State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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Preface

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2020 Annual State of the Market Report for PJM.*[3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement (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 Annual State of the Market Report for PJM.*

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Introduction

2020 in Review

The goal of competition in PJM is to provide customers reliable wholesale power at the lowest possible price, but no lower. The PJM markets have done that. The PJM markets work, even if not perfectly. The results of the energy market were competitive in 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. The results of PJM markets were reliable in 2020. But the PJM markets, and wholesale power markets in the U.S., continue to face challenges that potentially threaten the viability of competitive wholesale power 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, without guaranteed long term contracts. Innovation will occur in renewable technologies in unpredictable and beneficial ways.

The Minimum Offer Price Rule (MOPR) has been a contentious issue in PJM markets. Both FERC and the states have significant and overlapping authority affecting wholesale power markets. While FERC's MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, while the FERC market would be unaffected by subsidies, many states would just withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would not be an efficient outcome for the markets and would not serve the interests of customers or generators.

With the expected elimination of the current MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable or clean resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a demand curve for clean resources based on the quantity of such resources identified by one or more states and clear a market for clean resources as part of the capacity market clearing process.

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 has proposed 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, but only if done correctly and only if all the required assumptions are made explicit and decided explicitly. Implementing ELCC incorrectly, as PJM has proposed to do, based on average rather than marginal values, and locking in values for old technology for long periods regardless of market realities, and basing the results on incorrect assumptions about the dispatch of some resource types, would be a significant mistake and create new issues for the PJM capacity markets. The results could degrade reliability, impede innovation and the introduction of new technologies, and inefficiently displace 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.

Renewable energy was a relatively small share of PJM total energy and capacity in 2020 but many renewable projects are under development. While renewables currently make up the majority of both projects and nameplate MW in the interconnection queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by renewables and by thermal resources. Of the 23,095 MW of combined cycle projects in the queue, 15,849.4 MW (68.6 percent) are expected to go in service based on historical completion rates as of December 31, 2020, providing both energy and capacity at that level. Of the 129,844.9 MW of renewable projects in the queue, only 16,541 MW (12.7 percent) are expected to go in service based on historical completion rates and be available to supply energy. Of those 16,541 MW, only 6,487.5 MW (5.0 percent of the total) will be capacity, based on the average derate factors for wind and solar.

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. Delaware, Maryland and New Jersey were members of RGGI in 2020. Virginia joined RGGI on January 1, 2021, and Pennsylvania is preparing to join. 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 all PJM states in order to permit states to consider the development of a multistate framework that could benefit all states including those that currently do not belong to RGGI: for RECs markets; for potential agreement on carbon pricing including the distribution of carbon pricing revenues; and for coordination with PJM wholesale markets.

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 2020 than in any year since PJM markets were established in 1999. Energy prices in PJM were already among the lowest in PJM's history in 2019. The load-weighted average real-time LMP was 20.3 percent lower in 2020 than in 2019, $21.77 per MWh versus $27.32 per MWh. Of the $5.55 per MWh decrease, 50.3 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 4.0 percent compared to 2019, and load was down 3.4 percent after accounting for the impact of weather.

As input prices change, markets react immediately. In 2020, coal-fired generation was markedly less competitive with gas-fired generation. In 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 result of lower gas prices and the high efficiency of gas-fired combined cycle plants. The capacity factor of coal units fell from 30.1 percent to 25.6 percent, and the share of total PJM energy produced from coal fell from 23.8 percent in 2019 to 19.3 percent in 2020, while the share of gas increased from 36.4 to 39.8 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 and that PJM consider rules requiring capacity resources to have firm fuel supplies. It is also essential that FERC consider and address the implications of the inconsistencies between the gas pipeline business model and the power producer business model and the issue of market power in the gas commodity market under extreme weather conditions.

The recent events in ERCOT have refocused attention on reliability and on the role of very high energy prices under extreme weather conditions. The PJM system is reliable and PJM continues to focus on reliability. But it is essential to not be complacent. PJM's capacity market rules, including the resultant capacity reserve margin, contribute to but do not guarantee reliability under extreme weather conditions. The capacity market rules do not require that all resources have firm fuel supplies. Gas pipeline tariffs do not require that pipelines have the ability to serve all firm fuel customers simultaneously in an extreme weather event. Market power in the gas commodity market during extreme weather events has not been adequately addressed. The price impacts of extreme events in PJM can be significant. Under the current rules, PJM energy market prices can exceed $5,700 per MWh in emergency conditions. Under the rules for the extended ORDC, which will go into effect on June 1, 2022, PJM energy market prices can exceed $14,000 per MWh in emergency conditions. While appropriate scarcity pricing is important, there is no demonstrated benefit of imposing extreme prices for either long term generation incentives to invest in reliable capacity or customer incentives to curtail usage during an emergency.

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 2020 compared to 2019 as a result of lower energy prices. Theoretical net revenues decreased by 19 percent for a new combustion turbine, 23 percent for a new combined cycle, and 22 percent for a new nuclear plant. Theoretical net revenues decreased by 56 percent for a new coal unit, meaning that the theoretical capacity factor of a new entrant coal plant was 17 percent.

The competitiveness of energy market prices cannot be taken for granted. Despite low average marginal unit markups in 2020, 5.2 percent of marginal units set price with positive markups, in some cases over $150 per MWh, 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. During the cold and hot weather alerts in 2020, PJM scheduled and paid $821,403 in uplift to units that did not use 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 have been undermined. 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 is in the process of addressing a significant price formation issue in the real time process for defining prices and the underlying process for dispatching the system. PJM has not implemented available improvements to combined cycle modeling and has postponed systematic improvements to combined cycle modeling. 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 proposes to allow generators' use of real time values to avoid using their physical unit specific parameters required as part of the capacity performance incentives in the capacity market, undermining the market power protections to mitigate inflexible parameters that are currently in the PJM tariff.

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.

PJM Market Summary Statistics

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

Table 1-1 PJM market summary statistics: 2019 and 2020[1]

	2019	2020	Percent Change
Average Hourly Load Plus Exports (MW)	92,920	90,059	(3.1%)
Average Hourly Generation Plus Imports (MW)	94,618	91,681	(3.1%)
Peak Load (MW)	148,228	141,449	(4.6%)
Installed Capacity at December 31 (MW)	184,744	184,237	(0.3%)
Load Weighted Average Real Time LMP ($/MWh)	$27.32	$21.77	(20.3%)
Total Congestion Costs ($ Million)	$583.3	$528.6	(9.4%)
Total Uplift Credits ($ Million)	$88.5	$90.9	2.7%
Total PJM Billing ($ Billion)	$39.20	$33.64	(14.2%)

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2020, had installed generating capacity of 184,237 megawatts (MW) and 1,034 members including market buyers, sellers and traders of electricity in a region including more than 65 million people in all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia) and the District of Columbia (Figure 1-1).[2 3 4]

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

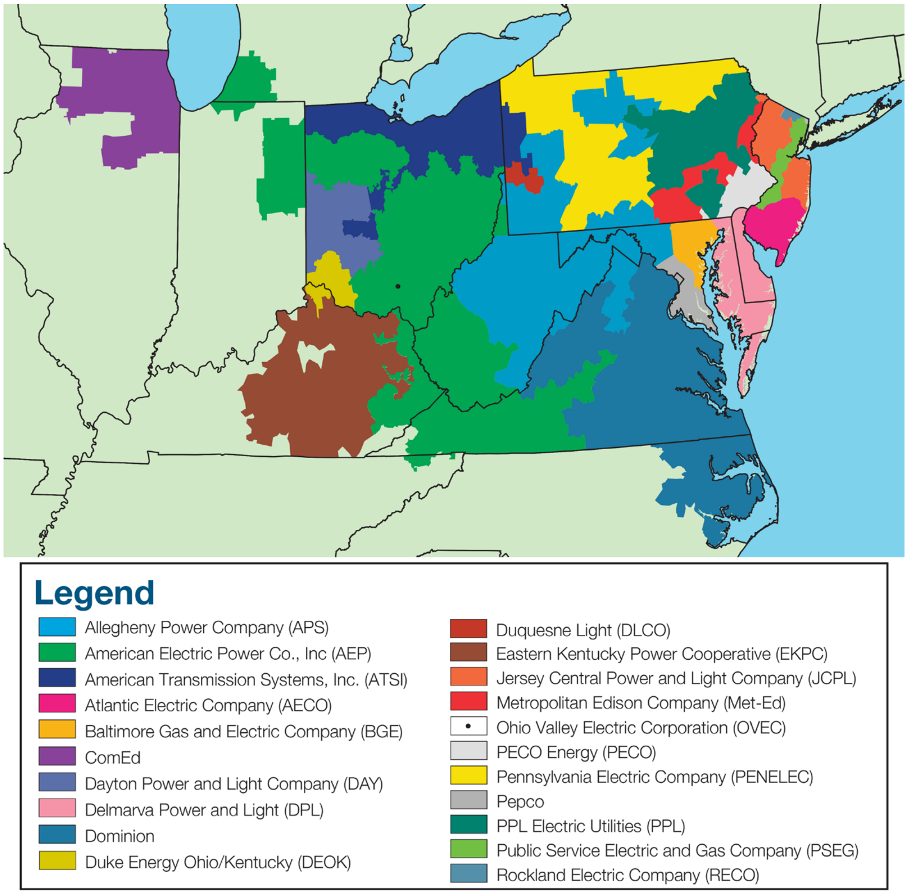
1 In Table 1-1, Average Hourly Load includes load and exports, and Average Hourly Generation includes generation and imports. Versions of this table prior to the *2020 Quarterly State of the Market Report for PJM: January through June* did not include exports or imports in these calculations.

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

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

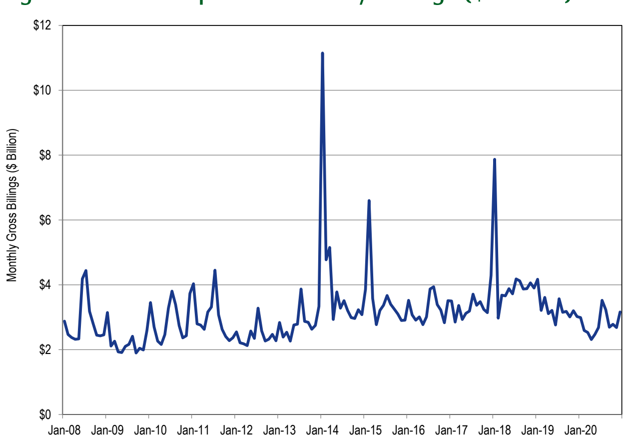
4 See the *2019 State of the Market Report for PJM*, Volume II, Appendix A: "PJM Overview" for maps showing the PJM footprint and its evolution prior to 2020.

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



In 2020, PJM had total billings of $33.64 billion, a decrease of 14.2 percent from $39.20 billion in 2019 (Figure 1-2).[5] The total of $33.64 billion in 2020 was the lowest annual total 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.

Figure 1-2 PJM reported monthly billings ($ Billion): 2008 through 2020



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

PJM operates the day-ahead energy market, the real-time energy market, the Reliability Pricing Model (RPM) capacity market, the regulation market, the synchronized reserve market, the day-ahead scheduling reserve (DASR) market and the financial transmission rights (FTRs) markets.

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

Conclusions

This report assesses the competitiveness of the markets managed by PJM in 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.

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,

6 See also the *2019 State of the Market Report for PJM*, Volume 2, Appendix A: "PJM Overview."
7 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."

pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in 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 2020 was unconcentrated by FERC HHI standards. Average HHI was 726 with a minimum of 526 and a maximum of 1080 in 2020. The peaking segment of supply was highly concentrated. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the 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.[8] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates. In the PJM energy market, market power mitigation occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[9] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

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.[10] The conclusions are a result of the MMU's evaluation of the last Base Residual Auction, for the 2021/2022 Delivery Year.

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.[11] 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.[12]
- 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

8 OATT Attachment M (PJM Market Monitoring Plan).

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

10 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.

11 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.

12 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.

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.

Tier 2 Synchronized Reserve Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for 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 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 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 1,235 hours in 2020. In 95.0 percent of hours when the clearing price was above $0, the clearing price was the offer price of the marginal unit. In the remaining 5.0 percent of hours, the price included 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 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 93.5 percent of the hours in 2020.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in 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 Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, offer behavior, and price. The MMU concludes that the PJM FTR auction market results were partially competitive in 2020.

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

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

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 2020/2023 Long Term FTR Auction, the 2020/2021 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and moderately concentrated for the 2020/2021 Annual FTR Auction. Ownership of FTRs is disproportionately (75.4 percent) by financial participants. The ownership of ARRs is unconcentrated.
- Participant behavior was evaluated as partially competitive as a result of the behavior of GreenHat Energy, LLC. Supply side participants are not permitted to participate in the market clearing.
- Market performance was evaluated as partially competitive because of the flaws in the market design. Sellers cannot set a sale price. Buyers can reclaim some of their purchase price after the market clears if the product does not meet a profitability target. The market resulted in a substantial shortfall in congestion payments to load and significant and unsupportable disparities among zones in the share of congestion returned to load. FTR purchases by financial entities remain persistently profitable in part as a result of the flaws in the market design.
- Market design was evaluated as flawed because there are significant and fundamental flaws with

the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Buyers have the ability to reclaim some of the price paid for FTRs after the market clears. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. The product sold to FTR buyers is incorrectly defined as target allocations rather than a share of congestion revenue. ARR holders' rights to congestion revenues are not correctly defined because the contract path based assignment of congestion rights is inadequate and incorrect. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue and a symptom of the fundamental flaws in the design. The product, the quantity of the product and the price of the product are all incorrectly defined.

- The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs and the fact that sellers are required to return some of the cleared auction revenue to FTR buyers when FTR profits are not adequate, means that the FTR design does not actually function as a market and is evidence of basic flaws in the market design.

Role of MMU

FERC assigns three core functions to MMUs: reporting, monitoring and market design.[13] 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.[14]

13 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).

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

Reporting

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

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

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[15] The MMU has direct, confidential access to FERC.[16] The MMU may also refer matters to the attention of state commissions.[17]

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[18] 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

15 OATT Attachment M § IV.

16 OATT Attachment M § IV.K.3.

17 OATT Attachment M § IV.H.

18 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.")

inefficiencies…”[19] [20] [21] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[22]

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.[23]

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.[24] [25] [26] [27]

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

The PJM markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[28] [29]

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.[30]

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.[31] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[32] 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

19 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.

20 OATT § I.1.

21 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.

22 OATT Attachment M § IV.C.

23 OATT Attachment M–Appendix § II.E.

24 OATT Attachment M–Appendix § II.B.

25 OATT Attachment M–Appendix § II.C.

26 OATT Attachment M–Appendix § IV.

27 OATT Attachment M–Appendix § VII.

28 OATT Attachment M–Appendix § II(p).

29 OATT Attachment M–Appendix § III.

30 OA Schedule 6 § 1.5.

31 OATT Attachment M § IV.D.

32 *Id.*

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.[33] 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.[34] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[35]

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.[36]

In this *2020 State of the Market Report for PJM*, the MMU includes 26 new recommendations made for 2020, eight of which are new in this 2020 annual report.[37] [38]

New Recommendations from Section 3, Energy Market

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. First reported Q3, 2020. 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported Q3, 2020. 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported Q3, 2020. Status: Not adopted.)

33 *Id.*; see also, e.g., 171 FERC ¶ 61,039; 167 FERC ¶ 61,084 at PP 70–76, *reh'g denied*, 168 FERC ¶ 61,141.
34 *Id.*
35 OATT Attachment M § VI.A.
36 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
37 New recommendations include all MMU recommendations that were reported for the first time in the *2020 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2020.
38 For a complete list of MMU recommendations, see the *2020 State of the Market Report for PJM*, Vol II, Section 2, Recommendations.

- 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.)

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. First reported Q3, 2020. Status: Not adopted.)

New Recommendation from Section 5, Capacity Market

- The MMU recommends that PJM update the values in the CRF table in the tariff when the components change. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendation from Section 6, Demand Response

- 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.)

New Recommendations from Section 9, Interchange Transactions

- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from 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 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: Adopted Q4, 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: Adopted Q4, 2020.)

New Recommendations from Section 10, Ancillary Services

- The MMU recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. Specifically, such eligibility should be determined

based on whether a generation facility's point of interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.[39] (Priority: Medium. New recommendation. 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.)

New Recommendations from Section 12, Generation and Transmission Planning

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends a comprehensive review of the ways in which the solution-based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution-based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported Q3, 2020. Status: Not adopted.)

New Recommendations 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. First reported Q3, 2020. Status: Adopted 2021.)
- 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.)

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of wholesale electricity in PJM markets.[40] The total price is an average price. Prices vary by location and time period. The total price includes the price of energy, capacity, transmission service, ancillary services, and administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-8 shows the average price, by component, for 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

39 *See* PJM Transmission Facilities (note that this requires you first log into a PJM Tools account. If you do not, then the link sends you to an Access Request page, https://pjm.com/markets-and-operations/ops-analysis/transmission-facilities.

40 Accounting load is used in the calculation of total price because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, 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.

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.[41]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[42]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[43]
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.[44]
- 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 (AC2) 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.[45]
- 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.[46]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[47]
- 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.[48]
- 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.[49]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the synchronized reserve market.[50]
- The Black Start component is the average cost per MWh of black start service.[51]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[52]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[53]
- The Economic Load Response component is the average cost per MWh of day-ahead and real-time economic load response program charges to LSEs.[54]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[55]
- The nonsynchronized reserve component is the average cost per MWh of non-synchronized reserve procured through the nonsynchronized reserve market.[56]
- The Emergency Energy component is the average cost per MWh of emergency energy.[57]

41 OATT §§ 13.7, 14.5, 27A & 34.
42 OA Schedules 1 §§ 3.2.3 & 3.3.3.
43 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 18 includes all reactive services charges.
44 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
45 OATT Schedule 12.
46 RAA Schedule 8.1.
47 OATT PJM Emergency Load Response Program.
48 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
49 OATT Schedule 1A.
50 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
51 OATT Schedule 6A. The line item in Table 18 includes all Energy Uplift (Operating Reserves) charges for Black Start.
52 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
53 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
54 OA Schedule 1 § 3.6.
55 OA Schedule 1 § 5.3b.
56 OA Schedule 1 § 3.2.3A.001.
57 OA Schedule 1 § 3.2.6.

Table 1-8 shows that energy, capacity and transmission charges are the three largest components of the total price per MWh of wholesale power, comprising 96.9 percent of the total price per MWh in 2020. The cost of capacity has been a larger share of the total price per MWh of wholesale power than the cost of transmission service. Starting in the third quarter of 2019, the cost of transmission service was greater than the cost of capacity. In 2020, for the first time since the start of the PJM RPM Capacity Market in 2007, the cost of transmission in the total price per MWh of wholesale power was greater than the cost of capacity.

Table 1-8 Total price per MWh by category: 2019 and 2020[58 59 60 61]

Category	2019 $/MWh	2019 ($ Millions)	2019 Percent of Total	2020 $/MWh	2020 ($ Millions)	2020 Percent of Total	Percent Change
Load Weighted Energy	$27.32	$21,088	54.3%	$21.77	$16,171	48.8%	(20.3%)
Capacity	$11.27	$8,700	22.4%	$9.45	$7,023	21.2%	(16.1%)
Capacity	$11.25	$8,686	22.4%	$9.45	$7,023	21.2%	(16.0%)
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	$10.39	$8,019	20.6%	$11.98	$8,898	26.9%	15.3%
Transmission Service Charges	$9.75	$7,524	19.4%	$11.29	$8,388	25.3%	15.8%
Transmission Enhancement Cost Recovery	$0.55	$427	1.1%	$0.59	$441	1.3%	7.5%
Transmission Owner (Schedule 1A)	$0.09	$69	0.2%	$0.09	$69	0.2%	4.6%
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	$0.72	$555	1.4%	$0.73	$544	1.6%	1.7%
Reactive	$0.44	$336	0.9%	$0.48	$355	1.1%	9.8%
Regulation	$0.12	$91	0.2%	$0.10	$77	0.2%	(11.8%)
Black Start	$0.08	$65	0.2%	$0.09	$65	0.2%	4.5%
Synchronized Reserves	$0.04	$34	0.1%	$0.03	$25	0.1%	(24.4%)
Non-Synchronized Reserves	$0.02	$12	0.0%	$0.01	$8	0.0%	(28.1%)
Day Ahead Scheduling Reserve (DASR)	$0.02	$18	0.0%	$0.02	$13	0.0%	(22.0%)
Administration	$0.51	$394	1.0%	$0.52	$383	1.2%	1.2%
PJM Administrative Fees	$0.47	$365	0.9%	$0.48	$355	1.1%	1.0%
NERC/RFC	$0.03	$27	0.1%	$0.04	$28	0.1%	8.4%
RTO Startup and Expansion	$0.00	$2	0.0%	$0.00	$1	0.0%	(58.1%)
Energy Uplift (Operating Reserves)	$0.11	$88	0.2%	$0.12	$90	0.3%	6.9%
Demand Response	$0.00	$4	0.0%	$0.00	$1	0.0%	(70.2%)
Load Response	$0.00	$3	0.0%	$0.00	$1	0.0%	(57.6%)
Emergency Load Response	$0.00	$1	0.0%	$0.00	$0	0.0%	(100.0%)
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Total Price	$50.33	$38,848	100.0%	$44.57	$33,111	100.0%	(11.4%)
Total Load (GWh)	771,929			742,987			(3.7%)
Total Billing ($ Billions)	$38.85			$33.11			(14.8%)

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

59 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.

60 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.

61 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 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).[62]

Table 1-9 Inflation adjusted total price per MWh by category: 2019 and 2020[63]

Category	2019 $/MWh	2019 ($ Millions)	2019 Percent of Total	2020 $/MWh	2020 ($ Millions)	2020 Percent of Total	Percent Change
Load Weighted Energy	$17.28	$13,337	54.3%	$13.58	$10,091	48.8%	(21.4%)
Capacity	$7.13	$5,506	22.4%	$5.90	$4,385	21.2%	(17.2%)
Capacity	$7.12	$5,497	22.4%	$5.90	$4,385	21.2%	(17.1%)
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	$6.57	$5,069	20.6%	$7.48	$5,556	26.9%	13.9%
Transmission Service Charges	$6.16	$4,756	19.4%	$7.05	$5,238	25.3%	14.4%
Transmission Enhancement Cost Recovery	$0.35	$270	1.1%	$0.37	$276	1.3%	6.2%
Transmission Owner (Schedule 1A)	$0.06	$43	0.2%	$0.06	$43	0.2%	3.4%
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	$0.45	$351	1.4%	$0.46	$339	1.6%	0.5%
Reactive	$0.28	$213	0.9%	$0.30	$222	1.1%	8.5%
Regulation	$0.07	$57	0.2%	$0.06	$48	0.2%	(12.8%)
Black Start	$0.05	$41	0.2%	$0.05	$41	0.2%	3.2%
Synchronized Reserves	$0.03	$22	0.1%	$0.02	$16	0.1%	(25.5%)
Non-Synchronized Reserves	$0.01	$7	0.0%	$0.01	$5	0.0%	(28.9%)
Day Ahead Scheduling Reserve (DASR)	$0.01	$11	0.0%	$0.01	$8	0.0%	(23.1%)
Administration	$0.32	$249	1.0%	$0.32	$239	1.2%	(0.1%)
PJM Administrative Fees	$0.30	$231	0.9%	$0.30	$221	1.1%	(0.2%)
NERC/RFC	$0.02	$17	0.1%	$0.02	$17	0.1%	6.8%
RTO Startup and Expansion	$0.00	$1	0.0%	$0.00	$1	0.0%	(57.9%)
Energy Uplift (Operating Reserves)	$0.07	$55	0.2%	$0.08	$56	0.3%	5.3%
Demand Response	$0.00	$2	0.0%	$0.00	$1	0.0%	(70.0%)
Load Response	$0.00	$2	0.0%	$0.00	$1	0.0%	(57.1%)
Emergency Load Response	$0.00	$1	0.0%	$0.00	$0	0.0%	(100.0%)
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Total Price	$31.83	$24,570	100.0%	$27.82	$20,668	100.0%	(12.6%)
Total Load (GWh)	771,929			742,987			(3.7%)
Total Billing ($ Billions)	$24.57			$20.67			(15.9%)

62 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (January 13, 2021).

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

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

Figure 1-3 Top three components of quarterly total price ($/MWh): 1999 through 2020[64]

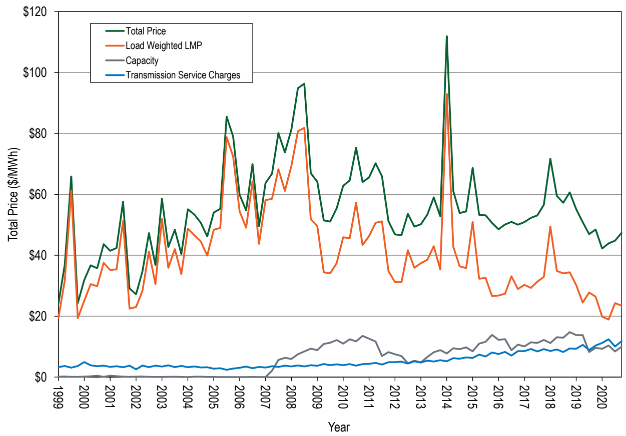


Figure 4 shows the inflation adjusted contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.[65]

Figure 1-4 Inflation adjusted top three components of quarterly total price ($/MWh): 1999 through 2020[66]

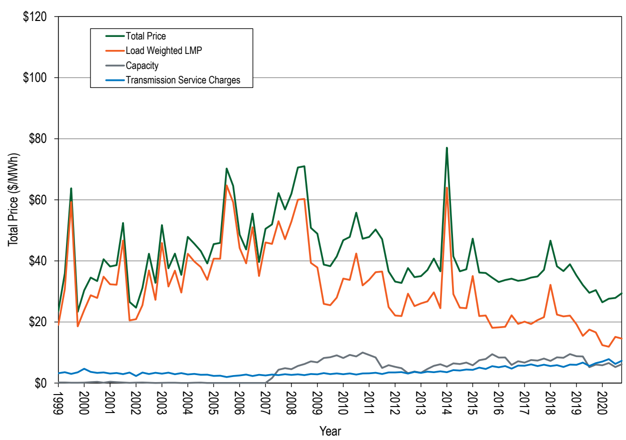
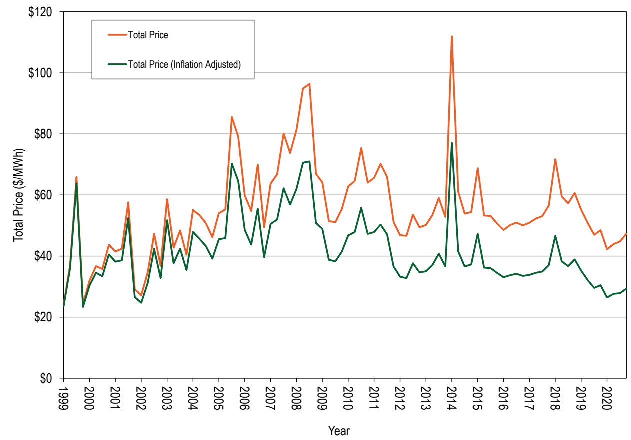


Figure 5 shows the total price of wholesale power and the inflation adjusted total price of wholesale power for each quarter since 1999.[67]

Figure 1-5 Quarterly total price and quarterly inflation adjusted total price ($/MWh): 1999 through 2020[68]



Section Overviews

Overview: Section 3, Energy Market

Supply and Demand

Market Structure

- **Supply.** The average hourly day-ahead supply was 157,005 for 2020, and 171,443 MW for 2019. The average on-peak hourly offered real-time supply was 135,383 MW for 2020, and 138,779 MW for 2019. In 2020, 2,556.7 MW of new resources were added in the energy market, and 3,255.0 MW of resources and 457.0 MW of pseudo tied resources were retired.

- PJM average hourly real-time cleared generation in 2020 decreased by 2.7 percent from 2019, from 93,434 MWh to 90,946 MWh.

  PJM average hourly day-ahead cleared supply in 2020, including INCs and up to congestion transactions, decreased by 4.9 percent from 2019, from 117,250 MWh to 111,470 MWh.

- **Demand.** The PJM system real-time hourly peak load in 2020 was 141,449 MWh in the HE 1700 on July 20, 2020, which was 6,778 MWh, 4.6 percent,

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

65 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (January 13, 2021).

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

67 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (January 13, 2021).

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

lower than the PJM peak load in 2019, which was 148,228 MWh in the HE 1800 on July 19, 2019.

- PJM average hourly real-time load in 2020 decreased by 4.0 percent from 2019, from 88,120 MWh to 84,584 MWh, the largest percent decrease since 2009. Both the weather and COVID-19 contributed to the significant change. Based on the weather normalized demand analysis, 3.4 of the 4.0 percent decrease in load was related to COVID-19.
- PJM average hourly day-ahead demand in 2020, including load, DECs and up to congestion transactions, decreased by 5.7 percent from 2019, from 112,588 MWh to 106,209 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 2020, 16.1 percent of real-time load was supplied by bilateral contracts, 24.7 percent by spot market purchases and 59.2 percent by self supply. Compared to 2019, reliance on bilateral contracts increased by 0.8 percentage points, reliance on spot market purchases decreased by 0.1 percentage points and reliance on self supply decreased by 0.7 percentage points.
- **Generator Offers.** In day-ahead market offers, generators define the commitment status and the dispatch status of their units. In the day-ahead market in 2020, 21.8 percent of MW were offered as must run, 32.1 percent were offered as economic minimum MW for dispatchable units, 45.0 percent were offered as dispatchable MW, and 1.0 percent were offered as emergency maximum MW.
- **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 2.7 percent and cleared MW decreased by 16.0 percent in 2020. The hourly average submitted decrement offer MW increased by 24.4 percent and cleared MW increased by 16.6 percent in 2020. The hourly average submitted up to congestion bid MW decreased by 23.8 percent and cleared MW decreased by 12.4 percent in 2020.

Market Performance

- **Generation Fuel Mix.** In 2020, coal units provided 19.3 percent, nuclear units 34.2 percent and natural gas units 39.8 percent of total generation. Compared to 2019, generation from coal units decreased 20.6 percent, generation from natural gas units increased 6.7 percent and generation from nuclear units decreased 0.8 percent. The trend toward more energy from natural gas and less from coal accelerated in 2020.
- **Fuel Diversity.** The fuel diversity of energy generation in 2020, measured by the fuel diversity index for energy (FDI_e), decreased 1.5 percent compared to 2019.
- **Marginal Resources.** In the PJM Real-Time Energy Market in 2020, coal units were 17.5 percent and natural gas units were 72.3 percent of marginal resources. In 2019, coal units were 24.4 percent and natural gas units were 69.4 percent of marginal resources.

  In the PJM Day-Ahead Energy Market in 2020, up to congestion transactions were 51.4 percent, INCs were 13.2 percent, DECs were 18.8 percent, and generation resources were 16.5 percent of marginal resources. In 2019, up to congestion transactions were 57.4 percent, INCs were 12.8 percent, DECs were 17.0 percent, and generation resources were 12.7 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 2020. Both the weather and COVID-19 played a role in this significant drop in prices.

  PJM load-weighted, average, real-time LMP in 2020 decreased 20.3 percent from 2019, from $27.32 per MWh to $21.77 per MWh.

  PJM load-weighted, average day-ahead LMP in 2020 decreased 21.4 percent from 2019, from $27.23 per MWh to $21.40 per MWh.
- **Components of LMP.** In the PJM Real-Time Energy Market in 2020, 23.7 percent of the load-weighted LMP was the result of coal costs, 41.5 percent was

the result of gas costs and 1.7 percent was the result of the cost of emission allowances.

In the PJM Day-Ahead Energy Market, in 2020, 24.4 percent of the load-weighted LMP was the result of coal costs, 18.8 percent was the result of gas costs, 15.2 percent was the result of INC offers, 24.0 percent was the result of DEC bids, and 3.0 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 \$0.33 per MWh in 2020, and -\$0.01 per MWh in 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 nine intervals with five minute shortage pricing in 2020. There were no emergency actions that resulted in Performance Assessment Intervals in 2020.
- There were 1,819 five minute intervals, or 1.7 percent of all five minute intervals in 2020 for which at least one RT SCED solution showed a shortage of reserves, and 592 five minute intervals, or 0.6 percent of all five minute intervals in 2020 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for nine 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 2020, the average number of suppliers providing constraint relief was 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 1.3 percent in 2019 to 1.6 percent in 2020. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.7 percent in 2019 to 1.0 percent in 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 2020, 10 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working 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 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 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 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 2020, in the PJM Real-Time Energy Market, 98.2 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 2020 was more than $450 per MWh when using unadjusted cost-based offers.

