25	22	0	341
2023	6	91	0	11	2	1	14	9	0	6	1	2	0	21	0	3	14	0	18	24	0	223
2024	4	52	0	4	2	3	0	1	0	0	2	1	2	1	0	0	3	1	7	2	0	85
2025	3	37	0	3	3	0	0	0	0	2	1	0	0	3	0	0	3	0	5	0	0	60
2026	4	19	0	1	8	1	0	0	1	0	0	0	0	0	0	0	0	0	17	0	0	51
2027	0	9	0	0	0	0	0	0	1	2	0	1	0	0	0	0	0	0	12	0	0	25
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	0	0	0	0
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	1	0	0	0	0	1
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	0	0	0	0
Total	94	1,296	103	238	49	217	30	108	56	244	158	36	52	174	5	34	208	15	253	318	0	3,688

Table 12-46 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average cost of supplemental projects in each expected in service year increased by 2,129.4 percent, from \$65.0 million for years 1998 through 2007 (pre Order No. 890) to \$1,449.1 million for years 2008 through 2020 (post Order No. 890).

Table 12-46 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	\$0.77	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.77
2000	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$32.94	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$32.94
2001	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$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	\$8.32	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$8.77	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$9.60	\$0.00	\$0.00	\$0.00	\$0.00	\$26.69
2004	\$4.45	\$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	\$14.66	\$10.11	\$0.00	\$0.00	\$2.57	\$0.00	\$0.00	\$0.00	\$0.02	\$10.98	\$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	\$0.93	\$0.00	\$0.00	\$48.92	\$0.00	\$0.00	\$0.00	\$0.00	\$11.62	\$0.00	\$6.00	\$0.00	\$0.00	\$0.00	\$1.50	\$0.00	\$4.63	\$18.80	\$0.00	\$406.13
2007	\$1.12	\$2.06	\$9.85	\$0.00	\$37.61	\$4.65	\$0.00	\$0.00	\$31.75	\$0.00	\$12.93	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.34	\$2.28	\$0.00	\$102.59
2008	\$2.84	\$0.00	\$12.03	\$0.00	\$0.45	\$7.61	\$0.00	\$0.00	\$7.00	\$14.01	\$2.77	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1.59	\$0.00	\$0.00	\$48.30
2009	\$0.77	\$0.90	\$12.22	\$0.00	\$5.00	\$21.11	\$0.00	\$0.00	\$19.60	\$2.12	\$7.35	\$0.00	\$0.00	\$0.00	\$0.00	\$48.10	\$2.73	\$0.00	\$0.16	\$17.60	\$0.00	\$137.66
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	\$1.86	\$17.72	\$0.00	\$172.19
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	\$11.87	\$34.60	\$0.00	\$311.22
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	\$19.66	\$223.01	\$0.00	\$532.54
2013	\$3.15	\$134.93	\$1.10	\$33.68	\$0.00	\$59.25	\$0.00	\$9.93	\$79.10	\$25.03	\$0.99	\$0.00	\$0.05	\$4.10	\$0.00	\$22.50	\$0.00	\$2.40	\$76.70	\$503.72	\$0.00	\$956.63
2014	\$15.53	\$568.00	\$5.97	\$58.70	\$21.20	\$60.37	\$0.00	\$2.43	\$14.90	\$88.61	\$5.95	\$0.38	\$5.60	\$0.00	\$0.00	\$13.30	\$1.30	\$0.00	\$33.47	\$401.11	\$0.00	\$1,296.82
2015	\$3.73	\$237.67	\$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	\$1,662.58
2016	\$74.54	\$84.13	\$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	\$59.20	\$744.18	\$0.00	\$1,677.88
2017	\$66.28	\$648.74	\$8.60	\$164.45	\$0.09	\$145.97	\$0.00	\$64.31	\$3.62	\$104.25	\$92.29	\$2.21	\$0.00	\$14.70	\$0.00	\$0.00	\$8.30	\$12.00	\$264.88	\$994.43	\$0.00	\$2,595.12
2018	\$66.55	\$817.94	\$14.60	\$42.12	\$4.08	\$80.94	\$0.00	\$69.80	\$3.13	\$162.94	\$68.94	\$10.87	\$0.00	\$0.00	\$0.00	\$47.60	\$0.00	\$156.00	\$197.34	\$631.25	\$0.00	\$2,374.10
2019	\$64.30	\$1,115.55	\$11.97	\$186.20	\$149.36	\$90.19	\$0.68	\$97.60	\$0.30	\$76.04	\$33.55	\$23.67	\$2.30	\$80.18	\$0.00	\$2.00	\$75.80	\$70.00	\$272.50	\$356.41	\$0.00	\$2,708.60
2020	\$59.58	\$1,090.63	\$1.48	\$246.41	\$64.86	\$78.09	\$20.28	\$153.76	\$24.50	\$74.70	\$46.00	\$23.72	\$65.80	\$57.90	\$0.00	\$0.00	\$209.06	\$0.00	\$221.85	\$1,926.08	\$0.00	\$4,364.70
2021	\$28.00	\$1,814.59	\$0.50	\$356.25	\$23.34	\$73.50	\$24.40	\$100.43	\$0.00	\$107.96	\$18.61	\$29.70	\$41.00	\$257.10	\$4.40	\$35.30	\$86.80	\$0.00	\$335.65	\$585.42	\$0.00	\$3,922.95
2022	\$180.56	\$1,614.11	\$5.50	\$147.80	\$249.30	\$32.80	\$10.00	\$7.15	\$45.00	\$373.90	\$107.60	\$0.00	\$0.00	\$40.16	\$0.00	\$0.00	\$35.60	\$527.50	\$340.00	\$1,342.87	\$0.00	\$5,059.85
2023	\$80.60	\$928.20	\$0.00	\$214.16	\$82.60	\$1.00	\$54.15	\$70.01	\$0.00	\$21.05	\$6.10	\$20.40	\$0.00	\$184.00	\$0.00	\$160.00	\$156.60	\$0.00	\$297.81	\$491.60	\$0.00	\$2,768.28
2024	\$38.74	\$668.81	\$0.00	\$41.30	\$0.00	\$184.00	\$0.00	\$15.38	\$0.00	\$0.00	\$29.72	\$15.20	\$30.50	\$6.00	\$0.00	\$0.00	\$12.80	\$0.50	\$132.50	\$78.00	\$0.00	\$1,253.45
2025	\$30.39	\$373.30	\$0.00	\$200.10	\$148.22	\$0.00	\$0.00	\$0.00	\$0.00	\$36.40	\$11.20	\$0.00	\$0.00	\$16.30	\$0.00	\$0.00	\$29.30	\$0.00	\$136.70	\$0.00	\$0.00	\$981.91
2026	\$64.00	\$201.10	\$0.00	\$80.00	\$339.11	\$67.00	\$0.00	\$0.00	\$30.40	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$398.58	\$0.00	\$0.00	\$1,180.19
2027	\$0.00	\$134.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$23.97	\$105.00	\$0.00	\$4.70	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$247.28	\$0.00	\$0.00	\$514.95
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	\$0.00	\$0.00	\$0.00	\$0.00
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	\$200.00	\$0.00	\$0.00	\$0.00	\$0.00	\$200.00
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	\$0.00	\$0.00	\$0.00	\$0.00
Total	\$801.54	\$10,876.98	\$153.60	\$1,976.12	\$1,148.32	\$1,657.92	\$109.51	\$670.08	\$458.55	\$1,507.63	\$577.21	\$127.96	\$159.35	\$667.39	\$4.40	\$607.20	\$829.79	\$818.70	\$3,104.74	\$9,112.99	\$0.00	\$35,369.98

The MMU recommends, to increase the role of competition, that the exemption of supplemental from the Order No. 1000 competitive process be terminated.

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that has, or is approaching, the end of its useful life.⁴⁸ Some Transmission Owners include end of life transmission projects in their Transmission Owner Form 715 Planning Criteria. Form 715 is the annual transmission planning and evaluation report that all utilities that operate a transmission facility rated at or above 100 kV are required to file with the Commission. The purpose of Form 715 is “to provide information adequate to inform potential transmission customers, State regulatory authorities and the public of potential transmission capacity and known constraints, to support the Commission’s expanded responsibilities under §§ 211, 212 and 213(a) of the Federal Power Act (as amended by the Energy Policy Act), and to assist in rate or other regulatory proceedings.”⁴⁹ Form 715 requires utilities to “provide a narrative evaluation or assessment of the performance of its transmission system in future time periods based on the application of its reliability criteria. It must provide a clear understanding of existing and likely future transmission constraints, their sources, how it identified these constraints, and a description of any plans to mitigate the constraints.”⁵⁰

Projects submitted through the Form 715 planning criteria were exempt from the competitive planning process.⁵¹ On August 30, 2019, the Commission issued an Order on Remand, which rejected the 2015 PJM Transmission Owner Tariff Revisions that “allocate 100 percent of costs for projects that are included in the PJM Regional Transmission Expansion Plan (RTEP) solely to address individual transmission owner Form No. 715 local planning criteria to the transmission zone of the transmission owner whose Form No. 715 local planning criteria underlie each project.”⁵² The Order directed PJM to regionally allocate cost responsibility to Transmission Owner Form 715 Planning Criteria projects.⁵³ Additionally, On August 30, 2019, the Commission issued an

Order Instituting Section 206 Proceeding that removed the proposal window exemption for Form No. 715 Planning Criteria.⁵⁴

Not all end of life transmission projects are included in Form No. 715 filings. There is currently an issue about whether end of life transmission projects are subject to the PJM RTEP open window process.⁵⁵ If end of life transmission projects are not subject to the RTEP open window process, end of life transmission projects would be a form of supplemental project and exempt from competition under the existing rules.

The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects.

Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These project types include:

- **Immediate Need Exclusion.** Due to the immediate need of the violation (3 years or less), the timing required for an RTEP proposal window is defined to be infeasible and such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.⁵⁶ On October 17, 2019, the Commission issued an Order Instituting Section 206 Proceedings to determine if RTOs have implemented the exemption in a manner consistent with the Commission’s directives under Order 1000.⁵⁷ Some supplemental projects are in this category.
- **Below 200kV.** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.⁵⁸ Some supplemental projects are in this category.

48 The useful life of a transmission investment typically exceeds its depreciable life.

49 See FERC, “Form No. 715 – Annual Transmission Planning and Evaluation Report,” at <https://www.ferc.gov/docs-filing/forms/form-715/instructions.asp#general_information>.

50 See FERC, “Form No. 715 – Annual Transmission Planning and Evaluation Report,” at <https://www.ferc.gov/docs-filing/forms/form-715/instructions.asp#general_information>.

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

52 168 FERC ¶ 61,133 at P 1 (2019).

53 *Id.* at PP 29–31.

54 168 FERC ¶ 61,132 at P 13 (2019).

55 164 FERC ¶ 61,160 at P 31 (2018), *Id.* at P 33. See PJM Interconnection, LLC. (October 7, 2019) (Docket Nos. EL19-61 and ER20-45).

56 See OA Schedule 6 § 1.5.8(m).

57 169 FERC ¶ 61,054 (2019).

58 See OA Schedule 6 § 1.5.8(n).

- **Substation Equipment.** Due to identification of the limiting element(s) as substation equipment, such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.⁵⁹ Some supplemental projects are in this category.

While the PJM Operating Agreement defines who will be the Designated Entity for projects that are excluded from the competitive planning process, neither the PJM Operating Agreement nor the various commission orders on transmission competition prohibit PJM from permitting competition to provide financing for such projects. The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. In addition, the criteria for and need for all exclusions from the competitive process should be reviewed. There does not appear to be any market reason to exclude transmission projects from competition for any of these exclusion categories.

Cost Capping

The MMU recommended that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. On March 20, 2020, the Commission approved PJM's filing to amend the PJM Operating Agreement to incorporate this requirement.⁶⁰

Storage As A Transmission Asset (SATA)

The PJM Planning Committee is currently considering whether storage devices should be included in the RTEP process as transmission assets.⁶¹

Transmission and generation have, and have always had, a symbiotic relationship in the provision of wholesale power. Transmission needs generation to function and generation needs transmission to function. Transmission can substitute for generation at the margin and generation can substitute for transmission at the margin. This relationship has always been a relatively unexamined area in the design of competitive wholesale power markets. For example, there is little if any explicit consideration of the impact of transmission planning on competitive generation investment in RTO/ISO market rules. Improvement is needed in these areas. Introducing confusion about what assets are classified as generation and what assets are classified as transmission frustrates potential reform and undermines the competitive markets.

Storage devices like batteries that are defined to be part of PJM markets should not be treated as transmission assets. The MMU recommends that storage resources not be includable as transmission assets for any reason.

Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.⁶²

An RTEP project can be approved by the PJM Board if the project ensures compliance with NERC, regional and local transmission owner planning criteria or to address market efficiency congestion relief. These projects are considered Baseline Projects. PJM Board approved RTEP projects that are necessary to allow new generation to interconnect reliably are considered Network Projects.

In the first nine months of 2020, the PJM Board approved a net change of \$770.4 million in transmission upgrades. As of September 30, 2020, the PJM

⁵⁹ See OA Schedule 6 § 1.5.8(p).

⁶⁰ 170 FERC ¶ 61,243 (2020).

⁶¹ See PJM, "Storage As A Transmission Asset: Problem / Opportunity Statement". <<https://pjm.com/-/media/committees-groups/committees/pc/2020/20200605-special/20200605-item-02a-storage-as-a-transmission-asset-problem-statement-clean.ashx>>.

⁶² Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

Board had approved \$38.3 billion in transmission system enhancements since 1999. On February 10, 2020, the PJM Board of Managers authorized an additional \$233.9 million in transmission upgrades and additions. On April 20, 2020, the PJM Board of Managers authorized an additional \$417.6 million in transmission upgrades and additions. On July 28, 2020, the PJM Board of Managers authorized an additional \$113.1 million in transmission upgrades and additions. On September 23, 2020, the PJM Board of Managers authorized an additional \$5.8 million in transmission upgrades and additions.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions.

If a QTU that was cleared in a 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 September 30, 2020, no QTUs have cleared a BRA.

Cost Allocation

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for \$1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of “whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects.”⁶³ FERC convened

a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.⁶⁴

The issues identified in the complaints and at the technical conference included: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the 0.01 distribution factor cutoff are appropriate.

On February 20, 2020, the Commission issued an Order denying rehearing requests.⁶⁵ The Commission found that PJM’s solution-based dfax method for regional cost allocation, including the 0.01 distribution cutoff factor, is just and reasonable.

It is clear that the allocation issues are difficult. Nonetheless, the allocation methods affect the efficiency of the markets and the incentives for merchant transmission owners to compete to build new transmission. The use of the arbitrary 0.01 distribution factor cutoff can result in large and inappropriate shifts in cost allocation. If the intent of the use of the 0.01 cutoff is to help eliminate small, arbitrary cost allocations to geographically distant areas, this could be achieved by adding a threshold for a minimum usage impact on the line. The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum impact on the load on the line based on a complete analysis of the intent of the allocation and the impacts of the allocation.

Transmission Line Ratings

Transmission line ratings, and more broadly transmission facility ratings, are the metric for the ability of transmission lines to transmit power from one point to another. Transmission line ratings have significant and frequently underappreciated impacts on competitive wholesale power markets like PJM.

⁶³ 153 FERC ¶ 61,245 at P 35 (2015).

⁶⁴ See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).

⁶⁵ 170 FERC ¶ 61,122 (2020).

These include direct impacts on energy and capacity prices, the frequency and level of congestion in the day-ahead and real-time energy market, day-ahead nodal price differences and the associated value of FTRs, locational price differences in the capacity market, the need to invest in additional transmission capacity, the need to invest in additional generation capacity, the location of new power plants, and the interconnection costs for new power plants. The impact of transmission facility ratings on markets is a function both of the line ratings directly and the use of those ratings by the RTO/ISO.

Congestion payments by load result when lower cost generation is not available to meet all the load in an area as a result of limits on the transmission system. When higher cost local generation is needed to meet part of the local load because of transmission limits, 100 percent of the local load pays the higher price while only the local generation receives the higher price. The difference between what the load pays and generators receive is congestion. Since 2008, congestion costs in PJM have ranged from \$0.5 billion to \$2.05 billion per year. Congestion costs were significantly higher during extreme winter weather conditions such as January 2014, when the congestion costs in PJM were \$825.1 million for one month.⁶⁶

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing. Transmission penalty factors were fully implemented in PJM pricing effective February 1, 2019.

Transmission line ratings can result in short term, significant increases in prices as a result of the application of transmission penalty factors. For example, violation of a transmission constraint, meaning that the flow exceeds the line limit, could result in a \$2,000 per MWh price. As the power flows

approach their rated limits, PJM dispatchers may reduce the limits.⁶⁷ Violation of these reduced line ratings results in penalty factors setting prices. In 2019, there were 152,675 transmission constraint intervals in the real-time market with a non-zero shadow price. For nearly five percent of these transmission constraints, the line limit was violated, meaning the flow exceeded the facility limit and prices were set by transmission penalty factors. In 2019, the average shadow price of transmission constraints when the line limit was violated was nearly 15 times higher than when transmission constraint was binding at its limit.⁶⁸

Capacity market prices separate locally when transmission capability into Locational Deliverable Areas (LDA) is not adequate to meet the LDA capacity requirement with the lowest cost capacity. The available transmission capability into LDAs is defined as the Capacity Emergency Transfer Limit (CETL). Higher cost LDAs are the equivalent in the capacity market of congestion in the energy market. Load in the higher cost LDAs pay more for capacity than those in lower cost LDAs. For example, the clearing price for the BGE LDA in the 2021/2022 Base Residual Auction was \$200.30 per MW-day. The clearing price for the EMAAC LDA was \$165.73 per MW-day.⁶⁹

Transmission line ratings for a given transmission facility vary by the duration of the power flow, by ambient temperatures, by wind speed and by other conditions. Transmission lines can operate with higher loads for shorter periods of time. This is significant when a contingency is expected to last for only a short period. The transmission line rating can mean the difference between substantial congestion costs and no congestion costs. The transmission line rating can mean the difference between a transmission penalty factor and no penalty factor.

In PJM, transmission owners use a range of ratings by duration.⁷⁰ PJM requires transmission owners to provide thermal ratings under normal

⁶⁶ See the 2018 State of the Market Report for PJM, Volume 2, Section 11: Congestion and Marginal Losses.

⁶⁷ See "Transmission Constraint Control Logic and Penalty Factors," presented at May 10, 2018 meeting of the Markets Implementation Committee Special Session Transmission Constraint Penalty Factors at p14. <<https://www.pjm.com/-/media/committees-groups/committees/mic/20180510-special/20180510-item-03-transmission-constraint-penalty-factor-education.ashx>>.

⁶⁸ See the 2019 State of the Market Report for PJM, Volume 2, Section 3: Energy Market.

⁶⁹ See the "Analysis of the 2021/2022 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24 2018).

⁷⁰ See "PJM Manual 3: Transmission Operations," Rev. 57 (May 29, 2020) § 2.1.1, at p 28.

operating conditions, long term emergency operating conditions, short term emergency operating conditions and the extreme load dump conditions. But there is no requirement that the ratings differ for these operating conditions. PJM typically uses normal line ratings for precontingency (base case) constraints and long term emergency line ratings (four hours) for contingency constraints. PJM requires transmission owners to provide temperature based line ratings separately for night and day times. The temperature ranges from 32 degree Fahrenheit or below to 95 degree Fahrenheit or above in nine degree increments. But there is no requirement that the ratings differ for these operating condition temperatures. In PJM, transmission owners are responsible for developing their own methods to compute line ratings subject to a range of NERC guidelines and requirements. PJM does not review or verify the accuracy of transmission owners' methods to compute line ratings. In PJM, transmission owners have substantial discretion in the approach to line ratings.⁷¹

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current line ratings. The ongoing analysis of dynamic line ratings is a promising area that should be pursued.

The MMU recommends that all PJM transmission owners use the same methods to define line ratings, subject to NERC standards and guidelines, subject to review by NERC and approval by FERC. The same facilities should have the same basic ratings under the same operating conditions regardless of the transmission owner. Transmission owner discretion should be minimized or eliminated. The line rating methods should be based on the

⁷¹ PJM presentation to the Planning Committee (PC) (May 3, 2018) "Transmission Owner Ratings Development and Reporting in PJM" ("There are no requirements for PJM to approve or verify a TO's ratings or do any kind of consistency check.") at 24.

basic engineering facts of the transmission system components and reflect the impact of actual operating conditions on the ratings of transmission facilities, including ambient temperatures and wind speed when relevant.⁷² The line rating methods should be public and fully transparent.

The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.⁷³ All line rating changes and the detailed reasons for those changes should be public and fully transparent.

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.⁷⁴ 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.⁷⁵ The specific timeline is shown in Table 12-48.⁷⁶

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 2019/2020 planning period and the first four months of the 2020/2021 planning period, regardless of when they were initially submitted.⁷⁷ The

⁷² See "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee. <<https://www.pjm.com/-/media/committees-groups/committees/pc/20180503/20180503-item-13-to-ratings-process-and-reporting.ashx>>.

⁷³ See the 2018 State of the Market Report for PJM, Volume 2, Section 2: Recommendations.

⁷⁴ 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. 57 (May 29, 2020).

⁷⁵ See PJM, "Manual 3: Transmission Operations," Rev. 57 (May 29, 2020).

⁷⁶ See PJM, "Manual 3: Transmission Operations," Rev. 57 (May 29, 2020).

⁷⁷ 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.

outage data for the day-ahead market are for outages scheduled to occur from January 2015 through September 2020.

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.⁷⁸ Table 12-47 shows that 75.2 percent of requested outages were planned for less than or equal to five days and 11.4 percent of requested outages were planned for greater than 30 days in the first four months of the 2020/2021 planning period. Table 12-47 also shows that 77.8 percent of the requested outages were planned for less than or equal to five days and 7.8 percent of requested outages were planned for greater than 30 days in the 2019/2020 planning period.

Table 12-47 Transmission facility outage request summary by planned duration: June 2019 through September 2020

Planned Duration (Days)	2019/2020 (12 months)		2020/2021 (4 months)	
	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	16,809	77.8%	5,159	75.2%
>5 <=30	3,116	14.4%	913	13.3%
>30	1,691	7.8%	784	11.4%
Total	21,616	100.0%	6,856	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 12-48.⁷⁹

The purpose of the rules defined in Table 12-48 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.⁸⁰

⁷⁸ *Id.* at 70.

⁷⁹ See PJM, "Manual 3: Transmission Operations," Rev. 57 (May 29, 2020).

⁸⁰ See "Report of PJM Interconnection, LLC on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).

Table 12-48 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 12-49 shows a summary of requests by received status. In the first four months of the 2020/2021 planning period, 46.8 percent of outage requests received were late. In the 2019/2020 planning period, 44.6 percent of outage requests received were late.

Table 12-49 Transmission facility outage request summary by received status: June 2019 through September 2020

Planned Duration (Days)	2019/2020 (12 months)				2020/2021 (4 months)			
	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,660	7,149	16,809	42.5%	2,848	2,311	5,159	44.8%
>5 <=30	1,648	1,468	3,116	47.1%	457	456	913	49.9%
>30	664	1,027	1,691	60.7%	341	443	784	56.5%
Total	11,972	9,644	21,616	44.6%	3,646	3,210	6,856	46.8%

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.⁸¹

⁸¹ See PJM, "Manual 3: Transmission Operations," Rev. 57 (May 29, 2020). The following language was removed from Manual 3 Rev. 50: PJM retains the right to deny all jobs submitted after 8 a.m. three days prior to the requested start date unless the request is an emergency job or an exception request (i.e. a generator tripped and the Transmission Owner is taking advantage of a situation that was not available before the unit trip).

Outages with emergency status will be approved even if submitted late after PJM determines that the outage does not result in Emergency Procedures. PJM cancels or withholds approval of any outage that results in Emergency Procedures.⁸² Table 12-50 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first four months of the 2020/2021 planning period, 15.2 percent were for emergency outages. Of all outage requests scheduled to occur in the 2019/2020 planning period, 12.5 percent were for emergency outages.

Table 12-50 Transmission facility outage request summary by emergency: June 2019 through September 2020

Planned Duration (Days)	2019/2020 (12 months)				2020/2021 (4 months)			
	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	2,011	14,798	16,809	12.0%	733	4,426	5,159	14.2%
>5 <=30	421	2,695	3,116	13.5%	183	730	913	20.0%
>30	269	1,422	1,691	15.9%	123	661	784	15.7%
Total	2,701	18,915	21,616	12.5%	1,039	5,817	6,856	15.2%

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.”⁸³

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 12-51 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first four months of the 2020/2021 planning period, 7.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 2.5 percent (13 out of 516) were denied by PJM in the first four months of the 2020/2021 planning period and 18.4 percent (95 out of 516) were cancelled (Table 12-53). Of all outage requests submitted to occur in the 2019/2020 planning period, 6.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 2.0 percent (29 out of 1,415) were denied by PJM in the 2019/2020 planning period and 21.7 percent (307 out of 1,415) were cancelled (Table 12-53).

Table 12-51 Transmission facility outage request summary by congestion: June 2019 through September 2020

Planned Duration (Days)	2019/2020 (12 months)				2020/2021 (4 months)			
	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	991	15,818	16,809	5.9%	377	4,782	5,159	7.3%
>5 <=30	268	2,848	3,116	8.6%	90	823	913	9.9%
>30	156	1,535	1,691	9.2%	49	735	784	6.3%
Total	1,415	20,201	21,616	6.5%	516	6,340	6,856	7.5%

Table 12-52 shows the outage requests summary by received status, congestion status and emergency status. In the first four months of the 2020/2021 planning period, 31.9 percent of requests were submitted late and were nonemergency while 1.2 percent of requests (84 out of 6,856) were late, nonemergency, and expected to cause congestion. In the 2019/2020 planning period, 32.3 percent of request were submitted late and were nonemergency while 1.1 percent of requests (239 out of 21,616) were late, nonemergency, and expected to cause congestion.

⁸² PJM, “Manual 3: Transmission Operations,” Rev. 57 (May 29, 2020).

⁸³ PJM added this definition to Manual 38 in February 2017. PJM, “Manual 38: Operations Planning,” Rev. 13 (Jan. 23, 2020).

Table 12-52 Transmission facility outage request summary by received status, emergency and congestion: June 2019 through September 2020

		2019/2020 (12 months)				2020/2021 (4 months)			
Received Status		Congestion Expected		Total	Percent of Total	Congestion Expected		Total	Percent of Total
		No	No			No	No		
Late	Emergency	69	2,600	2,669	12.3%	39	984	1,023	14.9%
	Non Emergency	239	6,736	6,975	32.3%	84	2,103	2,187	31.9%
On Time	Emergency	5	27	32	0.1%	0	16	16	0.2%
	Non Emergency	1,102	10,838	11,940	55.2%	393	3,237	3,630	52.9%
Total		1,415	20,201	21,616	100.0%	516	6,340	6,856	100.0%

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.⁸⁴ Table 12-53 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 12-53. Table 12-53 shows that of all the outage requests that were expected to cause congestion, 2.5 percent (13 out of 516) were denied by PJM in the first four months of the 2020/2021 planning period, 58.5 percent were complete and 18.4 percent (95 out of 516) were cancelled. Of all the outage requests that were expected to cause congestion, 2.0 percent (29 out of 1,415) were denied by PJM in the 2019/2020 planning period, 70.1 percent were complete and 21.7 percent (307 out of 1,415) were cancelled.

Table 12-53 Transmission facility outage requests that might cause congestion status summary: June 2019 through September 2020

		2019/2020 (12 months)						2020/2021 (4 months)					
Received Status		Cancelled		In Process	Denied	Congestion Expected	Percent Complete	Cancelled		In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	7	61	0	1	69	88.4%	3	35	0	1	39	89.7%
	Non Emergency	37	186	7	8	239	77.8%	13	58	8	4	84	69.0%
On Time	Emergency	1	4	0	0	5	80.0%	0	0	0	0	0	0.0%
	Non Emergency	262	741	77	20	1,102	67.2%	79	209	89	8	393	53.2%
Total		307	992	84	29	1,415	70.1%	95	302	97	13	516	58.5%

⁸⁴ See PJM Markets & Operations, PJM Tools "Outage Information," <<http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx>> (2019).

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.⁸⁵ However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-53 shows that in the 2019/2020 planning period, 239 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 12-54 is a summary of all the outage requests planned for the 2019/2020 planning period and the first four months of the 2020/2021 planning period which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In the first four months of the 2020/2021 planning period, 28.6 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 11.3 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2019/2020 planning period, 30.7 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 11.1 percent of

⁸⁵ PJM Operating Agreement Schedule 1 § 1.9.2.

the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-54 Rescheduled and cancelled transmission outage request summary: June 2019 through September 2020

Planned Duration (Days)	2019/2020 (12 months)					2020/2021 (4 months)				
	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	16,809	3,823	22.7%	2,140	12.7%	5,159	1,177	22.8%	711	13.8%
>5 & <=30	3,116	1,772	56.9%	179	5.7%	913	461	50.5%	36	3.9%
>30	1,691	1,043	61.7%	80	4.7%	784	320	40.8%	29	3.7%
Total	21,616	6,638	30.7%	2,399	11.1%	6,856	1,958	28.6%	776	11.3%

If a requested outage is determined to be late and TO reschedules the outage, the outage will be reevaluated 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.⁸⁶ 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.⁸⁷ This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month six months prior to the month in which the outage was expected to occur. The rescheduling rule allows TOs to avoid the timing requirements associated with outages exceeding five days.

The MMU recommends that PJM reevaluate all transmission outage tickets as On Time or Late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages.

⁸⁶ PJM, "Manual 3: Transmission Operations," Rev. 57 (May 29, 2020).

⁸⁷ *Id.*

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-48) 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 12-55 shows equipment outages by the equipment instead of by outage request.

Table 12-55 shows that there were 13,130 transmission equipment planned outages in the first four months of the 2020/2021 planning period, of which 732 were longer than 30 days, and of which 30 or 0.6 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-55 Transmission outage summary: June 2019 through September 2020

Planned Duration (Days)	2019/2020 (12 months)			2020/2021 (4 months)		
	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total	
> 30	No	1,472	11.2%	702	13.2%	
	Yes	229	1.7%	30	0.6%	
<= 30		11,429	87.0%	4,589	86.2%	
Total		13,130	100.0%	5,321	100.0%	

Table 12-56 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 request of the equipment. In the first four months of the 2020/2021 planning period, within effective duration greater than a month and shorter than two months, there were 11 outages with a combined duration longer than 30 days.

Table 12-56 Equipment outages: June 2019 through September 2020

Effective Duration of Outage	2019/2020 (12 months)		2020/2021 (4 months)	
	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	3	1.3%	1	3.3%
>31 <=62	27	11.8%	11	36.7%
>62 <=93	21	9.2%	6	20.0%
>93	178	77.7%	12	40.0%
Total	229	100.0%	30	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 weeks as an initial list. Then PJM may exercise significant discretion in selecting outages to be modeled in the final model. PJM posts the final FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.⁸⁸

In the first four months of the 2020/2021 planning period, 45 outage requests were included in the annual FTR market outage list and 6,811 outage requests were not included.⁸⁹ In the 2019/2020 planning period, 245 outage requests were included in the annual FTR market outage list and 21,371 outage requests were not included. Table 12-57, Table 12-58, Table 12-59 and Table 12-60 show the summary information on the modeled outage requests and Table 12-61 and Table 12-62 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-57 shows that 0.0 percent of the outage requests modeled in the Annual FTR Market for the first four months of the 2020/2021 planning period had a planned duration of less than two weeks and that 24.4 percent of the outage requests (11 out of 45) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 6.9 percent of the outage requests modeled in the Annual FTR Market for the 2019/2020 planning period had a planned duration of less than two weeks and that 15.9 percent of the outage requests (39 out of 245) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

⁸⁸ PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <<https://www.pjm.com/-/media/markets-ops/ftr/annual-ftr-auction/2018-2019/2018-2019-annual-outage-modeling.ashx?la=en>> (April 5, 2018). There is no documentation on the deadline for when modeling outages should be posted on the PJM website.

⁸⁹ PJM's treatment of transmission outages in the FTR models is discussed in the 2019 Quarterly State of the Market Report for PJM: January through September, Section 13: FTRs and ARRs: Supply and Demand.

Table 12-57 Annual FTR market modeled transmission facility outage requests by received status: June 2019 through September 2020

Planned Duration	2019/2020 (12 months)				2020/2021 (4 months)			
	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	13	4	17	6.9%	0	0	0	0.0%
>=2 weeks & <2 months	77	8	85	34.7%	6	1	7	15.6%
>=2 months	116	27	143	58.4%	28	10	38	84.4%
Total	206	39	245	100.0%	34	11	45	100.0%

Table 12-58 shows the annual FTR market modeled outage requests summary by emergency status and received status. One of the annual FTR market modeled outages expected to occur in the first four months of the 2020/2021 planning period were emergency outages. Two of the modeled outages expected to occur in the 2019/2020 planning period were emergency outages.

Table 12-58 Annual FTR market modeled transmission facility outage requests by emergency and received status: June 2019 through September 2020

Received Status	Planned Duration	2019/2020 (12 months)				2020/2021 (4 months)			
		Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	13	13	100.0%	0	0	0	0.0%
	>=2 weeks & <2 months	0	77	77	100.0%	0	6	6	100.0%
	>=2 months	0	116	116	100.0%	0	28	28	100.0%
	Total	0	206	206	100.0%	0	34	34	100.0%
Late	<2 weeks	0	4	4	100.0%	0	0	0	0.0%
	>=2 weeks & <2 months	0	8	8	100.0%	0	1	1	100.0%
	>=2 months	2	25	27	92.6%	1	9	10	90.0%
	Total	2	37	39	94.9%	1	10	11	90.9%

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 12-59 shows a summary of requests by expected congestion and received status. Of all the annual FTR market modeled outages expected to occur in the first four months of the 2020/2021 planning period and submitted late, none was expected to cause congestion. Overall, of all the annual FTR market modeled outages expected to occur in the 2019/2020 planning period and submitted late, 12.8 percent (5 out of 39) were expected to cause congestion.

Table 12-59 Annual FTR market modeled transmission facility outage requests by congestion and received status: June 2019 through September 2020

Received Status	Planned Duration	2019/2020 (12 months)				2020/2021 (4 months)			
		Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	6	7	13	46.2%	0	0	0	0.0%
	>=2 weeks & <2 months	23	54	77	29.9%	1	5	6	16.7%
	>=2 months	21	95	116	18.1%	3	25	28	10.7%
	Total	50	156	206	24.3%	4	30	34	11.8%
Late	<2 weeks	2	2	4	50.0%	0	0	0	0.0%
	>=2 weeks & <2 months	2	6	8	25.0%	0	1	1	0.0%
	>=2 months	1	26	27	3.7%	0	10	10	0.0%
	Total	5	34	39	12.8%	0	11	11	0.0%

Table 12-60 shows that 71.4 percent of outage requests modeled in the annual FTR market for the first four months of the 2020/2021 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 31.8 percent for the 2019/2020 planning period. Table 12-60 also shows that 18.4 percent of outages requests modeled in the Annual FTR Market for the first four months of the 2020/2021 planning period and with a duration of two months or longer were cancelled, compared to 21.7 percent for the 2019/2020 planning period.

Table 12-60 Annual FTR market modeled transmission facility outage requests by processed status: June 2019 through September 2020

Planned Duration	Processed Status	2019/2020 (12 months)		2020/2021 (4 months)	
		2019/2020	Percent	Outage Requests	Percent
<2 weeks	In Progress	0	0.0%	0	0.0%
	Cancelled	3	17.6%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	14	82.4%	0	0.0%
	Total	17	100.0%	0	0.0%
>=2 weeks & <2 months	In Progress	14	16.5%	0	0.0%
	Cancelled	27	31.8%	5	71.4%
	Active	0	0.0%	1	14.3%
	Completed	44	51.8%	1	14.3%
	Total	85	100.0%	7	100.0%
>=2 months	In Progress	24	16.8%	7	18.4%
	Cancelled	31	21.7%	7	18.4%
	Active	7	4.9%	16	42.1%
	Completed	81	56.6%	8	21.1%
	Total	143	100.0%	38	100.0%
Total Cancelled		61	24.9%	12	26.7%
Grand Total		245		45	

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first four months of the 2020/2021 planning period, 45 outage requests were modeled and 6,811 outage requests were not modeled in the Annual FTR Market. In the 2019/2020 planning period, 245 outage requests were modeled and 21,371 outage requests were not modeled in the Annual FTR Market.

Table 12-61 shows that 5.1 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted after the Annual FTR Auction bidding opening date for the first four months of the 2020/2021 planning period compared to 13.2 percent in the 2019/2020 planning period.

Table 12-61 Transmission facility outage requests not modeled in Annual FTR Auction: June 2019 through September 2020

Planned Duration	2019/2020 (12 months)						2020/2021 (4 months)					
	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
<2 weeks	1,709	8,788	83.7%	240	7,798	97.0%	1,148	1,884	62.1%	143	2,429	94.4%
>=2 weeks & <2 months	628	413	39.7%	153	838	84.6%	369	34	8.4%	97	248	71.9%
>=2 months	198	30	13.2%	224	352	61.1%	168	9	5.1%	181	101	35.8%
Total	2,535	9,231	78.5%	617	8,988	93.6%	1,685	1,927	53.3%	421	2,778	86.8%

Table 12-62 shows that 33.7 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 first four months of the 2020/2021 planning period. It also shows that 79.0 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 2019/2020 planning period.

Table 12-62 Late transmission facility outage requests not modeled in Annual FTR Auction and submitted after annual bidding opening date: June 2019 through September 2020

Planned Duration	2019/2020 (12 months)			2020/2021 (4 months)		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	6,643	7,798	85.2%	2,060	2,429	84.8%
>=2 weeks & <2 months	712	838	85.0%	160	248	64.5%
>=2 months	278	352	79.0%	34	101	33.7%
Total	7,633	8,988	84.9%	2,254	2,778	81.1%

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 those 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.⁹⁰ Table 12-63 and Table 12-64 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-65 and Table 12-66 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-63 shows that on average, 34.6 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 first four months of the 2020/2021 planning period. On average, 32.4 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 2019/2020 planning period.

⁹⁰ 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 12-63 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2019 through September 2020

Month	2019/2020				2020/2021			
	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	162	115	277	41.5%	215	101	316	32.0%
Jul	92	96	188	51.1%	96	71	167	42.5%
Aug	131	86	217	39.6%	118	81	199	40.7%
Sep	379	147	526	27.9%	468	140	608	23.0%
Oct	533	183	716	25.6%				
Nov	431	163	594	27.4%				
Dec	311	146	457	31.9%				
Jan	189	86	275	31.3%				
Feb	223	93	316	29.4%				
Mar	428	141	569	24.8%				
Apr	461	181	642	28.2%				
May	391	167	558	29.9%				
Average	311	134	445	32.4%	224	98	323	34.6%

Table 12-64 shows that on average, 15.0 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first four months of the 2020/2021 planning period. On average, 19.7 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2019/2020 planning period.

Table 12-64 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2019 through September 2020

Planning Year	Month	In							Total	Percent
		Process	Denied	Approved	Cancelled	Revised	Active	Complete		Cancelled
2019/2020	Jun	17	2	2	47	0	82	127	277	17.0%
	Jul	13	4	0	45	0	72	54	188	23.9%
	Aug	14	5	0	37	0	79	82	217	17.1%
	Sep	58	2	25	93	0	178	170	526	17.7%
	Oct	65	2	13	131	1	200	304	716	18.3%
	Nov	30	1	11	120	0	173	259	594	20.2%
	Dec	27	4	8	86	1	74	257	457	18.8%
	Jan	21	0	9	52	0	95	98	275	18.9%
	Feb	37	0	8	51	0	111	109	316	16.1%
	Mar	55	0	13	130	0	160	211	569	22.8%
2020/2021	Apr	54	0	12	148	0	177	251	642	23.1%
	May	26	2	10	111	1	126	282	558	19.9%
	Avg	35	2	9	88	0	127	184	445	19.7%
	Jun	27	5	7	48	1	75	153	316	15.2%
	Jul	9	16	4	22	0	73	43	167	13.2%
	Aug	22	2	4	26	0	71	74	199	13.1%
	Sep	65	0	19	114	0	195	215	608	18.8%
	Avg	31	6	9	53	0	104	121	323	15.0%

Table 12-65 shows that on average, 11.3 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the first four months of the 2020/2021 planning period, compared to 8.7 percent in the 2019/2020 planning period. On average, 69.8 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the first four months of the 2020/2021 planning period, compared to 66.1 percent in the 2019/2020 planning period.