  In 2020, in the PJM Day-Ahead Energy Market, 99.2 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 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 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 2020, the unadjusted markup component of LMP was $0.50 per MWh or 2.3 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 35 hours in 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 $30.70 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2020, the unadjusted markup component of LMP resulting from generation resources was -$0.11 per MWh or -0.5 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 5.2 percent of marginal unit intervals in 2020 the marginal unit had local market power as determined by the TPS test and a positive markup, compared to 10.0 percent of marginal unit intervals in 2019. 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported Q3, 2020. 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. First reported Q3, 2020. 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: 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. First reported Q3, 2020. 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.)

Offer Behavior

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

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: Partially 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.[69] [70] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 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.)

69 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.

70 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>.

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported Q3, 2020. Status: Not adopted.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 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 load in 2020 decreased by 4.0 percent from 2019, from 88,120 MWh to 84,584 MWh, the largest percent decrease since 2009. Both the weather and COVID-19 contributed to the significant change. Based on the weather normalized demand analysis, 3.4 of the 4.0 percent decrease in load was related to COVID-19. The relationship between supply and demand, regardless of the specific market, along with market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals or market structure. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[71] 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 all costs that are related to electric production are short run marginal costs, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially fixed 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. 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

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

elasticity of demand on prices. Energy market results in 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 substantially increase markups in energy offers 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.

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. PJM has a plan to make these changes, and PJM should prioritize implementing it. These issues are even more critical now that PJM settles real-time energy transactions on a five minute basis and will soon implement fast start pricing.

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 significant price increases 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. Rather than sending dispatch signals consistent with resource offers and holding resources accountable when they fail to follow them, DGP accommodates resources that do not follow dispatch. 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 actually fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM will pay new forms of uplift in an attempt to counter the distorted incentives. 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 2020 or prior years. In 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 31.2 percent in 2016 to 64.3 percent in 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 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 2020.

Overview: Section 4, Energy Uplift

Energy Uplift Credits

- **Types of credits.** In 2020, energy uplift credits were $90.9 million, including $9.3 million in day-ahead generator credits, $58.2 million in balancing generator credits, $19.4 million in lost opportunity cost credits, and $3.4 million in local constraint control credits.
- **Types of units.** In 2020, coal units received 90.6 percent of all day-ahead generator credits. During the same time period, combustion turbines received 91.2 percent of all balancing generator credits and 95.1 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In 2020, 87.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.8 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2020, less than 0.1 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 74.4 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 17.0 percent of all credits. The top 10 organizations received 71.8 percent of all credits. The HHI for day-ahead operating reserves was 8387, the HHI for balancing operating reserves was 3582 and the HHI for lost opportunity cost was 5457, all of which are classified as highly concentrated.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $2.2 million or 12.9 percent, in 2020 compared to 2019, from $17.1 million to $19.4 million. Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 94.0 percent of the $19.4 million. The day-ahead generation paid LOC credits for this reason increased by 534.2 GWh or 70.3 percent during 2020, compared to 2019, from 759.9 GWh to 1,294.1 GWh.
- **Following Dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with proper offer parameters. Since 2018, the MMU has made cumulative resettlement requests that total $3.5 million, of which PJM has agreed and resettled 39.1 percent.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges increased by $2.4 million, or 2.7 percent, in 2020 compared to 2019, from $88.5 million to $90.9 million.
- **Energy Uplift Charges Categories.** The increase of $2.4 million in 2020 was comprised of a $6.2 million decrease in day-ahead operating reserve charges, an $8.8 million increase 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 $0.040 per MWh, a DEC paid $0.341 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.329 per MWh. In November and December 2020, which were the only months of the year that

UTCs were allocated uplift charges, a UTC paid $0.305 per MWh.

- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.012 per MWh, real-time load paid $0.030 per MWh, a DEC paid $0.296 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.285 per MWh in 2020. In November and December 2020, which were the only months of the year that UTCs were allocated uplift charges, a UTC paid $0.224 per MWh.
- **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 $0.008 per MWh, PPL had a rate of $0.004 per MWh, and EKPC had a rate of $0.004.

Geography of Charges and Credits

- In 2020, 89.1 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 3.8 percent by transactions at hubs and aggregates, and 7.2 percent by transactions at interchange interfaces.
- In 2020, generators in the Eastern Region received 36.3 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2020, generators in the Western Region received 61.1 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2020, external generators received 2.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Section 4 Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 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 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 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead 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 units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends 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.[72])
- 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.[73])
- 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 eliminate the exemption for fast start resources (CTs and diesels) from the requirement to follow dispatch. The

72 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.

73 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. 166 FERC ¶ 61,210. PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. 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.

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). Fast start pricing has been approved by FERC subject to a PJM compliance filing on the definition of fast start resources, and is expected to be implemented in 2021. Fast start pricing will affect uplift calculations.[74]

When units receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC

74 FERC Docket No. ER19-2722.

Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[75] 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.

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.[76] The uplift payments for UTCs began on November 1, 2020. Up to congestion transactions did not pay energy uplift charges in the first ten months of 2020.[77]

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

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make these units ineligible for uplift credits. Since 2018, the MMU has identified $3.5 million of incorrect uplift credits.

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

Overview: Section 5, Capacity Market

RPM Capacity Market

Market Design

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

Under RPM, capacity obligations are annual.[79] 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.[80] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[81] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting

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

76 See 172 FERC ¶ 61,046.

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

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

79 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.

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

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

from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[82]

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

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[83] 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 2020, RPM installed capacity decreased 486.0 MW or 0.3 percent, from 184,722.8 MW on January 1 to 184,236.8 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2020, 45.6 percent was gas; 27.0 percent was coal; 17.5 percent was nuclear; 4.8 percent was hydroelectric; 3.0 percent was oil; 1.2 percent was wind; 0.4 percent was solid waste; and 0.6 percent was solar.
- **Market Concentration.** In the 2020/2021 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test. In the 2021/2022 RPM Second Incremental Auction, two participants in the EMAAC LDA market passed the TPS test.[84] 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.[85] [86] [87]
- **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

- **2020/2021 RPM Third Incremental Auction.** Of the 521 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for zero generation resources (0.0 percent).
- **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).

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

83 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.

84 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).

85 See OATT Attachment DD § 6.5.

86 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).

87 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).

Market Performance

- The 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted in 2020.[88] 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 2020 was 6.3 percent, an increase from 5.5 percent in 2019.[89]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in 2020 was 84.8 percent, an increase from 83.5 percent in 2019.

Recommendations[90]

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.[91] [92] (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.[93] [94] 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

88 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).

89 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 February 1, 2021. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

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

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

92 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).

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

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

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.)

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.[95] (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.[96] (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

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

96 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).

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.)
- The MMU recommends that PJM update the values in the CRF table in the tariff when the components change. (Priority: High. New recommendation. 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.[97] 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 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.[98] [99] [100] [101] [102] [103] In 2019 and 2020, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

97 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).

98 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).

99 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).

100 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).

101 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).

102 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).

103 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 15,882.6 ICAP MW on June 1, 2021, based on current positions.[104] A majority of capacity investments in PJM were financed by market sources.[105] Of the 41,979.4 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2019/2020 Delivery Years, 32,348.9 MW (77.1 percent) were based on market funding. Of the 2,711.8 MW of additional capacity that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years, 2,613.4 MW (96.4 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. These subsidy programs 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 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. 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.

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

The 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 when it replaces participation in the PJM markets.[106] 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

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

105 "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).

106 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%20Ohio_FRRs_20200717.pdf>.

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.[107] 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.[108] [109] [110] [111] 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.

The MMU recognizes that both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC market would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would not be an efficient outcome and would not serve the interests of customers or generators.

With the expected elimination of the current MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable or clean resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a demand curve for clean resources based on the quantity of such resources identified by one or more states and clear a market for clean resources as part of the capacity market clearing process.

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, but only if done correctly and only if all the required assumptions are made explicit and decided explicitly. Implementing ELCC incorrectly, based on average rather than marginal values, and locking in values for old technology for long periods regardless of market realities, and basing the results on incorrect assumptions about the dispatch of some resource types, would be a significant mistake

107 In the Matter of the Investigation of Resource Adequacy Alternatives, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).

108 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).

109 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).

110 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).

111 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).

and create new issues for the PJM capacity markets. The results could degrade reliability, impede innovation and the introduction of new technologies, and inefficiently displace 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.

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.[112]

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.[113] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

  Total demand response revenue decreased by $131.4 million, 26.8 percent, from $490.5 million in 2019 to $359.1 million in 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 $128.2 million, 26.5 percent, from $483.3 million in 2019 to $355.1 million in 2020. This decrease consisted entirely of capacity market revenue.[114]

  Economic demand response revenue decreased by $0.7 million, 70.0 percent, from $1.0 million in 2019

112 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).

113 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.

114 The total credits and MWh numbers for demand resources were calculated as of January 12, 2021 and may change as a result of continued PJM billing updates.

to $0.3 million in 2020.[115] Demand response revenue in the synchronized reserve market decreased by $0.4 million, 14.3 percent, from $2.8 million in 2019 to $2.4 million in 2020. Demand response revenue in the regulation market decreased by $1.0 million, 41.7 percent, from $2.4 million in 2019 to $1.4 million in 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.[116]
- **Demand Response Market Concentration.** The ownership of economic load response resources was highly concentrated in 2019 and 2020. The HHI for economic resource reductions increased by 796 points from 8261 in 2019 to 9056 in 2020. The ownership of emergency load response resources was highly concentrated in 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.

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

116 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 84 (Dec. 17 2020).

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 resources, comparable to the rule applicable to generation

capacity resources.[117] (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.[118] (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 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.[119])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes

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

118 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.

119 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.

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.)

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.[120] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[121] [122] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate

120 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>.

121 *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).

122 *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).

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.[123] 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. 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.[124] 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 2020 than in 2019.
- In 2020, average energy market net revenues decreased by 17 percent for a new combustion turbine (CT), 19 percent for a new combined cycle (CC), 51 percent for a new coal plant (CP), 22 percent for a new nuclear plant, 49 percent for a new diesel (DS), 27 percent for a new onshore wind installation, 22 percent for a new offshore wind installation and 25 percent for a new solar installation compared to 2019.
- The prices of natural gas, coal, and oil fell in 2020. The marginal costs of a new CC and a new CT were less than the marginal cost of a new CP in 2020.
- Based on Western Hub prices, the spark spread in 2020 decreased by 1 percent while the spark spread standard deviation decreased by 46 percent. The

123 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).

124 577 U.S. 260 (2016).

dark spread decreased by 17 percent while the dark spread standard deviation decreased by 46 percent, and the quark spread decreased by 27 percent while the quark spread standard deviation decreased by 46 percent.

- In 2020, capacity market revenue accounted for 55 percent of total net revenues for a new CT, 44 percent for a new CC, 82 percent for a new CP, 20 percent for a new nuclear plant, 88 percent for a new DS, 10 percent for a new onshore wind installation, 19 percent for a new offshore wind installation and 8 percent for a new solar installation.
- In 2020, no new CT, CC, CP, nuclear, or DS units would have received sufficient net revenue to cover levelized total costs in any zone as a result of lower energy prices.
- In 2020, a new entrant onshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the four zones analyzed. Net revenues would have covered between 34 and 37 percent of levelized total costs of a new entrant onshore wind installation in AEP, APS, ComEd and PENELEC. Renewable energy credits accounted for at least 29 percent of the total net revenue of an onshore wind installation.
- In 2020, a new entrant offshore wind installation in AECO would not have received sufficient net revenue to cover levelized total costs. Net revenues would have covered 19 percent of levelized total costs. Renewable energy credits accounted for 30 percent of the total net revenue of an offshore wind installation.
- In 2020, a new entrant solar installation would have covered more than 100 percent of levelized total costs in four of the five zones analyzed. Renewable energy credits accounted for at least 68 percent of the total net revenue of a solar installation.
- In 2020, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2020, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal units and some nuclear units.
- Using a forward analysis, a total of 4,751 MW of coal, CT, diesel, and oil fired capacity are at risk of retirement, in addition to the units that are currently planning to retire. The 4,751 MW at risk of retirement include 2,361 MW of coal, 227 MW of CT, and 2,841 MW of other capacity.
- 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.[125]

Section 7 Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking 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 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

125 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.

capacity is a function of the calculation methods used by RTOs and ISOs.

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.[126] On May 22, 2020, the EPA published its determination that MATS is not appropriate and necessary based on a cost-benefit analysis.[127] The list of coal steam units subject to MATS, however, remains in place.[128] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.
- **Air Quality Standards (NO_x and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[129] On October 15, 2020, the EPA proposed to revise upward the good neighbor obligations under the 2008 ozone NAAQS for 12 states, including 10 PJM states.[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 January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's Affordable Clean Energy (ACE) rule which would have permitted more CO_2 emissions than under the Clean Power Plan, which ACE had replaced.[133]
- **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.[134]
- **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"

126 *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).

127 *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.

128 *Id.* at 31291.

129 CAA § 110(a)(2)(D)(i)(I).

130 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. [EPA-HQ-OAR-2020-0272; FRL-10013-42- OAR, 85 Fed. Reg. 68964 (Oct. 30, 2020).

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 American Lung Association et al. v. EPA, No. 19-1140.

134 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).

when pollutants are conveyed by groundwater into jurisdictional waters.[135]

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[136] 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 CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont that applies to power generation facilities. New Jersey rejoined on January 1, 2020.[137] Virginia joined RGGI on January 1, 2021, and Pennsylvania is preparing to join.[138] [139] The auction price in the December 2, 2020, auction for the 2018/2020 compliance period was $7.41 per ton, or $8.17 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 126.5 percent for a new combustion turbine (CT) unit, $16.71 per MWh or 124.6 percent for a new combined cycle (CC) unit and $43.15 per MWh or 156.2 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 December 31, 2020, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia had a voluntary RPS in 2020, but a new mandatory RPS became effective on January 1, 2021. 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 December31, 2020, 93.9 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 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 NOX 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 3.7 percent of total generation in PJM in 2020. RPS Tier I generation was 5.2 percent of total generation in PJM and RPS Tier II generation was 2.1 percent of total generation in PJM in 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.)

135 *County of Maui v. Hawaii Wildlife Fund*, Slip. Op. No. 18-260 (April 23, 2020).
136 42 U.S.C. §§ 6901 *et seq.*
137 "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>.
138 "Statement on Virginia Greenhouse Gas Rule," RGGI, (July 8, 2020) <https://www.rggi.org/news-releases/rggi-releases>.
139 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/>.

- 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.[140] 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 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

140 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.").

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 $6.17 per tonne in Washington, DC to $18.36 per tonne in New Jersey. The price of carbon implied by SREC prices ranges from $60.97 per tonne in Pennsylvania to $883.41 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in December 2020 of $8.17 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[141] 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.[142] 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 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.[143] RPS costs are payments by customers to the sellers of qualifying

141 "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>.

142 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 818.

143 Several states that have compliance periods that align with the PJM Capacity Market have not released compliance reports for the period June 1, 2019 through May 31, 2020.

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 $7.41 per short ton and emissions levels were five percent below 2020 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 $16.6 billion if the carbon price were $50 per short ton and emission levels were five percent below 2020 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 $7.41 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 2020, PJM was a monthly net exporter of energy in the real-time energy market in all months.[144] In 2020, the real-time net interchange was -41,630.2 GWh. The real-time net interchange in 2019 was -31,674.1 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2020, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In 2020, the total day-ahead net interchange was -15,414.6 GWh. The day-ahead net interchange in 2019 was -7,174.9 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2020, gross imports in the day-ahead energy market were 538.7 percent of gross imports in the real-time energy market (492.5 percent in 2019). In 2020, gross exports in the day-ahead energy market were 104.4 percent of the gross exports in the real-time energy market (138.5 percent in 2019).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2020, there were net scheduled exports at 15 of PJM's 19 interfaces in the real-time energy market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 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 2020, there were net scheduled exports at 15 of PJM's 19 interfaces in the day-ahead energy market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 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 2020, up to congestion transactions were net exports at four of PJM's 18 interface pricing points eligible for day-ahead transactions in the day-ahead energy market.[148]
- **Inadvertent Interchange.** In 2020, net scheduled interchange was -41,630 GWh and net actual interchange was -41,716 GWh, a difference of 86 GWh. In 2019, the difference was 128 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 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 -11,906 GWh of net actual interchange, a difference of 10,283 GWh. In 2020, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,433 GWh of net scheduled interchange and 24,369 GWh

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.

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. On October 1, 2020, PJM retired the Northwest interface pricing point. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points. These retirements reduced the number of real-time interface pricing points to 10.

147 On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points. On October 1, 2020, PJM retired the Northwest interface pricing point. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points. These retirements reduced the number of day-ahead interface pricing points to 10.

148 On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points. On October 1, 2020, PJM retired the Northwest interface pricing point. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points. These retirements reduced the number of day-ahead interface pricing points to 10.

of net actual interchange, a difference of 20,936 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 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 67.9 percent of the hours.
- **PJM and New York ISO Interface Prices.** In 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 49.9 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 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 70.0 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 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 61.4 percent of the hours.
- **Hudson DC Line.** In 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 58.5 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued two TLRs of level 3a or higher in 2020, compared to two such TLRs issued in 2019.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market decreased by 6.6 percent, from 52,046 bids per day in 2019 to 48,618 bids per day in 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 12.5 percent, from 500,819 MWh per day in 2019, to 438,170 MWh per day in 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: Adopted Q4, 2020.)

- 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: Adopted Q4, 2020.)
- 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 NISPCO 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.

In 2020, PJM terminated a number of interface pricing points, consistent with longstanding MMU recommendations. On June 1, 2020, PJM terminated the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP interface pricing points. It was not clear why PJM did not also terminate the NCMPAIMP and NCMPAEXP interface pricing points at that time. On October 1, 2020, PJM terminated the Northwest interface pricing point. But following this termination, PJM failed to correctly map the pricing points to transactions that had been mapped to the Northwest pricing point to pricing points that are consistent with electrical impacts on the PJM system. 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 electrical impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. On November 3, 2020, PJM terminated the NCMPAIMP and NCMPAEXP interface pricing points. The MMU continues to recommend the termination of the Southeast and Southwest interface pricing points, and the Ontario interface pricing point. These pricing points can either 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.[149]

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.

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 2020, the average primary reserve requirement was 2,454.3 MW in the RTO Zone and 2,429.6 MW in the MAD Subzone.

Tier 1 Synchronized Reserve

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and

149 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 39 (Nov. 19, 2019).

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 2020, there was an average hourly supply of 2,039.2 MW of tier 1 available in the RTO Zone and an average hourly supply of 957.9 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.
- **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.[150] 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 nonsynchronized reserve market clearing price was above $0 in 2,015 intervals (1.9 percent of intervals) in 2020 resulting in a payment to tier 1 resources of $3,319,263.

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. In PJM the required amount of synchronized reserve is defined to be no less than the largest single contingency, and 10 minute primary reserve as 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.[151]

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM uses the tier 2 synchronized reserve market to satisfy the balance of the requirement. 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 2020, the supply of daily offered and eligible tier 2 synchronized reserve was 30,576.8 MW in the RTO Zone of which 4,919.9 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,705.4 MW in the RTO Reserve Zone and 1,684.9 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 218.3 MW in the MAD Subzone and 415.6 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.

150 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 112 (January 5,, 2021).

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

The average HHI for tier 2 synchronized reserve in the RTO Zone was 5439 which is classified as highly concentrated. The MMU calculates that the three pivotal supplier test would have been failed in 39.2 percent of intervals in 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 hours in the MAD Subzone was $1.71 per MW in 2020. The weighted average price for tier 2 synchronized reserve for all cleared intervals in the RTO Synchronized Reserve Zone was $1.62 per MW in 2020.

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 2020, the average supply of eligible and available nonsynchronized reserve was 1,548.0 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.[152]
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 99.8 percent of intervals where the price was above $0.01 in 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 $0.19 in 2020.

Secondary Reserve (DASR)

There is no NERC standard for secondary reserve. PJM defines secondary reserve in the day-ahead market 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.[153] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

152 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § $b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 112 (Jan. 5, 2021). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. "

153 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 112 (Jan. 5, 2021).

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 2020, the average available hourly DASR was 52,303.9 MW.
- **Demand.** The DASR requirement is the sum of the PJM requirement and the Dominion requirement based on the VACAR reserve sharing agreement. For the PJM RTO between November 2019 through October 2020, the DASR daily requirement was 5.07 percent of peak load forecast. For November 2020 through October 2021, the DASR requirement was 4.78 percent of peak load forecast. The average hourly DASR MW purchased in 2020 was 4,911.5 MW, a reduction from the 5,594.9 hourly MW in 2019.
- **Concentration.** The three pivotal supplier test would have failed in zero hours in 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 2020, 39.4 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 2020.

Market Performance

- **Price.** In 2020, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.75.

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 2020, the average hourly offered supply of regulation for nonramp hours was 720.9 performance adjusted MW (721.3 effective MW). This was a decrease of 64.6 performance adjusted MW (a decrease of 67.0 effective MW) from 2019. In 2020, the average hourly offered supply of regulation for ramp hours was 1,017.4 performance adjusted MW (1,058.9 effective MW). This was a decrease of 97.9 performance adjusted MW (a decrease of 60.8 effective MW) from 2019, when the average hourly offered supply of regulation was 1,115.3 performance adjusted MW (1,119.7 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 492.0 hourly average performance adjusted actual MW in 2020. This is an increase of 22.5 performance adjusted actual MW from 2019, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 469.5 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 702.5 hourly average performance adjusted actual MW in 2020. This is a decrease of 25.3 performance adjusted actual MW from 2019, where the average hourly regulation cleared MW for ramp hours were 727.8 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 1.45 in 2020 (1.53 in 2019). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.47 in 2020 (1.67 in 2019).

- **Market Concentration.** In 2020, the three pivotal supplier test was failed in 93.5 percent of hours. In 2020, the actual MW weighted average HHI of RegA resources was 2488 which is highly concentrated and the weighted average HHI of RegD resources was 1853 which is moderately concentrated. The weighted average HHI of all resources was 1410, 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.[154] In 2020, there were 230 resources following the RegA signal and 53 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $13.55 per MW of regulation in 2020, a decrease of $2.72 per MW, or 16.7 percent, from the weighted average clearing price of $16.27 per MW in 2019. The weighted average cost of regulation in the 2020 was $16.73 per MW of regulation, a decrease of 17.6 percent, from the weighted average cost of $20.31 per MW in 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.
- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. The current incorrect and inconsistent implementation of the MBF has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in an inefficient market signal about the value of RegD in every hour.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[155]

In 2020, total black start charges were $64.9 million, including $64.7 million in revenue requirement charges and $0.228 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 payment. 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 2020 ranged from $0.04 per MW-day in the BGE Zone (total charges were $139,118) to $2.94 per MW-day in the PENELEC Zone (total charges were $4,335,964).

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. The CRF values were later added to the black start rules. The capital recovery factor (CRF) defines the revenue requirement associated with the capital costs of black start units. The CRF is a

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

155 OATT Schedule 1 § 1.3BB.

rate, multiplied by the relevant capital investment, which defines the annual payment needed to provide a return on and of capital for the investment over a defined time period. CRFs were and are calculated using a standard financial model that incorporates the weighted average cost of capital and its components, including the rate of return on equity and the interest rate on debt and the capital structure, in addition to depreciation and taxes. For example, a five year CRF will allow the recovery of 100 percent of the investment plus a return over five years. The CRF is not a black box. The basis for the CRF was clear when the CRF values were calculated in 2007 and the basis has been explained again in the PJM stakeholder process.[156] Any market participant should be able to calculate CRF rates using the same assumptions.

As a result of the significant changes to the federal tax code in December 2017, the CRF (capital recovery factor) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A are not correct. 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. These tables should have been updated in 2018 and should be updated prior to the next capacity market auction. Correct CRFs will ensure that offer caps and offer floors in the capacity market are correct. The required changes are clear and unambiguous. An immediate filing to change the table based only on the known changes to the tax code would avoid potential uncertainty and confusion among market participants and would avoid any potential delay in procuring addition black start resources. PJM could file the changes under FPA Section 205.

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.

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 to ensure that the commitment to provide service matches the obligation of customers to pay 100 percent of the fixed and variable costs of the black start units over accelerated time periods.

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.[157] 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 5.68 percent from $336.3 million in 2019 to $355.4 million in 2020. Reactive capability charges increased 5.74 percent from $335.8 million in 2019 to $355.0 million in 2020. Total reactive service charges in 2020 ranged

156 "Black Start Issues," presented at the August 6, 2020, and September 3, 2020, PJM Operating Committee Meetings, and revised on September 9, 2020. The presentations can be found at: <https://www.monitoringanalytics.com/reports/Presentations/2020.shtml>.

157 OATT Schedule 2.

from $0 in the RECO and OVEC Zones, to $49.0 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.[158 159]

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.[160] In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

The response of generators within PJM to NERC identified frequency events remains under evaluation. NERC uses a threshold value (L_{10}) equal to 250.8 MW/0.1 Hz and has selected four events between June 1, 2020 and December 31, 2020 as well as several events in the first two months of 2021 to evaluate. Evaluation will continue in 2021 when further recommendations will be discussed within PJM and the NERC Operating Committee.

Market Procurement of Real-Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services, including primary reserves and regulation. Ideally, all ancillary services would be procured taking full account of the interactions with the energy market. When a resource is used for an ancillary service instead of providing energy in real time, the cost of removing the resource, either fully or partially, from the energy market should be weighed against the benefit the ancillary service provides. The degree to which PJM markets account for these interactions depends on the timing of the product clearing and software limitations and the accuracy of unit parameters and offers.

The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services. Resources categorized as flexible tier 2 reserve, those that can provide reserves by backing down according to their ramp rate, are jointly cleared along with energy in every real-time market solution. Given the joint clearing of energy and flexible tier 2, the synchronized reserve market clearing price should always cover the opportunity cost of providing flexible tier 2. PJM should never need to pay uplift to flexible tier 2. The uplift paid to flexible tier 2 results from issues with the dispatch and pricing software timing. Inflexible tier 2 reserves, provided by resources that require longer notice to take actions to prepare for reserve deployment, are not cleared along with energy in the real-time market solution. Inflexible tier 2 reserves are cleared hourly by the Ancillary Service Optimizer (ASO). The ASO uses forward looking information about the energy market, flexible tier 2, tier 1, and regulation to estimate the costs and benefits of using a resource for inflexible tier 2 synchronized reserves.

Nonsynchronized reserves are cleared with every real-time energy market solution, but its costs are not fully known by the real-time energy market software (RT SCED) because the resources are offline. PJM uses an estimate of the cost of using a resource for nonsynchronized reserve instead of energy from a previously solved IT SCED solution. IT SCED runs every 15 minutes looking ahead at target dispatch times up to two hours in the future. The energy commitment decisions for the offline resources have already been made when the RT SCED clears the nonsynchronized reserve market. RT SCED compares the IT SCED estimated cost of nonsynchronized reserve clearing to the RT SCED determined cost of synchronized reserve clearing in satisfying the primary reserve requirement. Nonsynchronized reserve clearing indirectly interacts with energy clearing through both products' substitutability with synchronized reserves.

158 See 157 FERC ¶ 61,122 (2016).
159 See 164 FERC ¶ 61,224 (2018).
160 OATT Attachment O § 4.7.2 (Primary Frequency Response).

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which is based on the RT SCED solution, but the software setting the prices is partially, but not fully clearing the market.

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.[161])
- 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.[162] FERC rejected.[163])
- 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.[164])
- 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.[165])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[166])
- 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

161 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

162 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.

163 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

164 *Id.*

165 *Id.*

166 *Id.*

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 the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that offers in the DASR market be based on opportunity cost only in order to 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.[167] Status: Partially adopted.)
- The MMU recommends that Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. Specifically, such eligibility should be determined based on whether a generation facility's point of interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.[168] (Priority: Medium. New recommendation. Status: Not adopted.)

Section 10 Conclusion

The design of the PJM Regulation Market is significantly flawed.[169] 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.[170] 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.[171] The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.[172]

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

167 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.

168 *See* PJM Transmission Facilities (note that this requires you first log into a PJM Tools account. If you do not, then the link sends you to an Access Request page, <https://pjm.com/markets-and-operations/ops-analysis/transmission-facilities>.

169 The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders. Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

170 18 CFR § 385,211 (2017)

171 162 FERC ¶ 61,295.

172 170 FERC ¶ 61,259.

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, 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 $54.7 million or 9.4 percent, from $583.3 million in 2019 to $528.6 million in 2020.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $51.5 million or 7.2 percent, from $714.0 million in 2019 to $662.5 million in 2020.
- **Balancing Congestion.** Negative balancing congestion costs increased by $3.2 million or 2.5 percent, from -$130.7 million in 2019 to -$133.9 million in 2020. Negative balancing explicit charges decreased by $5.7 million, from -$83.3 million in 2019 to -$77.6 million in 2020.
- **Real-Time Congestion.** Real-time congestion costs decreased by $3.0 million or 0.4 percent, from $752.3 million in 2019 to $749.3 million in 2020.
- **Monthly Congestion.** Monthly total congestion costs in 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 Three Mile Island Transformer, the Conastone - Peach Bottom Line, and the Harwood - Susquehanna Line.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in 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 24.1 percent from 103,140 congestion event hours in 2019 to 78,239 congestion event hours in 2020.

  Real-time congestion frequency increased by 4.1 percent from 21,122 congestion event hours in 2019 to 21,984 congestion event hours in 2020.
- **Congested Facilities.** The monthly average of daily day-ahead congestion event hours decreased in November 2020 as a result of decreased UTC activity due to a FERC order issued effective November 1, 2020, directing PJM to charge uplift to up to congestion transactions.[173] Day-ahead, congestion event hours decreased on all types of facilities except interfaces. The congestion event hours on

173 172 FERC ¶ 61,046 (2020).

the PA Central Interface increased from 872 hours in 2019 to 1,412 hours in 2020.

The Bagley – Graceton Line was the largest contributor to congestion costs in 2020. With $81.7 million in total congestion costs, it accounted for 15.5 percent of the total PJM congestion costs in 2020.

- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** CT Price Setting Logic caused -$0.4 million of day-ahead congestion in 2020 and -$1.7 million of balancing congestion in 2020. None of the closed loop interfaces was binding in 2020 or 2019.
- **Zonal Congestion.** AEP had the largest zonal congestion costs among all control zones in 2020. AEP had $92.7 million in zonal congestion costs, comprised of $112.3 million in zonal day-ahead congestion costs and -$19.6 million in zonal balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $163.5 million or 25.5 percent, from $642.0 million in 2019 to $478.5 million in 2020. The loss MWh in PJM decreased by 891.3 GWh or 5.9 percent, from 15,208.5 GWh in 2019 to 14,317.2 GWh in 2020. The loss component of real-time LMP in 2020 was $0.01, compared to $0.02 in 2019.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 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 $170.3 million or 24.4 percent, from $696.5 million in 2019 to $526.3 million in 2020.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $6.8 million or 12.4 percent, from -$54.5 million in 2019 to -$47.7 million in 2020.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2020 by $45.8 million or 22.5 percent, from $203.7 million in 2019, to $157.9 million in 2020.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs increased by $116.2 million or 26.7 percent, from -$435.2 million in 2019 to -$319.0 million in 2020.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs increased by $127.2 million or 24.1 percent, from -$528.6 million in 2019 to -$401.4 million in 2020.
- **Balancing System Energy Costs.** Balancing system energy costs decreased by $15.0 million or 15.8 percent, from $94.9 million in 2019 to $79.9 million in 2020.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in 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 2020 was lower than congestion in 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 2020.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all congestion revenues. The congestion offset for the first seven months of the 2020/2021 planning period was 55.8.8 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first seven months of the 2020/2021 planning period, using the rules effective for each planning period, was 74.9 percent. Load has been underpaid by $2.2 billion from the 2011/2012 planning period through the first seven months of the 2020/2021 planning period.

Overview: Section 12, Planning

Generation Interconnection Planning

Existing Generation Mix

- As of December 31, 2020, PJM had a total installed capacity of 198,129.0 MW, of which 50,230.8 MW (25.4 percent) are coal fired steam units, 50,602.0 MW (25.5 percent) are combined cycle units and 33,452.6 MW (16.9 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 198,129.0 MW of installed capacity, 72,244.4 MW (36.5 percent) are from units older than 40 years, of which 37,578.4 MW (52.0 percent) are coal fired steam units, 532.0 MW (0.7 percent) are combined cycle units and 16,184.6 MW (22.4 percent) are nuclear units.