Table 12-65 Transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction: June 2019 through September 2020

	2019/2020						2020/2021					
	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	674	85	11.2%	347	694	66.7%	805	98	10.9%	333	790	70.3%
Jul	391	64	14.1%	268	729	73.1%	433	87	16.7%	271	605	69.1%
Aug	357	44	11.0%	300	640	68.1%	448	64	12.5%	262	617	70.2%
Sep	896	122	12.0%	318	661	67.5%	1,088	60	5.2%	277	636	69.7%
Oct	1,111	119	9.7%	388	929	70.5%						
Nov	1,000	63	5.9%	458	658	59.0%						
Dec	739	61	7.6%	328	636	66.0%						
Jan	581	36	5.8%	292	572	66.2%						
Feb	653	43	6.2%	280	603	68.3%						
Mar	1,328	88	6.2%	333	702	67.8%						
Apr	1,518	162	9.6%	448	693	60.7%						
May	1,279	75	5.5%	486	700	59.0%						
Avg	877	80	8.7%	354	685	66.1%	694	77	11.3%	286	662	69.8%

Table 12-66 shows that on average, 71.5 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 first four months of the 2020/2021 planning period, compared to 71.9 percent in the 2019/2020 planning period.

Table 12-66 Late transmission facility outage requests that are not modeled and submitted after monthly bidding opening date: June 2019 through September 2020

	2019/2020			2020/2021		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	528	694	76.1%	574	790	72.7%
Jul	489	729	67.1%	436	605	72.1%
Aug	500	640	78.1%	447	617	72.4%
Sep	455	661	68.8%	436	636	68.6%
Oct	616	929	66.3%			
Nov	472	658	71.7%			
Dec	469	636	73.7%			
Jan	441	572	77.1%			
Feb	475	603	78.8%			
Mar	461	702	65.7%			
Apr	480	693	69.3%			
May	518	700	74.0%			
Avg	492	685	71.9%	473	662	71.5%

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.⁹¹

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.

⁹¹ PJM, "Manual 3: Transmission Operations," Rev. 57 (May 29, 2020).

Figure 12-4 Illustration of day-ahead market analysis: May 5, 2018

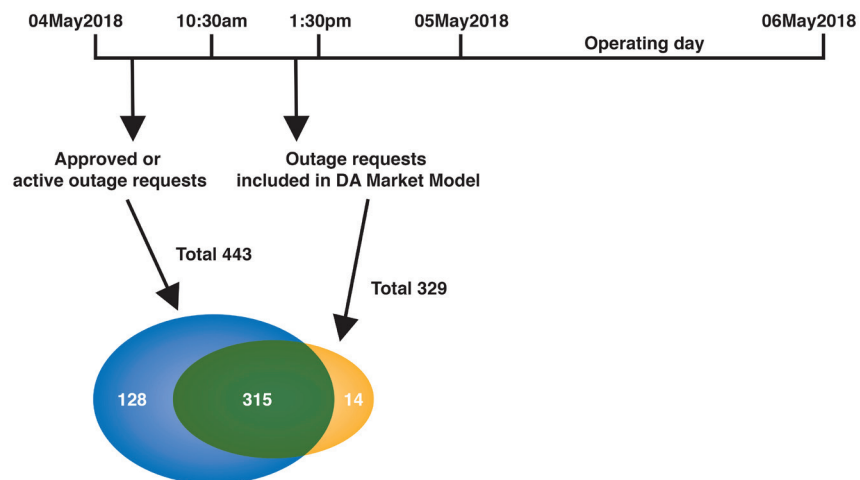


Figure 12-5 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

Figure 12-5 Approved or active outage requests: January 2015 through September 2020

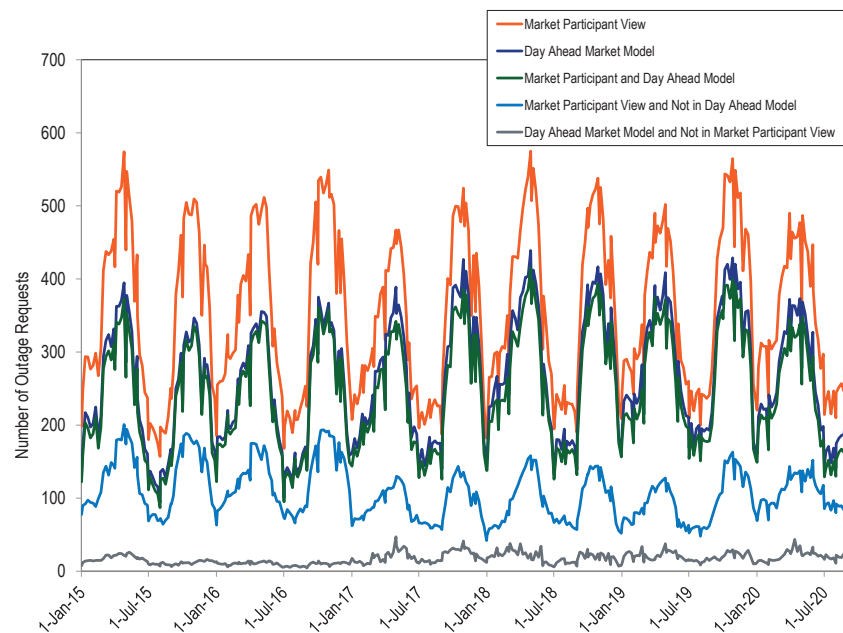


Figure 12-6 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-6 Day-ahead market model outages: January 2015 through September 2020

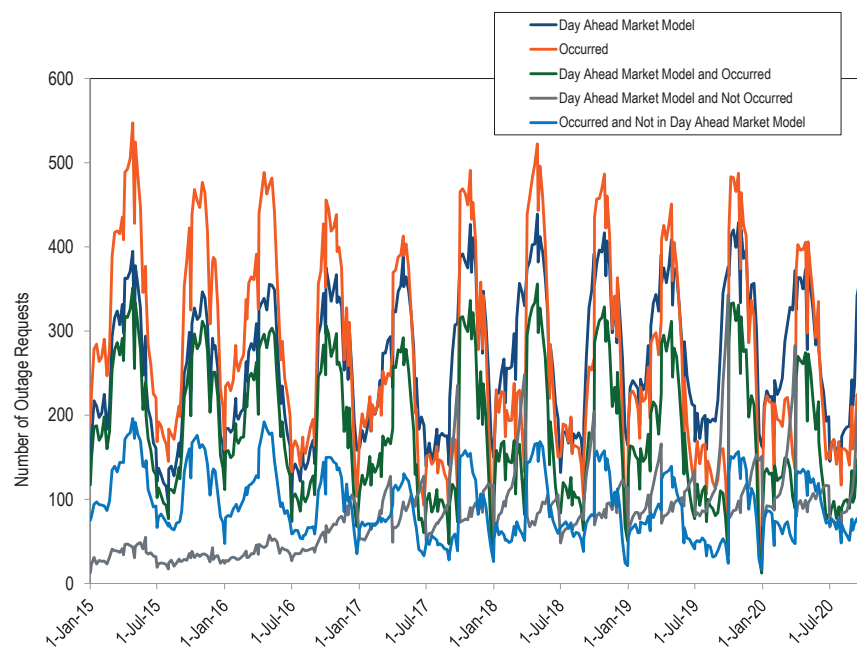


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-7 Approved or active outage requests: January 2015 through September 2020

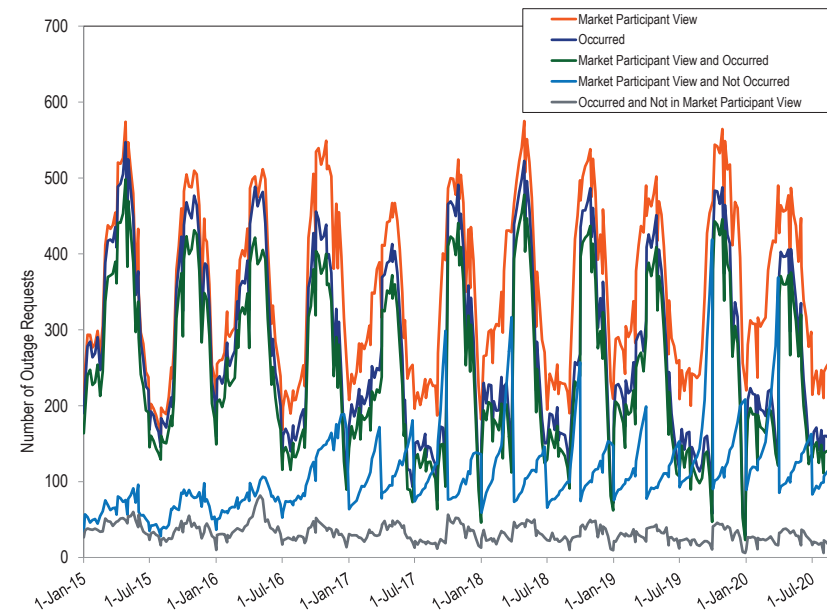


Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or 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, but when there are transmission constraints, load pays the high local price for all generation, including the low cost generation serving part of that load. The result is that load pays the correct local price but pays too much in total for energy. In an LMP market, load pays more than generation receives. FTRs are the mechanism for returning those excess payments to load. But the FTR mechanism in PJM does not and cannot return all the excess payments to load. The FTR mechanism in PJM needs a significant redesign in order to achieve that objective.

The FTR mechanism should be a simple accounting method for assigning congestion rights to load. But PJM has had to add increasingly complex rules and regularly intervene in the FTR mechanism because the PJM FTR design has moved further and further from these economic fundamentals. Market participants have profited in various ways from these design flaws and now strongly defend the current design.

When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load, subject to transmission limits. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. Prior to the introduction of LMP markets, payment for the delivery of low cost generation to load was based both on intrazonal generation and intrazonal transmission under cost of service rates, and on contracts with specific remote generation outside the local zone and the associated point to point transmission contracts. In both cases, customers paid for the physical rights associated with the transmission system used to provide for the delivery of low cost generation to load. There was no congestion revenue because customers paid only the actual cost of the low cost generation. Most generation was intrazonal and the transmission system used to deliver the related energy to intrazonal load was also intrazonal.

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. FTRs permitted the loads, which pay for the transmission system, to continue to receive the benefits of access to either local or remote low cost generation by returning congestion to the load.¹ FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load was required to pay more for low cost generation than is paid to low cost generation. But there was a flaw built in from the very beginning that had no significant impact initially but which was ultimately the source of all the issues with the FTR mechanism. That flaw was the idea that congestion was based on contract paths in a network system rather than a result of the actual operation of the complex network. That flaw was inconsistent with the most basic logic of LMP and the resultant fissure continued to widen. The origin of FTRs was the recognition that the way to hold load harmless from making these excess payments created by the LMP system was to return the excess payments to load. The rights to congestion belong to load. If implemented correctly, FTRs would be the financial equivalent of firm transmission service for load. If implemented correctly, FTRs would be a perfect hedge against congestion for load.

The notion that FTRs exist in order to provide a hedge for generation is a fallacy. In an LMP system, the basic incentive structure for generation derives from the fact that generation is paid the LMP at the generator bus. If generation were to be guaranteed a price at a distant constrained load bus rather than at the generation bus, there would be no incentive for generation to locate where it is needed on the system. In addition, the payment of the price at the generator bus is fundamental to the logic of locational marginal pricing which produces local prices equal to the marginal value of generation at every point. There is no logical or theoretical basis in locational marginal pricing for the assertion that generation at low price nodes is underpaid and should be paid more from congestion dollars. Generation does not pay congestion. Some generation receives a price lower than the system marginal price (SMP) and some generation receives a price greater than SMP but that does not mean

¹ See 81 FERC ¶ 61,257 at 62,241 (1997).

that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP. If a generating unit wants, it may enter into an arms length transaction with a willing counter party as a hedge. That is the way hedges work in markets. That is not the way the FTR mechanism works.

In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. FTRs were the mechanism selected in PJM to offset the congestion costs that load pays in an LMP market. Congestion revenues are the source of the funds to pay FTRs. Congestion revenues are assigned to the load that paid them through FTRs.² The only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to ensure that all congestion revenues are returned to load or, more precisely, that the rights to all congestion revenues are assigned to load. In order to do that, congestion must be defined correctly based on the operation of the network and not on arbitrary contract paths.

Effective April 1, 1999, when FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and balancing 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, the right to all congestion revenues should belong to load. All congestion surplus should be assigned to load. But the actual implementation produces a very different result.

² See *id.* at 62, 259–62, 260 & n. 123.

ARRs were an add on concept, defined based on a misunderstanding of FTRs which had its roots in the assignment of congestion to load using contract paths (generation to load paths) rather than on the calculation of congestion actually paid. The ARR concept as it is currently implemented, does not allow the FTR sellers, load, to establish a selling price, but forces load to accept whatever prices buyers are willing to pay. The revenue from the sale of congestion rights is not even paid in full to ARR holders. So called surplus revenue is paid to FTR holders to ensure payment despite the fact that willing FTR buyers paid the revenues in the auction for the rights to congestion.

The use of generation to load paths rather than the direct calculation of congestion led to an increased divergence between the congestion on the generation to load paths and total congestion. This divergence between actual network use and historic paths was exacerbated as new zones were added with their own historic generation to load paths and as significant numbers of generating units retired and new units were added.³ Rather than understanding that the divergence resulted from the fact that a path based approach did not correctly calculate congestion in a network system, especially as the system grew significantly, the issue was characterized as the existence of excess capacity on the transmission system. But congestion was never about capacity on the transmission system. Prior to the introduction of ARRs, the so called excess congestion that exceeded the congestion on the defined paths was returned to load. There is no such thing as excess congestion. The overlay of ARRs on the FTR concept did not change the fundamental logic of congestion, but permitted the introduction of a system in which the divergence was formally created between the amount of congestion paid by load and the amount of congestion returned to load. Congestion belongs to the load, by definition. The introduction of ARRs based on a contract path fiction undermined the assignment of all congestion rights to load.

The 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

³ For a comprehensive report on capacity retirements and capacity additions in PJM, see: "2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022," (September 15, 2020) available at <http://www.monitoringanalytics.com/reports/Reports/2020/Constraint_Based_Congestion_Calculations_20200722.pdf>

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, the definition and allocation of surplus, and numerous cross subsidies among participants. The fundamental distortion was the assignment of the rights to congestion revenue based on specific generation to load transmission paths. This approach retained the contract path based view of congestion rooted in physical transmission rights and inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

The cumulative offset by ARRs for the 2011/2012 planning period through the first four months of the 2020/2021 planning period, using the rules effective for each planning period, was 75.0 percent. Load has been underpaid by \$2.2 billion from the 2011/2012 planning period through the first four months of the 2020/2021 planning period.

The overall underassignment of congestion to load includes dramatically different results by zone. Load in some zones receives congestion revenues well in excess of the congestion they pay while the reverse is true for other zones.

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 and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy. The design should simply have provided for the return of all congestion revenues to load. 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 *2020 Quarterly State of the Market Report for PJM: January through September* focuses on the 2020/2021 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2020, through September 30, 2020.

Table 13-1 The FTR auction markets results were competitive

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

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 20/23 Long Term FTR Auction and the 20/21 Annual FTR Auction. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and moderately concentrated for the 20/21 Annual FTR Auction. Ownership of FTRs is disproportionately (73.6 percent) by financial participants.
- Participant behavior was evaluated as partially competitive as a result of the behavior of GreenHat Energy, LLC.
- Market performance was evaluated as competitive because it reflected the interaction between buyer behavior and the FTRs that PJM made available for sale. 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 and fundamental flaws with the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. ARR holders' rights to congestion revenues are not correctly defined. The path based assignment of congestion rights is inadequate and incorrect. 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.

- The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs and the fact that auction surplus, despite resulting from FTR buyers' actual offer prices, is returned to buyers as needed rather than the sellers, means that the FTR design does not actually function as a market and raises questions about the market structure, the market performance and the market design.

Overview

Auction Revenue Rights

Market Structure

- **Residual ARR.** 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 four months of the 2020/2021 planning period, PJM allocated a total of 16,997.8 MW of residual ARRs with a total target allocation of \$3.6 million, up from 11,162.7 MW in the first four months of the 2019/2020 planning period, with a total target allocation of \$2.7 million.

- **ARR Reassignment for Retail Load Switching.** There were 13,606 MW of ARRs associated with \$78,900 of revenue that were reassigned in the first four months of the 2020/2021 planning period. There were 18,913 MW of ARRs associated with \$223,800 of revenue that were reassigned for the same time frame of the 2019/2020 planning period.

Market Performance

- **Revenue Adequacy.** For the first four months of the 2020/2021 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were \$509.1 million, while PJM collected \$670.5 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue

adequate. The allocation of surplus congestion revenue provides for revenue adequacy for FTRs first, and any remaining revenues at the end of the planning period are allocated to ARR holders. For the 2019/2020 planning period, the ARR target allocations were \$752.2 million while PJM collected \$982.0 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.

- **ARRs as an Offset to Congestion.** ARRs have historically not served as an effective way to return all congestion revenues to load. For the first four months of the 2020/2021 planning period, 50.6 percent of total congestion was offset by ARR credit allocations to ARR holders. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. The goal of the ARR/FTR market design should be to ensure that load has the rights to 100 percent of the congestion revenues. The cumulative offset was 75.0 percent based on the rules that were in place for each planning period. Load has been underpaid by \$2.2 billion from the 2011/2012 planning period through the first four months of the 2020/2021 planning period.

Financial Transmission Rights

Market Structure

- **Monthly Balance of Planning Period FTR Auctions.** The structure of the Monthly Balance of Planning Period FTR Auctions was changed effective with the 2020/2021 planning period. The new structure makes available the FTRs for each remaining month in the planning period. The prior design made available the FTRs for the next three individual months and then any eligible quarters. Beginning in the 2020/2021 planning period any individual remaining calendar month is available for bids or offers. For example, in the June auction June through May are available as individual periods. In the January auction, January through May are available as individual periods.
- **Sell Offers.** In a given auction, market participants can sell FTRs that they have acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first four

months of the 2020/2021 planning period, total participant FTR sell offers were 8,033,682 MW.

- **Buy Bids.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2020/2021 planning were 17,505,199 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 84.5 percent of prevailing flow and 87.1 percent of counter flow FTRs for January through September, 2020. Financial entities owned 74.4 percent of all prevailing and counter flow FTRs, including 67.5 percent of all prevailing flow FTRs and 83.3 percent of all counter flow FTRs during the period from January through September 2020.

Market Behavior

- **FTR Forfeitures.** Under the modified FTR forfeiture rules, total FTR forfeitures were \$22.1 million for the period January 19, 2017, through September 30, 2020.
- **Credit.** There were three collateral defaults in the first nine months of 2020 for a total of \$34,410. There were 22 payment defaults in the first nine months of 2020 not involving GreenHat Energy, LLC for a total of \$31,796. GreenHat Energy accrued payment defaults of \$15.6 million in the first nine months of 2020 for a total of \$162.6 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.⁴ In addition, PJM added the settlement fee and claimant payee funds to the default allocation, resulting in allocations of \$12.5 million and \$5.0 million for a total of \$180.1 million.

Market Performance

- **Volume.** In the first four months of the 2020/2021 planning period, Monthly Balance of Planning Period FTR Auctions cleared 2,720,662 MW (15.5 percent) of FTR buy bids and 1,357,952 MW (16.9 percent) of FTR sell offers. For the first four months of the 2019/2020 planning period, Monthly Balance of Planning Period FTR Auctions cleared 1,588,345 MW (16.6 percent) of FTR buy bids and 832,832 MW (21.5 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods of the first four months of the 2020/2021 planning period was \$0.14.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated \$20.8 million in net revenue for all FTRs of the first four months of the 2020/2021 planning period, down from \$27.9 million for the same time period in the 2019/2020 planning period.
- **Revenue Adequacy.** FTRs were paid at 100.0 percent of the target allocation level for the first four months of the 2020/2021 planning period, including the distribution of the current surplus revenue.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of the FTR. In the first four months of 2020/2021 planning period, physical entities made \$38.0 million profits on FTRs purchased directly (not self scheduled), up from \$2.1 million losses for the same time period in the 2019/2020 planning period and financial entities made \$98.4 million including GreenHat's losses, up from \$5.6 million profits for the same time period in the 2019/2020 planning period.

⁴ See the 2019 Quarterly State of the Market Report for PJM: January through June for a more complete explanation of credit issues that occurred in 2019.

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
2021/2024 Long Term	6/2/2020	3/2021
2019/2020 ARR	3/2/2020	4/3/2020
2019/2020 Annual	4/7/2020	5/4/2020

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 all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a network design in which the rights to actual congestion are assigned directly to load by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, the Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, 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 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.⁵ (Priority: High. First reported 2015. Status: Not 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 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 a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)

⁵ See "PJM Manual 6: Financial Transmission Rights," Rev. 254 (July 23, 2020).

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the 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. First reported 2018. Status: Adopted, 2019. Pending at FERC.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported Q2, 2020. Status: Not adopted.)
- The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately. (Priority: High. New recommendation. Status: PJM planning to implement.)

Conclusion

Solutions

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 security constrained LMP markets. When there are

binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

The current path based design should be replaced with a network design in which the rights to actual congestion are assigned directly to load by node. The assigned right is to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the network congestion or sell the right through auctions.

Issues

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 and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

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

of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARR, but continued to conservatively select outages to manage FTR funding levels.

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

Load should never be required to subsidize payments to FTR holders, regardless of the reason.⁶ The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.⁷ The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As 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. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and reduced 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 pays for the physical transmission system, pays in excess of generator revenues and pays negative balancing congestion again. The result is that load gets back less than total congestion. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There was no reason to impose these costs on load.

⁶ Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.

⁷ See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

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

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 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.

A subsequent rule change was implemented by PJM that modified the allocation of surplus auction revenue to the benefit of load. Beginning with the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up to the point of revenue adequacy, and then distributed to ARR holders.⁸ However, under the rules, ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. The new rules do not fully recognize ARR holders' rights to surplus congestion revenue. With this rule in effect for the first four months of the 2020/2021 planning period, ARRs and FTRs offset 50.6 percent of total congestion rather than 50.2 percent.

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

⁸ 163 FERC ¶61,165 (2018).

Proposed Design

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

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

Under this proposed design, the rights to congestion can be kept by the physical load or the rights to the congestion can be sold in an auction and the proceeds from the sale of the rights would go to the physical load.

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is the network based financial transmission right (NFTR) to the physical load at a defined bus, zone or aggregate. The LSE could choose to sell all or a portion of the NFTR and its associated congestion revenue stream through an annual and/or monthly auction or through a bilateral arrangement with a third party.

An NFTR is the right to actual, realized network related congestion that is collected from a specific bus, zone or aggregate. A NFTR is therefore not defined as a fixed MW amount between two points and it is not a realized path specific price spread. A NFTR is defined as the right to total actual network congestion collected from the defined bus, zone or aggregate. Rather than being sold in terms of MW, NFTRs are sold as a fixed proportion of the total actual network congestion that will be returned to the defined bus, zone or aggregate.

Under the MMU proposal a bus, zone or aggregate specific NFTR could be sold as portions of the actual congestion. For example, an LSE could sell 50 percent of its congestion credit for the planning year to a third party. The third party buyer would then be entitled to 50 percent of the congestion that will be credited to that specific bus, zone or aggregate for the planning year. The remaining 50 percent of the congestion credit for the specified bus, zone or aggregate would be paid to the LSE along with auction clearing price for the 50 percent of NFTR that was sold to the third party.

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

Auction Revenue Rights

ARRs

Auction Revenue Rights (ARRs) are the mechanism used to define the rights to congestion and assign those rights to congestion revenues to load. ARRs are assigned to load using an archaic path based approach. Congestion rights represented by ARRs are sold to FTR buyers in FTR Auctions. ARR values

are based on nodal price differences established by cleared FTR bids in the Annual FTR Auction. ARR sellers have no opportunity to define a price at which they are willing to sell. ARR holders must accept the prices as defined by FTR buyers. ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available supply. PJM has significant discretion over the level of supply made available to FTR buyers. 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 the product of the ARR MW and the price difference between the ARR sink and source from the Annual FTR Auction.⁹ An ARR's target allocation, or value, which is established from the Annual FTR Auction, can be a benefit or liability depending on the price difference between sink and source. 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 auction revenues are greater than 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 congestion revenues, and that ARR holders receive the auction revenues associated with all potential congestion revenues whether through self scheduling or selling the rights to FTR holders. Given that 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.

⁹ 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.

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.

IARRs

Incremental Auction Revenue Rights (IARRs) are ARRs made available by physical transmission system upgrades from customer funded transmission projects or from merchant transmission or generation interconnection requests. In order for a transmission project to result in IARRs, the project must create simultaneously feasible incremental market flow capability in PJM's ARR market model, over and above all system capability being used by existing allocated ARRs and/or would be used by granting any prorated outstanding ARR requests, in the ARR market model.¹⁰

There are three approaches to the creation and assigning of IARRs: IARRs can be requested based on specific transmission investment; IARRs can be the granted based on merchant transmission or generation interconnection projects; and IARRs can be the result of RTEP upgrades. In each case, the participants paying for the upgrades are allocated the IARR that are created. There have been 13 successful IARR requests totaling 2,990.1 MW of IARRs. One IARR path of 64.5 MW was terminated early (June 1, 2012), leaving 12 unique source and sink combinations of 2,925.6 MW of IARRs active in PJM's current ARR/FTR market. Of the 12 unique paths, 6 paths consisting of 1,047.4 MW, were from merchant transmission requests, 3 paths consisting of

¹⁰ 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>>.

1,200.0 MW were from generation interconnection requests and three paths consisting of 678.6 MW were from customer funded transmission projects.

IARRs are allocated to customers that have been assigned cost responsibility for certain upgrades included in PJM's 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 share of cost responsibility. The customers may choose to decline the IARR allocation during the annual ARR allocation process.¹¹ 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.

The MMU recommends that IARRs be eliminated from the PJM tariff. The MMU supports increased competition to provide transmission using market mechanisms. The IARR process is not a viable mechanism for facilitating competitive transmission investments. Continuing to pretend that the IARR process is viable may impede the search for real solutions. PJM's process for using IARRs is fundamentally flawed and cannot be made consistent with the requirements of Order No. 681 which established IARRs.¹²

Order No. 681 requires that long-term firm transmission rights made feasible by transmission upgrades or expansions must be available upon request to the party that pays for such upgrades or expansions.¹³ Order No. 681 also requires that the rights granted by upgrades/expansions cannot come at the expense of transmission rights held by others. IARRs are treated as Stage 1A rights. Granting Stage 1A status to IARRs is preferential treatment of IARR rights relative to the ARR rights belonging to load. Only a subset of the ARR rights are treated as Stage 1A rights. Stage 1A rights are given first and absolute priority in PJM's annual allocation process. If the annual market model used

to assign existing ARR rights in a given year cannot simultaneously support all Stage 1A ARR requests, the system model is modified so as to make the Stage 1A ARR requests feasible. The result is an over allocation of congestion rights relative to expected congestion. To avoid having FTR target allocations exceed expected congestion, PJM reduces the annual supply (market model system capability) available to non-Stage 1A rights through selective line outages and line rating reductions. The resulting market model artificially supports all the Stage 1A ARR requests and artificially reduces the amount of remaining later tier ARRs from other rights holders. Stage 1A ARRs, including IARRs, are artificially approved at the expense of other preexisting congestion rights. In the case of IARRs, this is in violation of Order No. 681.

If IARRs are not eliminated, the MMU recommends that IARRs be subject to the same proration rules that apply to all other ARR rights.

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

The concept of system capability is not relevant to assigning the rights to congestion revenues to load. The use, or misuse, of system capability in assigning ARRs is derived entirely from the contract path approach used by PJM. In that approach, system capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model. PJM's annual FTR transmission market model represents annual, expected system capability, modified by PJM to achieve PJM's goal of guaranteeing revenue equal to target allocations for FTRs, and subject

¹¹ "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020); "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>>.

¹² See November 7, 2019 Comments on TranSource, LLC v. PJM, 168 FERC ¶ 61,119 (2019) ("Opinion No. 566").

¹³ Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681, 116 FERC ¶ 61,077 (2006) ("Order No. 681"), order on reh'g, Order No. 618-A, 117 FERC ¶ 61,201 (2006), order on reh'g, Order No. 681-A, 126 FERC ¶ 61,254 (2009).

to the requirement that all Stage 1A 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.

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.¹⁴ Stage 1A ARRs can give LSEs the ability to offset at least some of their congestion costs, through the return of congestion revenues, on a long-term basis up to Zonal Base Load. Stage 1B and Stage 2 ARRs must be simultaneously feasible in PJM's network model. Stage 1B and Stage 2 ARRs provide a method for ARR holders to have additional congestion revenues returned to them, up to Zonal Peak Load, 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.¹⁵

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.

- **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 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.¹⁶ Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015/2016 planning period, when residual zonal 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.¹⁷

¹⁴ 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.

¹⁵ OATT Attachment K 7.1.1.(b).

¹⁶ *Id.* at 21.

¹⁷ 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>>.

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 uses a power flow model of security constrained dispatch based on assumptions about generation and transmission outages.¹⁸ 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 ARRs¹⁹

$$MW = \text{Constraint Capability} \times \left(\frac{\text{Individual Requested MW}}{\text{Total Requested MW}} \right) \times \left(\frac{1}{\text{MW impact on line}} \right)$$

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 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.²⁰ PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs).²¹

The method PJM implemented continues to rely on a contract path based approach. Existing Stage 1A resources are given their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources are prorated based on the feasibility of these ARRs after existing resources are allocated. As a result of this proration, ARRs for QRRs have lower priority than ARRs from generators that existed in 1998.

Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load paths should not be used as a basis for assigning the rights to congestion revenue. Contract paths are not an accurate representation of the reasons that congestion is created or that load is served in a network and will, by definition, not accurately measure the exposure of load to congestion, especially by location.

Market Performance

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required to ensure that the long term ARRs can remain feasible. The rules provide that if a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process.²² But such transmission upgrades must pass PJM's RTEP process.

PJM's transmission planning process (RTEP) does not identify a need for new transmission associated with Stage 1A overallocations because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows. This continues to be true even with the replacement of retired generating units.

¹⁸ "PJM Manual 6: Financial Transmission Rights," Rev. 245 (April 1/July 23, 2020).

¹⁹ 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>.

²⁰ 156 FERC ¶ 61,180 (2016).

²¹ See FERC Docket No. EL16-6-003.

²² See "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020) at 23.

For the 2018/2019 planning period, Stage 1A of the Annual ARR Allocation was infeasible, resulting in an over allocation of ARRs on the affected facilities. As a result, modeled system capability, in excess of actual system capability, was provided to the Stage 1A ARRs and added to the FTR auction. According to Section 7.4.2 (i) of the OATT, the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and these increased limits must be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances.

Revenue

ARRs are allocated to qualifying customers rather than sold, so ARR revenue (target allocation) is different from the revenue that results from the FTR auctions which generally exceeds the sum of the ARR target allocations.

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.²³ 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.

²³ See "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

There were 31,683 MW of ARRs associated with \$657,300 of revenue that were reassigned for the 2019/2020 planning period. There were 13,606 MW of ARRs associated with \$78,900 of revenue that were reassigned in the first four months of the 2020/2021 planning period.

Table 13-3 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2019 and September 2020.

Table 13-3 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2019 through September 2020

Control Zone	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
	2019/2020 (12 months)	2020/2021 (4 months)	2019/2020 (12 months)	2020/2021 (4 months)
AECO	373	200	\$4.8	\$1.0
AEP	5,435	1,627	\$151.0	\$5.8
APS	1,383	699	\$39.4	\$5.3
ATSI	2,865	1,407	\$42.6	\$6.9
BGE	2,252	907	\$103.9	\$15.3
ComEd	2,583	1,155	\$27.1	\$6.2
DAY	765	278	\$9.3	\$1.1
DEOK	839	335	\$58.3	\$6.6
DLCO	1,622	895	\$5.8	\$1.0
Dominion	632	370	\$6.2	\$3.6
DPL	702	270	\$52.2	\$3.8
EKPC	0	0	\$0.0	\$0.0
JCPL	1,032	414	\$4.8	\$1.2
Met-Ed	540	166	\$5.6	\$0.6
OVEC	0	0	\$0.0	\$0.0
PECO	3,196	1,831	\$24.8	\$3.0
PENELEC	570	176	\$15.7	\$1.3
Pepco	1,947	548	\$35.4	\$3.3
PPL	3,538	1,542	\$38.3	\$8.5
PSEG	1,340	707	\$31.8	\$4.3
RECO	69	80	\$0.2	\$0.0
Total	31,683	13,606	\$657.3	\$78.9

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. If ARR allocations are reduced as the result of a modeled transmission outage and the transmission outage ends during the relevant planning period, 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 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.²⁴

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 four months of the 2020/2021 planning period, PJM allocated a total of 16,997.8 MW of Residual ARRs with a target allocation of \$3.6 million. In the same time period for the 2019/2020 planning period, PJM allocated a total of 11,162.7 MW of residual ARRs with a target allocation of \$2.7 million. In the 2017/2018 planning period, PJM allocated a total of 39,597.4 MW of residual ARRs, up from 35,034.9 MW for the 2016/2017 planning period. Residual ARRs had a total target allocation of \$17.5 million for the 2017/2018 planning period, up from \$7.0 million for the 2016/2017 planning period. In prior planning periods, 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.

²⁴ See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

Table 13-4 Residual ARR allocation volume and target allocation: January through September, 2020

Month	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-20	4,635.1	2,534.1	54.7%	\$3,469,317
Feb-20	5,972.9	2,506.8	42.0%	\$799,038
Mar-20	4,905.7	2,659.5	54.2%	\$1,269,201
Apr-20	4,529.7	2,619.0	57.8%	\$787,262
May-20	5,717.4	2,523.5	44.1%	\$471,472
Jun-20	3,889.8	1,945.8	50.0%	\$397,786
Jul-20	3,845.1	2,027.7	52.7%	\$973,082
Aug-20	3,493.2	2,029.0	58.1%	\$1,256,615
Sep-20	5,769.7	2,040.8	35.4%	\$968,024
Total	42,758.6	20,886.2	48.8%	\$10,391,797

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 day-ahead congestion prices (CLMPs) rather than the difference in LMPs, which includes both congestion and marginal losses. The difference in day-ahead congestion prices is not congestion. Negative target allocations require the FTR holder to pay into the FTR market. After FERC's order assigning balancing congestion and M2M payments directly to load, available revenue to pay FTR holders' target allocations 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. The target allocations are a cap on payments to FTR holders. At the end of the planning period, any surplus revenue above the target allocations is distributed proportionally to ARR holders.

FTR funding is not on a path specific basis or on an hour to hour basis and treats all FTRs the same. The result is widespread cross subsidies because

assignment of path specific ARRs/FTRs may exceed system capability and affect the payments to FTRs on other paths. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months within a planning period. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning period.

Auction market participants are free to request FTRs between any eligible pricing nodes on the system, as released by PJM for each auction. 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.

Market Structure

FTRs are bought from supply defined by PJM. There are no sellers of congestion revenue rights, although FTR buyers can resell FTRs. Load cannot determine the price at which PJM sells FTRs. PJM's objective in the auctions is to maximize auction revenue, given the bid prices but absent reservation prices from load. The absence of sellers who can decide at what price to sell FTRs is a fundamental flaw in the FTR market. The result is that PJM cannot actually maximize auction revenue.

Once bought from PJM, 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 auctions 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 periods.²⁵ 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 and can only be purchased in the Annual FTR Auction. Self scheduled FTRs exchange an ARR for a matching FTR without making a payment. From a settlements perspective, the self

²⁵ See "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

scheduling participant is paid the ARR target allocation, which is used to pay the price of the FTR. 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. There is no requirement to provide PJM any information on bilateral transactions, including price, counterparties, or ultimate separation by path.

Supply and Demand

Total FTR supply in each auction is limited by the capability of the transmission system included in the PJM FTR market model as modified, for example, by PJM assumptions about outages, for which there are no clear rules. 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 target allocations exceeding congestion revenue. FTR supply less

than system capability contributes to congestion revenue in excess of 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 resulting in a drop of Stage 1B and Stage 2 ARR capacity of 86.1 percent from the 2013/2014 to the 2014/2015 planning periods. After balancing congestion was assigned to load and exports, beginning in the 2017/2018 planning period, PJM partially reversed their approach and ARR capacity increased to 2013/2014 planning period levels.

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.²⁶ 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.

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).²⁷ FERC's goal was

²⁶ See the 2019 State of the Market Report for PJM, Volume 2, Section 12: Transmission Facility Outages: Transmission Facility Outages Analysis for the FTR Market.

²⁷ 116 FERC ¶ 61,077 (2006).

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 ARR holders nor are LSEs guaranteed rights to the revenue from Long Term FTR Auctions in PJM’s long term FTR auction market design. Excess system capability in years two and three of the long term FTR auction are never made available to load in the form of ARRs and are only made available to FTR buyers.

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 implemented revisions to the determination of residual system capability made available in the Long Term FTR Auctions, and eliminated the YRALL product, consistent with the MMU’s recommendation. The revisions affect the determination of ARR rights reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM reruns the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year’s ARR requests, prorated when necessary, and use the resulting ARRs as the basis for reserving capacity for ARR holders in the Long Term FTR Auction. The ARR requests are greater than previously cleared ARRs. The difference between the requested ARRs and ARR/FTR market model’s system capability, without outages, determines the residual capability offered in the Long Term FTR Auction. This method provides ARR holders with an improved representation of future system capability and preserves more congestion rights in the Long Term FTR Auction for ARR holders that will carry into the Annual FTR Auction than was preserved for ARR holders before this change. But this change does not address the system capability sold in years two and three of the Long Term FTR Auction which remains unavailable to ARRs. 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 upcoming 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 variable nature of the ARR/FTR model’s outage selections and system topology, reserving the previous year’s ARR bids does not 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 which is to return all congestion revenues to load.

The 2009/2012 and 2010/2013 Long Term FTR Auctions consisted of two rounds.²⁸ 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.

²⁸ FERC approved, on December 7, 2009, the addition of a third round to the Long Term FTR Auction. FERC letter order accepting PJM Interconnection, LLC’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).

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 determination of the simultaneous feasibility for the Annual FTR Auction.²⁹ 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. Before the 2020/2021 planning period, the first three individual months,

²⁹ See "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

and quarterly periods that had not yet begun, were available for bid or offer. Beginning with the 2020/2021 planning period, market participants can bid for or offer monthly FTRs for any of the remaining individual calendar months in the planning period. FTRs in the auctions include obligations and options and 24 hour, on peak and off peak products.³⁰

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM bilateral market which is actually a voluntary posting bulletin board and not a PJM administered market, or market participants can trade FTRs among themselves without PJM involvement. There is currently no requirement to report bilateral transactions, or any information about them, to PJM. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system. Bilateral transactions not reported to PJM are dependent on the contract established between the parties.

For bilateral trades reported to, 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.

FTR Bid Limits

PJM has had a cap of 10,000 bids and offers per auction round and per period at the corporate family level for more than a year, although the rule has not been enforced.³¹ On December 11, 2019, PJM made an informational announcement to urge participants to respect the rule. Some participants have exceeded and continued to exceed the limit although the number has been

³⁰ "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

³¹ Operating Agreement Schedule 1 § 7.3.5(d) allows PJM to limit participant's bids to 5,000 to avoid or mitigate significant system performance problems related to bid/offer volume.

significantly reduced very recently. The MMU recommends that PJM enforce the FTR auction bid limits at the corporate family level starting immediately.