Generation Retirements[174]

- There are 44,181.3 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 32,084.1 MW (72.6 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 2020, 3,255.0 MW of generation retired. The largest generator that retired in 2020 was the 786.0 MW Possum Point 5 oil fired steam unit located in the Dominion Zone. Of the 3,255.0 MW of generation that retired, 786.0 MW (24.1 percent) were located in the Dominion Zone.
- As of December 31, 2020, there are 4,163.9 MW of generation that have requested retirement after December 31, 2020, of which 1,794.5 MW (43.1 percent) are located in the ComEd Zone. Of the generation requesting retirement in the ComEd Zone, 1,786.5 MW (99.6 percent) are nuclear units.

Generation Queue[175]

- There were 126,818.9 MW in generation queues, in the status of active, under construction or suspended, at the end of 2019. In 2020, the AF2 and AG1 queue windows closed, and the AG2 queue window opened. 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 December 31, 2020, there were 173,581.3 MW in generation queues, in the status of active, under construction or suspended, an increase of 46,762.4 MW (36.9 percent) from the end of 2019.[176]
- As of December 31, 2020, 5,821 projects, representing 657,391.2 MW, have entered the queue process since its inception in 1998. Of those, 953 projects, representing 73,137.3 MW, went into service. Of the projects that entered the queue process, 2,983 projects, representing 410,672.5 MW (62.5 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 December 31, 2020, 173,581.3 MW were in generation request queues in the status of active, under construction or suspended. Based on historical completion rates, 37,214.3 MW of new generation in the queue are expected to go into service.
- The number of queue entries has increased during the past several years, primarily renewable projects. Of the 3,169 projects entered from January 2015 through December 2020, 2,380 projects (75.1 percent) were renewable. Of the 969 projects entered in 2020, 768 projects (79.3 percent) were renewable. Renewable projects make up 78.6 percent of all projects in the queue and those projects account for 74.8 percent of the nameplate MW currently active, suspended or under construction in the queue as of December 31, 2020.

  But of the 129,844.9 MW of renewable projects in the queue, only 6,487.5 MW (5.0 percent) of capacity resources are expected to go into service, based on both historical completion rates and average derate factors for wind and solar.

174 See PJM. Planning. "Generator Deactivations," (Accessed on December 31, 2020) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

175 See PJM. Planning. "New Services Queue," (Accessed on December 31, 2020) <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.

176 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 December 31, 2020, PJM has completed four market efficiency cycles under Order No. 1000.[177]

PJM MISO Interregional Market Efficiency Process (IMEP)

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

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

PJM MISO Targeted Market Efficiency Process (TMEP)

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

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[178] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 715.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890[179]) to 163 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.[180]

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project. Under the current approach, end of life projects are excluded from competition.[181]

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 authorization.[182] In

177 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).

178 See PJM. "Transmission Construction Status," (Accessed on December 31, 2020) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

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

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

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

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

2020, the PJM Board approved $235.2 million in upgrades. As of December 31, 2020, the PJM Board has approved $37.8 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 December 31, 2020, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[183]
- There were 11,827 transmission outage requests submitted in the first seven months of 2020/2021 planning period. Of the requested outages, 75.9 percent of the requested outages were planned for less than or equal to five days and 9.2 percent of requested outages were planned for greater than 30 days. Of the requested outages, 43.9 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.[184] (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.)
- 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

183 See PJM. "PJM Manual 03: Transmission Operations," Rev. 58 (November 19, 2020).

184 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>.

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.)

Comparative Cost Framework

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

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)
- 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. First reported Q3, 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution-based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution-based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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.[185] (Priority: Medium. First reported 2015. Status: Not adopted.)

185 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 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 MMU recognizes that the Commission has recently issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and 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.

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

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

In addition, the use of an inaccurate cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/

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

If it is retained, there are significant issues with PJM's 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 ARRs

Auction Revenue Rights

Market Structure

- **ARR Ownership.** In the 2020/2021 planning period ARRs were allocated to 1,392 individual participants, held by 131 parent companies. ARR ownership for the 2020/2021 planning period was unconcentrated with an HHI of 851.

Market Behavior

- **Self Scheduled FTRs.** For the 2020/2021 planning period, 25.4 percent of eligible ARRs were self scheduled as FTRs.

Market Performance

- **ARRs as an Offset to Congestion.** ARRs have not served as an effective mechanism to return all congestion revenues to load. For the first seven months of the 2020/2021 planning period, ARRs offset only 55.8 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. Load has been underpaid congestion revenues by $2.2 billion from the 2011/2012 planning period through the first seven months of the 2020/2021 planning period. The cumulative offset for that period was 74.9 percent of total congestion.
- **Revenue Adequacy.** For the first seven 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 $511.2 million, while PJM collected $681.4 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. 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.
- **Residual ARRs.** Residual ARRs are only available on contract paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first seven months of the 2020/2021 planning period, PJM allocated a total of 13,601.8 MW of residual ARRs with a total target allocation of $5.7 million, down from 14,390.3 MW in the first seven months of the 2019/2020 planning period, with a total target allocation of $5.6 million.
- **ARR Reassignment for Retail Load Switching.** There were 21,833 MW of ARRs associated with $290,500

of revenue that were reassigned in the first seven months of the 2020/2021 planning period. There were 24,341 MW of ARRs associated with $404,700 of revenue that were reassigned for the same time frame of the 2019/2020 planning period.

Financial Transmission Rights

Market Design

- **Monthly Balance of Planning Period FTR Auctions.** The design of the Monthly Balance of Planning Period FTR Auctions was changed effective with the 2020/2021 planning period. The new design includes auctions for each remaining month in the planning period. The prior design included auctions for the next three individual months plus remaining quarters.

Market Structure

- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 86.0 percent of prevailing flow and 88.9 percent of counter flow FTRs for January through December, 2020. Financial entities owned 75.4 percent of all prevailing and counter flow FTRs, including 68.7 percent of all prevailing flow FTRs and 83.9 percent of all counter flow FTRs during the period from January through December 2020. Self scheduled FTRs account for 3.9 percent of all FTRs held.
- **Market Concentration.** For prevailing flow obligation FTRs in the Monthly Balance of Planning Period Auctions for the first seven months of the 2020/2021 planning period, all market periods were unconcentrated. For counter flow obligation FTRs for the first seven months of the 2020/2021 planning period, 87.3 of periods were unconcentrated and 12.7 percent of periods were moderately concentrated. All periods were highly concentrated for FTR options. FTR options in the Annual FTR Auction were moderately concentrated.

Market Behavior

- **Sell Offers.** In a given auction, market participants can sell FTRs acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2020/2021 planning period, total participant FTR sell offers were 12,730,496 MW.
- **Buy Bids.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2020/2021 planning were 27,360,901 MW.
- **FTR Forfeitures.** Total FTR forfeitures were $2.2 million for the first seven months of the 2020/2021 planning period.
- **Credit.** There were seven collateral defaults in 2020, for a total of $82,019. There were 27 payment defaults in 2020 not involving GreenHat Energy, LLC for a total of $113,643. GreenHat Energy accrued payment defaults of $14.8 million in 2020 for a total of $161.8 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.[186] 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 $179.3 million.

Market Performance

- **Quantity.** In the first seven months of the 2020/2021 planning period, Monthly Balance of Planning Period FTR Auctions cleared 4,200,340 MW (15.4 percent) of FTR buy bids and 2,085,566 MW (16.4 percent) of FTR sell offers. For the first seven months of the 2019/2020 planning period, Monthly Balance of Planning Period FTR Auctions cleared 2,690,460 (15.9 percent) of FTR buy bids and 1,390,171 MW (21.1 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 seven months of the 2020/2021 planning period was $0.14 per MWh.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $31.6 million in the first seven months of the 2020/2021 planning period, down from $42.6 million for the same time period in the 2019/2020 planning period.
- **Revenue Adequacy.** FTRs were paid at 99.6 percent of the target allocation level for the first seven months

186 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.

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 seven months of 2020/2021 planning period, physical entities made \$39.1 million profits on FTRs purchased directly (not self scheduled), up from \$4.5 million profits for the same time period in the 2019/2020 planning period and financial entities made \$141.3 million, up from \$25.0 million profits for the same time period in the 2019/2020 planning period.

Section 13 Recommendations

Market Design

ARR

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

FTR

- The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately. (Priority: High. First reported Q3, 2020. Status: Adopted 2021.)
- 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 continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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.)

Surplus

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[187] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

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

FTR Liquidation

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

Section 13 Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to load, without requiring contract path 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 contract 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. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by ARR holders of their congestion revenue rights.

Issues

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

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

187 See "PJM Manual 6: Financial Transmission Rights," Rev. 26 (Jan. 27, 2021).

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.[188] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[189] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and further reduced the offset to congestion payments by load. This approach ignores the fact that load pays both day-ahead and balancing congestion, and that congestion is defined, in an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays total congestion and pays negative balancing congestion again. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include inadequate transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There is no reason to impose these costs on load.

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

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

A subsequent rule change was implemented that modified the allocation of surplus auction revenue to 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 total target allocations, and then distributed to ARR holders.[190] ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. While this rule change increased the level of congestion revenues returned to load, the rules do not fully recognize ARR holders' rights to congestion revenue. With this rule in effect for the first seven months of the 2020/2021 planning period, ARRs and FTRs offset 55.8 percent of total congestion.

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 contract paths to assign Stage 1A rights that have nothing to do with actual power flows.

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

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

190 163 FERC ¶61,165 (2018).

Recommendations

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

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

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

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

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

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes," 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 State of the Market Report for PJM*, the MMU includes 26 new recommendations made for 2020, 8 of which are new in this 2020 annual report.[7] [8]

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

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
7 New recommendations include all MMU recommendations that were reported for the first time in the *2020 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2020.
8 For a complete list of MMU recommendations, see the *2020 State of the Market Report for PJM*, Vol II, Section 2, Recommendations.

New Recommendations from Section 3, Energy Market

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. First reported Q3, 2020. 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported Q3, 2020. 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported Q3, 2020. 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.)

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. First reported Q3, 2020. Status: Not adopted.)

New Recommendation from Section 5, Capacity Market

- The MMU recommends that PJM update the values in the CRF table in the tariff when the components change. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendation from Section 6, Demand Response

- 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.)

New Recommendations from Section 9, Interchange Transactions

- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from 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 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: Adopted Q4, 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: Adopted Q4, 2020.)

New Recommendations from Section 10, Ancillary Services

- The MMU recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. Specifically, such eligibility should be determined based on whether a generation facility's point of interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.[9] (Priority: Medium. New recommendation. 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.)

9 *See* PJM Transmission Facilities (note that this requires you first log into a PJM Tools account. If you do not, then the link sends you to an Access Request page, https://pjm.com/markets-and-operations/ops-analysis/transmission-facilities.

New Recommendations from Section 12, Generation and Transmission Planning

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends a comprehensive review of the ways in which the solution-based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution-based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported Q3, 2020. Status: Not adopted.)

New Recommendations 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. First reported Q3, 2020. Status: Adopted 2021.)
- 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.)

History of MMU Recommendations

The MMU began making recommendations to PJM in the 1999 State of the Market Report. Since that time, the MMU has made 326 recommendations in the State of the Market Reports. In 2014, the MMU began including a priority and status with each recommendation. In this 2020 State of the Market Report for PJM, the MMU has reviewed all past recommendations, assigned priority and determined their current status.

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

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

Table 2-1 shows the status of all recommendations reported by the MMU from 1999 through 2020. Over that time, 22 percent of all MMU recommendations have been adopted, 11 percent have been partially adopted, and 60 percent are not adopted. Of the 93 high priority recommendations, 26 (28 percent) have been adopted. Table 2-1 includes past recommendations that are no longer included in this report.

Table 2-1 Status of MMU reported recommendations: 1999 through 2020

Status	Priority High	Priority Medium	Priority Low	Total	Percent of Total
Adopted	26	22	25	73	22%
Partially Adopted - Stakeholder Process	0	0	0	0	0%
Partially Adopted - FERC	1	0	0	1	0%
Partially Adopted (Continued Recommendation)	9	14	6	29	9%
Partially Adopted (Recommendation Closed)	1	2	4	7	2%
Partially Adopted (Total)	11	16	10	37	11%
Not Adopted	51	92	41	184	56%
Not Adopted (Pending before FERC)	3	5	0	8	2%
Not Adopted (Stakeholder Process)	0	2	1	3	1%
Not Adopted (Total)	54	99	42	195	60%
Replaced by Newer Recommendation	1	8	3	12	4%
Withdrawn, No Longer Relevant	0	3	2	5	2%
Withdrawn	1	2	1	4	1%
Total	93	150	83	326	100%

Table 2-2 shows the number of recommendations associated with each of the sections in this report. The Energy Market, Capacity Market, and Ancillary Service Markets sections are the source of 51 percent of the recommendations.

Table 2-2 MMU reported recommendations by section and priority: 1999 through 2020

Current Section	Priority High	Priority Medium	Priority Low	Total	Percent of Total
Section 1, Introduction (General Recommendations)	2	0	0	2	1%
Section 3, Energy Market	10	44	16	70	21%
Section 4, Energy Uplift	10	19	3	32	10%
Section 5, Capacity Market	21	23	10	54	17%
Section 6, Demand Response	12	12	9	33	10%
Section 7, Net Revenue	0	1	0	1	0%
Section 8, Environmental and Renewables	3	2	1	6	2%
Section 9, Interchange Transactions	6	11	12	29	9%
Section 10, Ancillary Service Markets	8	21	12	41	13%
Section 11, Congestion and Marginal Losses	0	1	1	2	1%
Section 12, Generation and Transmission Planning	1	14	12	27	8%
Section 13, Financial Transmission and Auction Revenue Rights	20	2	7	29	9%
Total	93	150	83	326	100%

Table 2-3 shows the total number of recommendations that were reported by the MMU by year. There were five years (2012, 2013, 2015, 2018, and 2020) in which the MMU reported ten or more high priority recommendations.

Table 2-3 MMU reported recommendations by year first reported: 1999 through 2020

Year First Reported	Priority High	Priority Medium	Priority Low	Total	Percent of Total
1999	3	3	0	6	2%
2000	1	0	0	1	0%
2001	0	0	1	1	0%
2002	1	1	1	3	1%
2003	1	3	1	5	2%
2004	0	0	0	0	0%
2005	0	1	0	1	0%
2006	2	0	0	2	1%
2007	0	0	0	0	0%
2008	1	0	0	1	0%
2009	5	5	13	23	7%
2010	3	10	6	19	6%
2011	3	1	4	8	2%
2012	10	16	14	40	12%
2013	11	16	16	43	13%
2014	5	10	3	18	6%
2015	11	13	7	31	10%
2016	3	18	3	24	7%
2017	5	7	2	14	4%
2018	10	18	7	35	11%
2019	7	14	4	25	8%
2020	11	14	1	26	8%
Total	93	150	83	326	100%

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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported Q3, 2020. 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. First reported Q3, 2020. 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: 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. First reported Q3, 2020. 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.)

Offer Behavior

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

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: Partially 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.[10] [11] (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

10 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.

11 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>.

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

- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported Q3, 2020. 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 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 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments

and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)

- The MMU recommends the elimination of day-ahead 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 units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends 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.[12])
- 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.)

12 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.

- 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.[13])
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 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.)

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.[14 15] (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.[16 17] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected.

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

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

15 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).

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

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

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

- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported 2017. Status: Not adopted.)
- 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.[18] (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.[19] (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

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

19 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).

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.)
- The MMU recommends that PJM update the values in the CRF table in the tariff when the components change. (Priority: High. New recommendation. 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.[20] (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

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

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.[21] (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 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.[22])
- 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.)

21 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.

22 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.

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 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 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: Adopted Q4, 2020.)

- 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: Adopted Q4, 2020.)
- 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.[23])

- 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.[24] FERC rejected.[25])
- 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.[26])
- 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.[27])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[28])
- 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.)
- 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

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

24 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.

25 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

26 *Id.*

27 *Id.*

28 *Id.*

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 the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that offers in the DASR market be based on opportunity cost only in order to 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.[29] Status: Partially adopted.)
- The MMU recommends that Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. Specifically, such eligibility should be determined based on whether a generation facility's point of

29 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.

interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.[30] (Priority: Medium. New recommendation. Status: Not adopted.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[31] (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.)
- 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.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital

30 *See* PJM Transmission Facilities (note that this requires you first log into a PJM Tools account. If you do not, then the link sends you to an Access Request page, https://pjm.com/markets-and-operations/ops-analysis/transmission-facilities.

31 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>.

expenditures; ongoing maintenance; and expected life. (Priority: Medium. New recommendation. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)
- 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. First reported Q3, 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution-based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution-based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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.[32] (Priority: Medium. First reported 2015. Status: Not adopted.)

32 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 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 13, FTRs and ARRs

Market Design

ARR

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

FTR

- The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately. (Priority: High. First reported Q3, 2020. Status: Adopted 2021.)
- 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 continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)

- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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.)

Surplus

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[33] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

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

33 See "PJM Manual 6: Financial Transmission Rights," Rev. 26 (Jan. 27, 2021).

FTR Liquidation

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

Adopted Recommendations

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

Adopted 2021

- The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately. (Priority: High. First reported Q3, 2020. Last reported 2020. Section 13, Financial Transmission and Auction Revenue Rights.)

Adopted 2020

- The MMU recommends incorporating startup and notification times as additional parameters subject to limits in order to ensure the reliability of the grid, as well as to deter market manipulation by offering artificially lengthy startup and notification time parameters to withhold generation from the market. (Priority: Medium. First reported 2010. Last reported 2010, Section 3, Energy Market.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Last reported 2018, Section 3, Energy Market.)
- The MMU recommends that the tariff be changed to allow units to have fuel cost policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for fuel cost policies but should not be required. (Priority: Low. First reported 2018. Last reported 2020, Section 3, Energy Market.)
- The MMU recommends that PJM change the fuel cost policy requirement to apply only to units that

will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved fuel cost policy be set to zero. (Priority: Low. First reported 2018. Last reported 2020, Section 3, Energy Market.)

- 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. Last reported 2020, Section 7, Net Revenue.)
- 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. Last reported 2020, Section 9, Interchange Transactions.)
- 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. Last reported 2020, Section 9, Interchange Transactions.)
- 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. Last reported 2020, Section 12, Generation and Transmission Planning.)

Adopted 2019

- 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. Last reported 2019, Section 3, Energy Market.)
- The MMU recommends that dispatchers classify the reasons for unit deselection and document all unit deselections. (Priority: Low. First reported 2009. Last reported 2009, Section 6, Ancillary Service Markets.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Last reported 2019, Section 9, Interchange Transactions.)
- 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. Last reported 2020, Section 12, Generation and Transmission Planning.)
- 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. Last reported 2020, Section 13, FTRs and ARRs. Pending at FERC.)
- The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the charges and credits to market participants in all other areas of the PJM Energy Market. (Priority: High. First reported 2009. Last reported 2012, Section 3, Operating Reserve.)
- 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. Last reported 2020, Section 10 Ancillary Service Markets.)

Adopted 2018

- The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour. (Priority: Medium. First reported 2013. Last reported Q3, 2018, Section 4, Energy Uplift.)

- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Last reported 2018, Section 4, Energy Uplift.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit uplift compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants must take to change the availability of cost-based energy offers that have been submitted day ahead. The MMU recommends that PJM eliminate the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. Last reported 2018, Section 4, Energy Uplift.[34])

Adopted 2017

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

Adopted 2016

- The MMU recommends that PJM report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2012. Last reported: 2018 Q3, Section 13, Financial Transmission and Auction Revenue Rights.)

- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Last reported: 2018 Q3, Section 10, Ancillary Service Markets)

Adopted 2015

- The MMU recommends that the lost opportunity cost in the energy market be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2009. Last reported: 2018 Q3 Section 4, Energy Uplift.)
- The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2012. Last reported: 2018 Q3 Section 4, Energy Uplift.)
- The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost. (Priority: Medium. First reported 2012. Last reported: 2018 Q3 Section 4, Energy Uplift.)
- The MMU recommends that all generation types face the same performance incentives. (Priority: High. First reported 2009. Last reported: 2012 Section 4, Capacity Market.)
- The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. The performance incentives in the RPM Capacity Market design need to be strengthened. (Priority: High. First reported 2009. Last reported: 2009 Section 5, Capacity Market.)
- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules. (Priority: High. First reported 2010. Last reported: 2011 Section 4, Capacity Market.)
- The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market. (Priority: Medium. First reported 2013. Last reported: 2018 Q3 Section 5, Capacity Market.)

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

- The MMU recommends immediate elimination of lack of fuel as an acceptable basis for an OMC outage. (Priority: Medium. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- PJM should scrutinize OMC outages for low Btu coal carefully. (Priority: Medium. First reported 2003. Last reported: 2009 Section 4, Capacity Market.)
- The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units. (Priority: Medium. First reported 2013. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent. (Priority: High. First reported 2012. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during the RPM peak period. (Priority: Low. First reported 2012. Last reported: 2012 Section 4 Capacity Market.)
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2012. Last reported: 2018 Q3 Section 5 Capacity Market.)
- The MMU recommends that the definition of demand side resources be modified to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources. (Priority: High. First reported 2012. Last reported: 2018 Q3 Section 5 Capacity Market.)
- The MMU recommends that PJM increase the Capacity Resource Deficiency Charge, which is a penalty charge. (Priority: High. First reported 2013. Last reported: 2013 Section 5 Capacity Market.)
- The MMU recommends that all capacity imports have firm transmission to the PJM border prior to offering in an RPM auction. (Priority: High. First reported 2014. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends that all capacity imports be required to be pseudo tied prior to the relevant delivery year in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. (Priority: High. First reported 2014. Last reported: 2017 Section 5, Capacity Market.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Last reported: 2018 Q3 Section 6, Demand Response.)
- Continued development of appropriate credit protections for transactions in PJM markets that are consistent with those available to participants in bilateral transactions. (Priority: Low. First reported 2002. Last reported: 2002 Section: Recommendations.)

Adopted 2014

- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Last reported: 2018 Q1 Section 3, Energy Market.)
- Pending elimination of these DR products, the MMU recommends that PJM procure the maximum amount of Annual and Extended Summer capacity resources available during an RPM auction, without impacting the clearing price. Currently, PJM procures a minimum level of Extended Summer and Annual Resources, but could procure additional MW of these superior products without a change in the clearing price. (Priority: Medium. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- The MMU recommends that demand resources whose technology type (load drop method) is designated

as "Other" explicitly record the technology type. (Priority: Low. First reported 2013. Last reported: 2018 Q3 Section 6, Demand Response.)

- The MMU recommends that the Enhanced energy Scheduler (EES) application be modified to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible. This business rule is currently in the PJM Manuals, but is not being enforced. (Priority: Low. First reported 2009. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU recommends that the rules for compliance with calls to respond to actual spinning events be reevaluated. (Priority: Low. First reported 2011. Last reported: 2012 Section 9, Ancillary Service Markets.)
- The MMU recommends that no payments be made to tier 1 synchronized reserve resources if they are deselected in the PJM market solution. The MMU also recommends that documentation of the tier 1 synchronized reserve deselection process be published. (Priority: High. First reported 2014. Status: Adopted, 2014. Last reported: 2018 Q3 Section 10, Ancillary Service Markets.)

Adopted 2013

- The PJM Tariff defines offer capped units as those units capped to maintain system reliability as a result of limits on transmission capability. Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules. (Priority: Low. First reported 2013. Last reported: 2014 Q1, Section 3, Energy Market.)
- The MMU recommends that the notification requirement for deactivations be modified to include required notification of six to twelve months prior to an auction in which the unit will not be offered due to deactivation. The purpose of this deadline is to allow adequate time for potential Capacity Market Sellers to offer new capacity in the auction. (Priority: Low. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- The MMU recommends modifying the evaluation criteria via a change to PJM's market software, to ensure that not willing to pay congestion transactions are not permitted to flow in the presence of congestion. (Priority: Low. First reported 2009. Last reported: 2009 Section 4, Interchange Transactions.)
- The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions). (Priority: Low. First reported 2010. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. PJM should have responsibility to prepare the black start restoration plan for the region, with Members playing an advisory role. PJM should have the responsibility to procure required black start service on a least cost basis through a transparent process. (Priority: Low. First reported 2009. Last reported: 2011 Section 9, Ancillary Service Markets.)
- The MMU recommends that PJM document the reasons each time it changes the Tier 1 synchronized reserve transfer capability into the Mid-Atlantic subzone market because of the potential impacts on the market. (Priority: Low. First reported 2011. Last reported: 2011 Section 9, Ancillary Service Markets.)

Adopted 2012

- The MMU recommends that PJM should, on an expedited basis, request that the tariff be modified to permit allocation of day-ahead operating reserve charges consistent with the prior allocation of these charges in real time. This would be a short term solution to the issue created by shifting operating reserve charges to the Day-Ahead Energy Market and therefore changing the allocation of those charges. In addition, PJM should start a stakeholder process to consider the market design and cost allocation issues in detail and propose a permanent tariff change that results from the process. (Priority: High. First reported 2012. Last reported: 2012-Q3 Section 3, Operating Reserve.)

- The MMU recommends that PJM conduct a detailed review of the Day-Ahead Market software in order to address the issue of occasional anomalous loss factors and their effect on the day-ahead market results. (Priority: Low. First reported 2011. Last reported: 2011 Section 10, Congestion and Marginal Losses.)
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013. Last reported 2018 Q3, Section 3, Energy Market.)
- The MMU recommends the use of a single five minute clearing price based on actual five minute LMP and lost opportunity cost to improve the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Adopted in 2012. Last reported 2018 Q3, Section 10, Ancillary Service Markets.)

Adopted 2011

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

Adopted 2010

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

Adopted 2009

- Retention and application of enhancements to rules governing the payment of operating reserve credits to generators and the allocation of operating reserves charges among market participants that were implemented on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors. (Priority: High. First reported 2006. Last reported: 2007 Section 1, Introduction.)
- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity. (Priority: High. First reported 2006. Last reported: 2011 Section 4, Capacity.)
- Retention and application of the improved market power mitigation rules in the Regulation Market to prevent the exercise of market power in the Regulation Market while ensuring appropriate economic signals when investment is required and an efficient market mechanism. The PJM Regulation Market continues to be characterized by structural market power. PJM's application of targeted, flexible real-time, market power mitigation in the Regulation Market addresses only the hours in which structural market power exists and therefore provides an incentive for the continued development of competition. (Priority: High. First reported 2006. Last reported: 2009 Section 1, Introduction.)
- While it is reasonable to limit the authority of LSE/EDCs in the review of demand side settlements as the LSE/EDCs have economic incentives to deny settlements, LSE/EDCs should be able to initiate PJM settlement reviews. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- The MMU recommends ways to further improve the Economic program by increasing the probability that payments are made only for economic and deliberate load reducing activities in response

to price. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)

- The four steps in the normal operations review should be routinely applied to all registrations from the beginning of participation. This would include the ongoing evaluation of whether CBL accurately represents customer load for each customer; analysis of settlements to determine responsiveness to price and; required submission of detailed description of load reduction activities on specific days.
- The definition of CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions. When used to determine compliance in Load Management testing for GLD customers, the CBL calculation should include adjustments for ambient conditions.
- It is the MMU's recommendation that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should initiate a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken prior to acceptance of such settlements. Further, in order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM.
- If, for any settlement, the number of consecutive hours showing load reduction is beyond a reasonable window for load reducing actions in response to price, it should initiate a CBL review and warrant further substantiation from the customer and CSP.
- Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen.

Adopted 2008

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

Adopted 2006

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

Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in 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 2020 was unconcentrated by FERC HHI standards. Average HHI was 726 with a minimum of 526 and a maximum of 1080 in 2020. The peaking segment of supply was highly concentrated. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the 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. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates. In the PJM energy market, market power mitigation occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[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. Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

Overview

Supply and Demand

Market Structure

- **Supply.** The average hourly day-ahead supply was 157,005 for 2020, and 171,443 MW for 2019. The average on-peak hourly offered real-time supply was 135,383 MW for 2020, and 138,779 MW for 2019. In 2020, 2,556.7 MW of new resources were added in the energy market, and 3,255.0 MW of resources and 457.0 MW of pseudo tied resources were retired.
- PJM average hourly real-time cleared generation in 2020 decreased by 2.7 percent from 2019, from 93,434 MWh to 90,946 MWh.

  PJM average hourly day-ahead cleared supply in 2020, including INCs and up to congestion transactions, decreased by 4.9 percent from 2019, from 117,250 MWh to 111,470 MWh.
- **Demand.** The PJM system real-time hourly peak load in 2020 was 141,449 MWh in the HE 1700 on July 20, 2020, which was 6,778 MWh, 4.6 percent,

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.

lower than the PJM peak load in 2019, which was 148,228 MWh in the HE 1800 on July 19, 2019.

- PJM average hourly real-time load in 2020 decreased by 4.0 percent from 2019, from 88,120 MWh to 84,584 MWh, the largest percent decrease since 2009. Both the weather and COVID-19 contributed to the significant change. Based on the weather normalized demand analysis, 3.4 of the 4.0 percent decrease in load was related to COVID-19.
- PJM average hourly day-ahead demand in 2020, including load, DECs and up to congestion transactions, decreased by 5.7 percent from 2019, from 112,588 MWh to 106,209 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 2020, 16.1 percent of real-time load was supplied by bilateral contracts, 24.7 percent by spot market purchases and 59.2 percent by self supply. Compared to 2019, reliance on bilateral contracts increased by 0.8 percentage points, reliance on spot market purchases decreased by 0.1 percentage points and reliance on self supply decreased by 0.7 percentage points.
- **Generator Offers.** In day-ahead market offers, generators define the commitment status and the dispatch status of their units. In the day-ahead market in 2020, 21.8 percent of MW were offered as must run, 32.1 percent were offered as economic minimum MW for dispatchable units, 45.0 percent were offered as dispatchable MW, and 1.0 percent were offered as emergency maximum MW.
- **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 2.7 percent and cleared MW decreased by 16.0 percent in 2020. The hourly average submitted decrement offer MW increased by 24.4 percent and cleared MW increased by 16.6 percent in 2020. The hourly average submitted up to congestion bid MW decreased by 23.8 percent and cleared MW decreased by 12.4 percent in 2020.

Market Performance

- **Generation Fuel Mix.** In 2020, coal units provided 19.3 percent, nuclear units 34.2 percent and natural gas units 39.8 percent of total generation. Compared to 2019, generation from coal units decreased 20.6 percent, generation from natural gas units increased 6.7 percent and generation from nuclear units decreased 0.8 percent. The trend toward more energy from natural gas and less from coal accelerated in 2020.
- **Fuel Diversity.** The fuel diversity of energy generation in 2020, measured by the fuel diversity index for energy (FDI_e), decreased 1.5 percent compared to 2019.
- **Marginal Resources.** In the PJM Real-Time Energy Market in 2020, coal units were 17.5 percent and natural gas units were 72.3 percent of marginal resources. In 2019, coal units were 24.4 percent and natural gas units were 69.4 percent of marginal resources.

  In the PJM Day-Ahead Energy Market in 2020, up to congestion transactions were 51.4 percent, INCs were 13.2 percent, DECs were 18.8 percent, and generation resources were 16.5 percent of marginal resources. In 2019, up to congestion transactions were 57.4 percent, INCs were 12.8 percent, DECs were 17.0 percent, and generation resources were 12.7 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 2020. Both the weather and COVID-19 played a role in this significant drop in prices.

  PJM load-weighted, average, real-time LMP in 2020 decreased 20.3 percent from 2019, from $27.32 per MWh to $21.77 per MWh.

  PJM load-weighted, average day-ahead LMP in 2020 decreased 21.4 percent from 2019, from $27.23 per MWh to $21.40 per MWh.
- **Components of LMP.** In the PJM Real-Time Energy Market in 2020, 23.7 percent of the load-weighted LMP was the result of coal costs, 41.5 percent was

the result of gas costs and 1.7 percent was the result of the cost of emission allowances.