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.

Table 13-5 presents the monthly balance of planning period FTR auction cleared FTRs for the first nine months of 2020 by trade type, organization type and FTR direction. Financial entities purchased 84.5 percent of prevailing flow FTRs, up 12.8 percentage points, and 87.1 percent of counter flow FTRs, up 7.2 percentage points, from 2019, with the result that financial entities purchased 85.8 percent, up 10.5 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction cleared FTRs for 2020.

Table 13-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through September, 2020

Trade Type	Organization Type	FTR Direction		
		Prevailing Flow	Counter Flow	All
Buy Bids	Physical	15.5%	12.9%	14.2%
	Financial	84.5%	87.1%	85.8%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	8.1%	10.9%	9.0%
	Financial	91.9%	89.1%	91.0%
	Total	100.0%	100.0%	100.0%

Table 13-6 shows the HHI values for cleared MW for the first four months of the 2020/2021 planning period monthly auctions by period. Cleared buy bids are unconcentrated.³²

Table 13-6 Monthly Balance of Planning Period FTR Auction HHIs by period

Auction	Auction Period										
	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR
Jun-20	283	361	425	427	585	566	644	544	576	625	650
Jul-20		293	306	373	460	441	521	473	471	500	535
Aug-20			326	340	373	382	432	409	417	439	452
Sep-20				363	374	388	462	499	509	505	551

Table 13-7 shows the average daily held FTR ownership for all FTRs for the first nine months of 2020, by FTR direction.

Table 13-7 Daily FTR held position ownership by FTR direction: January through September, 2020

Organization Type	FTR Direction		All
	Prevailing Flow	Counter Flow	
Physical	32.5%	16.7%	25.6%
Financial	67.5%	83.3%	74.4%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

PJM regularly intervenes in the FTR market based on subjective judgment which is not based on clear or documented guidelines. Such intervention in the FTR, or any market, is not appropriate and not consistent with the operation of competitive markets. In an apparent effort to manage FTR revenues, PJM may adjust normal transmission limits in the FTR auction model. If, in PJM's judgment, the normal 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.³³ PJM may also remove or reduce infeasibilities caused by transmission outages by clearing counter

³² See 2020 Quarterly State of the Market Report for PJM: January through June Section 3: Energy Market, Competitive Assessment for HHI definitions.

³³ See "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

flow bids without being required to clear the corresponding prevailing flow bids.³⁴ 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.

Monthly Balance of Planning Period Auctions

Table 13-8 provides the monthly balance of planning period FTR auction market volume for the entire 2019/2020 and the first four months of the 2020/2021 planning periods. There were 14,666,168 MW of FTR obligation buy bids and 6,262,241 MW of FTR obligation sell offers for all bidding periods in the first four months of the 2020/2021 planning period. The monthly balance of planning period FTR auction cleared 2,535,158 (17.3 percent) of FTR obligation buy bids and 1,093,325 MW (17.5 percent) of FTR obligation sell offers.

There were 2,839,031 MW of FTR option buy bids and 1,771,441 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2020/2021 planning period. The monthly auctions cleared 185,504 MW (6.5 percent) of FTR option buy bids, and 264,627 MW (14.9 percent) of FTR option sell offers.

Table 13-8 Monthly Balance of Planning Period FTR Auction market volume: January through September, 2020

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-20	Obligations	Buy bids	466,394	1,632,289	306,659	18.8%	1,325,630	81.2%
		Sell offers	303,736	618,111	125,762	20.3%	492,349	79.7%
	Options	Buy bids	6,647	195,528	5,493	2.8%	190,035	97.2%
		Sell offers	12,782	109,543	21,508	19.6%	88,034	80.4%
Feb-20	Obligations	Buy bids	474,510	1,592,984	309,317	19.4%	1,283,667	80.6%
		Sell offers	185,838	470,656	102,698	21.8%	367,958	78.2%
	Options	Buy bids	5,425	162,253	8,471	5.2%	153,782	94.8%
		Sell offers	11,296	112,091	28,274	25.2%	83,817	74.8%
Mar-20	Obligations	Buy bids	494,921	1,719,197	362,450	21.1%	1,356,747	78.9%
		Sell offers	242,038	598,102	126,227	21.1%	471,875	78.9%
	Options	Buy bids	4,460	105,294	8,701	8.3%	96,594	91.7%
		Sell offers	12,688	143,455	33,009	23.0%	110,445	77.0%
Apr-20	Obligations	Buy bids	351,392	1,119,598	255,378	22.8%	864,220	77.2%
		Sell offers	135,345	391,710	83,809	21.4%	307,901	78.6%
	Options	Buy bids	2,168	79,078	4,892	6.2%	74,186	93.8%
		Sell offers	7,951	96,040	24,500	25.5%	71,540	74.5%
May-20	Obligations	Buy bids	257,961	776,159	172,022	22.2%	604,137	77.8%
		Sell offers	76,694	201,438	45,392	22.5%	156,046	77.5%
	Options	Buy bids	217	4,076	1,060	26.0%	3,017	74.0%
		Sell offers	4,091	50,564	14,164	28.0%	36,400	72.0%
Jun-20	Obligations	Buy bids	875,884	3,659,757	655,465	17.9%	3,004,293	82.1%
		Sell offers	564,024	1,712,557	306,600	17.9%	1,405,956	82.1%
	Options	Buy bids	10,981	477,584	25,913	5.4%	451,671	94.6%
		Sell offers	90,894	547,263	90,228	16.5%	457,035	83.5%
Jul-20	Obligations	Buy bids	915,321	3,905,518	656,876	16.8%	3,248,642	83.2%
		Sell offers	512,929	1,583,035	275,966	17.4%	1,307,070	82.6%
	Options	Buy bids	13,915	733,188	59,777	8.2%	673,411	91.8%
		Sell offers	85,233	433,833	62,005	14.3%	371,828	85.7%
Aug-20	Obligations	Buy bids	822,326	3,611,313	610,999	16.9%	3,000,314	83.1%
		Sell offers	522,235	1,577,873	284,252	18.0%	1,293,621	82.0%
	Options	Buy bids	14,022	822,980	56,719	6.9%	766,261	93.1%
		Sell offers	77,645	412,804	61,991	15.0%	350,813	85.0%
Sep-20	Obligations	Buy bids	724,927	3,489,579	611,818	17.5%	2,877,761	82.5%
		Sell offers	441,244	1,388,776	226,507	16.3%	1,162,268	83.7%
	Options	Buy bids	11,736	805,278	43,094	5.4%	762,184	94.6%
		Sell offers	60,552	377,541	50,403	13.4%	327,138	86.6%
2019/2020*	Obligations	Buy bids	5,926,122	20,396,353	3,975,985	19.5%	16,420,368	80.5%
		Sell offers	3,436,131	7,709,887	1,586,486	20.6%	6,123,402	79.4%
	Options	Buy bids	86,428	2,779,104	148,918	5.4%	2,630,186	94.6%
		Sell offers	179,301	1,656,059	409,029	24.7%	1,247,031	75.3%
2020/2021**	Obligations	Buy bids	3,338,458	14,666,168	2,535,158	17.3%	12,131,009	82.7%
		Sell offers	2,040,432	6,262,241	1,093,325	17.5%	5,168,915	82.5%
	Options	Buy bids	50,654	2,839,031	185,504	6.5%	2,653,527	93.5%
		Sell offers	314,324	1,771,441	264,627	14.9%	1,506,814	85.1%

* Shows 12 months for 2019/2020 ** Shows 4 months for 2020/2021

³⁴ See *id.*

Figure 13-1 shows the bid volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The prompt month is the first month for which FTRs are sold. The bid volume for the non-prompt months is significantly lower than in the prompt months. On average, the non-prompt month bid volume is 38.2 percent of the prompt month bid volume.

Figure 13-1 Monthly Balance of Planning Period FTR Auction bid volume (MW per period): June through September, 2020 Auction

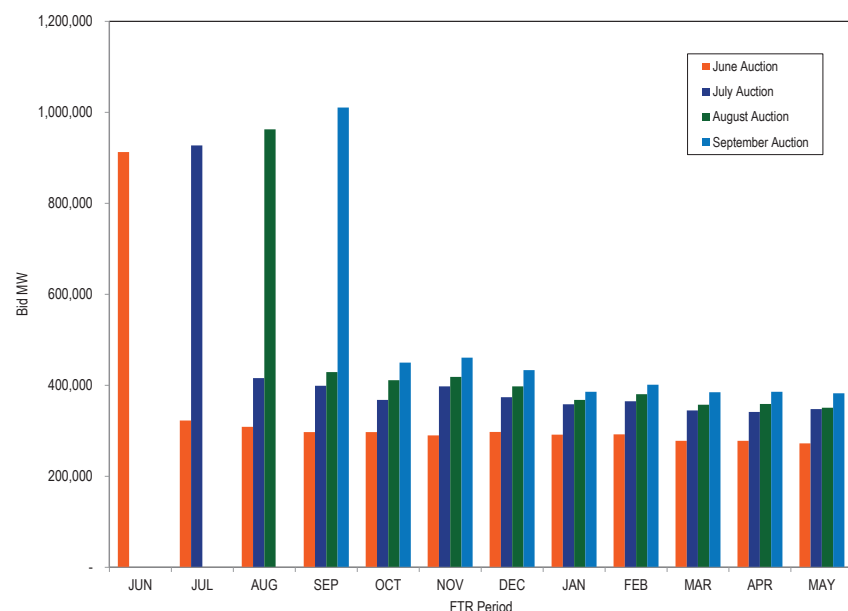
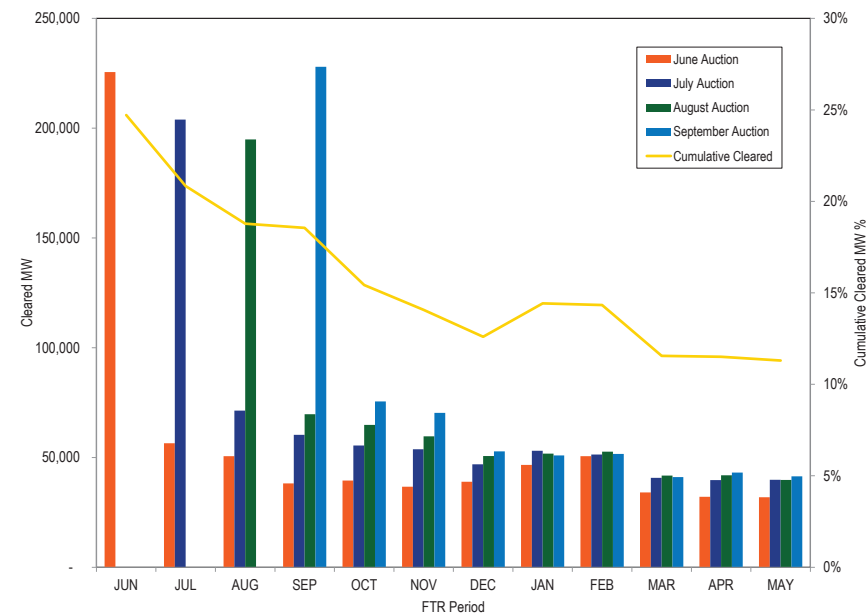


Figure 13-2 shows the cleared volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The cleared volume for non-prompt months is also significantly lower than in prompt months. On average, the non-prompt month cleared volume is 23.5 percent of the prompt month cleared volume.

Figure 13-2 Monthly Balance of Planning Period FTR Auction cleared volume (MW per period): June through September, 2020 Auction



Secondary Bilateral Market

Table 13-9 provides the PJM registered secondary bilateral FTR market volume for the 2019/2020 and the 2020/2021 planning periods. Bilateral FTR transactions registered through PJM do not need to include an accurate price or the entire volume of the transaction. Bilateral FTR transactions are not required to be registered through PJM. As a result, the bilateral data are not a reliable basis for evaluating actual bilateral activity in PJM FTRs.

Table 13-9 Secondary bilateral FTR market volume: 2019/2020 and 2020/2021³⁵

Planning Period	Type	Class Type	Volume (MW)
2019/2020	Obligation	24-Hour	5,032.9
		On Peak	1,996.1
		Off Peak	1,661.8
		Total	8,690.8
	Option	24-Hour	0.0
		On Peak	0.0
2020/2021	Obligation	24-Hour	2,404.0
		On Peak	22.0
		Off Peak	21.0
		Total	2,447.0
	Option	24-Hour	0.0
		On Peak	0.0
		Off Peak	0.0
		Total	0.0

Figure 13-3 shows the FTR bid, net bid and cleared volume from June 2003 through September 2020 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume includes FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self scheduled offers, excluding sell offers. The cleared volume in August 2018 was negative due to the liquidation of the GreenHat FTR portfolio, which resulted in a large quantity of FTRs selling in the monthly auction.

Figure 13-3 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through September 2020

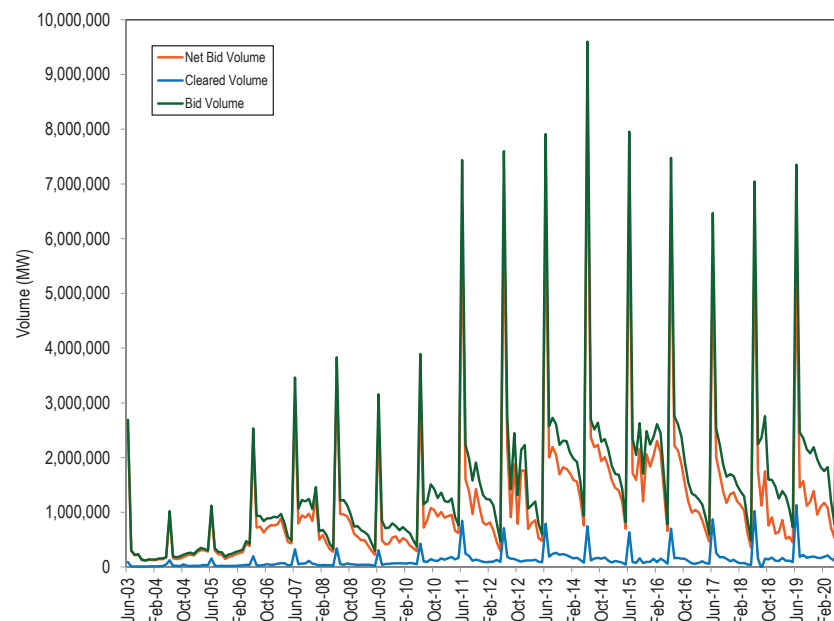
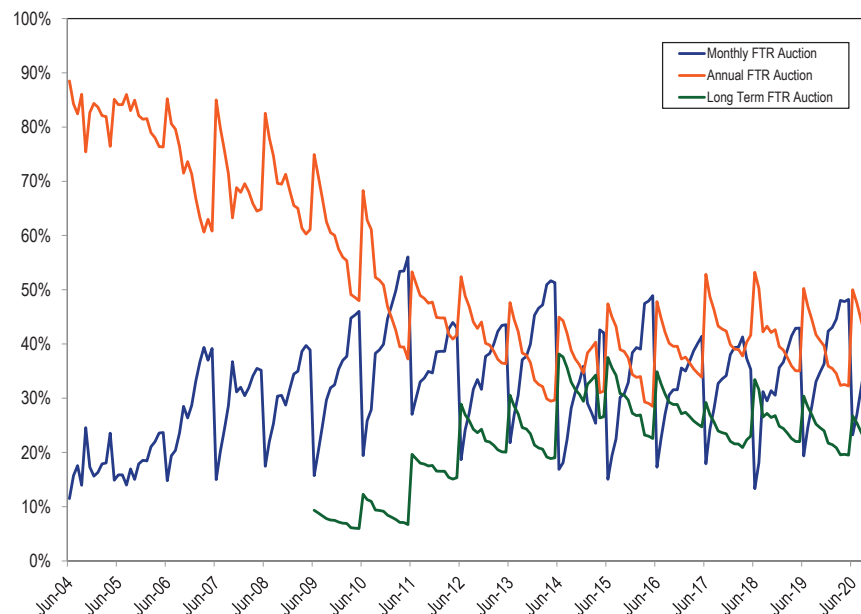


Figure 13-4 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through September 2020. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volumes spread equally to each month in the relevant planning period. Over the course of each planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, resulting in a greater share of total FTRs. When the Annual FTR Auction occurs, FTRs purchased in previous Monthly Balance of Planning Period Auctions, other than the current June auction, are no longer effective, resulting in a smaller share for monthly and a greater share for annual FTRs.

³⁵ The 2019/2020 planning period covers bilateral FTRs that are effective for any time between June 1, 2019 through May 31, 2020, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

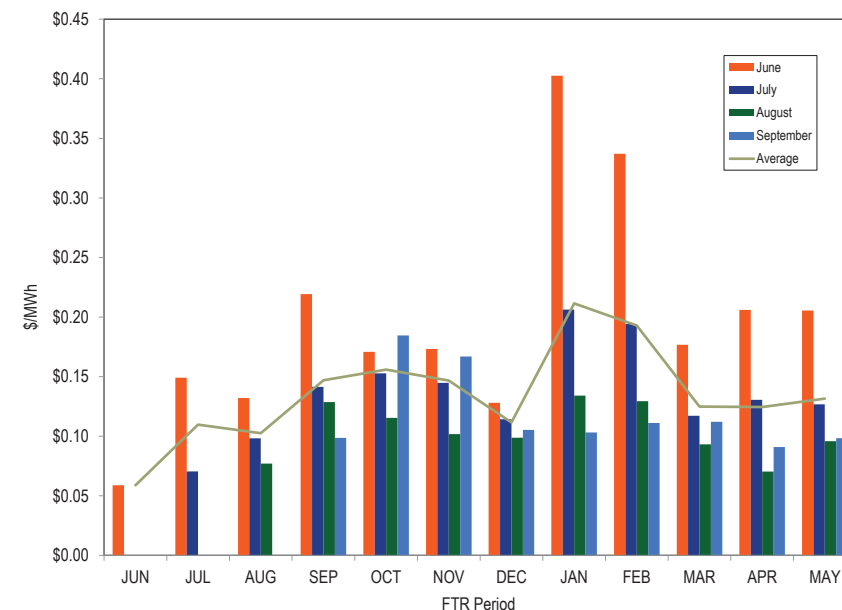
Figure 13-4 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through September 2020



Price

Figure 13-5 shows the weighted average cleared buy bid price of obligations in the Monthly Balance of Planning Period FTR Auctions by bidding period for the first four months of the 2020/2021 planning period and the average price per MWh for each of the FTR periods.

Figure 13-5 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy bid price per period (Dollars per MWh): 2020/2021 planning period



Profitability

FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of the FTR. For a prevailing flow FTR, the FTR revenue is the actual revenue that an FTR holder is paid as the target allocation plus the auction price from the sale of the FTR, if relevant, and the FTR cost is the auction price. For a counter flow FTR, the FTR revenue is the auction price that an FTR holder is paid to take the FTR plus the positive auction price from the sale of the FTR, if relevant, and the FTR cost is the target allocation that the FTR holder must pay plus the negative auction price from the sale of the FTR, if relevant. Bilateral transactions are excluded from the profit calculations because there are inconsistent reporting requirements and no assurance that reported

prices reflect the actual prices. ARR holders that self schedule FTRs receive congestion revenues but do not receive profits from those FTRs because ARR holders are assigned rights to congestion revenues which they choose to take directly as the congestion payments associated with the corresponding FTRs.

Hourly FTR profits are the sum of the hourly revenues minus the hourly costs for each FTR (not self scheduled) held by an organization. The hourly revenues equal hourly FTR target allocations, adjusted by the payout ratio. The hourly auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in hours. The FTR revenues do not include after the fact adjustments which are very small and do not occur in every month.

The surplus includes surplus day-ahead congestion revenue and FTR auction surplus. At least part of the surplus is included in FTR profits because the surplus is first allocated to FTR holders to cover any shortfall in paying FTR target allocations. Beginning with the 2018/2019 planning period, after covering any shortfall in FTR target allocations within the planning period, the net surplus at the end of the planning period is distributed to ARR holders.