In the PJM Day-Ahead Energy Market, in 2020, 24.4 percent of the load-weighted LMP was the result of coal costs, 18.8 percent was the result of gas costs, 15.2 percent was the result of INC offers, 24.0 percent was the result of DEC bids, and 3.0 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 $0.33 per MWh in 2020, and -$0.01 per MWh in 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 nine intervals with five minute shortage pricing in 2020. There were no emergency actions that resulted in Performance Assessment Intervals in 2020.
- There were 1,819 five minute intervals, or 1.7 percent of all five minute intervals in 2020 for which at least one RT SCED solution showed a shortage of reserves, and 592 five minute intervals, or 0.6 percent of all five minute intervals in 2020 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for nine 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 2020, the average number of suppliers providing constraint relief was 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 1.3 percent in 2019 to 1.6 percent in 2020. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.7 percent in 2019 to 1.0 percent in 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 2020, 10 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working 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 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 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

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 2020, in the PJM Real-Time Energy Market, 98.2 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 2020 was more than $450 per MWh when using unadjusted cost-based offers.

  In 2020, in the PJM Day-Ahead Energy Market, 99.2 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 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 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 2020, the unadjusted markup component of LMP was $0.50 per MWh or 2.3 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 35 hours in 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 $30.70 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2020, the unadjusted markup component of LMP resulting from generation resources was -$0.11 per MWh or -0.5 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 5.2 percent of marginal unit intervals in 2020 the marginal unit had local market power as determined by the TPS test and a positive markup, compared to 10.0 percent of marginal unit intervals in 2019. 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported Q3, 2020. 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. First reported Q3, 2020. 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: 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. First reported Q3, 2020. 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.)

Offer Behavior

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

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: Partially 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.[3] [4] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 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.)

3 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.

4 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 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported Q3, 2020. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 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 load in 2020 decreased by 4.0 percent from 2019, from 88,120 MWh to 84,584 MWh, the largest percent decrease since 2009. Both the weather and COVID-19 contributed to the significant change. Based on the weather normalized demand analysis, 3.4 of the 4.0 percent decrease in load was related to COVID-19. The relationship between supply and demand, regardless of the specific market, along with market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals or market structure. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[5] 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 all costs that are related to electric production are short run marginal costs, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially fixed 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

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

an indicator of the level of competition in a market. 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 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 substantially increase markups in energy offers 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.

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. PJM has a plan to make these changes, and PJM should prioritize implementing it. These issues are even more critical now that PJM settles real-time energy transactions on a five minute basis and will soon implement fast start pricing.

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 significant price increases 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. Rather than sending dispatch signals consistent with resource offers and holding resources accountable when they fail to follow them, DGP accommodates resources that do not follow dispatch. 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 actually fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM will pay new forms of uplift in an attempt to counter the distorted incentives. 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 2020 or prior years. In 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 31.2 percent in 2016 to 64.3 percent in 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 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 2020.

Supply and Demand

Market Structure

Supply

Supply includes physical generation, imports and virtual transactions.

In 2020, 2,556.7 MW of new resources were added in the energy market, and 3,255.0 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 2019 and 2020.[6][7][8] 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 and 2020

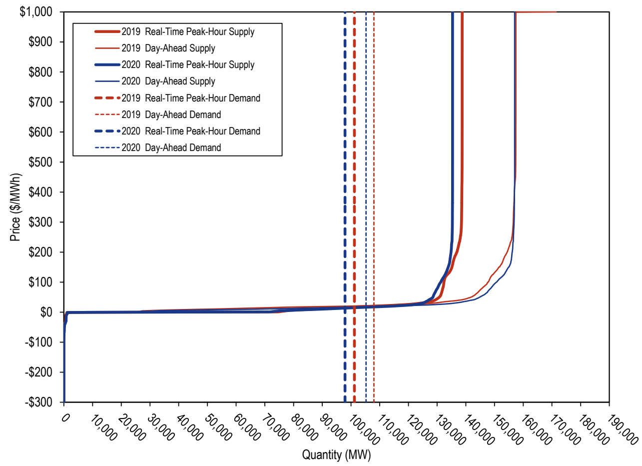
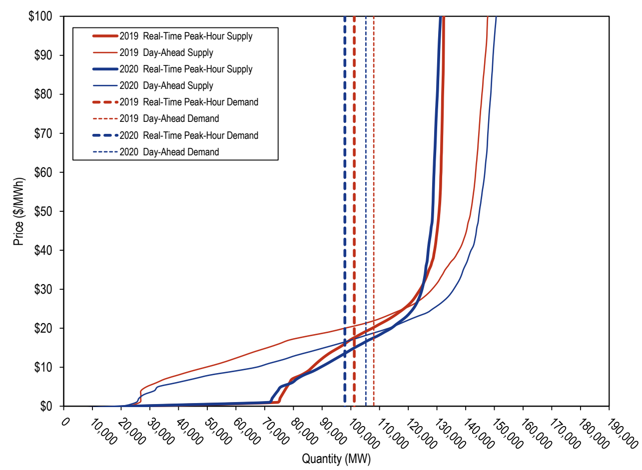


Figure 3-2 Typical dispatch range of supply curves



6 Real-time generation offers and real-time import MWh are included.
7 Real-time load and export MWh are included.
8 The supply curve period is from January 1 to December 31.

Table 3-2 shows the price elasticity of the real-time supply curve for the on peak hours in 2019 and 2020 by load level.

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

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

The supply curve is elastic when elasticity is greater than 1.0. The supply curve 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 the supply curve

	Elasticity of Supply	
GW	2019	2020
Min - 75	0.021	0.022
75 - 95	0.388	0.188
95 - 115	0.025	0.325
115 - Max	0.004	0.004

Real-Time Supply

The maximum average on-peak hourly offered real-time supply was 135,383 MW for 2020 and 138,779 MW for 2019. 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 rates and start times.

PJM average hourly real-time cleared generation in 2020 decreased by 2.7 percent from 2019, from 93,434 MWh to 90,946 MWh.[9]

PJM average hourly real-time cleared supply including imports in 2020 decreased by 3.1 percent from 2019, from 94,618 MWh to 91,681 MWh.

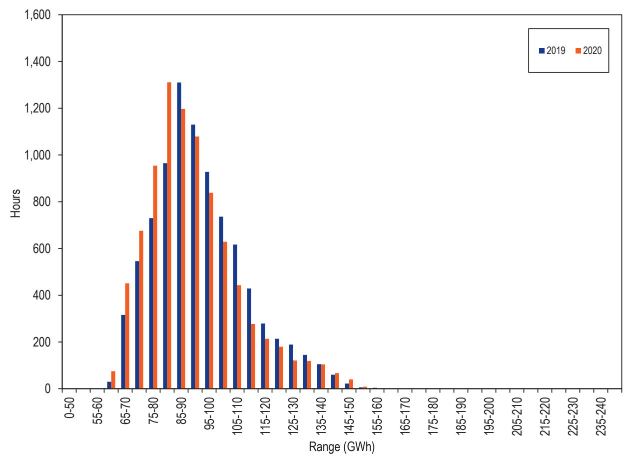
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **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.

PJM Real-Time Supply Frequency

Figure 3-3 shows the hourly distribution of PJM real-time generation plus imports in 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: 2019 and 2020[10]



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

10 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 20 year period from 2001 through 2020.

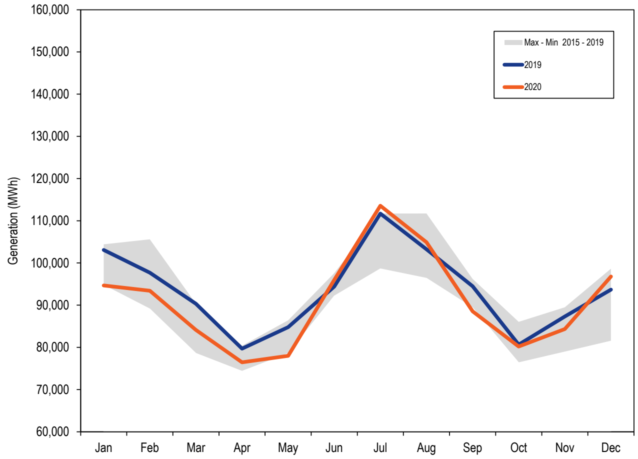
Table 3-3 Average hourly real-time generation and real-time generation plus imports: 2001 through 2020

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	29,553	4,937	32,552	5,285	NA	NA	NA	NA
2002	34,928	7,535	38,535	7,751	18.2%	52.6%	18.4%	46.7%
2003	36,628	6,165	40,205	6,162	4.9%	(18.2%)	4.3%	(20.5%)
2004	51,068	13,790	55,781	14,652	39.4%	123.7%	38.7%	137.8%
2005	81,127	15,452	86,353	15,981	58.9%	12.0%	54.8%	9.1%
2006	82,780	13,709	86,978	14,402	2.0%	(11.3%)	0.7%	(9.9%)
2007	85,860	14,018	90,351	14,763	3.7%	2.3%	3.9%	2.5%
2008	83,476	13,787	88,899	14,256	(2.8%)	(1.7%)	(1.6%)	(3.4%)
2009	78,026	13,647	83,058	14,140	(6.5%)	(1.0%)	(6.6%)	(0.8%)
2010	82,585	15,556	87,386	16,227	5.8%	14.0%	5.2%	14.8%
2011	85,775	15,932	90,511	16,759	3.9%	2.4%	3.6%	3.3%
2012	88,708	15,701	94,083	16,505	3.4%	(1.4%)	3.9%	(1.5%)
2013	89,769	15,012	94,833	15,878	1.2%	(4.4%)	0.8%	(3.8%)
2014	90,894	15,151	96,295	16,199	1.3%	0.9%	1.5%	2.0%
2015	88,628	16,118	94,330	17,313	(2.5%)	6.4%	(2.0%)	6.9%
2016	91,304	17,731	95,054	17,980	3.0%	10.0%	0.8%	3.9%
2017	90,945	15,194	92,721	15,493	(0.4%)	(14.3%)	(2.5%)	(13.8%)
2018	94,236	16,326	96,109	16,595	3.6%	7.5%	3.7%	7.1%
2019	93,434	16,357	94,618	16,515	(0.9%)	0.2%	(1.6%)	(0.5%)
2020	90,946	16,528	91,681	16,629	(2.7%)	1.1%	(3.1%)	0.7%

PJM Real-Time, Monthly Average Generation

Figure 3-4 compares the real-time, monthly average hourly generation in 2019 and 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: 2019 through 2020



Day-Ahead Supply

PJM average hourly day-ahead cleared supply in 2020, including INCs and up to congestion transactions, decreased by 4.9 percent from 2019, from 117,250 MWh to 111,470 MWh. When imports are added, PJM average hourly, day-ahead cleared supply in 2020 decreased by 5.1 percent from 2019, from 117,622 MWh to 111,636 MWh.

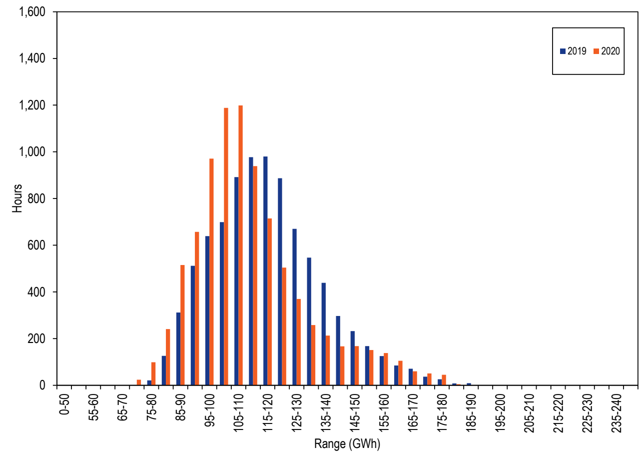
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **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 cleared supply, including increment offers, up to congestion transactions, and imports in 2019 and 2020.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: 2019 and 2020[11]



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

PJM Day-Ahead, Average Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics for the 20 year period from 2001 through 2020.

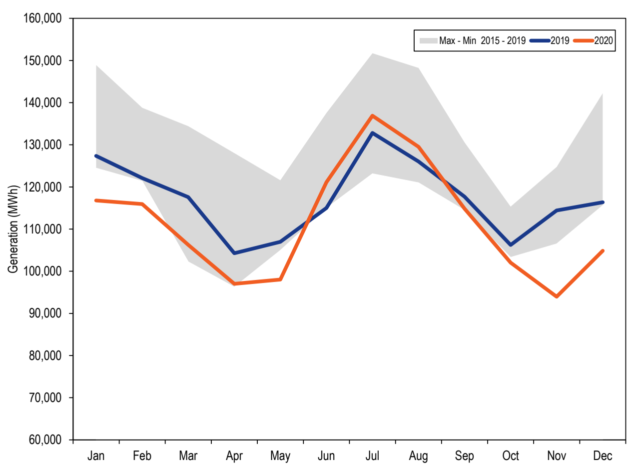
Table 3-4 Average hourly day-ahead cleared supply and day-ahead cleared supply plus imports: 2001 through 2020

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	26,762	4,595	27,497	4,664	NA	NA	NA	NA
2002	31,434	10,007	31,982	10,015	17.5%	117.8%	16.3%	114.7%
2003	40,642	8,292	41,183	8,287	29.3%	(17.1%)	28.8%	(17.3%)
2004	62,755	17,141	63,654	17,362	54.4%	106.7%	54.6%	109.5%
2005	94,438	17,204	96,449	17,462	50.5%	0.4%	51.5%	0.6%
2006	100,056	16,543	102,164	16,559	5.9%	(3.8%)	5.9%	(5.2%)
2007	108,707	16,549	111,023	16,729	8.6%	0.0%	8.7%	1.0%
2008	105,485	15,994	107,885	16,136	(3.0%)	(3.4%)	(2.8%)	(3.5%)
2009	97,388	16,364	100,022	16,397	(7.7%)	2.3%	(7.3%)	1.6%
2010	107,307	21,655	110,026	21,837	10.2%	32.3%	10.0%	33.2%
2011	117,130	20,977	119,501	21,259	9.2%	(3.1%)	8.6%	(2.6%)
2012	134,479	17,905	136,903	18,080	14.8%	(14.6%)	14.6%	(15.0%)
2013	148,323	18,783	150,595	18,978	10.3%	4.9%	10.0%	5.0%
2014	146,672	33,145	148,906	33,346	(1.1%)	76.5%	(1.1%)	75.7%
2015	114,890	19,165	117,147	19,406	(21.7%)	(42.2%)	(21.3%)	(41.8%)
2016	131,618	22,329	133,246	22,368	14.6%	16.5%	13.7%	15.3%
2017	130,603	20,035	131,142	20,153	(0.8%)	(10.3%)	(1.6%)	(9.9%)
2018	114,556	20,239	114,967	20,224	(12.3%)	1.0%	(12.3%)	0.4%
2019	117,250	18,909	117,622	18,881	2.4%	(6.6%)	2.3%	(6.6%)
2020	111,470	19,749	111,636	19,729	(4.9%)	4.4%	(5.1%)	4.5%

PJM Day-Ahead, Monthly Average Cleared Supply

Figure 3-6 compares the day-ahead, monthly average hourly cleared supply, including increment offers and up to congestion transactions in 2019 and 2020 with the historic five year range.

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



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for 2019 and 2020, for day-ahead cleared supply and real-time supply, which is generation plus imports. 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): 2019 and 2020

		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	93,498	2,889	20,862	373	117,622	93,434	94,618	64	23,005
	2020	90,786	2,427	18,257	166	111,636	90,946	91,681	(159)	19,955
Median	2019	91,096	2,753	20,664	340	115,949	91,006	92,159	90	23,790
	2020	87,852	2,364	19,196	125	107,798	88,107	88,830	(254)	18,969
Standard Deviation	2019	16,925	1,018	4,732	233	18,881	16,357	16,515	568	2,366
	2020	17,343	852	5,908	166	19,729	16,528	16,629	814	3,100
Peak Average	2019	102,570	3,389	22,303	330	128,592	101,815	103,078	755	25,515
	2020	99,578	2,758	18,960	152	121,448	98,949	99,724	630	21,724
Peak Median	2019	99,921	3,313	22,120	287	125,612	99,190	100,352	731	25,260
	2020	96,111	2,713	19,883	100	116,084	95,567	96,441	543	19,642
Peak Standard Deviation	2019	15,023	1,012	4,506	237	16,065	14,968	15,095	56	970
	2020	16,544	868	5,866	155	19,322	16,028	16,151	517	3,171
Off-Peak Average	2019	85,587	2,454	19,606	410	108,057	86,126	87,241	(539)	20,815
	2020	83,048	2,135	17,639	179	103,000	83,902	84,603	(854)	18,397
Off-Peak Median	2019	83,416	2,366	19,274	390	105,987	83,939	84,926	(524)	21,061
	2020	80,536	2,076	18,490	145	100,743	81,652	82,365	(1,116)	18,378
Off-Peak Standard Deviation	2019	14,321	800	4,565	222	15,680	13,815	13,968	506	1,713
	2020	14,025	721	5,877	174	15,618	13,476	13,539	549	2,079

Figure 3-7 shows the average cleared volumes of day-ahead supply and real-time supply by hour of the day in 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): 2020

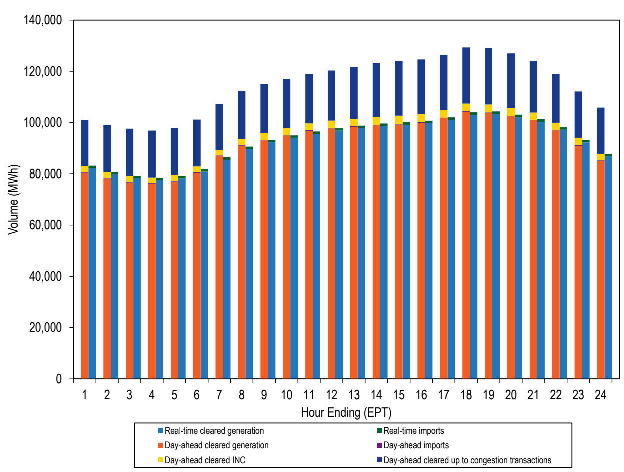
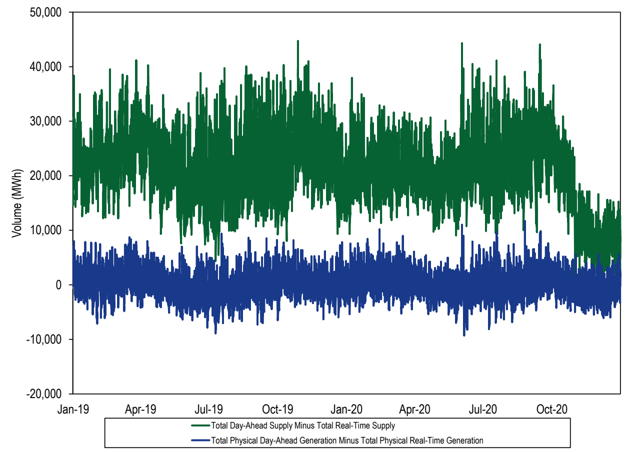


Figure 3-8 shows the difference between the day-ahead and real-time average daily supply in 2019 and 2020.

Figure 3-8 Difference between cleared day-ahead and real-time supply (Average daily volumes): 2019 through 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.[12]

The PJM system real-time hourly peak load in 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 2019, 148,228 MWh in the HE 1800 on July 31, 2019.

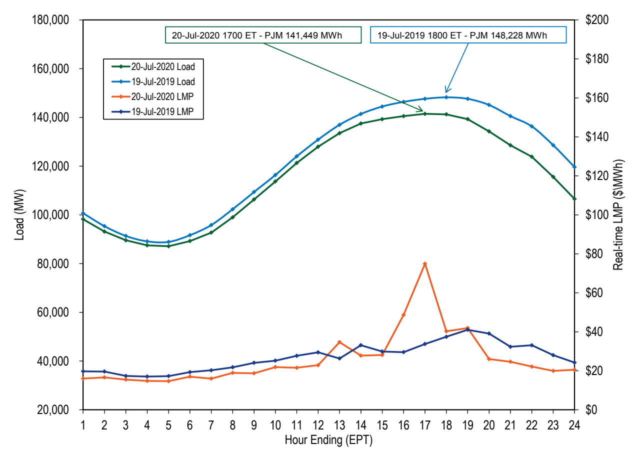
Table 3-6 shows the peak loads for 1999 through 2020.

Table 3-6 Actual footprint peak loads: 1999 through 2020[13 14]

	Date	Hour Ending (EPT)	PJM Load (MWh)	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	Mon, December 20	19	96,838	35,168	57.0%
2005	Tue, July 26	16	134,017	37,179	38.4%
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%)

Figure 3-9 compares prices and load on the peak load days in 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



12 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.

13 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>.

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

Real-Time Demand

PJM average hourly real-time demand in 2020 decreased by 4.0 percent from 2019, from 88,120 MWh to 84,584 MWh.[15] PJM average hourly real-time demand including exports in 2020 decreased by 3.1 percent from 2019, from 92,920 MWh to 90,059 MWh. Both the weather and COVID-19 played a role in this significant drop in demand.

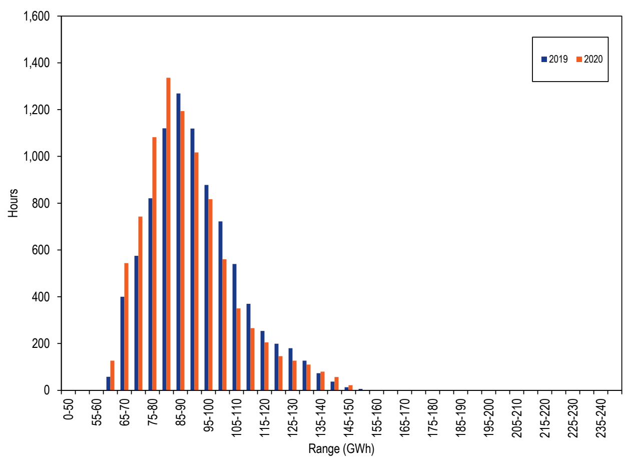
In the PJM Real-Time Energy Market, there are two types of demand:

- **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 in 2019 and 2020.[16]

Figure 3-10 Distribution of real-time accounting load plus exports: 2019 and 2020[17]



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

16 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>.

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

PJM Real-Time, Average Load

Table 3-7 presents real-time hourly demand summary statistics for 2001 through 2020.[18] Real-time annual load in 2020 reached its lowest level since 2011.

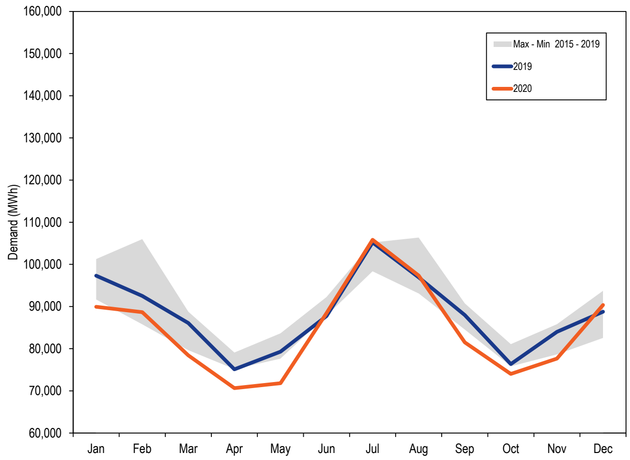
Table 3-7 Real-time load and real-time load plus exports: 2001 through 2020

	PJM Real-Time Demand (MWh)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	30,297	5,873	32,165	5,564	NA	NA	NA	NA
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)
2014	89,099	15,763	94,471	15,677	0.9%	1.8%	1.7%	1.7%
2015	88,594	16,663	92,665	16,784	(0.6%)	5.7%	(1.9%)	7.1%
2016	88,601	17,229	93,551	17,498	0.0%	3.4%	1.0%	4.3%
2017	86,618	15,170	91,015	15,083	(2.2%)	(11.9%)	(2.7%)	(13.8%)
2018	90,308	15,982	94,351	16,142	4.3%	5.4%	3.7%	7.0%
2019	88,120	15,867	92,920	16,085	(2.4%)	(0.7%)	(1.5%)	(0.4%)
2020	84,584	16,016	90,059	16,233	(4.0%)	0.9%	(3.1%)	0.9%

PJM Real-Time, Monthly Average Load

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

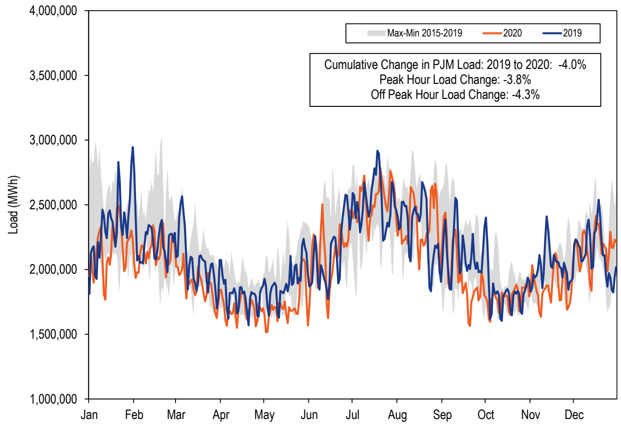
Figure 3-11 Real-time monthly average hourly load: 2019 through 2020



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

Figure 3-12 compares the real-time, average daily loads in 2019 and 2020, with the historic five year range.

Figure 3-12 Real-time daily load: 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 2020.[19] Heating degree days decreased 11.3 percent compared to 2019. Cooling degree days decreased 2.2 percent compared to 2019.

Table 3-8 Heating and cooling degree days: 2019 through 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	139	1	38.5%	(95.3%)
Nov	576	0	313	0	(45.7%)	0.0%
Dec	675	0	719	0	6.6%	0.0%
Total	3,723	1,277	3,302	1,249	(11.3%)	(2.2%)

Figure 3-13 and Figure 3-14 show the real-time daily load and the weather normalized load for 2019 and 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 was very close to actual load under 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 a result of changes in the pattern and level of activity due to COVID-19 and associated policy responses.

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

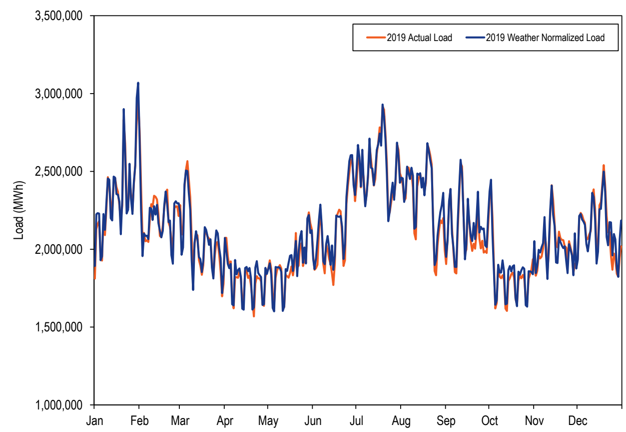
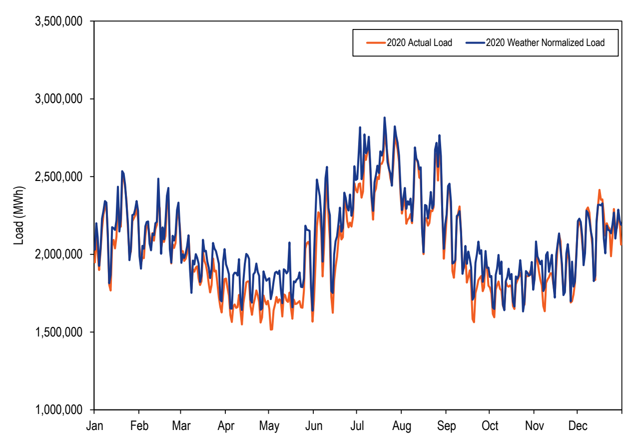


Figure 3-14 Real-time daily load and weather normalized load: 2020



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

Table 3-9 compares the total monthly actual load and the weather normalized load. Load was 3.4 percent below weather normalized load in 2020.

Table 3-9 Actual load less weather normalized load: 2019 and 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%)	55,061,813	56,572,150	(2.7%)
Nov	60,560,333	60,431,775	0.2%	55,993,432	57,678,640	(2.9%)
Dec	66,051,844	66,183,659	(0.2%)	67,232,280	67,074,317	0.2%
Annual	771,928,988	776,534,994	(0.6%)	742,987,135	768,958,933	(3.4%)

Day-Ahead Demand

PJM average hourly day-ahead demand in 2020, including DECs and up to congestion transactions, decreased by 5.7 percent from 2019, from 112,588 MWh to 106,209 MWh. When exports are added, PJM average hourly day-ahead demand in 2020 decreased by 5.1 percent from 2019, from 115,444 MWh to 109,506 MWh.

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

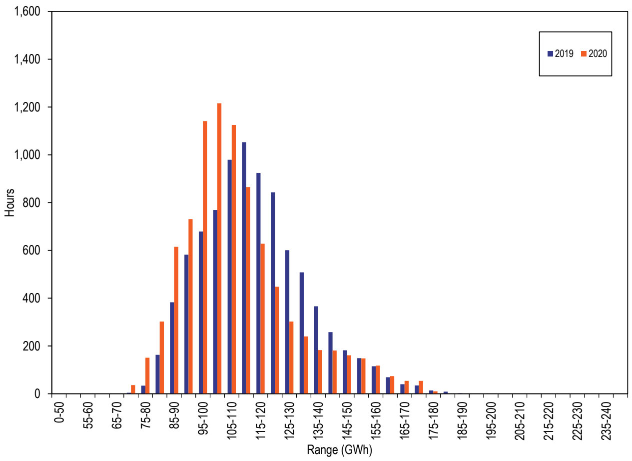
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of 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 in 2019 and 2020.

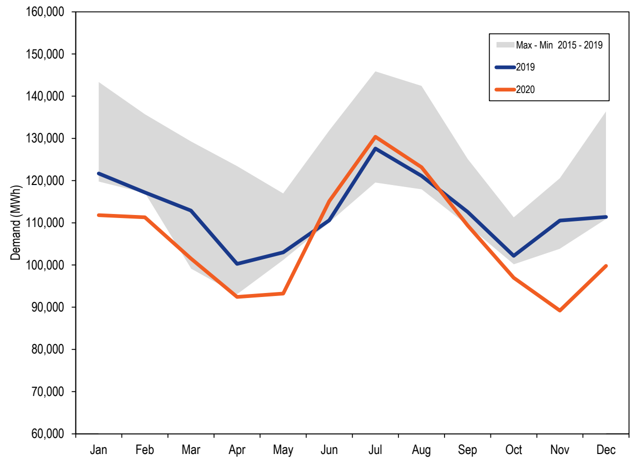
Figure 3-15 Distribution of day-ahead demand plus exports: 2019 and 2020[20]



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 2020 with the historic five-year range.

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



PJM Day-Ahead, Average Demand

Table 3-10 presents day-ahead hourly demand summary statistics from 2001 through 2020.