The fact that FTR profits in each planning period have been positive for financial entities as a group, regardless of the payout ratio, raises questions about the competitiveness of the market. FTR profits for financial entities were not positive in the 2019/2020 planning period when accounting for GreenHat losses but were positive otherwise. FTR profits for financial entities without GreenHat losses were positive in every completed planning period from 2012/2013 through 2020/2021 except the 2016/2017 planning period, and were positive if summed over the entire period (Table 13-12). It is not clear, in a competitive market, why FTR profits for financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed to zero.

Table 13-10 lists FTR profits, and the congestion returned through self scheduled FTRs, by organization type and FTR direction for FTRs for the

first four months of the 2020/2021 planning period. This table includes the auction cost and revenue from both buying and selling FTRs that were effective between June 2020 and September 2020. This includes FTRs from the 2018/2021, 2019/2022 and 2020/2023 Long Term auctions, the 2020/2021 Annual auction, and the Monthly auctions from June 2020 to September 2020. The costs and revenues of the yearly FTR products are prorated based on the time period of the FTRs. Any revenues or costs related to bilateral transactions are not included in profits. All participants who were assigned ARRs are classified as physical ARR. Some participants that are not eligible for ARRs are classified as physical because they are physical participants, for example companies that own only generation.

Self scheduled FTRs have zero cost. ARR holders who self scheduled FTRs received \$65.0 million in congestion revenues. Revenues from self scheduled FTRs are a return of congestion to the load that paid the congestion and are not profits.

Table 13-10 FTR profits and revenues by organization type and FTR direction: 2020/2021

Organization Type	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	\$24,807,375	\$73,597,541	\$98,404,916			
Financial without GreenHat	\$25,227,516	\$73,310,330	\$98,537,846			
Physical	(\$472,235)	\$27,115,544	\$26,643,309			
Physical ARR	(\$5,528,371)	\$16,907,850	\$11,379,479	\$378,540	\$64,663,515	\$65,042,055
Total	\$18,806,769	\$117,620,935	\$136,427,704	\$378,540	\$64,663,515	\$65,042,055

Table 13-11 lists the monthly FTR profits for the 2019/2020 planning period and the first four months of the 2020/2021 planning period by organization type. FTR profits include revenue from FTR sales and do not include any revenue or cost from bilateral transactions. FTR revenues for self scheduled FTRs are not included. FTR profits for FTRs purchased in auctions by ARR holders are included. In the first four months of the 2020/2021 planning period, profits for all participants were \$136.4 million, up from \$3.5 million profits for the same time period in the 2019/2020 planning period. The largest month to month increase in profits was in August, \$54.9 million. Among

organization types, financial organizations had the largest increase in profits in the first four months of the 2020/2021 planning period, \$92.8 million. The increase in profits was primarily a result of higher target allocations.

Table 13-11 Monthly FTR profits by organization type: 2019/2020 and 2020/2021³⁶

Month	Organization Type				Total
	Financial	Financial without GreenHat	Physical	Physical ARR	
Jun-19	(\$7,530,412)	(\$5,175,703)	(\$4,406,629)	(\$5,300,686)	(\$17,237,726)
Jul-19	\$11,073,631	\$13,727,088	\$1,715,298	\$2,195,625	\$14,984,553
Aug-19	(\$11,192,103)	(\$7,445,637)	(\$4,515,760)	(\$2,965,124)	(\$18,672,988)
Sep-19	\$13,219,100	\$20,305,030	\$6,308,310	\$4,870,000	\$24,397,410
Oct-19	\$6,628,121	\$12,845,824	\$2,404,277	\$3,916,338	\$12,948,736
Nov-19	\$6,579,914	\$10,996,869	\$2,167,865	\$2,038,284	\$10,786,063
Dec-19	\$6,176,313	\$11,021,397	(\$212,596)	(\$3,696,208)	\$2,267,509
Jan-20	(\$5,308,687)	(\$132,954)	(\$10,539,357)	(\$10,405,137)	(\$26,253,180)
Feb-20	(\$14,980,199)	(\$11,873,252)	(\$11,213,649)	(\$10,337,622)	(\$36,531,470)
Mar-20	(\$14,165,737)	(\$12,669,353)	(\$8,006,489)	(\$10,777,549)	(\$32,949,775)
Apr-20	(\$14,526,206)	(\$11,926,918)	(\$11,145,117)	(\$11,779,700)	(\$37,451,023)
May-20	\$2,886,620	\$5,478,459	(\$5,416,808)	(\$7,372,412)	(\$9,902,600)
Summary for Planning Period 2019/2020					
Total	(\$21,139,644)	\$25,150,852	(\$42,860,656)	(\$49,614,191)	(\$113,614,490)
Jun-20	\$13,554,491	\$14,170,298	\$2,967,605	(\$105,462)	\$16,416,634
Jul-20	\$35,653,206	\$35,594,893	\$9,241,525	\$3,750,023	\$48,644,754
Aug-20	\$26,092,413	\$25,931,889	\$6,939,322	\$3,240,451	\$36,272,185
Sep-20	\$23,104,806	\$22,840,765	\$7,494,858	\$4,494,466	\$35,094,131
Summary for Planning Period 2020/2021					
Total	\$98,404,916	\$98,537,846	\$26,643,309	\$11,379,479	\$136,427,704

Table 13-12 lists the historical profits by calendar year by organization type beginning in the 2012/2013 planning period for FTRs purchased. (Profits do not include congestion revenue to self scheduled FTRs.) Profits include revenue from the sale of FTRs and exclude bilateral transactions. Profits include any end of planning period surplus distribution or uplift payments. The end of planning period surplus or uplift was distributed to FTR holders prorata based on FTR positive target allocations through the 2017/2018 planning period. Beginning with the 2018/2019 planning period, any net end of planning period surplus, after paying out any shortfall in FTR target allocations within the planning period, was distributed to ARR holders. Surplus allocated to ARR holders in the 2018/2019 planning period was \$112.3 million, in the 2019/2020 planning period, it was \$140.7 million and in the first four months of the 2020/2021 it was \$7.1 million.

³⁶ The GreenHat Default Allocation Assessment by PJM was \$46.3 million for the 2019/2020 planning period and \$133,000 for the 2020/2021 planning period, excluding the FTR Waiver Settlement of \$17.5 million. The calculated GreenHat losses do not exactly match the assessment. The loss calculation is based on GreenHat's actual portfolio instead of the assessment formula and does not consider bilateral transaction or GreenHat's collateral.

Table 13-12 FTR profits by organization type: 2012/2013 through 2020/2021³⁷

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021
Financial	Profit	\$201,825,234	\$913,502,323	\$250,551,943	\$68,895,867	(\$12,525,947)	\$239,981,474	\$113,086,231	(\$21,139,644)	\$98,404,916
	Surplus	(\$50,304,408)	(\$145,080,521)	\$19,453,837	\$4,921,078	\$8,810,267	\$90,361,918			
	Total	\$151,520,826	\$768,421,802	\$270,005,781	\$73,816,945	(\$3,715,680)	\$330,343,392	\$113,086,231	(\$21,139,644)	\$98,404,916
Financial without GreenHat	Profit	\$201,825,234	\$913,502,323	\$250,551,785	\$70,094,918	(\$11,821,248)	\$240,111,850	\$223,376,757	\$25,150,852	\$98,537,846
	Surplus	(\$50,304,408)	(\$145,080,521)	\$19,453,837	\$4,921,078	\$8,810,267	\$90,361,918			
	Total	\$151,520,826	\$768,421,802	\$270,005,623	\$75,015,995	(\$3,010,981)	\$330,473,768	\$223,376,757	\$25,150,852	\$98,537,846
Physical	Profit	\$68,537,800	\$297,456,284	\$82,853,390	\$10,007,327	(\$4,010,669)	\$57,532,872	(\$5,945,233)	(\$42,860,656)	\$26,643,309
	Surplus	(\$41,626,011)	(\$53,642,077)	\$5,395,706	\$1,865,146	\$4,181,855	\$34,296,618			
	Total	\$26,911,789	\$243,814,207	\$88,249,096	\$11,872,473	\$171,186	\$91,829,490	(\$5,945,233)	(\$42,860,656)	\$26,643,309
Physical ARR	Profit	\$26,572,818	\$366,128,947	\$112,609,140	\$82,181,795	(\$2,468,152)	\$66,458,939	(\$6,248,557)	(\$49,614,191)	\$11,379,479
	Surplus	(\$25,873,836)	(\$81,279,067)	\$18,515,990	\$7,110,576	\$12,040,688	\$47,753,635			
	Surplus from Self scheduled FTRs	(\$45,978,766)	(\$81,765,964)	\$15,530,158	\$3,073,711	\$6,469,297	\$42,513,186			
	Total	\$698,982	\$284,849,881	\$131,125,130	\$89,292,371	\$9,572,536	\$114,212,574	(\$6,248,557)	(\$49,614,191)	\$11,379,479
Total		\$179,131,597	\$1,297,085,890	\$489,380,007	\$174,981,788	\$6,028,043	\$536,385,456	\$100,892,442	(\$113,614,490)	\$136,427,704

* Bilateral transactions are included in surplus allocation calculation but are not included in profits calculation

* The first four months of the 2020/2021 planning period

Table 13-13 shows the profits and losses of the five most and the five least profitable participants by organization type. Total MWh is the sum of all MWh by organization type regardless of profitability. The Top 5 Profit is the sum of the profits of the five most profitable participants by organization type. The Top 5 Profit/MWh is the Top 5 Profit divided by the sum of the MWh of the top five participants by organization. The Top 5 Market Share of MWh is the sum of the MWh of the top five participants by organization type divided by Total MWh. The Top 5 Profit Share Among Profitable Participants is the Top 5 Profit divided by the sum of the profits of all profitable participants by organization type. The same logic applies for the statistics related to the Bottom 5 participants. The All row includes all participants including all organization types when calculating the share of the profits and losses of the top 5 and bottom 5 participants. When all participants across organization types are considered, four of the Top 5 participants are financial organizations and three of the Bottom 5 are financial organizations. Of all the organization types, the Top 5 physical ARR organizations' share of profits is the highest, 91.1 percent, as is their share of MWh, 81.2 percent. There is only a small number of physical ARR participants who directly purchase FTRs. The Bottom 5 financial participants' share of losses is 82.9 percent while and their share of MWh is 11.7 percent. The losses from financial organizations are concentrated in a small number of participants. The Loss/MWh of the Bottom 5 financial organizations was the lowest, by organization type.

Table 13-13 Top five and bottom five FTR profits by organization type: 2020/2021: June through September

Organization Type	Total MWh	Top 5 Profit	Top 5 Profit Share			Bottom 5 Loss	Bottom 5 Loss/MWh	Bottom 5 Loss Share Among	
			Top 5 Profit/MWh	Top 5 Market Share in MWh	Among Profitable Participants			Market Share in MWh	Unprofitable Participants
Financial	1,124,178,222	\$40,303,698	\$0.20	17.9%	33.3%	(\$18,612,256)	(\$0.14)	11.7%	82.9%
Financial without GreenHat	1,115,882,896	\$40,303,698	\$0.20	18.0%	33.3%	(\$18,612,256)	(\$0.14)	11.7%	83.4%
Physical	149,999,258	\$21,922,478	\$0.47	30.8%	59.2%	(\$6,348,258)	(\$0.28)	15.3%	61.3%
Physical ARR	146,994,659	\$18,915,747	\$0.16	81.2%	91.1%	(\$6,934,030)	(\$1.83)	2.6%	73.9%
All	1,421,172,140	\$42,405,150	\$0.18	16.2%	23.7%	(\$23,857,159)	(\$0.19)	8.6%	56.5%

³⁷ Bilateral profits and losses net to zero in market total profits and losses.

Table 13-14 shows the shares of profitable and unprofitable FTR MWh by organization type in the first four months of the 2020/2021 planning period. All organization types had more profitable MWh than unprofitable MWh.

Table 13-14 MWh share by profitability by organization type: 2020/2021: June through September

Organization Type	Unprofitable	Profitable
Financial	19.1%	80.9%
Financial without GreenHat	18.5%	81.5%
Physical	24.6%	75.4%
Physical ARR	9.5%	90.5%
Total	18.7%	81.3%

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-15 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for 2020. The Monthly Balance of Planning Period FTR Auctions for the first four months of the 2020/2021 planning period netted \$20.8 million in revenue, the difference between buyers paying \$125.7 million and sellers receiving \$105.0 million. For the entire 2019/2020 planning period, the Monthly Balance of Planning Period FTR Auctions netted \$52.9 million in revenue with buyers paying \$331.1 million and sellers receiving \$278.2 million.

Table 13-15 Monthly Balance of Planning Period FTR Auction revenue: January through September, 2020

Monthly Auction	Type	Trade Type	Class Type			
			24-Hour	On Peak	Off Peak	All
Jan-20	Obligations	Buy bids	\$2,722,807	\$9,772,463	\$5,897,569	\$18,392,839
		Sell offers	\$613,192	\$6,329,072	\$3,861,063	\$10,803,327
	Options	Buy bids	\$8,255	\$506,682	\$330,074	\$845,010
Sell offers		\$57,206	\$3,134,561	\$1,844,982	\$5,036,749	
Feb-20	Obligations	Buy bids	\$8,482,540	\$7,009,196	\$2,400,689	\$17,892,426
		Sell offers	\$554,350	\$7,558,765	\$3,516,954	\$11,630,068
	Options	Buy bids	\$0	\$614,467	\$273,334	\$887,800
Sell offers		\$39,630	\$3,015,705	\$1,524,774	\$4,580,110	
Mar-20	Obligations	Buy bids	\$5,723,624	\$6,212,182	\$2,869,495	\$14,805,301
		Sell offers	\$1,324,669	\$5,356,343	\$2,536,234	\$9,217,245
	Options	Buy bids	\$0	\$385,671	\$189,479	\$575,150
Sell offers		\$46,986	\$2,119,631	\$1,384,310	\$3,550,927	
Apr-20	Obligations	Buy bids	\$790,059	\$4,183,958	\$1,529,936	\$6,503,953
		Sell offers	\$41,448	\$2,776,189	\$734,853	\$3,552,490
	Options	Buy bids	\$0	\$166,392	\$110,528	\$276,920
Sell offers		\$24,751	\$1,253,544	\$677,821	\$1,956,117	
May-20	Obligations	Buy bids	(\$20,781)	\$2,228,724	\$942,289	\$3,150,231
		Sell offers	\$35,292	\$1,156,210	\$447,672	\$1,639,174
	Options	Buy bids	\$2,796	\$24,557	\$15,889	\$43,242
Sell offers		\$6,653	\$738,265	\$354,859	\$1,099,777	
Jun-20	Obligations	Buy bids	\$27,761,897	\$11,387,702	\$1,235,341	\$40,384,940
		Sell offers	\$522,757	\$16,675,803	\$9,108,134	\$26,306,694
	Options	Buy bids	\$34,116	\$577,513	\$278,460	\$890,089
Sell offers		\$193,426	\$4,818,477	\$4,281,572	\$9,293,476	
Jul-20	Obligations	Buy bids	\$10,769,326	\$6,260,865	\$12,724,621	\$29,754,813
		Sell offers	\$839,820	\$6,455,401	\$11,988,123	\$19,283,344
	Options	Buy bids	\$40,923	\$697,068	\$955,988	\$1,693,979
Sell offers		\$109,743	\$2,402,095	\$3,647,950	\$6,159,788	
Aug-20	Obligations	Buy bids	\$11,076,859	\$1,985,772	\$9,676,248	\$22,738,879
		Sell offers	\$548,721	\$3,457,199	\$10,686,371	\$14,692,290
	Options	Buy bids	\$9,471	\$889,062	\$1,194,634	\$2,093,167
Sell offers		\$176,942	\$2,268,717	\$3,353,809	\$5,799,468	
Sep-20	Obligations	Buy bids	\$10,907,926	\$4,158,962	\$11,628,905	\$26,695,793
		Sell offers	\$293,412	\$5,420,086	\$12,989,773	\$18,703,271
	Options	Buy bids	\$21,192	\$504,574	\$966,894	\$1,492,660
Sell offers		\$76,632	\$1,904,346	\$2,733,954	\$4,714,933	
2019/2020*	Obligations	Buy bids	\$133,437,559	\$129,554,826	\$45,741,569	\$308,733,954
		Sell offers	\$7,250,257	\$132,773,410	\$66,392,916	\$206,416,583
	Options	Buy bids	\$567,551	\$13,430,803	\$8,397,321	\$22,395,675
Sell offers		\$1,210,460	\$44,320,769	\$26,237,313	\$71,768,541	
	Net Total		\$125,544,393	(\$34,108,549)	(\$38,491,339)	\$52,944,505
2020/2021**	Obligations	Buy bids	\$60,516,008	\$23,793,302	\$35,265,115	\$119,574,425
		Sell offers	\$2,204,710.57	\$32,008,489	\$44,772,400	\$78,985,599
	Options	Buy bids	\$105,703	\$2,668,216	\$3,395,976	\$6,169,895
Sell offers		\$556,743	\$11,393,636	\$14,017,286	\$25,967,665	
	Net Total		\$57,860,257	(\$16,940,607)	(\$20,128,594)	\$20,791,056

* Shows Twelve Months for 2019/2020 **Shows four months for 2020/2021

FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source. Figure 13-6 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the first four months of the 2020/2021 planning period. The top 10 sinks that produced financial benefit accounted for 35.8 percent of total positive target allocations with the Western Hub accounting for 8.8 percent of all positive target allocations. The top 10 sinks that created liability accounted for 15.3 percent of total negative target allocations with PSEG accounting for 4.0 percent of all negative target allocations.

Figure 13-6 Ten largest positive and negative FTR target allocations summed by sink: 2020/2021

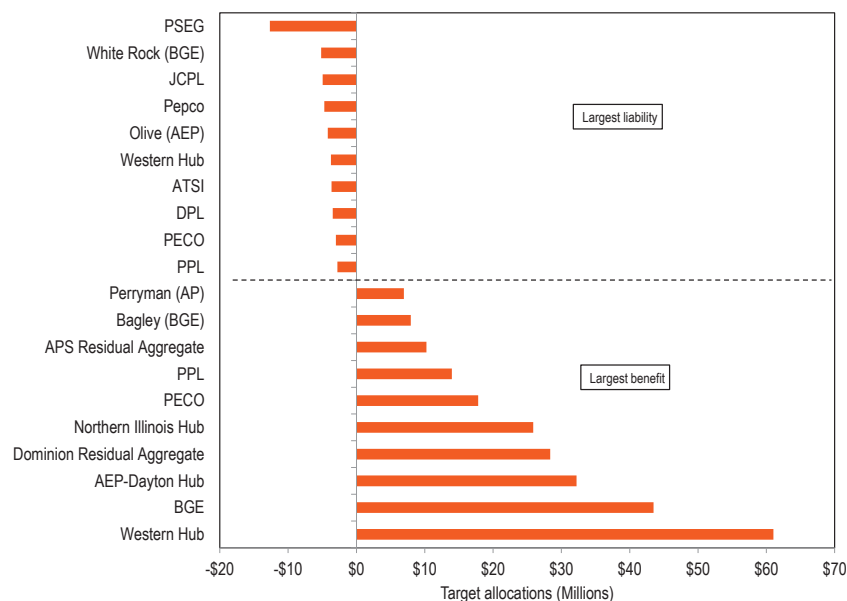
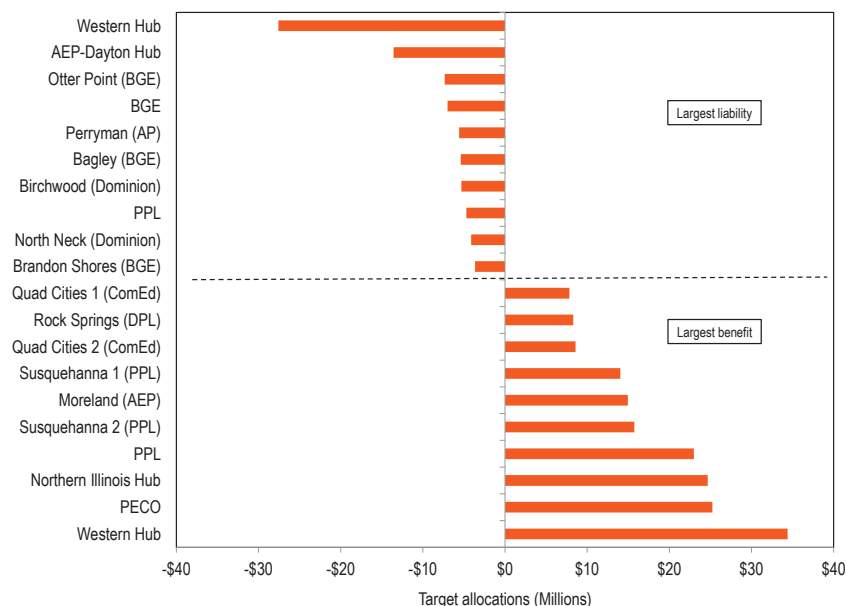


Figure 13-7 shows the 10 largest positive and negative FTR target allocations, summed by source, for the first four months of the 2020/2021 planning period. The top 10 sources with a positive target allocation accounted for 25.5 percent of total positive target allocations with the Western Hub accounting for 5.0 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 26.7 percent of all negative target allocations, with the Western Hub accounting for 8.7 percent.