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

	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,370	6,562	33,757	6,431	NA	NA	NA	NA
2002	42,305	10,161	42,413	10,208	26.8%	54.8%	25.6%	58.7%
2003	44,674	7,841	44,807	7,811	5.6%	(22.8%)	5.6%	(23.5%)
2004	62,101	16,654	63,455	17,730	39.0%	112.4%	41.6%	127.0%
2005	93,534	17,643	96,447	17,952	50.6%	5.9%	52.0%	1.3%
2006	98,527	16,723	101,592	17,197	5.3%	(5.2%)	5.3%	(4.2%)
2007	105,503	16,686	108,932	17,030	7.1%	(0.2%)	7.2%	(1.0%)
2008	101,903	15,871	105,368	16,119	(3.4%)	(4.9%)	(3.3%)	(5.3%)
2009	94,941	15,869	98,094	15,999	(6.8%)	(0.0%)	(6.9%)	(0.7%)
2010	103,937	21,358	108,069	21,640	9.5%	34.6%	10.2%	35.3%
2011	113,866	20,708	117,681	20,929	9.6%	(3.0%)	8.9%	(3.3%)
2012	131,612	17,421	134,947	17,527	15.6%	(15.9%)	14.7%	(16.3%)
2013	144,858	18,489	148,132	18,570	10.1%	6.1%	9.8%	6.0%
2014	142,251	32,664	146,120	32,671	(1.8%)	76.7%	(1.4%)	75.9%
2015	111,644	18,716	114,827	18,872	(21.5%)	(42.7%)	(21.4%)	(42.2%)
2016	127,374	21,513	130,808	21,803	14.1%	14.9%	13.9%	15.5%
2017	125,794	19,402	128,757	19,625	(1.2%)	(9.8%)	(1.6%)	(10.0%)
2018	110,091	19,521	112,885	19,724	(12.5%)	0.6%	(12.3%)	0.5%
2019	112,588	18,163	115,444	18,386	2.3%	(7.0%)	2.3%	(6.8%)
2020	106,209	18,972	109,506	19,270	(5.7%)	4.5%	(5.1%)	4.8%

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

Real-Time and Day-Ahead Demand

Table 3-11 presents summary statistics for 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): 2019 and 2020

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2019	86,756	1,265	3,704	20,862	2,857	115,444	88,120	92,920	(99)	22,524
	2020	82,417	1,217	4,318	18,257	3,297	109,506	84,584	90,059	(950)	19,447
Median	2019	84,908	1,274	3,370	20,664	2,754	113,793	85,857	90,527	326	23,267
	2020	79,869	1,215	3,847	19,196	3,247	105,764	81,950	87,286	(866)	18,478
Standard Deviation	2019	15,212	239	1,707	4,732	782	18,386	15,867	16,085	(416)	2,301
	2020	15,356	248	2,101	5,908	753	19,270	16,016	16,233	(412)	3,037
Peak Average	2019	95,383	1,393	4,137	22,303	2,940	126,155	96,383	101,199	392	24,956
	2020	90,254	1,344	5,091	18,960	3,464	119,113	92,373	97,921	(774)	21,193
Peak Median	2019	93,202	1,413	3,864	22,120	2,859	123,167	93,730	98,524	885	24,643
	2020	87,768	1,369	4,670	19,883	3,408	113,946	89,399	94,731	(263)	19,215
Peak Standard Deviation	2019	13,194	224	1,726	4,506	829	15,655	14,229	14,688	(811)	967
	2020	14,448	252	2,189	5,866	780	18,850	15,400	15,757	(700)	3,093
Off-Peak Average	2019	79,234	1,153	3,327	19,606	2,784	106,104	80,915	85,701	(528)	20,403
	2020	75,519	1,106	3,637	17,639	3,151	101,050	77,729	83,140	(1,105)	17,911
Off-Peak Median	2019	77,517	1,161	3,011	19,274	2,690	104,073	78,928	83,519	(250)	20,555
	2020	73,429	1,115	3,243	18,490	3,126	98,821	75,553	80,963	(1,009)	17,858
Off-Peak Standard Deviation	2019	12,647	190	1,597	4,565	730	15,227	13,539	13,579	(702)	1,649
	2020	12,569	183	1,758	5,877	697	15,256	13,161	13,216	(409)	2,040

Figure 3-17 shows the average hourly cleared volumes of day-ahead demand and real-time demand for 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): 2020

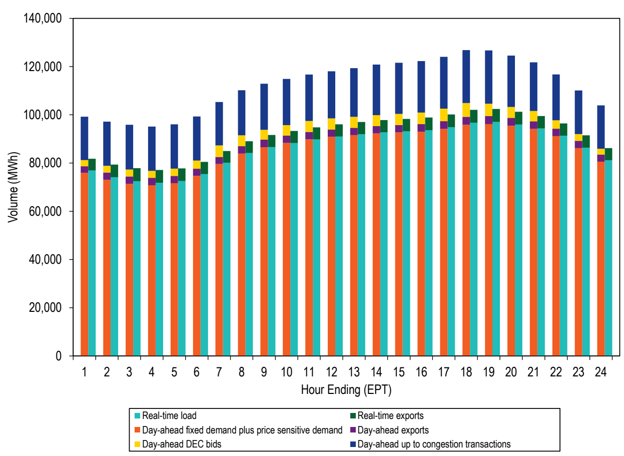
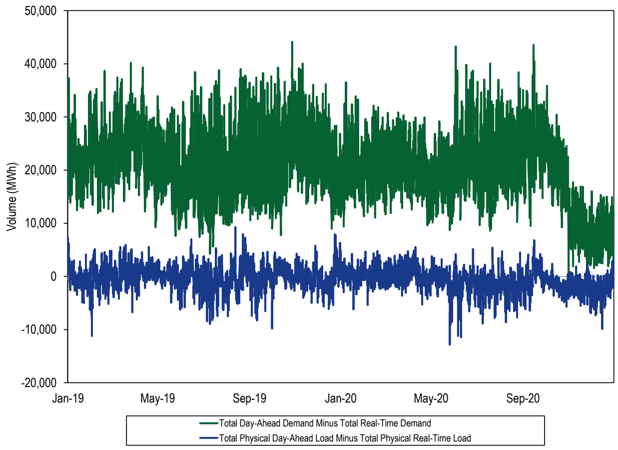


Figure 3-18 shows the difference between the day-ahead and real-time average daily demand for 2019 and 2020.

Figure 3-18 Difference between day-ahead and real-time demand (Average daily volumes): 2019 through 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 resources 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 resources 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 2019 and 2020. In 2020, 16.1 percent of real-time load was supplied by bilateral contracts, 24.7 percent by spot market purchase and 59.2 percent by self supply. Compared to 2019, reliance on bilateral contracts increased by 0.8 percentage points, reliance on spot supply decreased by 0.1 percentage points and reliance on self supply decreased by 0.7 percentage points.

Table 3-12 Sources of real-time supply: 2019 through 2020[21]

	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%	16.0%	28.1%	56.0%	(0.7%)	0.3%	0.4%
Nov	15.7%	28.6%	55.6%	15.3%	26.3%	58.4%	(0.4%)	(2.4%)	2.8%
Dec	19.8%	22.6%	57.6%	14.9%	26.4%	58.7%	(4.8%)	3.8%	1.0%
Annual	15.4%	24.7%	59.9%	16.1%	24.7%	59.2%	0.8%	(0.1%)	(0.7%)

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 2019 and 2020. In 2020, 15.3 percent of day-ahead demand was supplied by bilateral contracts, 25.1 percent by spot market purchases and 59.6 percent by self supply. Compared to 2019, reliance on bilateral contracts increased by 0.7 percentage points, reliance on spot supply increased by 0.2 percentage points, and reliance on self supply decreased by 0.9 percentage points.

Table 3-13 Sources of day-ahead supply: 2019 through 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%	15.2%	28.6%	56.2%	(0.7%)	0.9%	(0.1%)
Nov	14.9%	28.2%	56.8%	14.6%	27.1%	58.2%	(0.3%)	(1.1%)	1.4%
Dec	19.0%	22.3%	58.7%	14.2%	27.4%	58.4%	(4.8%)	5.1%	(0.3%)
Annual	14.6%	24.9%	60.5%	15.3%	25.1%	59.6%	0.7%	0.2%	(0.9%)

Generator Offers

In day-ahead market offers, generators define the commitment status and the dispatch status of their units. The commitment status indicates whether the generation owner will turn the unit on, regardless of market signals, or whether the generation owner will allow the energy market to commit the unit. The dispatch status indicates whether the generation owner will produce at full output regardless of market signals or whether the generation owner will follow PJM market dispatch signals. Market commitment is designated as economic status in the offer, allowing the market to decide whether to commit the unit at its economic minimum MW level. The Eco Min column in Table 3-14

21 Table 3-1 and Table 3-2 were calculated as of January 11, 2021. The values may change slightly as billing values are updated by PJM.

is the economic minimum MW of units offering with economic commitment status. Self scheduling is designated as must run status in the offer, meaning the unit owner will commit the unit to run regardless of market signals. Self scheduling includes committing the unit at economic minimum and permitting the balance to be dispatchable or block loading the full output of the unit. The Must Run column in Table 3-14 is the economic minimum MW of units offering with must run commitment status. Economic minimum for a self scheduled unit (must run commitment status) means the output level at which the unit self commits, including any point between the actual, physical economic minimum level and economic maximum level of the unit.

Table 3-14 shows the percent of MW offered as must run, the percent of MW of economic minimum levels of units offered as dispatchable, the percent of MW offered as dispatchable by price range, the percent of MW offered as maximum emergency and the total percent of MW offered as dispatchable. For example, combined cycle offers in the day-ahead energy market are comprised of 7.4 percent must run MW, 41.0 percent economic minimum MW for dispatchable units, 50.7 percent dispatchable MW, and 1.0 percent as emergency maximum MW.

For each price level along the energy offer curves of units in both must run and economic status, Table 3-14 shows the dispatchable MW for each price level by unit type. Units can also designate all or a portion of their capacity as emergency MW. Table 3-14 shows that 1.0 percent of offered MW are emergency MW. Emergency MW are calculated as the difference between the day-ahead submitted emergency max MW and economic max MW. In some cases, the higher share of emergency MW is a result of offer behavior and does not necessarily represent the actual availability of the emergency MW in real time.

In the day-ahead market in 2020, 21.8 percent of MW were offered as must run, 32.1 percent were offered as economic minimum MW for dispatchable units, 45.0 percent were offered as dispatchable MW, and 1.0 percent were offered as emergency maximum MW.

Table 3-14 Dispatchable status of day-ahead energy offers: 2020

			Dispatchable Range											
Unit Type	Must Run	Eco Min	($300) - $0	$0 - $25	$25 - $50	$50 - $75	$75 - $100	$100 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1000	Emergency MW	Dispatchable Percent
CC	7.4%	41.0%	0.3%	44.1%	3.6%	0.7%	0.7%	1.2%	0.1%	0.0%	0.0%	0.0%	1.0%	50.7%
CT	0.5%	68.1%	0.0%	10.3%	8.0%	1.9%	2.0%	6.6%	0.8%	0.1%	0.0%	0.0%	1.5%	29.8%
Diesel	0.0%	100.0%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro	80.1%	0.1%	3.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	16.8%	3.0%
Nuclear	70.1%	5.4%	15.6%	8.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	24.5%
Solar	22.0%	0.3%	77.6%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	77.6%
Steam - Coal	19.2%	19.0%	0.1%	46.7%	12.6%	0.9%	0.3%	0.3%	0.0%	0.1%	0.0%	0.0%	0.7%	61.1%
Steam - Other	6.2%	34.2%	4.0%	21.8%	10.5%	3.2%	5.4%	11.7%	2.3%	0.0%	0.0%	0.0%	0.8%	58.9%
Wind	7.3%	1.0%	84.6%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.6%	85.1%
Other	20.2%	44.6%	4.3%	8.8%	1.6%	0.8%	0.4%	12.4%	2.7%	0.0%	0.0%	0.0%	4.1%	31.1%
Total	21.8%	32.1%	4.7%	29.3%	6.3%	1.0%	1.0%	2.4%	0.3%	0.1%	0.0%	0.0%	1.0%	45.0%

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 3-15 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 2020, an average of 310 units per day made hourly offers, an increase of three units from 2019. In 2020, 398 units opted in for intraday offer updates, an increase of 20 units from 2019. In 2020, an average of 134 units made intraday offer updates each day, a decrease of eight units from 2019.

Table 3-15 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: 2019 and 2020

	Fuel Type	2019	2020	Difference
Hourly Offers	Natural Gas	286	291	5
	Other Fuels	21	19	(2)
	Total	307	310	3
Opt In	Natural Gas	338	349	11
	Other Fuels	40	49	9
	Total	378	398	20
Intraday Offer Updates	Natural Gas	135	128	(7)
	Other Fuels	7	6	(1)
	Total	142	134	(8)

ICAP Must Offer Requirement

Generation capacity resources are required to offer their full ICAP MW into the day-ahead and real-time energy market, or report an outage for the difference.[22] The full installed capacity (ICAP) is the ICAP of the resources that cleared in the capacity market. This is known as the ICAP must offer requirement.

Solar, wind, landfill gas, hydro and batteries can satisfy the must offer requirement by self scheduling or offering as dispatchable. The must offer requirement is thus not applied to these intermittent resource types and compliance is not enforceable.

The current enforcement of the ICAP must offer requirement is inadequate. The problem is a complex combination of generator behavior, and inadequate and inconsistent reporting tools that are not synchronized. Compliance is subject to mistakes and susceptible to manipulation.

Resources are required to submit their available capacity in three different systems. Resources are required to make offers in the energy market. Resources are required to report outages in the Dispatch Application Reporting Tool (eDART) in advance or in real time. Resources are required to report outages in the Generator Availability Data System (eGADS) after the fact. The three applications are not linked in a systematic way to ensure consistency.

Ambient derates are an example of an issue. When the weather is hotter than test conditions, the capacity of some units is reduced below the ICAP levels. While this fact may be reported by unit owners in eDART and reflected in lower offers in the energy market, the derates are never reported as outages in eGADS and are therefore not outages for purposes of defining capacity.

The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate.

The MMU recommends that intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources.

Table 3-16 shows average hourly MW, for each month, that violated the ICAP must offer requirement in 2020. On average for all hours, 1,167 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours 2,026 MW did not meet the must offer requirement. These MW levels are larger than the reserve shortages that triggered scarcity pricing in 2020 and larger than most supply contingencies that led to synchronized reserve events in 2020.

Table 3-16 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: 2020

Month	90th Percentile	Average	10th Percentile
Jan-20	1,683	1,001	447
Feb-20	1,368	752	215
Mar-20	1,924	1,250	752
Apr-20	2,192	1,123	510
May-20	2,137	1,291	693
Jun-20	2,205	1,431	519
Jul-20	1,914	1,237	619
Aug-20	1,180	681	320
Sep-20	1,634	910	411
Oct-20	2,358	1,400	668
Nov-20	2,554	1,596	705
Dec-20	2,063	1,320	578
2020	2,026	1,167	487

Emergency Maximum MW

Generation resources are offered with economic maximum MW and emergency maximum MW. The economic maximum MW is the output level the resource can achieve following economic dispatch. The emergency maximum MW is the output level the resource can achieve when emergency conditions are declared by PJM. The MW difference between the two ratings equals maximum emergency MW. FERC allows generators to include emergency maximum MW as part of ICAP offered in the capacity market.

22 Section 1.10.1A(d) of Schedule 1 to the PJM Operating Agreement.

Generation resources have to meet one of four conditions to offer any MW as emergency in the energy market: environmental limits imposed by a federal, state or other governmental agency that significantly limit availability; fuel limits beyond the control of the generation owner; temporary emergency conditions that significantly limit availability; or temporary MW additions not ordinarily available.[23]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[24] Capacity resources should offer their full output in the energy market and subject to economic dispatch. The result will be incentives for correct reporting of ICAP, more efficient energy market pricing, and a reduction in the need for manual overrides by PJM dispatchers during emergency conditions. Resources that do have capacity that can only be achieved with extraordinary measures could offer such capacity in the energy market but should not take on a capacity market obligation. The capacity performance rules in the capacity market provide incentives for such output during PAI.

Table 3-17 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, 10 percent of hours in September 2020 had maximum emergency MW greater than or equal to 3,526 MW while 10 percent of hours in January had maximum emergency MW less than 1,320 MW. The hourly average, in 2020, was 2,248 MW offered as maximum emergency.

Table 3-17 Maximum emergency MW by month

Month	90th Percentile	Average	10th Percentile
Jan-20	2,332	1,814	1,320
Feb-20	2,547	1,998	1,453
Mar-20	2,799	2,197	1,499
Apr-20	3,139	2,653	2,272
May-20	2,734	2,128	1,565
Jun-20	3,044	2,402	1,889
Jul-20	2,886	2,407	1,775
Aug-20	2,809	2,292	1,808
Sep-20	3,526	2,625	2,001
Oct-20	2,875	2,279	1,453
Nov-20	2,451	2,015	1,589
Dec-20	2,769	2,174	1,674
2020	2,883	2,248	1,624

23 OA Schedule 1 Section 1.10.1A (d)

24 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).

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. Cost-based offers, submitted by capacity resources for a defined set of technologies, are parameter limited based on a unit specific parameter limits. Nuclear, wind, solar and hydro units are not subject to parameter limits.

Price-Based Offers

All capacity resources that choose to offer price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). For resources that are not capacity resources, the price-based parameter limited schedule is 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.[25] 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 parameter limited schedules, which is to prevent the use of inflexible operating parameters to exercise market power.

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

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 2020. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost based schedules.[26] Table 3-18 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-18 shows that 30.3 percent of unit hours for units that failed the TPS test were committed on price-based schedules that were less flexible than their cost based schedules.

Table 3-18 Parameter mitigation for units failing TPS test: 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	31,381	30.3%
Committed on price schedule as flexible as cost	9,137	8.8%
Total committed on price schedule without parameter limits	40,518	39.1%
Committed on cost (cost capped)	62,146	59.9%
Committed on price PLS	1,013	1.0%
Total committed on PLS schedules (cost or price PLS)	63,159	60.9%

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 2020. PJM declared cold weather alerts on three days and hot weather alerts on 19 days in 2020.[27] The analysis includes units with technologies that are subject to parameter limits, 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 3-19 shows that 34.5 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.[28]

Table 3-19 Parameter mitigation during weather alerts: 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	31,069	34.5%
Committed on price schedule as flexible as PLS	15,208	16.9%
Total committed on price schedule without parameter limits	46,277	51.4%
Committed on cost (cost capped)	3,228	3.6%
Committed on price PLS	40,495	45.0%
Total committed on PLS schedules (cost or price PLS)	43,723	48.6%

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.

26 In previous reports, this analysis included all units that failed the TPS test, regardless of the technology type. The analysis in this report is updated to include only those units with technologies that are subject to parameter limits on their cost-based and price-based parameter limited schedules.

27 *2020 State of the Market Report for PJM*, Section 3: Energy Market, at Emergency Procedures.

28 In previous reports, this analysis included all units with CP commitment in the zones with the emergency alerts regardless of the technology type. The analysis in this report is updated to include only those units with technologies that are subject to parameter limits on their cost-based and price-based 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.[29] 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 3-20 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 3-20 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

29 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>.

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 3-20 Adjusted unit specific parameter limit statistics: 2020/2021 Delivery Year

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 used to calculate 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 market rules allow generators to communicate a resource's current operational capabilities to PJM when a resource cannot operate according to the unit specific parameters. These values are called real-time values (RTVs). The real-time values submittal process is not specified in the PJM Operating Agreement. The process is defined in PJM Manual 11. Unlike parameter exceptions, the use of real-time values makes a unit ineligible for make whole payments, unless the market seller can justify such operation based on an actual constraint.[30]

In practice, real-time values were meant to be 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 prevent 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 economically or physically withholds to decrease the likelihood of commitment, are compensated identically in the capacity market. If a market seller makes an economic decision to not staff the unit or to not have remote start capability, and uses real-time values to communicate the longer time to start to PJM, the unit's actual parameters are not recognized as inconsistent with its obligations as a capacity resource, not reflected in forced outages, and not reflected in eligibility for uplift payments. The market seller is able to withhold the unit in the energy market with no consequence, while other similarly situated units incur the costs associated with meeting their obligations.

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

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

parameter limits or approved parameter limit exceptions based on tariff defined justifications. The changes to the RTV rules proposed by PJM in the stakeholder process do not include a penalty and do not create incentives for resources to offer flexibly. PJM's proposed rules on RTVs instead encourage resources to use RTVs to offer parameter limited schedules with parameter values that violate the unit specific limits on days without weather alerts, with no consequences. PJM's proposed RTV rules weaken the market power protections offered by the parameter limited schedules rules in the PJM tariff.

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.[31] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[32] 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.[33]

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 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

31 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).
32 *Id* at P 439.
33 *Id* at P 440.

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 2020, there were 13 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 chosen 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.[34] Up to congestion transactions may be submitted between any two buses on a list of 47 buses eligible for up to congestion transaction bidding.[35] 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

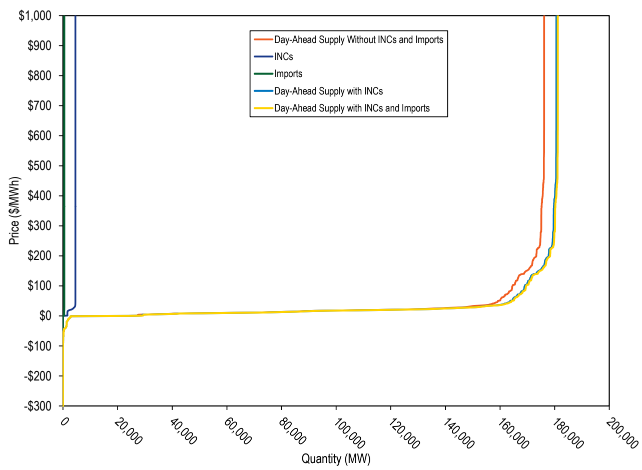


Figure 3-20 shows example PJM day-ahead aggregate supply curves for the typical dispatch price range.

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

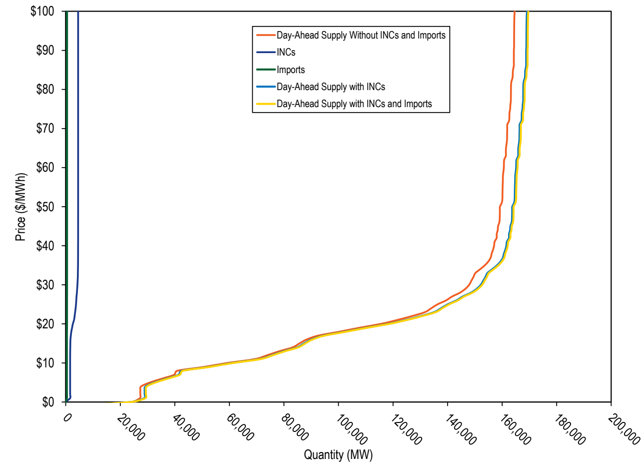


Table 3-21 shows the hourly average number of cleared and submitted increment offers and decrement bids by month for 2019 and 2020. The hourly average submitted increment MW increased by 2.7 percent and cleared increment MW decreased by 16.0 percent. The hourly average submitted decrement MW increased by 24.4 percent and cleared decrement MW increased by 16.6 percent.

34 162 FERC ¶ 61,139.

35 Prior to November 1, 2012, market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*,"<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Table 3-21 Average hourly number of cleared and submitted INCs and DECs by month: 2019 through 2020

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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	Oct	2,492	6,086	309	1,084	4,884	9,696	392	1,229
2020	Nov	2,505	7,000	277	1,125	4,612	9,570	335	1,037
2020	Dec	2,141	5,911	241	974	4,746	10,450	321	1,190
2020	Annual	2,427	6,737	257	1,065	4,318	8,937	337	1,000

Table 3-22 shows the average hourly number of up to congestion transactions and the average hourly MW from 2019 and 2020. In 2020, the average hourly submitted and cleared up to congestion MW decreased by 23.8 percent and 12.4 percent, compared to 2019.

Table 3-22 Average hourly cleared and submitted up to congestion bids by month: 2019 through 2020

		Up to Congestion			
Year		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	Oct	19,587	55,904	933	1,957
2020	Nov	8,667	21,141	578	1,053
2020	Dec	7,156	17,968	526	942
2020	Annual	18,257	45,501	1,021	2,026

Table 3-23 shows the average hourly number of day-ahead import and export transactions and the average hourly MW from January 2019 through December 2020. In 2020, the average hourly submitted and cleared import transaction MW decreased by 46.1 and 42.4 percent, and the average hourly submitted and cleared export transaction MW increased by 14.9 and 15.4 percent, compared to 2019.

Table 3-23 Hourly average day-ahead number of cleared and submitted import and export transactions by month: 2019 through 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	Oct	171	164	2	2	3,268	3,231	26	26
2020	Nov	189	199	2	2	3,158	3,182	32	32
2020	Dec	173	180	2	2	3,106	3,113	31	31
2020	Annual	215	223	3	3	3,298	3,304	28	28

Table 3-24 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal in 2019 and 2020. The frequency of marginal up to congestion transactions deceased significantly in November 2020, due to decreased UTC activity beginning November 1, 2020, when FERC required UTCs to pay uplift.[36]

Table 3-24 Type of day-ahead marginal resources: 2019 through 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%	14.7%	0.2%	58.2%	15.0%	12.0%	0.0%
Nov	16.2%	0.0%	57.9%	13.2%	12.8%	0.0%	21.0%	0.1%	27.6%	27.1%	24.2%	0.0%
Dec	23.2%	0.1%	55.2%	10.9%	10.5%	0.0%	20.8%	0.2%	32.7%	30.7%	15.5%	0.0%
Annual	12.7%	0.1%	57.4%	17.0%	12.8%	0.0%	16.5%	0.1%	51.4%	18.8%	13.2%	0.0%

36 172 FERC ¶ 61,046 (2020).

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

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

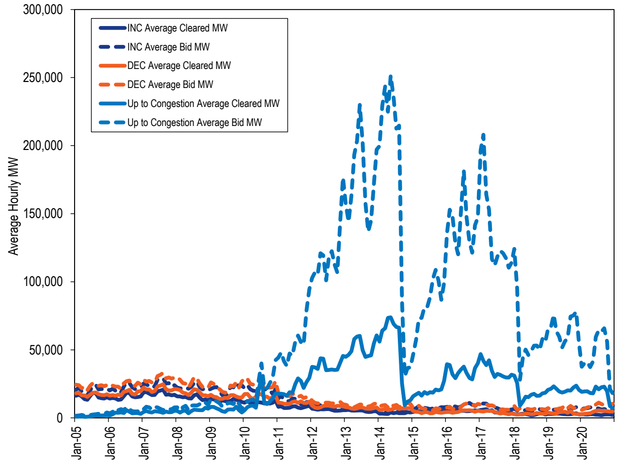
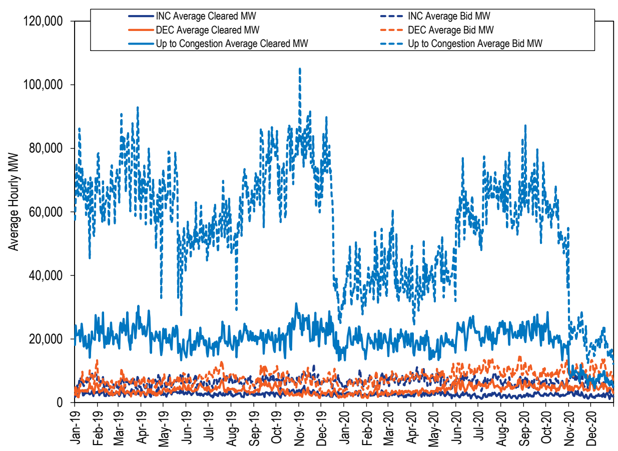


Figure 3-22 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from 2019 through 2020.

Figure 3-22 Daily bid and cleared INCs, DECs, and UTCs (MW): 2019 through 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 3-25 shows, in 2019 and 2020, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-25 INC and DEC bids and cleared MWh by type of parent organization (MWh): 2019 and 2020

	2019				2020			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	103,840,563	86.2%	48,295,203	83.6%	121,335,619	88.2%	48,574,531	82.1%
Physical	16,557,036	13.8%	9,464,401	16.4%	16,234,536	11.8%	10,587,919	17.9%
Total	120,397,599	100.0%	57,759,604	100.0%	137,570,155	100.0%	59,162,450	100.0%

Table 3-26 shows, in 2019 and 2020, the total up to congestion bids and cleared MWh by type of parent organization.

Table 3-26 Up to congestion transactions by type of parent organization (MWh): 2019 and 2020

	2019				2020			
Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	553,915,846	97.4%	173,330,340	94.8%	354,377,718	88.7%	140,616,388	87.7%
Physical	15,066,592	2.6%	9,441,573	5.2%	45,299,144	11.3%	19,753,718	12.3%
Total	568,982,438	100.0%	182,771,913	100.0%	399,676,862	100.0%	160,370,106	100.0%

Table 3-27 shows, in 2019 and 2020, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-27 Import and export transactions by type of parent organization (MW): 2019 and 2020

		2019		2020	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	7,734,097	27.3%	12,513,761	41.1%
	Physical	20,553,709	72.7%	17,908,057	58.9%
	Total	28,287,806	100.0%	30,421,818	100.0%
Real-Time	Financial	12,269,622	23.4%	15,520,882	31.0%
	Physical	40,145,398	76.6%	34,519,916	69.0%
	Total	52,415,020	100.0%	50,040,798	100.0%

Table 3-28 shows increment offers and decrement bids by top 10 locations in 2019 and 2020.

Table 3-28 Virtual offers and bids by top 10 locations (MW): 2019 and 2020

2019					2020				
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	114,883	6,034,524	6,149,408	MISO	INTERFACE	58,106	8,624,237	8,682,344
WESTERN HUB	HUB	1,159,532	2,025,863	3,185,395	WESTERN HUB	HUB	723,568	2,699,364	3,422,932
AEP-DAYTON HUB	HUB	519,622	973,759	1,493,381	AEP-DAYTON HUB	HUB	383,865	1,423,100	1,806,965
DOM_RESID_AGG	RESIDUAL METERED EDC	269,198	1,223,935	1,493,133	BGE_RESID_AGG	RESIDUAL METERED EDC	295,127	1,340,188	1,635,315
LINDENVFT	INTERFACE	36,615	1,374,392	1,411,007	DOM_RESID_AGG	RESIDUAL METERED EDC	202,235	1,240,902	1,443,137
SOUTHIMP	INTERFACE	1,361,985	0	1,361,985	NYIS	INTERFACE	752,258	298,276	1,050,534
BGE_RESID_AGG	RESIDUAL METERED EDC	276,217	960,392	1,236,610	NEW JERSEY HUB	HUB	548,816	400,685	949,501
DOMINION HUB	HUB	544,395	654,169	1,198,564	PECO_RESID_AGG	RESIDUAL METERED EDC	666,172	242,847	909,019
N ILLINOIS HUB	HUB	539,287	649,189	1,188,477	LINDENVFT	INTERFACE	38,492	858,203	896,695
NYIS	INTERFACE	772,228	248,645	1,020,873	N ILLINOIS HUB	HUB	377,415	509,377	886,792
Top ten total		5,593,962	14,144,869	19,738,831			4,046,055	17,637,179	21,683,234
PJM total		25,309,648	32,449,958	57,759,606			21,316,711	37,927,647	59,244,357
Top ten total as percent of PJM total		22.1%	43.6%	34.2%			19.0%	46.5%	36.6%

Table 3-29 shows up to congestion transactions by import bids for the top 10 locations and associated profits at each path in 2019 and 2020. The NORTHWEST interface was eliminated effective October 1, 2020. Before the elimination of this interface, trades sourcing at NORTHWEST were the largest source of revenue for import as well as overall up to congestion transactions in 2020.[37]

Table 3-29 Cleared up to congestion import bids by top 10 source and sink pairs (MW): 2019 and 2020

2019							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	4,867,357	$4,725,588	($1,793,203)	$2,932,386
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	2,868,027	$1,799,693	($683,359)	$1,116,334
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	2,702,231	$3,334,781	($1,669,112)	$1,665,669
NYIS	INTERFACE	RECO_RESID_AGG	AGGREGATE	1,844,665	($734,523)	$987,205	$252,682
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	1,534,041	$593,430	($443,930)	$149,500
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	1,516,032	$486,571	$229,194	$715,765
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	1,114,768	$762,111	$41,197	$803,307
SOUTHIMP	INTERFACE	AEP GEN HUB	HUB	890,981	$368,101	($224,941)	$143,161
SOUTHIMP	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	767,345	$482,803	($126,515)	$356,288
NORTHWEST	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	601,045	$601,399	($126,755)	$474,644
Top ten total				18,706,492	$12,419,955	($3,810,220)	$8,609,735
PJM total				36,735,678	$23,345,179	($8,019,291)	$15,325,888
Top ten total as percent of PJM total				50.9%	53.2%	47.5%	56.2%
2020							
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
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	1,449,045	$355,909	$596,289	$952,198
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	1,128,108	($747,445)	$625,201	($122,244)
NYIS	INTERFACE	RECO_RESID_AGG	AGGREGATE	1,035,117	($487,128)	$527,353	$40,226
SOUTHIMP	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	891,868	($318,309)	$421,182	$102,872
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				14,985,749	$7,278,829	($2,107,235)	$5,171,594
PJM total				26,395,388	$7,680,460	$406,128	$8,086,588
Top ten total as percent of PJM total				56.8%	94.8%	(518.9%)	64.0%

37 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 3-30 shows up to congestion transactions by export bids for the top 10 locations and associated profits at each path in 2019 and 2020. The NIPSCO interface was eliminated effective June 1, 2020. Prior to the elimination of this interface, trades sinking at NIPSCO were a large source of revenue for both export and overall up-to congestion transactions in 2020.