Figure 13-7 Ten largest positive and negative FTR target allocations summed by source: 2020/2021



Surplus Congestion Revenue

On May 31, 2018, a rule change was implemented. Effective for the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are allocated to ARR holders.³⁸

Surplus congestion revenue should be allocated to ARR holders because such revenue is part of total congestion revenues. In addition, FTR Auction revenue results from the prices paid by willing FTR buyers and should not be returned to FTR buyers for any reason.

Surplus day-ahead congestion is the difference between the day-ahead congestion collected and FTR target allocations. Surplus FTR auction revenue is the difference between the sum of monthly FTR auction revenue from the Long Term, Annual and monthly auctions, and ARR target allocations. Surplus FTR auction revenue can result from high prices in the FTR auctions, and can result from both FTR capacity sold in excess of assigned ARR capacity on specific paths, and FTR capacity sold on paths not available to ARR holders.

Surplus congestion revenue is the sum of the surplus day-ahead congestion revenue and the surplus FTR auction revenue at the end of each month. Beginning with the 2014/2015 planning period, may use surplus FTR auction revenue to pay for the clearing of counter flow FTRs as part of the auction clearing process.³⁹ The remaining surplus is first used to ensure that ARR target allocations in the month are fully funded. Any remaining surplus is used to pay any shortfall in FTR target allocations for the month. Any remaining surplus is used to pay any shortfall in FTR target allocations from prior months in the planning period. Any remaining surplus is used to pay any shortfall in FTR target allocations for subsequent months in the planning period. Any congestion surplus remaining at the end of the planning period is distributed to ARR holders based on their positive target allocations.

If, at the end of the planning period, all the surplus congestion revenue has been provided to FTR holders and target allocations for the year are not

covered, an uplift charge is assigned to FTR holders to cover the net planning period deficiency. An individual participant's uplift charge allocation is the ratio of their share of net positive target allocations to the total net positive target allocations.

Prior to the 2017/2018 planning period, the surplus congestion revenue was not the simple sum of the surplus FTR auction revenue and surplus day ahead congestion because there were various cross market charges subtracted from FTR revenue, including M2M and competing use charges, which reduced available surplus congestion revenue.

Figure 13-8 shows the distribution of the total monthly surplus congestion and auction revenue distributed to FTR holders as if it were settled monthly. The figure shows the portions of total monthly surplus, represented by the total height of the bar, that are from day-ahead congestion surplus, represented by the blue portion of the bar, and from auction surplus, represented by the orange portion of the bar. The horizontal green lines represent the amount of revenue that FTRs were paid from the surplus to be made whole for that month. If there was day-ahead congestion surplus, FTRs were made whole through the surplus and the auction revenue was reserved for ARR holders. The height of the bar below the green line is the portion of auction surplus that went to FTR holders, and the height of the bar above the green line is the portion that would have gone to ARR holders at the end of the planning year, but only if nothing changed and this surplus was not provided to FTRs. If a green line is above the bar that means there was not enough surplus in that month to make FTRs whole, and that month will use surplus from previous or future months to make FTRs whole. For example, September 2020 did not have enough surplus to make FTRs whole. In settlements, those FTRs were made whole using surplus revenue from previous months, reducing the total surplus for the planning period. The final settlements will not be known until the end of the planning period.

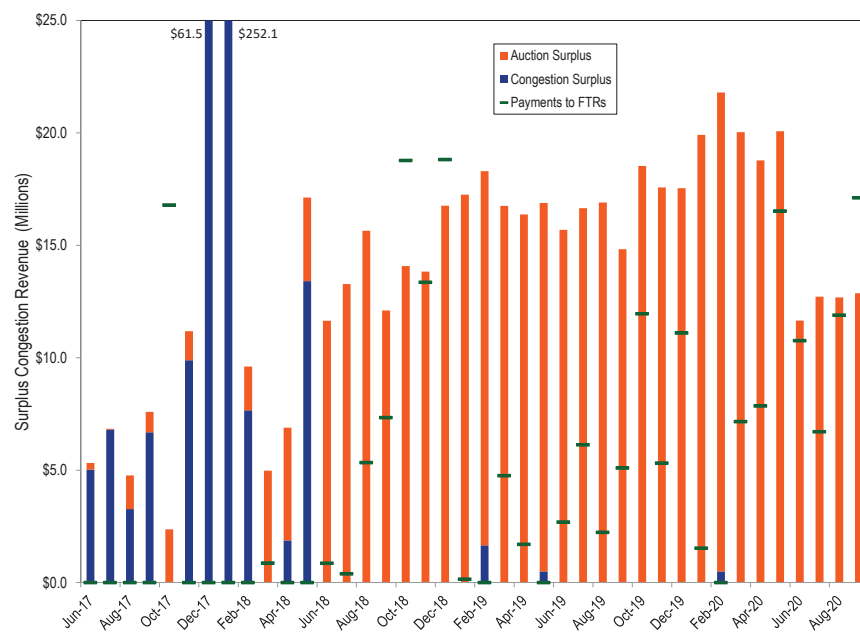
The market rules should recognize that ARR holders have the right to all surplus congestion revenue, not just the remainder after funding FTRs. The MMU recommends that all FTR auction revenue and all surplus day-ahead

³⁸ 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 (2018).

³⁹ See "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

congestion revenue be distributed directly to ARR holders on a monthly basis. In Figure 13-8 the amount represented by each bar would be assigned to ARR holders in every month. In late 2018, there were high target allocations with low congestion collected, resulting in the allocation of most or all of the surplus congestion revenue to FTR holders. This is an indication that too many FTRs were sold. In the first four months of the 2020/2021 planning period, the rules resulted in the payment of \$46.5 million of surplus congestion revenue to FTR holders that should have been paid to ARR holders.

Figure 13-8 Monthly surplus congestion and auction revenue distributed to FTR holders: June 2017 through September 2020⁴⁰



⁴⁰ The bars for December 2017 and January 2018 are truncated.

Figure 13-9 shows the surplus FTR auction revenue from the 2011/2012 planning period through the 2020/2021 planning period. Each new planning period introduces a new FTR model, including outages and PJM's discretionary adjustments for revenue adequacy. The differences in the assumptions in the market model can result in large differences in FTR auction surplus and ARR revenue from one planning period to another.

FTR auction revenue is the value that FTR buyers assign to congestion rights that belong to ARR holders. There is no logical or market based reason to assign any part of that auction revenue back to the FTR buyers. It is an unsupported wealth transfer. Auction revenue from the sale of FTRs should be distributed directly and completely to ARR holders. The MMU recommends that all FTR auction revenue be distributed to ARR holders on a monthly basis.

Figure 13-9 Monthly FTR auction surplus: 2011/2012 through 2020/2021

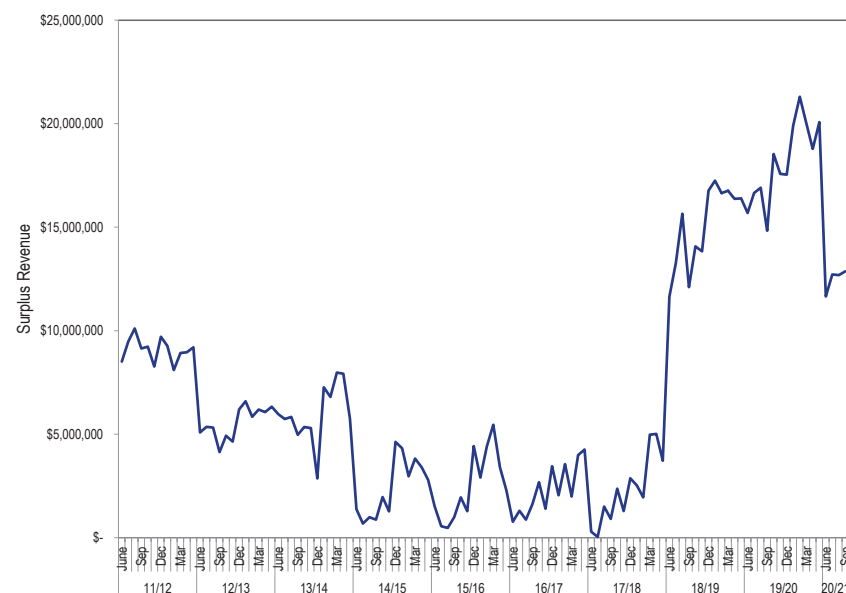


Table 13-16 shows the surplus FTR auction revenue, surplus day-ahead congestion revenue and surplus congestion revenue for planning periods 2010/2011 through the first four months of the 2020/2021 planning period.

Table 13-16 Surplus FTR Auction Revenue: 2010/2011 through 2020/2021⁴¹

Planning Period	Surplus FTR Auction Revenue (Millions)	Surplus Day-Ahead Congestion (Millions)	Surplus Congestion Revenue (Millions)
2010/2011	\$29.7	(\$1,218.7)	(\$449.3)
2011/2012	\$108.9	(\$460.3)	(\$192.5)
2012/2013	\$66.7	(\$328.5)	(\$292.3)
2013/2014	\$71.7	(\$715.3)	(\$678.7)
2014/2015*	\$29.0	\$139.8	\$139.6
2015/2016	\$29.6	\$56.4	\$42.5
2016/2017	\$27.9	\$97.1	\$72.6
2017/2018	\$27.4	\$344.0	\$371.2
2018/2019	\$180.8	(\$68.5)	\$112.3
2019/2020	\$217.8	(\$87.9)	\$140.7
2020/2021**	\$49.9	(\$47.7)	\$7.1
Total	\$839.4	(\$2,289.5)	(\$726.8)

*Start of counter flow "buy back"

**First four months

Revenue Adequacy

FTR revenue adequacy simply compares congestion revenues to FTR target allocations. Revenue adequacy is not a benchmark for how well the FTR process is working. Target allocations define the maximum payments to FTRs but target allocations are not congestion. FTR revenue adequacy is not equivalent to the adequacy of ARR as an offset for load against total congestion. A path specific target allocation is not a guarantee of payment.

Actual congestion revenues are unrelated to PJM's decisions about the FTR auction model. As a result, the fewer FTRs sold, the higher the probability that congestion will exceed the sum of the FTR target allocations. For example, PJM's subjective decision to reduce available system capability in FTR auctions for the 2014/2015 through 2016/2017 planning periods resulted in a high level of revenue adequacy. PJM's decisions have included the arbitrary use of higher outage levels and the decision to include additional constraints (closed

⁴¹ Total congestion surplus not equal to the sum of the columns in years prior to the 2017/2018 planning period because other charges were subtracted from the congestion surplus.

loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions have led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs and therefore a reduction in available FTRs.

While PJM's arbitrary decision to increase outages in the ARR allocation and in the Annual FTR Auction reduced FTR revenue inadequacy, it did not address the Stage 1A ARR over allocation issue directly because Stage 1A ARR allocations cannot be prorated. PJM's actions for the 2014/2015 through 2016/2017 planning periods resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability. The direct assignment of balancing congestion and M2M payments to load beginning in the 2017/2018 planning period increased the congestion revenue available to pay FTR holders. In response, PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing ARR allocations and FTR availability.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues in the current design. The reasons include: the use of generation to load paths rather than a measure of total congestion to assign congestion revenue rights; the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction; unavoidable modeling differences such as emergency outages; avoidable modeling differences such as outage modeling decisions; and cross subsidies among and between FTR participants and ARR holders.

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 load, and allocating surplus congestion revenue, which includes excess day-ahead congestion revenue and FTR auction revenue, solely to FTR holders, increased revenue to FTRs and reduced payments to load. The May 31, 2018, FERC Order, effective for the 2018/2019 planning period, assigned surplus congestion revenue to ARR holders and

increased payments to load, partially offsetting the impacts of the prior order.⁴²

Revenue adequacy for ARRs is an almost meaningless concept. Revenue adequacy for ARRs means that FTR buyers collectively pay more than zero for FTRs in FTR auctions, and that those payments were received by ARR holders. Unsurprisingly, ARRs have been revenue adequate for every auction to date. ARR revenue adequacy has nothing to do with the adequacy of ARRs as an offset to total congestion. ARRs can be revenue adequate at the same time that ARRs return only half of congestion to load.

Total net FTR auction revenue for the 2019/2020 planning period, before accounting for self scheduling, load shifts or residual ARRs, was \$982.0 million. The FTR auction revenue pays ARR holders' credits. For the first four months of the 2020/2021 planning period, total net FTR auction revenue was \$670.5 million.

Table 13-17 presents the PJM FTR revenue detail for the 2019/2020 planning period and the first four months of the 2020/2021 planning period. This includes expected 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. In this table, under the new balancing congestion and M2M payment rules, any negative congestion is from day-ahead congestion and does not include balancing congestion. A negative deficiency is a surplus, which will be distributed to ARR holders at the end of the planning period, while a positive deficiency is a shortfall, which will be charged as FTR uplift at the end of the planning period.

**Table 13-17 Total annual PJM ARR and FTR revenue detail (Dollars (Millions)):
2019/2020 and 2020/2021**

Accounting Element	2019/2020	2020/2021*
ARR information		
ARR target allocations	\$752.2	\$509.1
ARR credits	\$752.2	\$509.1
FTR auction revenue	\$982.0	\$670.5
Annual FTR Auction net revenue	\$844.6	\$577.0
Long Term FTR Auction net revenue	\$84.5	\$72.7
Monthly Balance of Planning Period FTR Auction net revenue	\$52.9	\$20.8
Surplus auction revenue		
ARR Surplus	\$217.8	\$49.9
ARR payout ratio	100%	100%
FTR targets		
Positive target allocations	\$904.3	\$452.8
Negative target allocations	(\$224.3)	(\$76.2)
FTR target allocations	\$680.1	\$376.6
Adjustments:		
Adjustments to FTR target allocations	(\$7.9)	(\$1.4)
Total FTR targets	\$673.5	\$375.2
FTR payout ratio	100%	100%
FTR revenues		
ARR excess	\$217.8	\$49.9
Congestion		
Net Negative Congestion (enter as negative)	\$0.0	\$0.0
Hourly congestion revenue	\$596.4	\$328.9
M2M Payments(credit to PJM minus credit to M2M entity)	\$0.0	\$0.0
Adjustments:		
Surplus revenues carried forward into future months	\$0.0	\$4.2
Surplus revenues distributed back to previous months	\$0.0	\$0.0
Other adjustments to FTR revenues	\$0.0	\$0.0
Total FTR revenues		
Surplus revenues distributed to other months	\$0.0	\$4.2
Net Negative Congestion charged to DA Operating Reserves	\$0.0	\$0.0
Total FTR congestion credits	\$814.2	\$383.0
Total congestion credits(includes end of year distribution)	\$814.2	\$383.0
Remaining deficiency	(\$140.7)	(\$7.9)

* First four months of 2020/2021 planning period

FTR target allocations are defined based on hourly CLMP differences in the day-ahead energy market for FTR paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations but are capped at target allocations. Table 13-18 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month.

42 163 FERC ¶61,165 (2018).

The total row in Table 13-18 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. September 2020 had revenue shortfalls totaling \$4.2 million, but were fully funded using excess revenue from previous months.

Table 13-18 Monthly FTR accounting summary (Dollars (Millions)): 2019/2020 and 2020/2021

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Surplus/Deficiency (with adjustments)
Jun-19	\$52.1	\$39.4	100.0%	\$52.1	100.0%	(\$13.0)
Jul-19	\$91.7	\$82.0	100.0%	\$91.7	100.0%	(\$10.5)
Aug-19	\$57.1	\$42.8	100.0%	\$57.1	100.0%	(\$14.7)
Sep-19	\$83.4	\$73.6	100.0%	\$83.4	100.0%	(\$9.7)
Oct-19	\$91.1	\$84.5	100.0%	\$91.1	100.0%	(\$6.6)
Nov-19	\$84.6	\$72.3	100.0%	\$84.6	100.0%	(\$12.3)
Dec-19	\$80.6	\$74.1	100.0%	\$80.6	100.0%	(\$6.4)
Jan-20	\$63.2	\$44.8	100.0%	\$63.2	100.0%	(\$18.4)
Feb-20	\$50.0	\$28.2	100.0%	\$50.0	100.0%	(\$21.8)
Mar-20	\$51.4	\$38.5	100.0%	\$51.4	100.0%	(\$12.9)
Apr-20	\$42.9	\$32.0	100.0%	\$42.9	100.0%	(\$10.9)
May-20	\$66.2	\$62.7	100.0%	\$66.2	100.0%	(\$3.5)
Summary for Planning Period 2018/2019						
Total	\$814.2	\$674.9		\$814.2		(\$140.7)
Jun-20	\$74.4	\$73.3	100.0%	\$74.7	100.0%	(\$1.1)
Jul-20	\$118.3	\$112.3	100.0%	\$118.3	100.0%	(\$6.0)
Aug-20	\$95.2	\$94.4	100.0%	\$95.2	100.0%	(\$0.8)
Sep-20	\$90.9	\$95.2	94.9%	\$95.2	100.0%	\$0.0
Summary for Planning Period 2019/2020						
Total	\$378.8	\$375.2		\$383.4		(\$7.9)

Figure 13-10 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through September 2020. The months with payout ratios above 100 percent have congestion revenue greater than the target allocations and the months with payout ratios under 100 percent have congestion revenue that is less than the target allocations. Figure 13-10 also shows the payout ratio after distributing surplus congestion revenue across months within the planning period. The payout ratio for revenue inadequate months in the current planning period may change if surplus congestion revenue is collected in the remainder of the planning period.