Table 3-30 Cleared up to congestion export bids by top 10 source and sink pairs (MW): 2019 and 2020

2019							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	2,636,234	$1,831,550	$1,096,309	$2,927,859
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	2,337,969	$2,218,567	($1,210,629)	$1,007,938
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	1,800,701	$165,259	$879,090	$1,044,350
CHICAGO HUB	HUB	NIPSCO	INTERFACE	1,366,410	$1,169,912	$195,344	$1,365,256
AEP GEN HUB	HUB	SOUTHEXP	INTERFACE	1,220,031	($620,959)	$1,662,042	$1,041,083
CHICAGO HUB	HUB	MISO	INTERFACE	816,878	$221,881	($129,516)	$92,365
N ILLINOIS HUB	HUB	SOUTHEXP	INTERFACE	754,401	$741,293	($402,807)	$338,486
N ILLINOIS HUB	HUB	MISO	INTERFACE	661,485	($626,991)	$587,860	($39,131)
CHICAGO GEN HUB	HUB	MISO	INTERFACE	595,663	($225,954)	$315,061	$89,107
COMED_RESID_AGG	AGGREGATE	MISO	INTERFACE	572,642	$331,145	($329,439)	$1,706
Top ten total				12,762,414	$5,205,704	$2,663,314	$7,869,018
PJM total				22,157,844	$2,417,205	$10,295,407	$12,712,612
Top ten total as percent of PJM total				57.6%	215.4%	25.9%	61.9%
2020							
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	1,461,150	($240,423)	$610,322	$369,899
CHICAGO GEN HUB	HUB	MISO	INTERFACE	971,764	($343,602)	$543,641	$200,038
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
CHICAGO HUB	HUB	MISO	INTERFACE	614,476	($461,132)	$584,862	$123,730
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	549,227	$204,334	($54,058)	$150,276
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	409,116	$318,507	($296,361)	$22,146
AEP GEN HUB	HUB	SOUTHEXP	INTERFACE	383,878	($232,230)	$694,516	$462,286
COMED_RESID_AGG	AGGREGATE	SOUTHEXP	INTERFACE	381,385	($139,863)	$367,974	$228,111
Top ten total				8,011,106	($378,456)	$3,898,484	$3,520,028
PJM total				14,306,955	($3,271,371)	$8,389,570	$5,118,199
Top ten total as percent of PJM total				56.0%	11.6%	46.5%	68.8%

Table 3-31 shows up to congestion transactions by wheel bids and associated profits at each path for the top 10 locations in 2019 and 2020.

Table 3-31 Cleared up to congestion wheel bids by top 10 source and sink pairs (MW): 2019 and 2020

2019							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	2,289,188	$1,849,277	($95,821)	$1,753,456
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	2,196,956	$2,222,121	($386,523)	$1,835,598
MISO	INTERFACE	SOUTHEXP	INTERFACE	1,172,080	($629,574)	$2,849,345	$2,219,771
NORTHWEST	INTERFACE	MISO	INTERFACE	1,156,963	$1,083,671	($312,206)	$771,464
MISO	INTERFACE	NORTHWEST	INTERFACE	839,589	$587,108	($69,742)	$517,366
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	476,351	$314,813	$463,417	$778,231
LINDENVFT	INTERFACE	HUDSONTP	INTERFACE	402,375	$232,113	($186,590)	$45,523
SOUTHIMP	INTERFACE	MISO	INTERFACE	360,845	$474,711	($260,955)	$213,757
NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	319,613	$455,625	($26,307)	$429,318
IMO	INTERFACE	SOUTHEXP	INTERFACE	218,225	$120,942	$390,584	$511,525
Top ten total				9,432,185	$6,710,808	$2,365,202	$9,076,010
PJM total				11,064,646	$7,141,228	$2,048,737	$9,189,965
Top ten total as percent of PJM total				85.2%	94.0%	115.4%	98.8%
2020							
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
LINDENVFT	INTERFACE	HUDSONTP	INTERFACE	897,659	($373,207)	$433,877	$60,670
SOUTHIMP	INTERFACE	MISO	INTERFACE	842,473	($246,631)	$242,109	($4,522)
MISO	INTERFACE	NIPSCO	INTERFACE	746,976	$230,632	($156,299)	$74,333
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	674,341	$339,914	($111,066)	$228,849
MISO	INTERFACE	SOUTHEXP	INTERFACE	669,729	$178,511	($40,126)	$138,385
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	60,743	$26,933	($44,079)	($17,146)
Top ten total				6,146,761	$1,865,467	($385,503)	$1,479,964
PJM total				6,960,599	$1,607,197	($205,644)	$1,401,553
Top ten total as percent of PJM total				88.3%	116.1%	187.5%	105.6%

The top 10 internal up to congestion transaction paths were 22.3 percent of the PJM total internal up to congestion transaction MW in 2020.

Table 3-32 shows up to congestion transactions by internal bids for the top 10 locations and associated profits at each path in 2019 and 2020. The total internal UTC profits increased by $9.8 million, from $6.5 million in 2019 to $16.3 million in 2020. The total internal cleared MW decreased by 0.1 million MW, or 0.08 percent, from 112.8 million MW in 2019 to 112.7 million MW in 2020.

Table 3-32 Cleared up to congestion internal bids by top 10 source and sink pairs (MW): 2019 and 2020

				2019			
				Internal			
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	2,846,126	$842,698	($370,498)	$472,200
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	2,660,863	$1,080,285	($337,062)	$743,223
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	2,453,785	($523,510)	$382,033	($141,477)
AEP GEN HUB	HUB	AEP-DAYTON HUB	HUB	2,127,248	$1,209,043	($1,050,912)	$158,131
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	2,003,971	$208,198	($109,728)	$98,470
N ILLINOIS HUB	HUB	CHICAGO HUB	HUB	1,974,408	$776,321	($587,077)	$189,244
AEP GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	1,803,194	$764,467	($753,713)	$10,753
AECO_RESID_AGG	AGGREGATE	VINELAND_RESID_AGG	AGGREGATE	1,452,479	($518,639)	($172,886)	($691,526)
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,398,835	$158,044	$143,641	$301,685
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	1,220,937	$1,156,104	($741,121)	$414,982
Top ten total				19,941,846	$5,153,010	($3,597,322)	$1,555,687
PJM total				112,813,746	$20,715,529	($14,188,778)	$6,526,752
Top ten total as percent of PJM total				17.7%	24.9%	25.4%	23.8%
				2020			
				Internal			
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	3,744,340	($286,705)	$762,854	$476,149
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	3,669,318	$84,850	$720,478	$805,328
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	3,246,574	($1,304,762)	$3,024,576	$1,719,814
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	2,963,981	$266,416	($179,122)	$87,294
N ILLINOIS HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	2,891,427	($945,347)	$1,719,669	$774,323
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	2,004,395	($34,813)	$745,091	$710,278
CHICAGO HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,833,368	($203,825)	$866,211	$662,386
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	1,766,602	$62,510	($251,174)	($188,664)
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	1,590,128	($78,682)	($29,508)	($108,190)
AEP GEN HUB	HUB	DAY_RESID_AGG	AGGREGATE	1,414,620	($145,613)	$203,404	$57,791
Top ten total				25,124,751	($2,585,971)	$7,582,479	$4,996,508
PJM total				112,707,163	($27,263,473)	$43,544,453	$16,280,980
Top ten total as percent of PJM total				22.3%	9.5%	17.4%	30.7%

Table 3-33 shows the number of source-sink pairs that were offered and cleared monthly for January 1, 2019 through December 31, 2020.

Table 3-33 Number of offered and cleared source and sink pairs: 2019 through 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	Oct	1,544	1,689	1,358	1,525
2020	Nov	1,306	1,497	1,203	1,387
2020	Dec	1,305	1,508	1,184	1,359
2020	Annual	1,719	1,977	1,561	1,805

Table 3-34 and Figure 3-23 show total cleared up to congestion transactions and share of the top ten up to congestion paths by transaction type (import, export, or internal) in 2019 and 2020. Total up to congestion transactions decreased by 12.3 percent from 182.8 million MW in 2019 to 160.3 million MW in 2020. Internal up to congestion transactions in 2020 were 70.3 percent of all up to congestion transactions compared to 61.7 percent in 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.[38] There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions. In 2018, total UTC activity and the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[39] The order limited UTC trading to hubs, residual metered load, and interfaces. UTC activity increased following that reduction. UTC activity decreased again beginning November 1, 2020, after a FERC order requiring UTCs to pay day-ahead and balancing operating reserve charges equivalent to a DEC at the UTC sink point became effective on that date.[40]

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

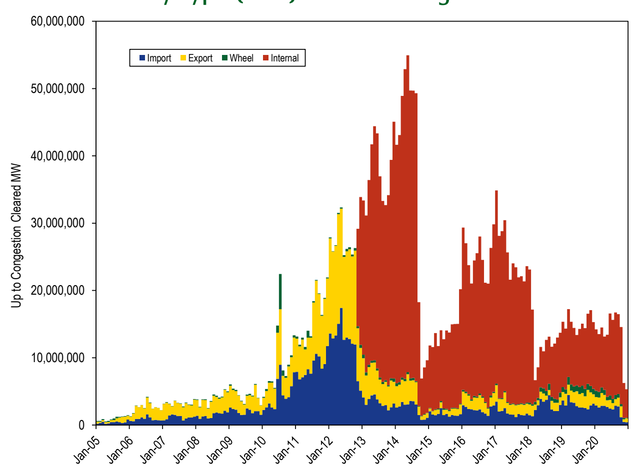


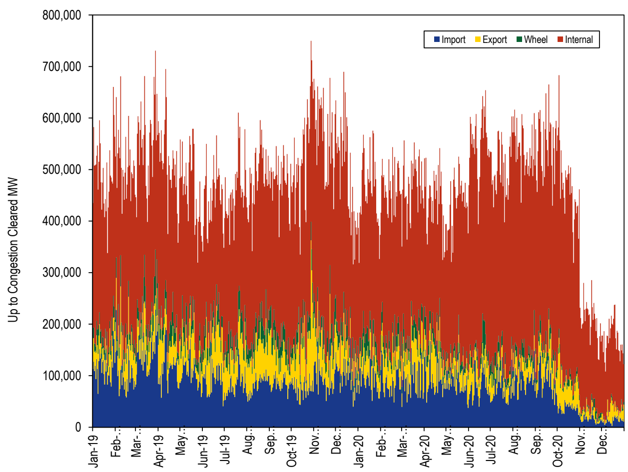
Table 3-34 Cleared up to congestion transactions and share of top 10 paths by type (MW): 2019 and 2020

	2019				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	18,706,492	12,762,414	9,432,185	19,941,846	60,842,938
PJM total (MW)	36,735,678	22,157,844	11,064,646	112,813,746	182,771,913
Top ten total as percent of PJM total	50.9%	57.6%	85.2%	17.7%	33.3%
PJM total as percent of all up to congestion transactions	20.1%	12.1%	6.1%	61.7%	100.0%
	2020				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	14,985,749	8,011,106	6,146,761	25,124,751	54,268,367
PJM total (MW)	26,395,388	14,306,955	6,960,599	112,707,163	160,370,106
Top ten total as percent of PJM total	56.8%	56.0%	88.3%	22.3%	33.8%
PJM total as percent of all up to congestion transactions	16.5%	8.9%	4.3%	70.3%	100.0%

38 See 162 FERC ¶ 61,139 (2018).
39 *Id.*
40 See 172 FERC ¶ 61,046 (2020).

Figure 3-24 shows the daily cleared up to congestion MW by transaction type from January 1, 2019 through December 31, 2020.

Figure 3-24 Daily cleared up to congestion transaction by type (MW): 2019 through 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 the day-ahead and real-time energy markets result from differences in the models used to operate each market that cannot be corrected through virtual bidding.[41]

A key assumption underlying the February 2018 order is that the limited set of nodes available for virtual trading is sufficiently protected from false arbitrage trades because price spreads resulting from modeling differences between the day-ahead and real-time markets are mitigated by the averaging of prices over a large number of buses at aggregate nodes.[42] This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational differences between day-ahead and real-time since the February 2018 order.

The assumption that modeling differences are averaged out over aggregate nodes does not hold for multiple nodes in the current list of available up to congestion bidding nodes. The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. For this reason, the MMU recommends eliminating UTC bidding at the following nodes: DPLEASTON_RESID_AGG, PENNPOWER_RESID_AGG, UGI_RESID_AGG, SMECO_RESID_AGG, AEPKY_RESID_AGG, and VINELAND_RESID_AGG.

Prices at larger aggregate nodes can also be affected by transmission constraints, especially when constraints are violated and transmission penalty factors are applied in the real-time energy market. Even when the same constraints are modeled in day ahead and real time, constraint violations in real time may result from differences in the day ahead and real time operational environments such as intra hourly ramping limitations, changes to constraint limits, and unit commitments and decommitments. Price spreads due to modeling or operational differences can be in the tens to hundreds of dollars, even when averaged over an aggregate node, and may persist for days or weeks. Virtual traders can often identify and profit from price spreads resulting from systematic modeling and operational differences between day ahead and real time affecting specific generators or aggregate nodes. The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues.

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.

41 PJM Interconnection, LLC, "Proposed Revisions To Reduce Bidding Points for Virtual Transactions," Docket No. ER18-88, October 17, 2017 at 9–10: "Discrepancies between the models can occur for various reasons despite PJM's best attempts to minimize them…Because individual nodes are more highly impacted by modeling discrepancies than aggregated locations due to averaging, they are often locations where Virtual Transactions can profit. Profits collected by Virtual Transactions in these cases lead to additional costs for PJM members without any benefits."

42 162 FERC ¶ 61,139 at PP 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."

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 20.3 percent and 21.4 percent lower in 2020 than in 2019. As a combined result of weather and COVID-19 related demand reductions, and low gas prices, energy prices were lower in 2020 than in any year since the beginning of PJM markets on April 1, 1999.

The average real-time LMP in 2020 decreased 20.6 percent from 2019, from $26.02 per MWh to $20.66 per MWh. The load-weighted average real-time LMP in 2020 decreased 20.3 percent from 2019, from $27.32 per MWh to $21.77 per MWh.

The, load-weighted, average, real-time LMP for 2020 was 11.4 percent lower than the fuel-cost adjusted, load-weighted, average real-time LMP for 2020. If fuel and emission costs in 2020 had been the same as in 2019, holding everything else constant, the load-weighted LMP would have been higher, $24.56 per MWh instead of the observed $21.77 per MWh.

The average day-ahead LMP in 2020 decreased 21.9 percent from 2019, from $26.03 per MWh to $20.33 per MWh. The load-weighted average day-ahead LMP decreased 21.4 percent from 2019, from $27.23 per MWh to $21.40 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.[43] 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.[44]

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.

43 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.

44 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.[45]

PJM Real-Time, Average LMP

Table 3-35 shows the PJM real-time, average LMP for 1998 through 2020.[46]

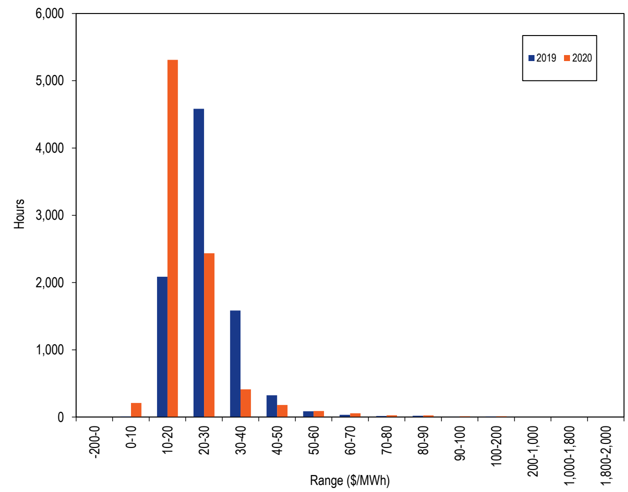
Table 3-35 Real-time, average LMP (Dollars per MWh): 1998 through 2020

	Real-Time LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	(22.7%)	(16.5%)	(28.8%)
2013	$36.55	$32.25	$20.57	10.4%	9.2%	(0.5%)
2014	$48.22	$34.46	$65.08	31.9%	6.8%	216.4%
2015	$33.39	$26.61	$27.80	(30.7%)	(22.8%)	(57.3%)
2016	$27.57	$24.10	$14.76	(17.4%)	(9.4%)	(46.9%)
2017	$29.42	$25.44	$17.40	6.7%	5.6%	17.9%
2018	$35.75	$28.28	$29.52	21.5%	11.2%	69.7%
2019	$26.02	$22.89	$21.19	(27.2%)	(19.1%)	(28.2%)
2020	$20.66	$18.35	$11.77	(20.6%)	(19.8%)	(44.4%)

PJM Real-Time Average LMP Duration

Figure 3-25 shows the hourly distribution of PJM real-time, average LMP for 2019 and 2020. There were 14 hours with an average LMP greater than $100 per MWh, and two hours with an average LMP greater than $200 per MWh in 2020.

Figure 3-25 Average LMP for the real-time energy market: 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.

45 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>.

46 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, Load-Weighted, Average LMP

Table 3-36 shows the PJM real-time, load-weighted, average LMP for 1998 through 2020.

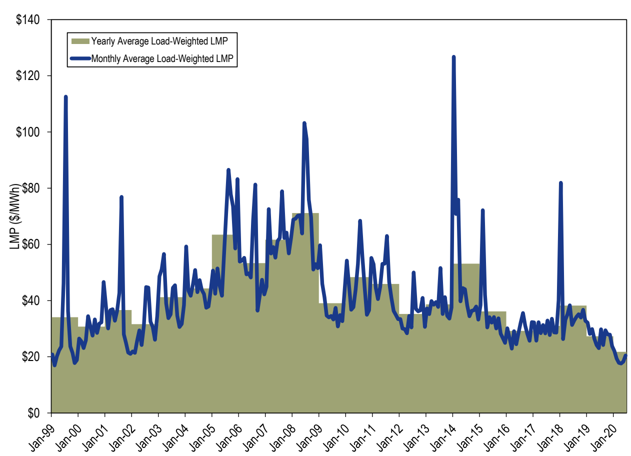
Table 3-36 Real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2020

	Real-Time, Load-Weighted, Average LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	37.4%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	(31.9%)	(23.6%)	(59.2%)
2016	$29.23	$25.01	$16.12	(19.2%)	(9.6%)	(48.1%)
2017	$30.99	$26.35	$19.32	6.0%	5.4%	19.9%
2018	$38.24	$29.55	$32.89	23.4%	12.1%	70.2%
2019	$27.32	$23.63	$23.12	(28.6%)	(20.0%)	(29.7%)
2020	$21.77	$19.07	$12.50	(20.3%)	(19.3%)	(45.9%)

PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 3-26 shows the PJM real-time monthly and annual load-weighted LMP for 1999 through 2020.

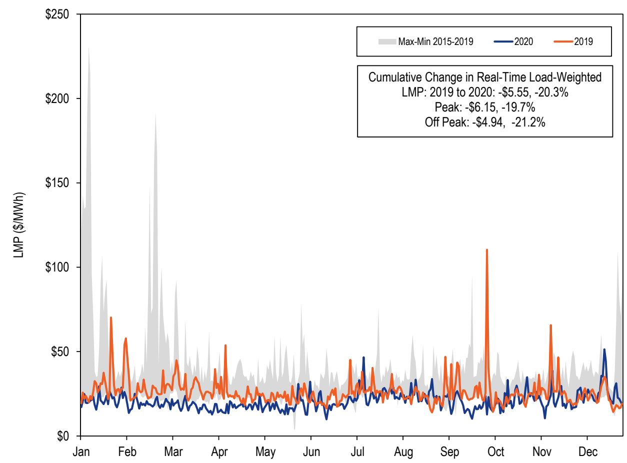
Figure 3-26 Real-time, monthly and annual, load-weighted, average LMP: 1999 through 2020



PJM Real-Time, Daily, Load-Weighted, Average LMP

Figure 3-27 shows the PJM real-time, daily, load-weighted LMP for 2019 and 2020.

Figure 3-27 Real-time, daily, load-weighted, average LMP: 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 December 2020.[47] Table 3-37 shows the PJM real-time, load-weighted, average LMP and inflation adjusted load-weighted, average LMP for every year from 1998 through 2020. The PJM real-time inflation adjusted, load-weighted, average LMP for 2020 was the lowest value since PJM real-time markets started on April 1, 1999 at $13.58 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.

47 To obtain the inflation adjusted, monthly, load-weighted, average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed January 13, 2021)

Figure 3-28 Real-time, monthly, load-weighted, average LMP unadjusted and adjusted for inflation: 1998 through 2020

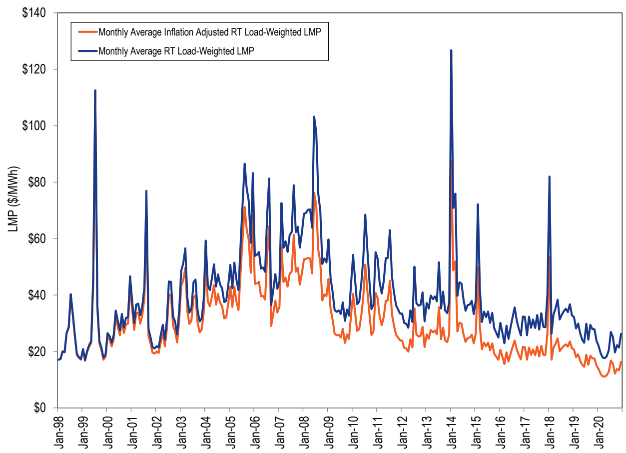


Table 3-37 Real-time, load-weighted, average LMP unadjusted and adjusted for inflation: 1998 through 2020

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
1998	$24.16	$23.94
1999	$34.07	$33.04
2000	$30.72	$28.80
2001	$36.65	$33.45
2002	$31.60	$28.35
2003	$41.23	$36.24
2004	$44.34	$37.91
2005	$63.46	$52.37
2006	$53.35	$42.73
2007	$61.66	$48.06
2008	$71.13	$53.27
2009	$39.05	$29.46
2010	$48.35	$35.83
2011	$45.94	$33.01
2012	$35.23	$24.80
2013	$38.66	$26.82
2014	$53.14	$36.37
2015	$36.16	$24.69
2016	$29.23	$19.68
2017	$30.99	$20.43
2018	$38.24	$24.65
2019	$27.32	$17.28
2020	$21.77	$13.58

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).[48] 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 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 solution per five minute target time to send dispatch signals to resources. PJM uses a subset of these approved RT SCED solutions in LPC to calculate real-time LMPs. As a result, a number of dispatch directives are not reflected in real-time energy market prices. Prior to October 15, 2020, LPC used the latest available approved RT SCED solution to calculate prices, regardless of the target dispatch time of the RT SCED solution. However, LPC assigns the prices to a five minute interval that does not contain the target time of the RT SCED case it used. On October 15, 2020, PJM updated its pricing process to use an approved RT SCED solution that solves for the same target time as the end of each five minute pricing interval to calculate LMPs applicable for that five minute interval, although the SCED cases are still for 10 minutes ahead while the LPC cases are for each five minute interval.

Table 3-38 shows, on a monthly basis in 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

48 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 112 (Jan. 5, 2021)

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 five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period.

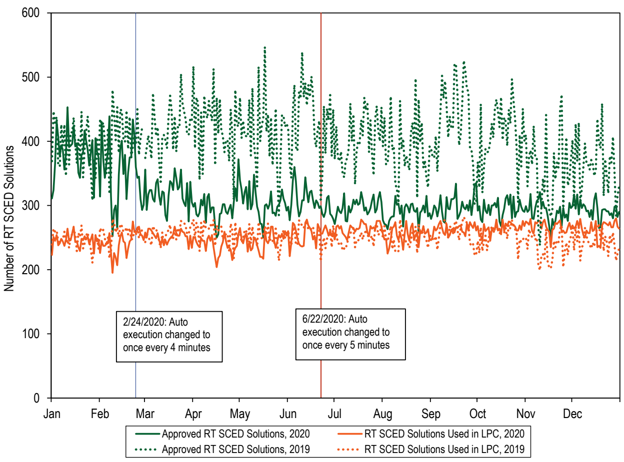
Table 3-38 shows that in 2020 only 82.1 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices. The percent of approved solutions used for pricing increased from 69.0 percent to 78.7 percent from February to 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 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 and to five minutes on June 22 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 3-38 RT SCED cases solved, approved and used in pricing: 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%
Oct	32,429	9,145	8,199	89.7%
Nov	30,360	8,695	8,004	92.1%
Dec	31,859	9,095	8,190	90.0%
Total	429,864	113,502	93,136	82.1%

Figure 3-29 Daily RT SCED solutions approved for dispatch signals and solutions used in pricing: 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 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. Prior to October 15, 2020, the interval that was priced in LPC was consistently before the target time from the RT SCED case used for the dispatch signal. LPC took the most recently approved RT SCED case to calculate LMPs for the present five minute interval. For example, the LPC case that 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 created a mismatch between the MW dispatch and real-time LMPs and undermined generators' incentive to follow dispatch. Under new RT SCED changes that were implemented on October 15, 2020, PJM resolved the mismatch between LPC and the RT SCED target time, but prices no longer apply at the time when resources receive and follow that dispatch signal.[49] For example, the LPC case that calculates prices for the interval ending 10:05 EPT uses an approved RT SCED case that sent MW dispatch signals at 9:55 EPT which are no longer effective from 10:00 to 10:05 EPT. There is still a mismatch between the MW dispatch and real-time LMPs that undermines generators' incentive to follow dispatch. 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 to five minute intervals.

Table 3-39 shows the average duration of the period when dispatch instructions corresponded to the prevailing prices in 2020. Prior to October 15, 2020, PJM used the latest approved RT SCED solution available at the time of LPC execution, regardless of the SCED target time, to calculate prices for the current five minute pricing interval. The average duration of correspondence ranged from 3 minutes 11 seconds to 3 minutes 37 seconds from January through October 15, 2020, varying with changes to the frequency of automatic RT SCED execution. The percent of time that prices were consistent with the dispatch instructions was 67.2 to 69.9 percent, on average. This is far from the goal of 100 percent correspondence between five minute dispatch instructions and prices. With the short term changes to RT SCED that were implemented on October 15, 2020, the prices no longer correspond to the dispatch instructions. Table 3-41 shows that during the period from October 15, 2020 through December 31, 2020, the dispatch instructions were consistent with prevailing prices for only 39 seconds. During this period, the percent of time that prices were consistent with the dispatch instructions was 9.9 percent. This is because by the time LMPs reflect the dispatch signals from an approved RT SCED solution, dispatchers have approved a new solution, and resources are instructed to follow new dispatch signals that do not align with the LMPs used to settle the current five minute interval. In other words, prices consistently lag dispatch instructions by five minutes, except in cases where dispatchers have not approved a new SCED solution five minutes after a previously approved solution.

Table 3-39 Dispatch instructions reflected in prices: 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 - Oct 14, 2020	Every 5 minutes	03:37	69.9%
Oct 15, 2020 - Dec 31, 2020	Every 5 minutes	00:39	9.9%

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.[50] 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.

49 See Docket No. ER19-2573-000.

50 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).

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 of the second business day following the operating day.[51] Table 3-40 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 2020, PJM recalculated LMPs for 943 five minute intervals or 0.89 percent of the total 105,408 five minute intervals. 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.[52]

Table 3-40 Number of five minute interval real-time prices recalculated: 2019 through 2020

	2019		2020	
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated
January	8,928	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	8,928	37
November	8,652	74	8,652	22
December	8,928	11	8,928	80
Total	105,120	534	105,408	943

Day-Ahead Average LMP

Day-ahead, average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[53]

PJM Day-Ahead, Average LMP

Table 3-41 shows the PJM day-ahead, average LMP for 2000 through 2020.

Table 3-41 Day-ahead, average LMP (Dollars per MWh): 2000 through 2020

	Day-Ahead LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	2.4%	10.8%	42.6%
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	(22.9%)	(19.0%)	(35.2%)
2013	$37.15	$34.63	$15.46	13.3%	12.1%	16.5%
2014	$49.15	$38.10	$51.88	32.3%	10.0%	235.6%
2015	$34.12	$29.09	$22.59	(30.6%)	(23.7%)	(56.5%)
2016	$28.10	$25.76	$10.68	(17.7%)	(11.4%)	(52.7%)
2017	$29.48	$26.94	$11.69	4.9%	4.6%	9.5%
2018	$35.69	$30.96	$22.32	21.1%	14.9%	91.0%
2019	$26.03	$24.36	$9.35	(27.1%)	(21.3%)	(58.1%)
2020	$20.33	$18.99	$7.00	(21.9%)	(22.0%)	(25.2%)

51 OA Schedule 1 § 1.10.8(e).

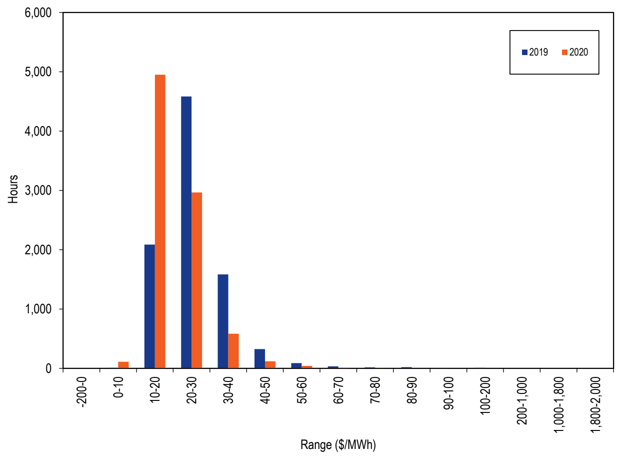
52 PJM changed this practice effective November 19, 2020. See PJM Manual 11: Energy and Ancillary Services Market Operations, Section 2.10 PJM Real-Time Price Verification Procedure, Rev. 111 (November 19, 2020).

53 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of day-ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Day-Ahead Average LMP Duration

Figure 3-30 shows the hourly distribution of PJM day-ahead, average LMP in 2019 and 2020.

Figure 3-30 Average LMP for the day-ahead energy market: 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 3-42 shows the PJM day-ahead, load-weighted, average LMP in 2000 through 2020.

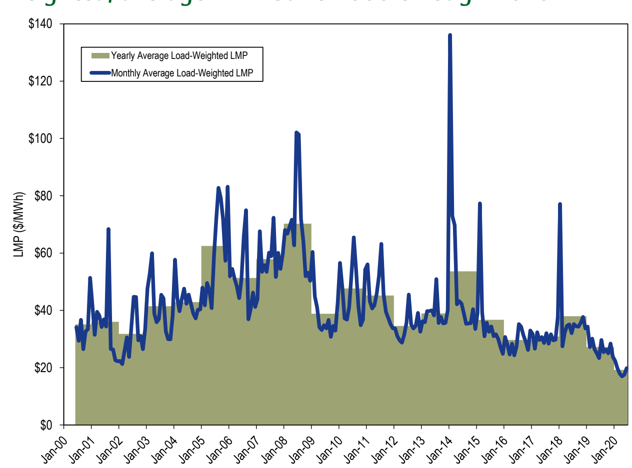
Table 3-42 Day-ahead, load-weighted, average LMP (Dollars per MWh): 2000 through 2020

	Day-Ahead, Load-Weighted, Average LMP			Year to Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.4%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	12.7%	12.3%	16.6%
2014	$53.62	$39.84	$59.62	37.8%	11.4%	230.4%
2015	$36.73	$30.60	$25.46	(31.5%)	(23.2%)	(57.3%)
2016	$29.68	$27.00	$11.64	(19.2%)	(11.8%)	(54.3%)
2017	$30.85	$28.21	$12.64	3.9%	4.5%	8.6%
2018	$37.97	$32.49	$24.76	23.1%	15.2%	95.9%
2019	$27.23	$25.28	$10.18	(28.3%)	(22.2%)	(58.9%)
2020	$21.40	$19.78	$7.59	(21.4%)	(21.7%)	(25.5%)

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 2020.[54]

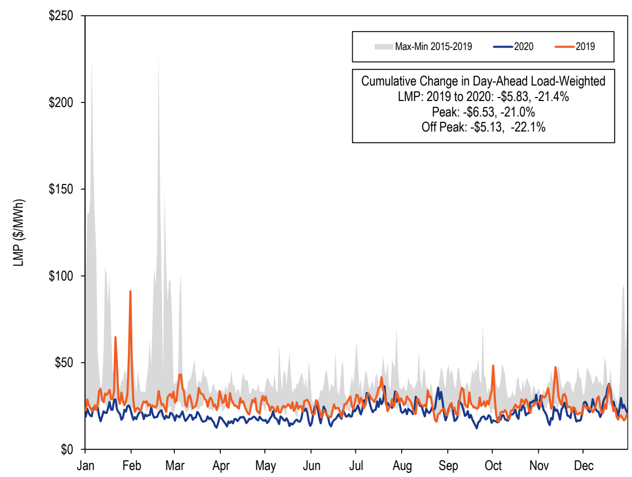
Figure 3-31 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through 2020



54 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 2019 and 2020 compared to the historic five year price range.

Figure 3-32 Day-ahead, daily, load-weighted, average LMP: 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 2020.[55] Table 3-43 shows the PJM day-ahead, load-weighted, average LMP and inflation adjusted load-weighted, average LMP for every year from 2001 through 2020. The PJM day-ahead, inflation adjusted, load-weighted, average LMP for 2020 was the lowest ($13.35 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 December 2020

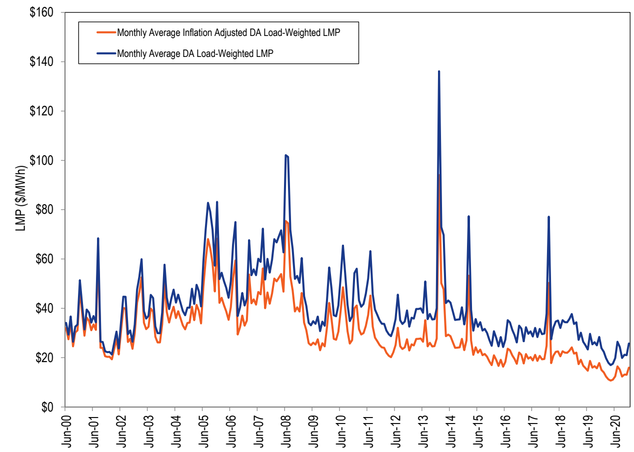


Table 3-43 Day-ahead, yearly, load-weighted, average LMP unadjusted and inflation adjusted: 2001 through 2020

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
2000	$35.13	$32.74
2001	$36.01	$32.87
2002	$31.80	$28.53
2003	$41.43	$36.42
2004	$42.87	$36.65
2005	$62.50	$51.58
2006	$51.33	$41.12
2007	$57.88	$45.11
2008	$70.25	$52.61
2009	$38.82	$29.29
2010	$47.65	$35.32
2011	$45.19	$32.48
2012	$34.55	$24.33
2013	$38.93	$27.00
2014	$53.62	$36.71
2015	$36.73	$25.08
2016	$29.68	$19.98
2017	$30.85	$20.34
2018	$37.97	$24.47
2019	$27.23	$17.23
2020	$21.40	$13.35

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.

55 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed January 13, 2021).

In practice, virtuals can profit anytime there is a difference in prices at any location in any hour between the day-ahead and real-time energy markets. Profitable virtual trading can only result in price convergence at a given location and market hour if the factors affecting prices at that location and hour, such as modeled contingencies, transmission constraint limits and sources of flows, are the same in both the day-ahead and real-time models.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may 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 and without improving the efficiency of the energy market. This is termed false arbitrage.

The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market. Price convergence does not necessarily mean a zero or even a very small difference in prices between day-ahead and real-time energy markets. There may be factors, from uplift charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences.

INCs, DECs and UTCs allow participants to profit from price differences between the day-ahead and real-time energy market. In theory, profitable virtual transactions contribute to price convergence, but with false arbitrage, high profits result with little or no price convergence. The seller of an INC must buy energy in the real-time energy market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, 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 3-44 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 2019 and 2020. In 2020, 50.1 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 62.1percent were profitable on the source side and 38.0 percent were profitable on the sink side, but only 7.3 percent were profitable on both the source and sink side.

Table 3-44 Cleared UTC profitability by source and sink point: 2019 and 2020[56]

	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	9,274,991	4,558,269	6,332,711	2,995,264	629,304	49.1%	68.3%	32.3%	6.8%
2020	8,967,923	4,497,081	5,568,865	3,410,843	652,476	50.1%	62.1%	38.0%	7.3%

Table 3-45 shows the number of cleared INC and DEC transactions and the number of profitable cleared transactions in 2019 and 2020. Of cleared INC and DEC transactions in 2020, 64.1 percent of INCs were profitable and 39.6 percent of DECs were profitable.

Table 3-45 Cleared INC and DEC profitability: 2019 and 2020

	Cleared INC	Profitable INC	Profitable INC Percent	Cleared DEC	Profitable DEC	Profitable DEC Percent
2019	2,230,626	1,542,439	69.1%	1,779,154	622,569	35.0%
2020	2,256,236	1,445,248	64.1%	2,956,349	1,169,256	39.6%

56 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 2020.

Figure 3-34 UTC daily gross profits and losses and net profits: 2020[57]

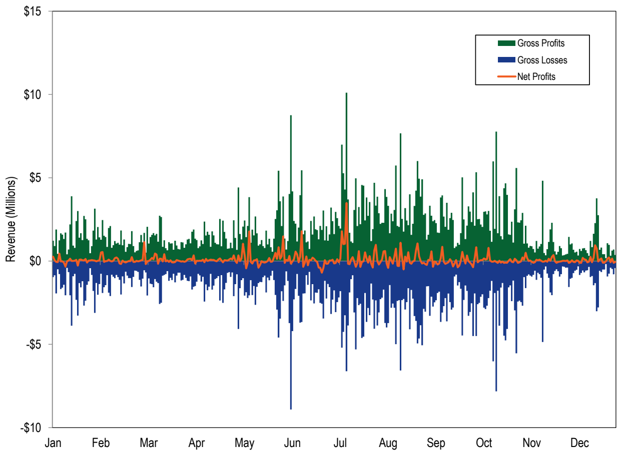


Figure 3-35 shows the cumulative UTC daily profits for each year from 2013 through 2020.

Figure 3-35 Cumulative daily UTC profits: 2013 through 2020

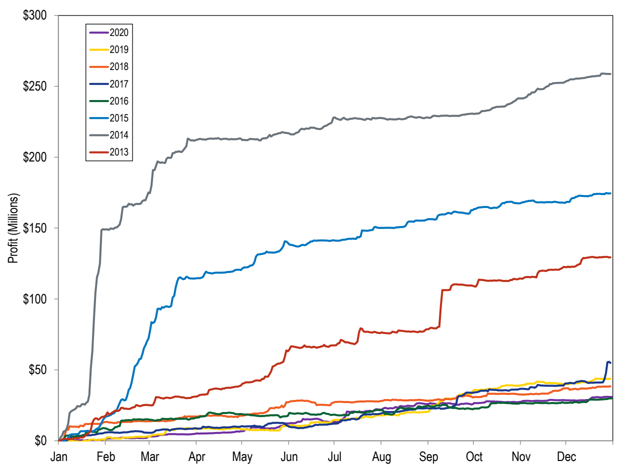


Table 3-46 shows UTC profits by month for 2013 through 2020. May 2016, September 2016, February 2017, June 2018 and September 2020 were the only months in this seven year period in which monthly profits were negative.

Table 3-46 UTC profits by month: 2013 through 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)	$1,628,186	$1,170,367	$2,319,727	$30,887,320

57 Calculations exclude PJM administrative charges.

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 2020.

Figure 3-36 INC and DEC daily gross profits and losses and net profits: 2020[58]

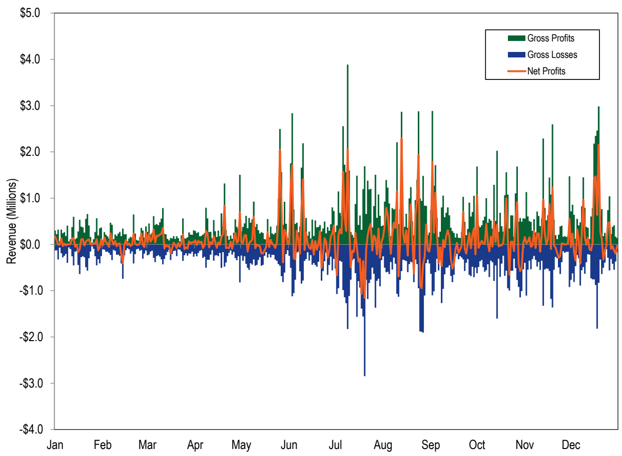


Figure 3-37 shows total INC daily gross profits and losses and net profits and losses in 2020.

Figure 3-37 INC daily gross profits and losses and net profits: 2020[59]

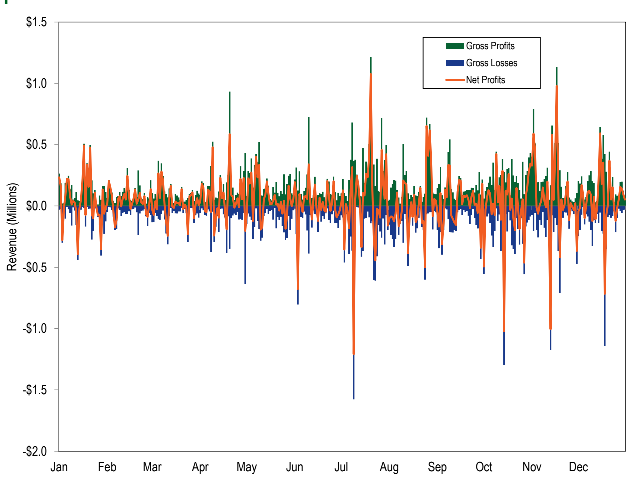


Figure 3-38 shows total DEC daily gross profits and losses and net profits and losses in 2020.

Figure 3-38 DEC daily gross profits and losses and net profits: 2020[60]

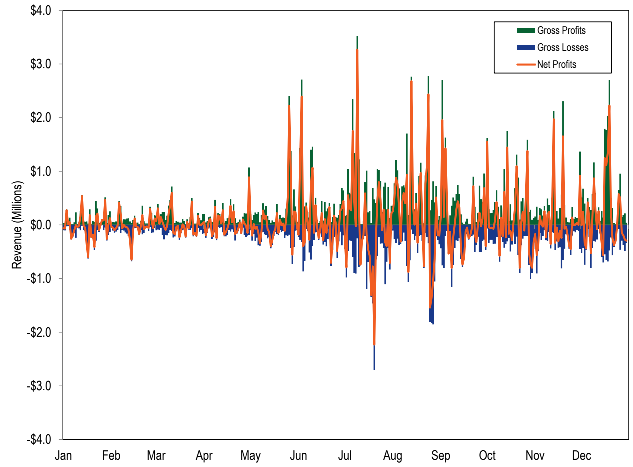
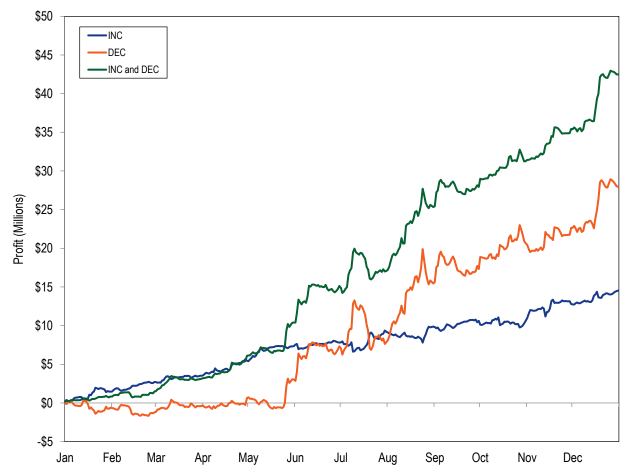


Figure 3-39 shows the cumulative INC and DEC daily profits for 2020.

Figure 3-39 Cumulative daily INC and DEC profits: 2020



58 Calculations exclude PJM administrative charges.
59 Calculations exclude PJM administrative charges.
60 Calculations exclude PJM administrative charges.

Table 3-47 shows INC and DEC profits by month for 2020.

Table 3-47 INC and DEC profits by month: 2020

	January	February	March	April	May	June	July	August	September	October	November	December	Total
INCs	$1,455,089	$1,259,625	$803,233	$1,944,109	$1,893,382	$452,115	$1,402,597	$659,910	$749,252	$7,784	$2,161,744	$1,730,590	$10,619,313
DECs	($614,734)	($606,579)	$833,364	$1,017,052	$2,404,925	$4,289,805	$522,583	$7,609,006	$1,857,777	$3,322,309	$2,019,746	$5,295,040	$17,313,199
INCs and DECs	$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	$3,330,093	$4,181,491	$7,025,630	$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 3-48 shows that the difference between the average real-time price and the average day-ahead price was -$0.01 per MWh in 2019 and $0.33 per MWh in 2020. The difference between average peak real-time price and the average peak day-ahead price was -$0.09 per MWh in 2019 and $0.42 per MWh in 2020.

Table 3-48 Day-ahead and real-time average LMP (Dollars per MWh): 2019 and 2020[61]

	2019				2020			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$26.03	$26.02	($0.01)	(0.1%)	$20.33	$20.66	$0.33	1.6%
Median	$24.36	$22.89	($1.47)	(6.4%)	$18.99	$18.35	($0.64)	(3.5%)
Standard deviation	$9.35	$21.19	$11.84	55.9%	$7.00	$11.77	$4.78	40.6%
Peak average	$30.23	$30.13	($0.09)	(0.3%)	$23.67	$24.09	$0.42	1.7%
Peak median	$27.95	$25.34	($2.61)	(10.3%)	$21.64	$20.52	($1.12)	(5.5%)
Peak standard deviation	$9.87	$26.26	$16.39	62.4%	$7.24	$13.99	$6.74	48.2%
Off peak average	$22.38	$22.43	$0.06	0.3%	$17.39	$17.64	$0.25	1.4%
Off peak median	$21.07	$20.35	($0.72)	(3.5%)	$16.54	$16.29	($0.25)	(1.5%)
Off peak standard deviation	$7.08	$14.55	$7.47	51.4%	$5.23	$8.30	$3.08	37.0%

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.

61 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 3-49 shows the difference between the real-time load-weighted and the day-ahead load-weighted energy market prices for 2001 through 2020.

Table 3-49 Day-ahead load-weighted and real-time load-weighted, average LMP (Dollars per MWh): 2001 through 2020

	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%
2012	$32.79	$33.11	$0.32	1.0%
2013	$37.15	$36.55	($0.60)	(1.6%)
2014	$49.15	$48.22	($0.93)	(1.9%)
2015	$34.12	$33.39	($0.73)	(2.1%)
2016	$28.10	$27.57	($0.53)	(1.9%)
2017	$29.48	$29.42	($0.06)	(0.2%)
2018	$35.69	$35.75	$0.06	0.2%
2019	$26.03	$26.02	($0.01)	(0.1%)
2020	$20.33	$20.66	$0.33	1.6%

Table 3-50 includes frequency distributions of the differences between PJM real-time, load-weighted, hourly LMP and PJM day-ahead, load-weighted, hourly LMP for 2019 and 2020.

Table 3-50 Frequency distribution by hours of real-time, load-weighted LMP minus day-ahead, load-weighted LMP (Dollars per MWh): 2019 and 2020

	2019		2020	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%
($200) to ($150)	0	0.00%	0	0.00%
($150) to ($100)	0	0.00%	0	0.00%
($100) to ($50)	5	0.06%	0	0.00%
($50) to $0	6,013	68.70%	5,522	62.86%
$0 to $50	2,681	99.30%	3,221	99.53%
$50 to $100	29	99.63%	35	99.93%
$100 to $150	16	99.82%	2	99.95%
$150 to $200	2	99.84%	2	99.98%
$200 to $250	3	99.87%	0	99.98%
$250 to $300	3	99.91%	1	99.99%
$300 to $350	1	99.92%	1	100.00%
$350 to $400	2	99.94%	0	100.00%
$400 to $450	1	99.95%	0	100.00%
$450 to $500	0	99.95%	0	100.00%
$500 to $750	4	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 2020.

Figure 3-40 Real-time hourly, LMP minus day-ahead hourly LMP: 2020

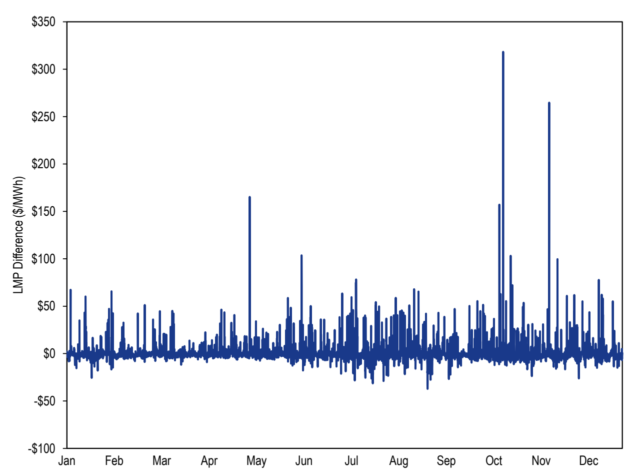
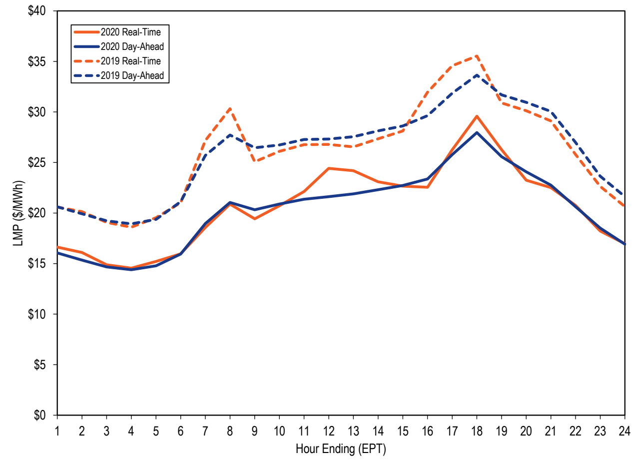


Figure 3-41 shows day-ahead and real-time, load-weighted, average hourly LMP 2019 and 2020.

Figure 3-41 System hourly average LMP: 2020



Zonal LMP and Dispatch

Table 3-51 shows zonal real-time, and real-time, load-weighted, average LMP in 2019 and 2020.

Table 3-51 Zonal real-time and real-time, load-weighted, average LMP (Dollars per MWh): 2019 and 2020

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2019	2020	Percent Change	2019	2020	Percent Change
AECO	$23.72	$18.44	(22.3%)	$25.07	$19.72	(21.3%)
AEP	$26.92	$21.17	(21.3%)	$28.21	$22.14	(21.5%)
APS	$26.55	$21.29	(19.8%)	$27.83	$22.40	(19.5%)
ATSI	$26.86	$21.34	(20.5%)	$28.06	$22.55	(19.6%)
BGE	$28.95	$23.98	(17.2%)	$30.82	$25.78	(16.3%)
ComEd	$23.53	$19.04	(19.1%)	$24.72	$20.18	(18.4%)
DAY	$27.96	$22.08	(21.0%)	$29.52	$23.23	(21.3%)
DEOK	$27.02	$21.33	(21.1%)	$28.49	$22.37	(21.5%)
DLCO	$27.59	$21.85	(20.8%)	$29.08	$23.05	(20.7%)
Dominion	$25.16	$20.68	(17.8%)	$27.71	$22.90	(17.4%)
DPL	$26.45	$21.37	(19.2%)	$27.69	$22.79	(17.7%)
EKPC	$26.54	$21.07	(20.6%)	$28.18	$22.14	(21.4%)
JCPL	$23.90	$18.63	(22.0%)	$25.40	$20.05	(21.1%)
Met-Ed	$24.92	$19.78	(20.6%)	$26.34	$21.16	(19.6%)
OVEC	$25.98	$20.64	(20.5%)	$26.23	$20.75	(20.9%)
PECO	$23.43	$18.25	(22.1%)	$24.75	$19.29	(22.1%)
PENELEC	$25.19	$19.94	(20.9%)	$26.17	$20.84	(20.4%)
Pepco	$28.03	$22.23	(20.7%)	$29.68	$23.59	(20.5%)
PPL	$23.55	$18.44	(21.7%)	$24.85	$19.42	(21.9%)
PSEG	$24.11	$18.73	(22.3%)	$25.28	$19.69	(22.1%)
RECO	$24.44	$19.38	(20.7%)	$25.72	$20.74	(19.4%)
PJM	$26.02	$20.66	(20.6%)	$27.32	$21.77	(20.3%)

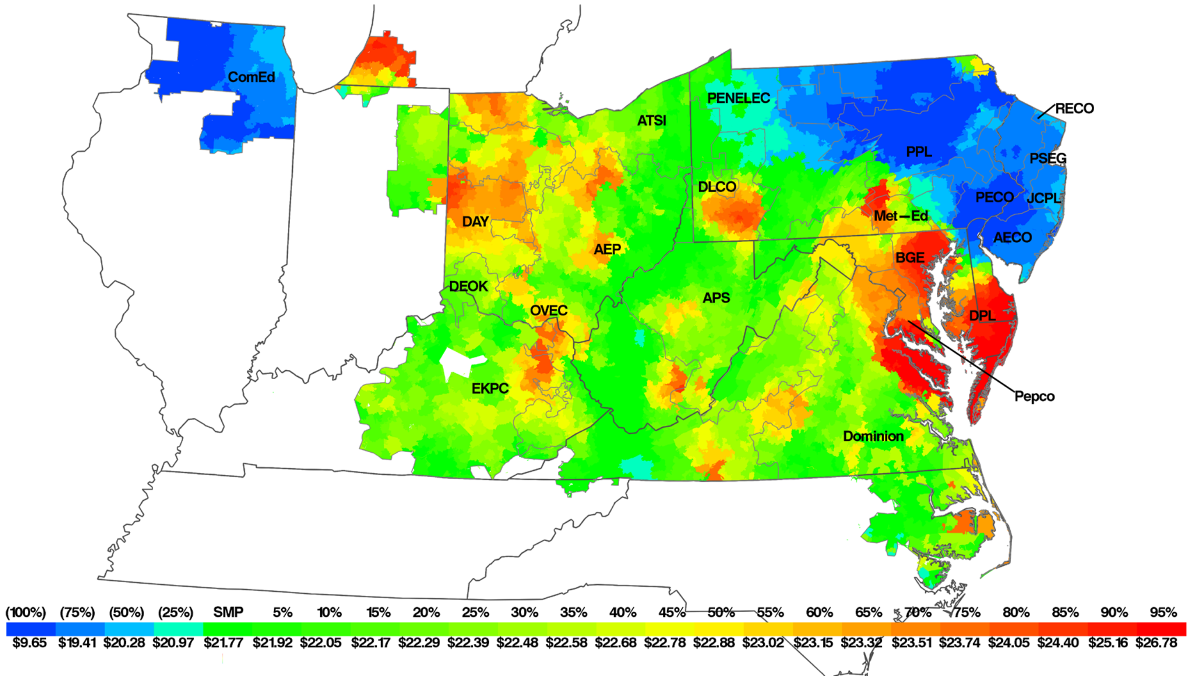
Table 3-52 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in 2019 and 2020.

Table 3-52 Zonal day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): 2019 and 2020

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2019	2020	Percent Change	2019	2020	Percent Change
AECO	$23.70	$18.01	(24.0%)	$24.92	$19.18	(23.0%)
AEP	$26.81	$20.92	(22.0%)	$28.02	$21.89	(21.9%)
APS	$26.68	$20.91	(21.6%)	$27.84	$21.96	(21.1%)
ATSI	$27.05	$20.92	(22.7%)	$28.14	$21.91	(22.2%)
BGE	$29.22	$23.74	(18.7%)	$30.93	$25.36	(18.0%)
ComEd	$23.59	$18.97	(19.6%)	$24.62	$20.01	(18.7%)
DAY	$27.93	$22.00	(21.2%)	$29.27	$23.19	(20.8%)
DEOK	$27.22	$21.35	(21.6%)	$28.64	$22.50	(21.4%)
DLCO	$27.83	$21.66	(22.2%)	$29.33	$22.89	(22.0%)
Dominion	$25.06	$19.55	(22.0%)	$27.44	$21.47	(21.7%)
DPL	$26.63	$21.00	(21.2%)	$27.72	$22.27	(19.6%)
EKPC	$26.39	$20.84	(21.0%)	$27.97	$22.17	(20.7%)
JCPL	$23.78	$18.07	(24.0%)	$25.04	$19.23	(23.2%)
Met-Ed	$24.60	$19.00	(22.8%)	$25.78	$20.23	(21.5%)
OVEC	$25.91	$20.45	(21.1%)	$28.03	$21.12	(24.7%)
PECO	$23.26	$17.78	(23.6%)	$24.38	$18.75	(23.1%)
PENELEC	$25.57	$19.90	(22.2%)	$26.89	$21.13	(21.4%)
Pepco	$28.38	$22.12	(22.1%)	$29.99	$23.55	(21.5%)
PPL	$23.30	$17.92	(23.1%)	$24.39	$18.82	(22.9%)
PSEG	$24.03	$18.24	(24.1%)	$25.13	$19.18	(23.7%)
RECO	$24.60	$18.74	(23.8%)	$25.94	$20.22	(22.0%)
PJM	$26.03	$20.33	(21.9%)	$27.23	$21.40	(21.4%)

Figure 3-42 is a map of the real-time, load-weighted, average LMP in 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: 2020



Transmission Penalty Factors

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 3-53 shows the frequency and average shadow price of transmission constraints in PJM. In 2020, there were 165,963 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.[62] In 2020, the average shadow price of transmission constraints when the line limit was violated was nearly 16.8 times higher than when the transmission constraint was binding at its limit.

Table 3-53 Frequency and average shadow price of transmission constraints: 2019 and 2020

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2019	2020	2019	2020
PJM Internal Violated Transmission Constraints	7,046	7,374	$1,480.03	$1,549.04
PJM Internal Binding Transmission Constraints	92,366	117,867	$96.89	$92.23
Market to Market Transmission Constraints	53,263	40,722	$228.92	$219.15
All Transmission Constraints	152,675	165,963	$206.78	$188.10

62 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.

Transmission penalty factors should be applied without discretion. 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 3-54 shows the frequency of changes to the transmission constraints for binding and violated transmission constraints in the PJM real-time market. In 2020, there were 6,779 or 92 percent of 7,374 internal violated transmission constraint intervals in the real-time market with constraint limit less than 100 percent of the actual constraint limit. In 2020, among the constraints with reduced constraint limits, the constraint limit was reduced on average by 6.8 percent.

Table 3-54 Frequency of reduction in line ratings (constraint intervals): 2019 and 2020

	Frequency (Constraint Intervals)		Constraints with Reduced Line Limits (Constraint Intervals)		Average Reduction (Percentage)	
Description	2019	2020	2019	2020	2019	2020
PJM Internal Violated Transmission Constraints	7,046	7,374	5,465	6,779	6.88%	6.80%
PJM Internal Binding Transmission Constraints	92,366	117,867	90,033	115,866	9.08%	8.87%
Market to Market Transmission Constraints	53,263	40,722	10,699	9,841	5.54%	5.94%
All Transmission Constraints	152,675	165,963	106,197	132,486	8.61%	8.54%

Table 3-55 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM Real-Time Energy Market. In 2020, there were 5,031 or 68 percent of internal violated transmission constraint intervals in the real-time market with a transmission penalty factor equal to the default $2,000 per MWh.

Table 3-55 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): 2019 and 2020

	2019			2020		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
PJM Internal Violated Transmission Constraints	4,623	70	2,353	5,031	88	2,255
PJM Internal Binding Transmission Constraints	86,071	707	5,588	109,731	155	7,981
Market to Market Transmission Constraints	11,033	3	42,227	2,956	-	37,766
All Transmission Constraints	101,727	780	50,168	117,718	243	48,002

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.[63] Frequently, PJM dispatchers also manually override the transmission violation penalty factor of the

63 PJM dispatchers generally log the resources paired with a constraint in the CT pricing logic. The data presented is based on PJM dispatcher logs.

constraint to match the offer price of the resource to artificially control the shadow price of the constraint. Table 3-56 shows the frequency of CT pricing logic used in the PJM Real-Time Energy Market. In 2020, there were 10,540 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.

PJM's use of CT pricing logic is inconsistent with the efficient market dispatch and pricing. For that reason, in 2019 FERC declared CT pricing logic to be unjust and unreasonable.[64] PJM should discontinue the use of CT pricing logic, regardless of whether the new fast-start pricing process is in place.

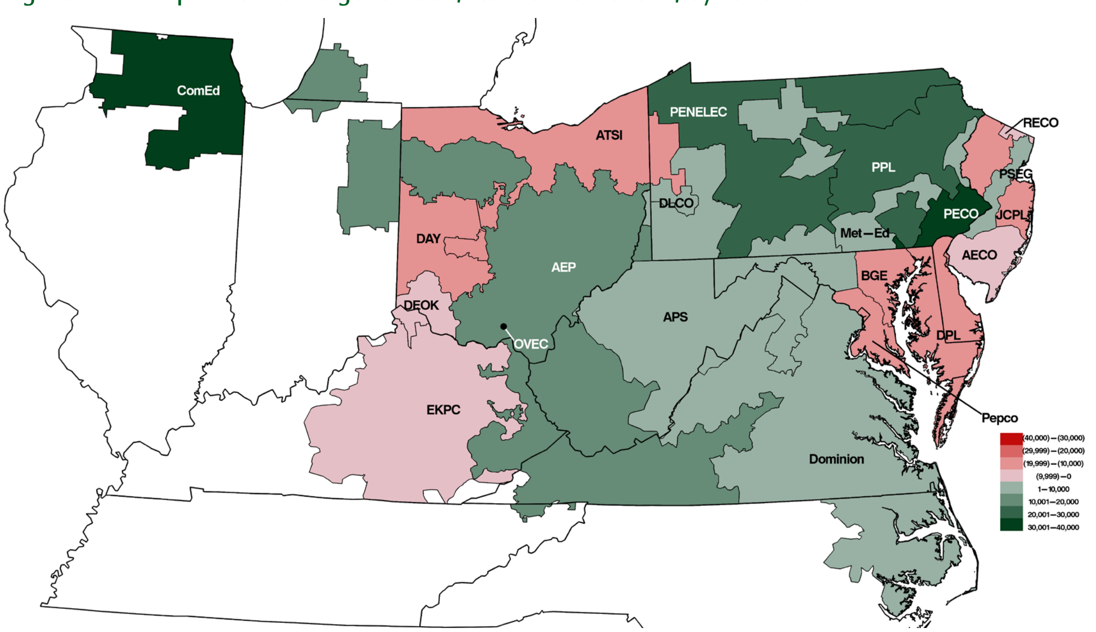
Table 3-56 Frequency of CT pricing logic used in the real-time market (constraint intervals): 2019 and 2020

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	2,017
Nov	2,229	956
Dec	835	1,404
Total	14,976	10,540

Net Generation by Zone

Figure 3-43 shows the difference between the PJM real-time generation and real-time load by zone in 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 3-57 shows the difference between the PJM real-time generation and real-time load by zone in 2019 and 2020.

Figure 3-43 Map of real-time generation, less real-time load, by zone: 2020[65]



64 *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,058 at P 69 (April 18, 2019).

65 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>.

Table 3-57 Real-time generation less real-time load by zone (GWh): 2019 and 2020

	Zonal Generation and Load (GWh)					
	2019			2020		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	6,083.1	9,887.9	(3,804.8)	3,489.7	9,489.2	(5,999.5)
AEP	144,785.2	125,736.1	19,049.1	135,989.6	120,710.5	15,279.1
APS	51,281.0	48,967.5	2,313.5	49,068.0	46,870.7	2,197.3
ATSI	38,923.7	65,005.0	(26,081.3)	46,182.2	62,400.1	(16,217.9)
BGE	18,068.0	31,127.5	(13,059.5)	16,588.2	29,631.1	(13,042.9)
ComEd	134,364.9	94,076.8	40,288.1	128,261.3	90,687.4	37,573.9
DAY	1,079.5	17,122.3	(16,042.8)	1,055.1	16,426.9	(15,371.8)
DEOK	18,402.7	26,800.9	(8,398.2)	18,686.7	25,464.3	(6,777.6)
Dominion	98,283.0	100,869.9	(2,586.8)	105,501.9	98,774.8	6,727.1
DPL	5,098.2	18,290.2	(13,192.1)	5,163.8	17,724.5	(12,560.6)
DLCO	16,330.6	13,383.6	2,947.1	16,052.6	12,818.6	3,234.0
EKPC	6,910.1	12,741.2	(5,831.1)	8,177.8	12,407.8	(4,230.0)
JCPL	11,370.9	21,998.2	(10,627.3)	8,492.6	21,515.4	(13,022.7)
Met-Ed	22,901.1	15,485.4	7,415.7	19,838.6	14,999.2	4,839.4
OVEC	11,234.4	127.9	11,106.4	9,033.1	111.9	8,921.1
PECO	69,694.5	39,480.2	30,214.3	73,151.5	37,413.7	35,737.8
PENELEC	41,064.4	16,871.0	24,193.3	38,245.1	16,424.3	21,820.8
Pepco	12,316.6	29,495.4	(17,178.8)	11,342.9	27,059.6	(15,716.7)
PPL	64,378.2	40,427.5	23,950.7	62,309.6	39,286.2	23,023.4
PSEG	45,906.2	42,608.7	3,297.5	42,237.0	41,385.2	851.8
RECO	0.0	1,425.7	(1,425.7)	0.0	1,385.8	(1,385.8)

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during 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 3-58 shows PJM generation by fuel source in GWh for 2019 and 2020. In 2020, generation from coal units decreased 20.6 percent, generation from natural gas units increased 6.9 percent, and generation from oil increased 14.9 percent compared to 2019. Wind and solar output rose by 12.5 percent compared to 2019, supplying 3.7 percent of PJM energy in 2020. Output from coal fell twice as much as total PJM output, but was offset by the increase in output from natural gas.