Figure 13-10 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through September 2020

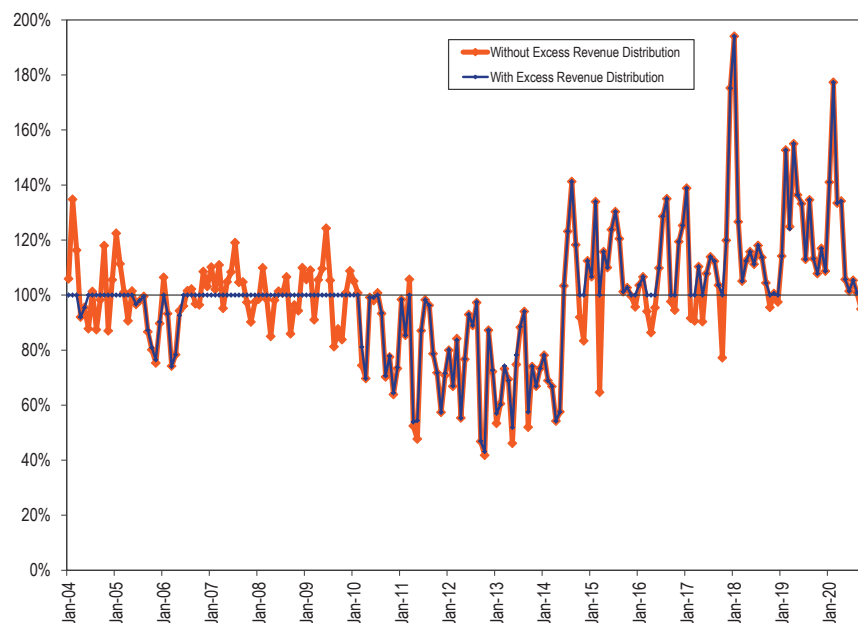


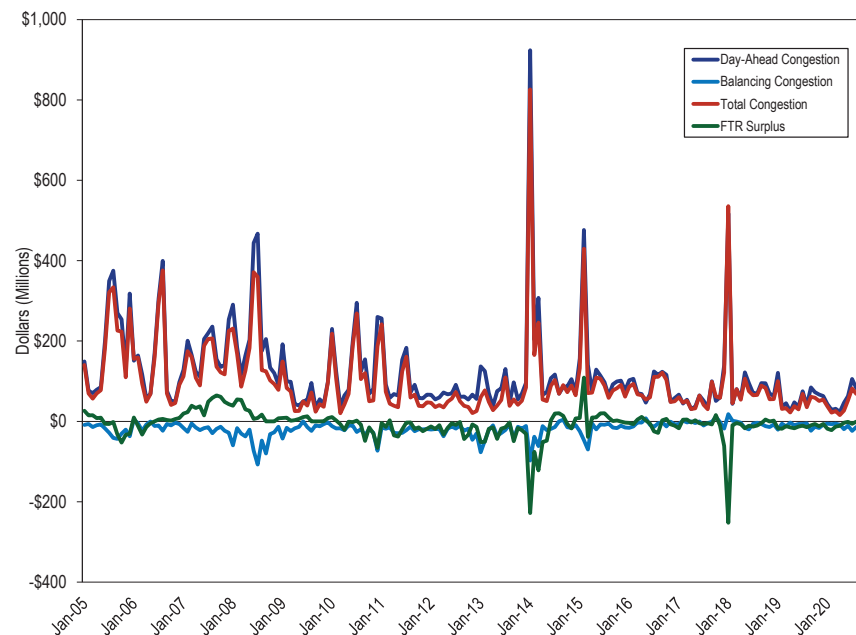
Table 13-19 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. Planning periods with a payout ratio over 100 percent are listed at 100 percent. Planning period 2013/2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For the 2014/2015, 2015/2016 and 2016/2017 planning periods, there was surplus congestion revenue paid to 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 13-19 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%
2019/2020	100.0%
2020/2021	100.0%

Figure 13-11 shows the FTR surplus, day-ahead, balancing and total congestion payments from January 2005 through September 2020.

Figure 13-11 FTR surplus and day-ahead, balancing and total congestion: January 2005 through September 2020



ARRs as an Offset to Congestion for Load

Load pays for the transmission system and pays congestion revenues. FTRs, and later ARR, were intended to return congestion revenues to load. With the implementation of the current, path based FTR/ARR design, the purpose of FTRs has been subverted. The inconsistencies between actual network solutions used to serve load and path based rights available to load cause a misalignment of congestion collected from ARR holders and the congestion that is collectable by the same ARR holders. These inconsistencies between actual network use and path based rights cause cross subsidies among ARR holders and between ARR holders and FTR holders. The result of this misalignment is individual zones with vastly different offsets due to cross subsidies between zones based on the location of their path based ARRs compared to their actual congestion costs.

Table 13-20 shows the ARR and FTR revenue paid to load, the congestion offset available to load with and without allocating balancing congestion to load and the congestion offset when surplus congestion revenue is allocated to load. Offsets highlighted are the actual offsets based on the effective rules in that planning period. The pre 2017/2018 offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total day-ahead congestion and the load share of balancing and M2M payments. The 103.6 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. 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 \$1,305.1 million less in congestion offsets from the 2011/2012 through the 2018/2019 planning period. The total overpayment to FTR holders for the 2011/2012 through 2018/2019 planning period would have been \$1,427.4 million.

If the surplus revenue available for the first four months of the 2020/2021 planning period were distributed to ARR holders, total ARR and self scheduled FTR revenue would offset 50.6 percent of total congestion costs for the first four months of the 2020/2021 planning period. The offset would be 50.2 percent without distribution of surplus revenue. For the 2019/2020 planning period, FTR bidders paid more in the auctions than the actual day-ahead target allocations for the same paths. This resulted in an offset over 100 percent because the resulting ARR value was greater than actual congestion costs. This had not happened previously, and was a result of an unexpected reduction in energy prices and in day-ahead target allocations. FTR prices were lower in the Annual FTR Auction, reducing the offset for the first four months of the 2020/2021 planning period.

Table 13-20 ARR and FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2020/2021

Planning Period	Revenue						Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Surplus)	
	ARR Credits	FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue	Total ARR/ FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset
2011/2012	\$512.2	\$249.8	\$1,025.4	(\$275.7)	\$749.7	(\$192.5)	\$762.0	101.6%	\$598.6	79.8%	\$563.0	79.8%
2012/2013	\$349.5	\$181.9	\$904.7	(\$379.9)	\$524.8	(\$292.3)	\$531.4	101.3%	\$275.9	52.6%	\$257.5	52.6%
2013/2014	\$337.7	\$456.4	\$2,231.3	(\$360.6)	\$1,870.6	(\$678.7)	\$794.0	42.4%	\$574.1	30.7%	\$623.1	30.7%
2014/2015	\$482.4	\$404.4	\$1,625.9	(\$268.3)	\$1,357.6	\$139.6	\$886.8	65.3%	\$686.6	50.6%	\$715.0	52.7%
2015/2016	\$635.3	\$223.4	\$1,098.7	(\$147.6)	\$951.1	\$42.5	\$858.8	90.3%	\$744.8	78.3%	\$745.2	78.4%
2016/2017	\$640.0	\$169.1	\$885.7	(\$104.8)	\$780.8	\$72.6	\$809.1	103.6%	\$727.7	93.2%	\$763.8	97.8%
2017/2018	\$427.3	\$294.2	\$1,322.1	(\$129.5)	\$1,192.6	\$371.2	\$721.5	60.5%	\$595.7	50.0%	\$886.5	74.3%
2018/2019	\$529.1	\$130.1	\$832.7	(\$152.6)	\$680.0	\$112.3	\$675.93	99.4%	\$530.8	78.1%	\$626.3	92.1%
2019/2020	\$542.0	\$91.9	\$612.1	(\$160.4)	\$442.7	\$140.7	\$652.54	147.4%	\$492.1	111.2%	\$614.2	138.8%
2020/2021*	\$124.4	\$65.2	\$328.9	(\$67.2)	\$257.2	\$7.9	\$196.29	76.3%	\$129.1	50.2%	\$130.2	50.6%
Total	\$4,579.9	\$2,266.3	\$10,538.4	(\$1,979.5)	\$8,550.0	(\$284.6)	\$6,692.0	78.3%	\$5,355.6	60.8%	\$5,794.8	67.3%

* Four months of 2020/2021 planning period

Table 13-20 demonstrates the inadequacies of the ARR/FTR design. The goal of the design should be to give the rights to 100 percent of the congestion revenues to the load.

The cumulative offset, beginning in the 2011/2012 planning period, is the sum of the revenue received for that planning period and all previous planning periods divided by the total congestion for that planning period and all previous planning periods. The cumulative shortfall is the cumulative difference between the ARR holders' revenue and the congestion they paid, for the planning period and prior planning periods.

Table 13-21 shows the cumulative offset and shortfall, assuming the rules implemented in the 2017/2018 planning period. The cumulative offset percentage has increased since the 2014/2015 planning period. However, the cumulative shortfall in dollars decreased only in the 2019/2020 planning period. The cumulative offset would have been 67.3 percent if the 2017/2018 surplus allocation rules had been in place for the entire period.

Table 13-21 ARR and FTR cumulative offset for ARR holders using 2017/2018 surplus allocation: 2011/2012 through 2020/2021

Planning Period	Cumulative Offset	Cumulative Shortfall (Millions)
2011/2012	79.8%	(\$151.1)
2012/2013	68.6%	(\$400.0)
2013/2014	46.1%	(\$1,696.5)
2014/2015	48.1%	(\$2,339.1)
2015/2016	53.3%	(\$2,544.9)
2016/2017	58.9%	(\$2,561.9)
2017/2018	61.4%	(\$2,868.0)
2018/2019	64.0%	(\$2,921.8)
2019/2020	67.8%	(\$2,750.2)
2020/2021	67.3%	(\$2,877.1)

* Four months of 2020/2021 Planning Period

Table 13-22 shows the cumulative offset and shortfall using the rules that were effective in the given planning period to calculate the ARR/FTR revenue. The cumulative offset was 75.0 percent based on the rules that were in place for each planning period. Load has been underpaid by \$2.2 billion from the 2011/2012 planning period through the first four months of the 2020/2021 planning period. The amount of underpayment would have been even greater, \$2.9 billion, if the 2017/2018 surplus allocation rules had been in place.

Table 13-22 ARR and FTR cumulative offset for ARR holders using effective surplus allocation rules: 2011/2012 through 2020/2021

Planning Period	Cumulative Offset	Cumulative Shortfall (Millions)
2011/2012	101.6%	\$12.3
2012/2013	101.5%	\$18.9
2013/2014	66.4%	(\$1,057.7)
2014/2015	66.1%	(\$1,528.5)
2015/2016	70.3%	(\$1,620.9)
2016/2017	74.5%	(\$1,592.6)
2017/2018	70.5%	(\$2,189.5)
2018/2019	72.3%	(\$2,243.2)
2019/2020	75.8%	(\$2,071.6)
2020/2021*	75.0%	(\$2,198.7)

* Four months of 2020/2021 Planning Period

Zonal ARR Congestion Offset

ARRs are allocated to zonal load based on historical generation to load transmission paths, in many cases based on pre 1999 paths. ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays in congestion charges net of payments to the generation that serves the zonal load, including generation in the zone and outside the zone.⁴³

Table 13-23 shows the day-ahead congestion and balancing congestion and M2M charges paid by load in each zone along with the congestion offsets paid to load: FTR auction revenue; self scheduled FTR revenue; and the allocation of end of planning period surplus.⁴⁴ The offset for the 2019/2020 planning period assigns the current surplus revenue at the end of the quarter to ARR holders Table 13-23 also shows payments by load for balancing congestion and M2M payments. The total congestion offset paid to load is the sum of all of those credits and charges.

The zonal offset percentage shown in Table 13-23 is the sum of the congestion related revenues (offset) paid to load in each zone divided by the total congestion payment made by load in each zone.

43 See "Constraint Based Congestion Calculations," PJM ARR FTR Market Task Force (July 17, 2020) <<https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/2020/20200722/20200722-item-03a-constraint-based-congestion-calculations.ashx>>.

44 See 2019 State of the Market Report for PJM, Volume 2, Section 11: Congestion and Marginal Losses

Table 13-23 Zonal ARR and FTR total congestion offset (in millions) for ARR holders: 2020/2021 planning period

Zone	ARR Credits	FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
AECO	\$1.5	\$0.0	(\$1.0)	\$0.1	\$0.5	\$3.6	(\$0.8)	(\$0.2)	\$2.7	19.6%
AEP	\$13.2	\$10.1	(\$10.4)	\$1.3	\$14.1	\$59.4	(\$9.5)	(\$1.6)	\$48.2	29.3%
APS	\$11.0	\$8.5	(\$4.0)	\$0.8	\$16.3	\$22.2	(\$3.4)	(\$0.6)	\$18.2	89.7%
ATSI	\$6.8	\$0.1	(\$5.5)	\$0.3	\$1.6	\$26.5	(\$4.8)	(\$0.9)	\$20.8	7.9%
BGE	\$19.5	\$1.2	(\$2.8)	\$0.9	\$18.9	\$13.5	(\$2.2)	(\$0.4)	\$10.9	172.5%
ComEd	\$12.2	\$4.4	(\$8.4)	\$0.7	\$8.8	\$38.9	(\$6.4)	(\$1.3)	\$31.1	28.3%
DAY	\$2.0	\$0.1	(\$1.5)	\$0.1	\$0.7	\$6.1	(\$1.2)	(\$0.2)	\$4.7	16.0%
DEOK	\$8.1	\$1.4	(\$2.3)	\$0.4	\$7.6	\$9.3	(\$1.9)	(\$0.4)	\$7.0	107.7%
DLCO	\$1.9	\$0.1	(\$1.2)	\$0.1	\$0.9	\$4.1	(\$1.1)	(\$0.3)	\$2.8	32.3%
Dominion	\$2.4	\$31.8	(\$9.0)	\$1.0	\$26.2	\$41.2	(\$9.9)	(\$0.2)	\$31.1	84.3%
DPL	\$10.0	\$2.4	(\$1.7)	\$0.5	\$11.2	\$17.5	(\$1.8)	(\$1.4)	\$14.3	78.0%
EKPC	\$1.0	\$0.0	(\$1.0)	\$0.0	\$0.1	\$4.5	(\$0.9)	(\$0.2)	\$3.5	1.5%
EXT	\$0.2	\$0.0	\$0.0	\$0.0	\$0.2	\$0.6	(\$1.0)	\$0.0	(\$0.5)	(37.3%)
JCPL	\$2.0	\$0.0	(\$2.1)	\$0.1	(\$0.0)	\$8.3	(\$1.8)	(\$0.3)	\$6.2	(0.6%)
Met-Ed	\$1.1	\$0.3	(\$1.3)	\$0.1	\$0.2	\$11.0	(\$1.9)	(\$0.2)	\$8.8	2.0%
OVEC	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.4	(\$0.1)	\$0.0	\$0.3	0.0%
PECO	\$5.0	\$0.1	(\$3.5)	\$0.2	\$1.8	\$12.3	(\$2.6)	(\$0.5)	\$9.1	20.0%
PENELEC	\$2.0	\$1.9	(\$1.4)	\$0.1	\$2.7	\$7.7	(\$1.2)	(\$0.2)	\$6.3	43.3%
Pepco	\$8.6	\$1.3	(\$2.5)	\$0.4	\$7.9	\$10.8	(\$2.0)	(\$0.4)	\$8.4	93.1%
PPL	\$7.7	\$1.4	(\$3.4)	\$0.4	\$6.1	\$14.8	(\$2.5)	(\$0.5)	\$11.7	52.2%
PSEG	\$8.2	\$0.0	(\$4.0)	\$0.4	\$4.5	\$15.6	(\$3.2)	(\$0.6)	\$11.8	38.2%
RECO	\$0.1	\$0.0	(\$0.1)	\$0.0	(\$0.1)	\$0.6	(\$0.3)	(\$0.0)	\$0.3	(21.1%)
Total	\$124.4	\$65.2	(\$67.2)	\$7.9	\$130.2	\$328.9	(\$60.5)	(\$10.5)	\$257.9	50.5%

The total congestion offset paid to loads in the first four months of the 2020/2021 planning period would be 50.5 percent of congestion costs if the surplus revenue available were distributed to ARR holders.⁴⁵ The results vary significantly by zone. Loads in some zones, like BGE, receive substantially more in offsets than their total congestion payments. Loads in other zones, like ATSI, receive substantially less in offsets than their total congestion payments. The offsets are a function of the assignment of ARRs and the valuation of ARRs in the FTR auctions.

⁴⁵ The 50.5 percent offset result is not exactly equal to 50.6 percent offset included in this section as a result of rounding.

Credit

There were three collateral defaults in the first nine months of 2020 for a total of \$34,410. There were 22 payment defaults in the first nine months of 2020 not involving GreenHat Energy, LLC for a total of \$31,796. GreenHat Energy accrued payment defaults of \$15.6 million in the first nine months of 2020 for a total of \$162.6 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.⁴⁶ In addition, PJM added the settlement fee and claimant payee funds to the default allocation, resulting in allocations of \$12.5 million and \$5.0 million for a total of \$180.1 million.

GreenHat Settlement Proceedings

On June 5, 2019, FERC issued an order that established a paper hearing and settlement judge procedures regarding the GreenHat liquidation waiver request.⁴⁷ FERC recognized “...there are multiple complexities associated with implementing the Waiver Order Directive that should be addressed in a paper hearing...”⁴⁸ Before the paper hearing began, FERC established a settlement procedure to “...encourage the parties to make every effort to settle their disputes before the paper hearing commences.”⁴⁹

By delegated order issued December 30, 2019, the Commission approved a settlement agreement between PJM and the interested parties.⁵⁰ The result of the settlement is a release of all claims of harm resulting from the July auction liquidation of GreenHat’s portfolio, the payment of \$12.5 million directly to

⁴⁶ See the 2019 Quarterly State of the Market Report for PJM: January through June for a more complete explanation of credit issues that occurred in 2019.

⁴⁷ 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. Daugherty, Suzanne, email sent to the MC, MRC, CS, and MSS email distribution list, “Notification of GreenHat Energy, LLC Payment Default,” (June 22, 2018).

⁴⁸ See 167 FERC ¶ 61, 2019 at P 27 (2019).

⁴⁹ See *Id.* at P 28.

⁵⁰ See 169 FERC ¶ 61,260 (2019).

two participants, and payment of up to \$5 million total to participants that can show economic harm from PJM's actions during the July auction.

This settlement, requiring up to \$17.5 million in payments, will be recovered via the default allocation assessment fund, which is allocated to all PJM members in proportion to their total net bill.

Default Portfolio Considerations

Under the method applied to the GreenHat default, when an FTR participant defaults on their positions, their portfolio remains in the FTR market. This portfolio will continue to accrue revenues and/or charges and must be reconciled. The current method to reconcile defaulted portfolios is that, while the defaulting participant is barred from the market, PJM treats the positions as unchanged, lets the positions settle at day ahead prices, and charges any net losses to the default allocation assessment. This method exposes all members in PJM to an uncertain charge for the default allocation assessment that will not be known until those FTRs settle.

The MMU recommends cancelling the FTRs in the defaulting portfolio rather than holding or liquidating them. This would release the capacity in the portfolio back to the FTR market. The market would then decide the value of the capacity released and the timing of its release. There is no discretion necessary to settle the defaulted position and the losses are contained within the ARR/FTR market.

Cancellation of a defaulting portfolio does not change congestion. Cancellation of a defaulting portfolio can affect ARR/FTR funding as a result of changes in auction revenue, changes in the net target allocations, and potential simultaneous feasibility violations, while any collateral collected from the defaulted participant is available to offset losses from the cancelled FTRs. However, PJM can and does address similar issues routinely. PJM has tools available, such as the counter flow buyback and Stage 1A over allocation rules, and uses them regularly in the Annual FTR Auction, to improve funding as well as address feasibility concerns. Cancellation of FTRs isolates the costs of the default to those participating in and benefitting from the FTR market.

FTR Forfeitures

Hourly FTR Cost

When the FTR forfeiture rule is triggered, only the related hourly profits are forfeited. Only the profit is forfeited and only for the hours in which the rule is violated. The rule does not impose a penalty, but only the return of the profit associated with the rule violation. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost.

FERC Order on FTR Forfeitures

Effective January 19, 2017, a modified FTR forfeiture rule was applied.⁵¹ 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 13-12 shows the monthly FTR forfeitures under the modified FTR forfeiture rule from January 19, 2017, through September 30, 2020. As required by the FERC order, PJM began retroactively billing FTR forfeitures with the September 2017 bill. In the period from January 2017 through September 2017, participants did not have good information about the level of their FTR forfeitures, so they could not accurately modify their bidding behavior to avoid FTR forfeitures. After September 2017, FTR forfeitures decreased significantly, and stabilized, as participants received information on their FTR forfeitures.

On June 24, 2019, PJM implemented a new method to properly calculate the hourly cost of an FTR only for hours in which it is effective.⁵² Beginning with the September 2019 bill, PJM began billing using the correct hourly cost

⁵¹ See 2019 State of the Market Report for PJM, Volume 2, Section 13: Financial Transmission Rights for the history.

⁵² See "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).

calculation. For the period of January 19, 2017, through September 30, 2020, total FTR forfeitures were \$22.1 million.

Figure 13-12 Monthly FTR forfeitures for physical and financial participants