Table 3-58 Generation (By fuel source (GWh)): 2019 and 2020[66 67 68]

	2019		2020		Change in
	GWh	Percent	GWh	Percent	Output
Coal	197,165.3	23.8%	156,575.9	19.3%	(20.6%)
Bituminous	169,958.4	20.5%	143,556.3	17.7%	(15.5%)
Sub Bituminous	20,981.7	2.5%	7,726.0	1.0%	(63.2%)
Other Coal	6,225.2	0.8%	5,293.7	0.7%	(15.0%)
Nuclear	278,911.8	33.6%	276,607.6	34.2%	(0.8%)
Gas	302,116.9	36.4%	322,504.5	39.8%	6.7%
Natural Gas CC	278,218.4	33.6%	294,712.8	36.4%	5.9%
Natural Gas CT	15,955.2	1.9%	18,825.6	2.3%	18.0%
Natural Gas Other Units	5,793.3	0.7%	7,019.2	0.9%	21.2%
Other Gas	2,150.1	0.3%	1,946.9	0.2%	(9.4%)
Hydroelectric	16,696.7	2.0%	16,423.3	2.0%	(1.6%)
Pumped Storage	4,642.9	0.6%	4,950.4	0.6%	6.6%
Run of River	10,728.7	1.3%	10,036.7	1.2%	(6.5%)
Other Hydro	1,325.1	0.2%	1,436.2	0.2%	8.4%
Wind	24,167.1	2.9%	26,460.7	3.3%	9.5%
Waste	4,237.3	0.5%	4,423.1	0.5%	4.4%
Oil	1,787.9	0.2%	2,054.8	0.3%	14.9%
Heavy Oil	102.9	0.0%	86.0	0.0%	(16.4%)
Light Oil	271.9	0.0%	282.2	0.0%	3.8%
Diesel	71.7	0.0%	30.1	0.0%	(58.0%)
Other Oil	1,341.4	0.2%	1,656.4	0.2%	23.5%
Solar, Net Energy Metering	2,780.6	0.3%	3,842.1	0.5%	38.2%
Battery	18.8	0.0%	36.1	0.0%	92.0%
Biofuel	1,279.6	0.2%	914.3	0.1%	(28.5%)
Total	829,162.0	100.0%	809,842.4	100.0%	(2.3%)

66 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.

67 Net Energy Metering is combined with Solar due to data confidentiality reasons.

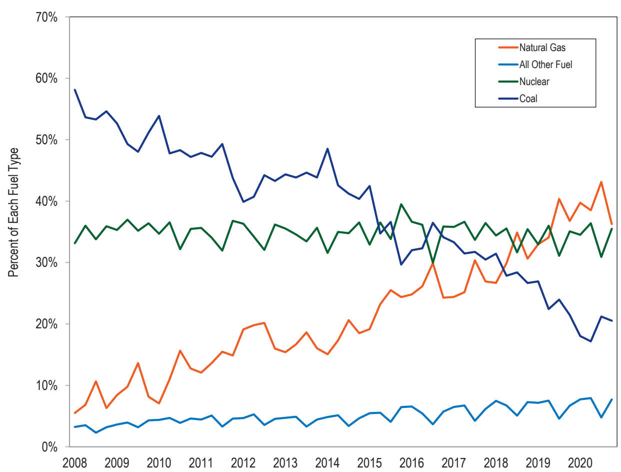
68 Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

Table 3-59 Monthly generation (By fuel source (GWh)): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	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	10,093.9	12,884.7	17,023.2	156,575.9
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	9,299.0	11,968.4	16,068.3	143,556.3
Sub Bituminous	348.1	570.5	340.4	452.2	295.2	834.4	1,661.9	1,389.1	592.6	290.4	537.5	413.6	7,726.0
Other Coal	538.6	517.3	402.2	389.5	296.8	283.7	456.1	502.1	482.9	504.4	378.8	541.3	5,293.7
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	21,836.6	22,734.6	24,609.6	276,607.6
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	24,478.2	20,599.1	26,035.5	322,504.5
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	22,051.3	18,993.4	24,614.5	294,712.8
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	1,879.7	1,111.3	1,064.7	18,825.6
Natural Gas Other Units	343.8	159.1	83.4	108.3	314.3	987.9	2,294.9	1,433.8	335.4	403.8	350.1	204.5	7,019.2
Other Gas	187.9	177.1	188.6	174.9	174.9	149.1	152.1	152.5	150.4	143.4	144.3	151.8	1,946.9
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	905.0	1,123.1	1,446.9	16,423.3
Pumped Storage	370.7	309.2	324.9	273.5	447.8	495.3	654.1	603.9	465.1	327.0	290.7	388.2	4,950.4
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	480.1	756.0	980.7	10,036.7
Other Hydro	88.9	122.2	82.4	58.3	118.3	167.4	215.0	202.8	128.7	97.9	76.4	78.0	1,436.2
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	2,332.0	3,278.4	2,860.1	26,460.7
Waste	366.3	297.0	391.2	357.9	380.3	352.5	400.5	389.9	362.6	358.2	369.7	397.0	4,423.1
Oil	128.2	159.1	165.2	160.2	152.9	165.9	307.8	178.1	162.0	142.5	159.5	173.4	2,054.8
Heavy Oil	0.0	0.0	0.0	0.0	0.0	0.0	24.9	14.2	33.9	13.0	0.0	0.0	86.0
Light Oil	10.8	6.4	2.2	2.2	3.7	29.9	132.5	26.0	11.7	9.9	28.9	18.2	282.2
Diesel	7.5	0.2	0.3	0.1	0.0	1.5	10.3	2.4	1.6	1.8	1.6	2.7	30.1
Other Oil	109.9	152.6	162.8	157.9	149.2	134.5	140.1	135.5	114.8	117.8	129.0	152.5	1,656.4
Solar, Net Energy Metering	187.3	208.8	288.5	363.0	401.1	424.0	455.5	359.5	319.3	302.0	296.0	237.2	3,842.1
Battery	2.0	2.4	3.6	3.0	3.0	3.1	3.4	3.4	3.1	3.2	3.0	2.9	36.1
Biofuel	84.7	101.9	102.2	36.6	46.8	66.2	96.3	91.7	94.7	63.9	71.9	57.5	914.3
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	60,515.4	61,519.9	72,843.2	809,842.4

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: 2008 through 2020



Fuel Diversity

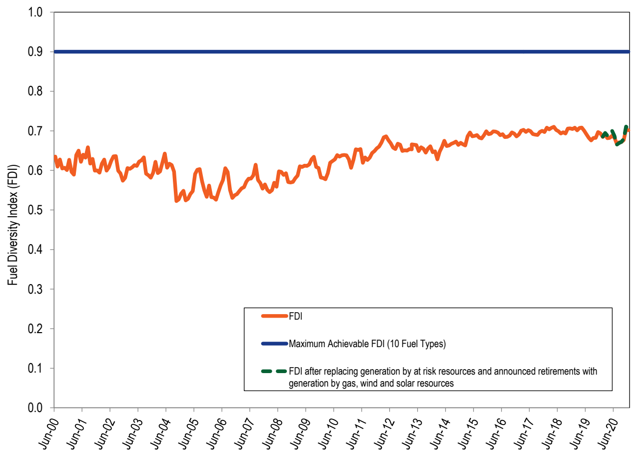
Figure 3-45 shows the fuel diversity index (FDI_e) for PJM energy generation.[69] The FDI_e is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-59 with nonzero

69 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.

generation values. As fuel diversity has increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 35.4 percent from 2012 through 2019. A significant drop in the FDI_e occurred in the fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light Control Zones and the increased shares of coal and nuclear that resulted.[70] 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 19.3 percent for 2020. Gas generation as a share of total generation was 7.4 percent for 2008 and 39.8 percent for 2020. Wind generation as a share of total generation was 0.5 percent for 2008 and 3.3 percent for 2020.

The FDI_e decreased 1.5 percent for 2020 compared to 2019. The FDI_e was also used to measure the impact on fuel diversity of potential retirements. A total of 4,763 MW of coal, CT, and other capacity were identified as being at risk of retirement.[71] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance.[72] There are 4,163.9 MW of generation that have requested retirement after December 31, 2020.[73] The at risk units and other generators with deactivation notices generated 23,945.2 GWh in 2020. The dashed line in Figure 3-45 shows a counterfactual result for FDI_e assuming the 23,945.2 GWh of generation from at risk units and other generators with deactivation notices were replaced by gas, wind and solar generation.[74] The FDI_e for 2020 under the counterfactual assumption would have been 0.5 percent higher than the actual FDI_e.

Figure 3-45 Fuel diversity index for monthly generation: June 2000 through December 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 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

70 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.

71 See Table 7-47 in the *2020 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

72 See PJM. OATT: § V "Generation Deactivation."

73 See *2020 State of the Market Report for PJM*, Section 12: Generation and Transmission Planning, Table 12-11.

74 It is assumed that 10,724.0 GWh of the replacement energy is from new wind and solar units. This value represents the increase over 2020 levels in renewable generation that is required by RPS in 2021, assuming zero load growth. The split between solar and wind, 7,509.0 GWh solar and 3,215.0 GWh wind, is based on queue data.

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 3-60 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 2020, coal units were 17.5 percent and natural gas units were 72.3 percent of marginal resources. In 2020, natural gas combined cycle units were 64.3 percent of marginal resources. In 2019, coal units were 24.4 percent and natural gas units were 69.4 percent of the total marginal resources. In 2019, natural gas combined cycle units were 62.1 percent of the total marginal resources. In 2020, 92.8 percent of the wind marginal units had negative offer prices, 7.2 percent had zero offer prices and none had positive offer prices. In 2019, 94.3 percent of the wind marginal units had negative offer prices, 5.0 percent had zero offer prices and 0.8 percent of wind marginal units had positive offer prices.

The proportion of marginal nuclear units increased from 1.31 percent in 2019 to 1.35 percent in 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 3-60 Type of fuel used and technology (By real-time marginal units): 2016 through 2020[75]

Fuel	Technology	2016	2017	2018	2019	2020
Gas	CC	31.22%	44.63%	53.45%	62.13%	64.33%
Coal	Steam	46.39%	32.28%	27.26%	24.37%	17.53%
Wind	Wind	2.98%	7.28%	2.56%	3.81%	6.75%
Gas	CT	6.57%	4.70%	7.80%	5.97%	5.89%
Gas	Steam	4.66%	3.52%	1.68%	1.29%	2.12%
Uranium	Steam	1.06%	1.23%	1.04%	1.31%	1.35%
Oil	CT	5.98%	5.18%	4.58%	0.49%	1.25%
Other	Solar	0.02%	0.18%	0.12%	0.07%	0.33%
Oil	Steam	0.04%	0.05%	0.29%	0.03%	0.06%
Other	Steam	0.12%	0.19%	0.15%	0.06%	0.03%
Municipal Waste	Steam	0.01%	0.01%	0.04%	0.02%	0.02%
Landfill Gas	CT	0.00%	0.00%	0.02%	0.01%	0.01%
Oil	RICE	0.75%	0.26%	0.42%	0.00%	0.00%
Oil	CC	0.02%	0.01%	0.13%	0.01%	0.00%
Municipal Waste	RICE	0.00%	0.00%	0.00%	0.00%	0.00%
Gas	Fuel Cell	0.00%	0.00%	0.00%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.02%	0.04%	0.00%	0.00%	0.00%
Gas	RICE	0.12%	0.40%	0.41%	0.00%	0.00%
Landfill Gas	RICE	0.04%	0.02%	0.04%	0.00%	0.00%

75 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): 2004 through 2020

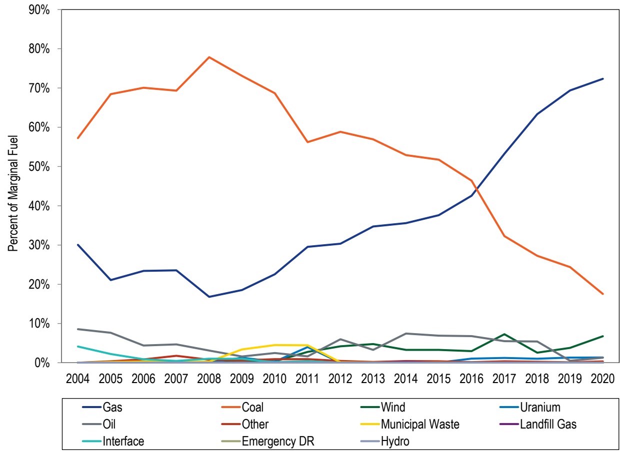


Table 3-61 shows the type of fuel used and technology where relevant, of marginal resources in the day-ahead energy market. In 2020, up to congestion transactions were 51.34 percent of marginal resources. Up to congestion transactions were 57.39 percent of marginal resources in 2019.

Table 3-61 Day-ahead marginal resources by type/fuel used and technology: 2016 through 2020

Type/Fuel	Technology	2016	2017	2018	2019	2020
Up to Congestion Transaction	NA	81.72%	79.35%	62.30%	57.39%	51.34%
DEC	NA	8.58%	10.15%	16.90%	17.04%	18.79%
INC	NA	4.15%	5.49%	9.78%	12.76%	13.24%
Gas	CC	2.14%	2.10%	5.34%	7.42%	9.91%
Coal	Steam	2.32%	1.95%	4.63%	4.45%	5.12%
Gas	Steam	0.40%	0.36%	0.28%	0.38%	0.47%
Wind	Wind	0.06%	0.15%	0.13%	0.10%	0.38%
Uranium	Steam	0.11%	0.08%	0.12%	0.10%	0.21%
Gas	CT	0.04%	0.04%	0.20%	0.11%	0.21%
Oil	CT	0.41%	0.25%	0.04%	0.05%	0.10%
Dispatchable Transaction	NA	0.05%	0.04%	0.13%	0.10%	0.10%
Gas	RICE	0.00%	0.02%	0.04%	0.06%	0.05%
Other	Steam	0.01%	0.00%	0.01%	0.01%	0.04%
Other	Solar	0.00%	0.00%	0.02%	0.01%	0.02%
Municipal Waste	RICE	0.00%	0.00%	0.01%	0.01%	0.01%
Oil	Steam	0.00%	0.00%	0.04%	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%
Municipal Waste	Steam	0.00%	0.00%	0.00%	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 December 2020, the daily proportion of marginal resources that were up to congestion transactions and/or generation units. The UTC share decreased from 57.39 percent in 2019 to 51.34 percent in 2020.

Up to congestion transaction volumes decreased following the allocation of uplift charges on November 1, 2020.[76] The average number of up to congestion bids submitted in the day-ahead energy market decreased by 6.6 percent, from 52,046 bids per day in 2019 to 48,618 bids per day in 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 12.5 percent, from 500,819 MWh per day in 2019, to 438,170 MWh per day in 2020.

76 172 FERC ¶ 61,046 (2020).

Figure 3-47 Day-ahead marginal up to congestion transaction and generation units: 2014 through 2020

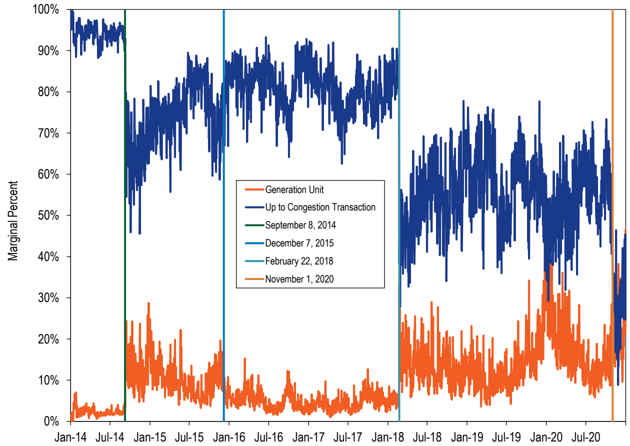
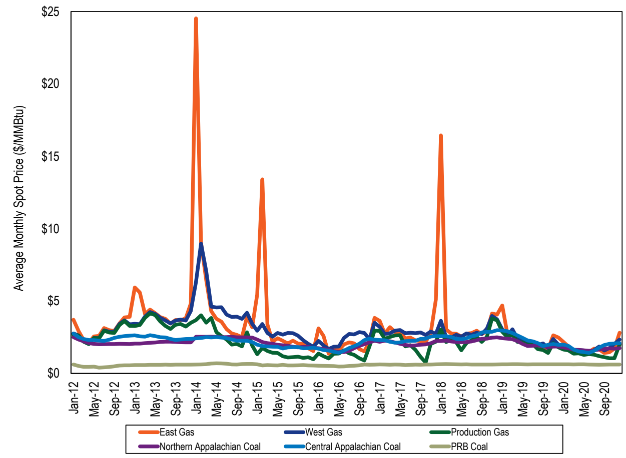


Figure 3-48 Spot average fuel price comparison: 2012 through 2020[78]



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 2020. Natural gas prices decreased in 2020 compared to 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 2020, the price of production gas was 34.6 percent lower than in 2019, the price of eastern natural gas was 30.9 percent lower and the price of western natural gas was 24.6 percent lower. The price of Northern Appalachian coal was 18.2 percent lower; the price of Central Appalachian coal was 23.9 percent lower; and the price of Powder River Basin coal was 1.9 percent lower.[77] The price of ULSD NY Harbor Barge was 36.3 percent lower.

Table 3-62 compares the PJM real-time fuel-cost adjusted, load-weighted, average LMP in 2020 to the load-weighted, average LMP in 2019.[79] The real-time, load-weighted average LMP in 2020 decreased by $5.55 or -20.3 percent from the real-time load-weighted, average LMP in 2019. The real-time load-weighted, average LMP for 2020 was 11.4 percent lower than the real-time, fuel-cost adjusted, load-weighted average LMP for 2020. The real-time, fuel-cost adjusted, load-weighted, average LMP for 2020 was 10.1 percent lower than the real-time, load-weighted, average LMP for 2019. If fuel and emissions costs in 2020 had been the same as in the 2019, holding the market dispatch constant, the real-time, load-weighted, average LMP in 2020 would have been higher, $24.56 per MWh, than the observed $21.77 per MWh. Only 50.3 percent of the decrease in real-time, load-weighted, average LMP, $2.79 per MWh out of $5.55 per MWh, is directly attributable to fuel costs. Contributors to the other $2.76 per MWh are decreased load, adjusted dispatch, including adjustments to dispatch due to changes in relative fuel costs among units, and lower markups.

77 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.

78 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.

79 The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO_2 and SO_x costs.

Table 3-62 Real-time, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): 2019 and 2020

	2020 Fuel-Cost Adjusted, Load-Weighted LMP	2020 Load-Weighted LMP	Change	Percent Change
Average	$24.56	$21.77	($2.79)	(11.4%)
	2019 Load-Weighted LMP	2020 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$27.32	$24.56	($2.76)	(10.1%)
	2019 Load-Weighted LMP	2020 Load-Weighted LMP	Change	Change
Average	$27.32	$21.77	($5.55)	(20.3%)

Table 3-63 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 2020. Table 3-63 shows that lower natural gas prices explain 80.9 percent of the fuel-cost related decrease in the real-time annual, load-weighted, average LMP in 2020 from 2019.

Table 3-63 Share of change in fuel-cost adjusted LMP ($/MWh) by fuel type: 2020 adjusted to 2019 fuel prices

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Gas	($2.25)	80.9%
Coal	($0.50)	17.9%
Oil	($0.03)	1.2%
Uranium	$0.00	0.0%
Municipal Waste	$0.00	0.0%
Other	$0.00	0.0%
NA	$0.00	0.0%
Wind	$0.00	0.0%
Total	($2.79)	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 up to fourteen minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance (VOM) costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland, and New Jersey.[80] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and reserves. 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.

The components of LMP are shown in Table 3-64, including markup using unadjusted cost-based offers.[81] Table 3-64 shows that in 2020, 23.7 percent of the load-weighted LMP was the result of coal costs, 41.5 percent was the result of gas costs and 1.7 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, markup was 2.3 percent of the load-weighted LMP. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM 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

80 New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020.

81 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>.

column is the difference (in percentage points) in the proportion of LMP represented by each component in 2020 and 2019.

Table 3-64 Components of real-time (Unadjusted), load-weighted, average LMP: 2019 and 2020

	2019		2020		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$11.51	42.1%	$9.03	41.5%	(0.7%)
Coal	$7.21	26.4%	$5.17	23.7%	(2.7%)
Ten Percent Adder	$2.07	7.6%	$1.68	7.7%	0.1%
Constraint Violation Adder	$1.85	6.8%	$1.67	7.7%	0.9%
Variable Maintenance	$1.71	6.3%	$1.34	6.2%	(0.1%)
Variable Operations			$0.84	3.9%	3.9%
NA	$0.35	1.3%	$0.57	2.6%	1.3%
Markup	$1.55	5.7%	$0.50	2.3%	(3.4%)
CO_2 Cost	$0.21	0.8%	$0.37	1.7%	0.9%
LPA Rounding Difference	$0.15	0.5%	$0.18	0.8%	0.3%
Ancillary Service Redispatch Cost	$0.24	0.9%	$0.13	0.6%	(0.3%)
Scarcity Adder	$0.24	0.9%	$0.08	0.4%	(0.5%)
Oil	$0.06	0.2%	$0.07	0.3%	0.1%
Opportunity Cost Adder	$0.10	0.4%	$0.07	0.3%	(0.0%)
Increase Generation Adder	$0.10	0.4%	$0.06	0.3%	(0.1%)
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%
Landfill Gas	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Renewable Energy Credits	($0.02)	(0.1%)	($0.01)	(0.0%)	0.1%
Decrease Generation Adder	($0.05)	(0.2%)	($0.02)	(0.1%)	0.1%
Total	$27.32	100.0%	$21.77	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 3-64 and Table 3-66), markup is simply the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-65 and Table 3-67), 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 3-65, including markup using adjusted cost-based offers.

Table 3-65 Components of real-time (Adjusted), load-weighted, average LMP: 2019 and 2020

	2019		2020		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$11.51	42.1%	$9.03	41.5%	(0.7%)
Coal	$7.21	26.4%	$5.17	23.7%	(2.7%)
Markup	$3.63	13.3%	$2.19	10.0%	(3.2%)
Constraint Violation Adder	$1.85	6.8%	$1.67	7.7%	0.9%
Variable Maintenance	$1.71	6.3%	$1.34	6.2%	(0.1%)
Variable Operations			$0.84	3.9%	3.9%
NA	$0.35	1.3%	$0.57	2.6%	1.3%
CO_2 Cost	$0.21	0.8%	$0.37	1.7%	0.9%
LPA Rounding Difference	$0.15	0.5%	$0.18	0.8%	0.3%
Ancillary Service Redispatch Cost	$0.24	0.9%	$0.13	0.6%	(0.3%)
Scarcity Adder	$0.24	0.9%	$0.08	0.4%	(0.5%)
Oil	$0.06	0.2%	$0.07	0.3%	0.1%
Opportunity Cost Adder	$0.10	0.4%	$0.07	0.3%	(0.0%)
Increase Generation Adder	$0.10	0.4%	$0.06	0.3%	(0.1%)
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%
Landfill Gas	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Renewable Energy Credits	($0.02)	(0.1%)	($0.01)	(0.0%)	0.1%
Decrease Generation Adder	($0.05)	(0.2%)	($0.02)	(0.1%)	0.1%
Total	$27.32	100.0%	$21.77	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 3-66 shows the components of the PJM day-ahead, annual, load-weighted, average LMP. In 2020, 24.4 percent of the load-weighted LMP was the result of coal costs, 18.8 percent of the load-weighted, LMP was the result of gas costs, 24.0 percent was the result of DEC bid costs, 15.2 percent was the result of INC bid costs and 3.0 percent was the result of the up to congestion transaction costs.

Table 3-66 Components of day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): 2019 and 2020

	2019		2020		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.01	22.1%	$5.22	24.4%	2.4%
DEC	$5.81	21.3%	$5.13	24.0%	2.6%
Gas	$5.36	19.7%	$4.02	18.8%	(0.9%)
INC	$5.69	20.9%	$3.25	15.2%	(5.7%)
Ten Percent Cost Adder	$1.28	4.7%	$1.12	5.2%	0.5%
Variable Maintenance	$1.21	4.4%	$0.89	4.1%	(0.3%)
Variable Operations			$0.74	3.4%	3.4%
Up to Congestion Transaction	$0.69	2.5%	$0.64	3.0%	0.4%
CO_2	$0.14	0.5%	$0.28	1.3%	0.8%
DASR LOC Adder	($0.04)	(0.1%)	$0.08	0.4%	0.5%
Dispatchable Transaction	$0.31	1.1%	$0.05	0.2%	(0.9%)
Constrained Off	$0.00	0.0%	$0.03	0.2%	0.2%
Oil	$0.06	0.2%	$0.02	0.1%	(0.1%)
Price Sensitive Demand	$0.01	0.0%	$0.01	0.1%	0.0%
NO_x	$0.01	0.0%	$0.01	0.0%	(0.0%)
DASR Offer Adder	$0.01	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%)
Municipal Waste	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.01)	(0.1%)	($0.00)	(0.0%)	0.0%
Markup	$0.70	2.6%	($0.11)	(0.5%)	(3.1%)
NA	$0.00	0.0%	$0.03	0.2%	0.2%
Total	$27.23	100.0%	$21.40	100.0%	0.0%

Table 3-67 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 3-67 Components of day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): 2019 and 2020

	2019		2020		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.01	22.1%	$5.22	24.4%	2.4%
DEC	$5.81	21.3%	$5.13	24.0%	2.6%
Gas	$5.36	19.7%	$4.02	18.8%	(0.9%)
INC	$5.69	20.9%	$3.25	15.2%	(5.7%)
Markup	$1.97	7.2%	$1.01	4.7%	(2.5%)
Variable Maintenance	$1.21	4.4%	$0.89	4.1%	(0.3%)
Variable Operations			$0.74	3.4%	3.4%
Up to Congestion Transaction	$0.69	2.5%	$0.64	3.0%	0.4%
CO_2	$0.14	0.5%	$0.28	1.3%	0.8%
DASR LOC Adder	($0.04)	(0.1%)	$0.08	0.4%	0.5%
Dispatchable Transaction	$0.31	1.1%	$0.05	0.2%	(0.9%)
Constrained Off	$0.00	0.0%	$0.03	0.2%	0.2%
Oil	$0.06	0.2%	$0.02	0.1%	(0.1%)
Price Sensitive Demand	$0.01	0.0%	$0.01	0.1%	0.0%
NO_x	$0.01	0.0%	$0.01	0.0%	(0.0%)
DASR Offer Adder	$0.01	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%)
Municipal Waste	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Ten Percent Cost Adder	$0.01	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.01)	(0.1%)	($0.00)	(0.0%)	0.0%
NA	$0.00	0.0%	$0.03	0.2%	0.2%
Total	$27.23	100.0%	$21.40	100.0%	0.0%

Scarcity

PJM's energy market experienced five minute shortage pricing for nine five minute intervals on six days in 2020. Table 3-68 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in 2019 and 2020. In 2020, there were no emergency actions that triggered a Performance Assessment Interval (PAI). The days with shortage pricing intervals did not correspond to the days with emergency alerts.

Table 3-68 Summary of emergency events declared: 2019 and 2020

	Number of days events declared	
Event Type	2019	2020
Cold Weather Alert	9	3
Hot Weather Alert	16	19
Maximum Emergency Generation Alert	2	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	1	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	17	6
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 from 2016 through 2020. Figure 3-50 shows the number of days emergency warnings were issued or actions taken in PJM from 2016 through 2020.

Figure 3-49 Declared emergency alerts: 2016 through 2020

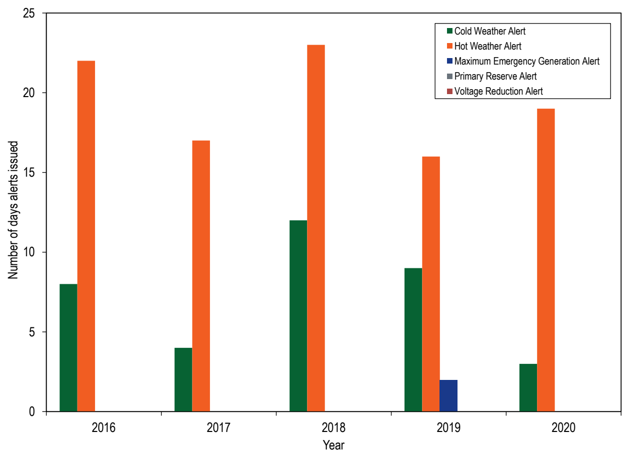
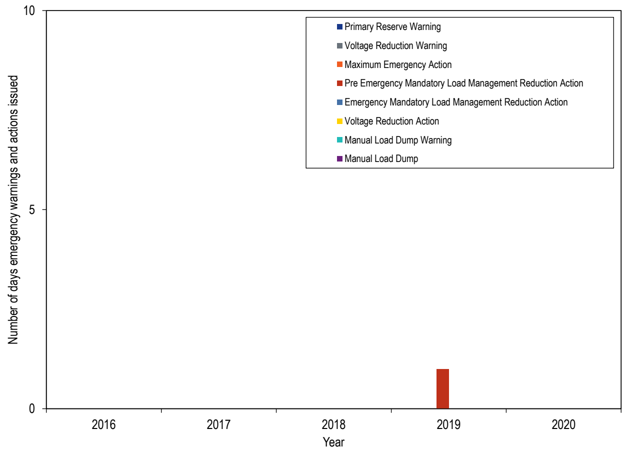


Figure 3-50 Declared emergency warnings and actions: 2016 through 2020[82]



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 3-69 provides a description of PJM declared emergency procedures.[83 84 85 86]

Table 3-69 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.

82 In prior reports, this graph incorrectly classified a local load shed directive in 2018 in the AEP zone for voltage control due to transmission outages as a Manual Load Dump.
83 See PJM. "Manual 13: Emergency Operations," Rev. 77 (Jan. 1, 2021), Section 3.3 Cold Weather Alert.
84 See PJM. "Manual 13: Emergency Operations," Rev. 77 (Jan. 1, 2021), Section 3.4 Hot Weather Alert.
85 See PJM. "Manual 13: Emergency Operations," Rev. 77 (Jan. 1, 2021), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.
86 See PJM. "Manual 13: Emergency Operations," Rev. 77 (Jan. 1, 2021), 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-70 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in 2020.

Table 3-70 Declared emergency alerts, warnings and actions: 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 Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Manual Load Dump Action	Load Shed Directive
1/19/2020	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.[87] 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. The average energy component of LMP in those 5 minute intervals with artificially increased supply to satisfy the power balance constraint was $351.56 per MWh in 2020.

Table 3-71 shows the number of five minute intervals for which the RT SCED solutions used to set prices did not balance demand and supply. PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In 2020, there were four 5 minute intervals using RT SCED solutions with a violated power balance constraint. The average energy component of LMP in those 5 minute intervals with artificially increased supply to satisfy the power balance constraint was $351.56 per MWh in 2020.[88]

Table 3-71 Number of five minute intervals using RT SCED solutions with violated power balance constraint by year

Year	Number of five minute intervals	Average Energy Component of LMP ($/MWh)
2013	-	
2014	655	$36.29
2015	71	($0.76)
2016	42	$93.06
2017	31	$279.86
2018	16	$268.21
2019	36	$845.48
2020	5	$351.56

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.[89] 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

87 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.

88 The energy component of LMP, or the shadow price of the power balance constraint, is the incremental cost of meeting a one MWh increase in the system load.

89 *2018 State of the Market Report for PJM: Volume 2*, Section 3: Energy Market, at Scarcity, pp. 201 – 202.

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.[90] 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 the exercise of aggregate market power by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage 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 2020, there were nine 5 minute intervals with shortage pricing that occurred on six days 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.[91] 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.[92]

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

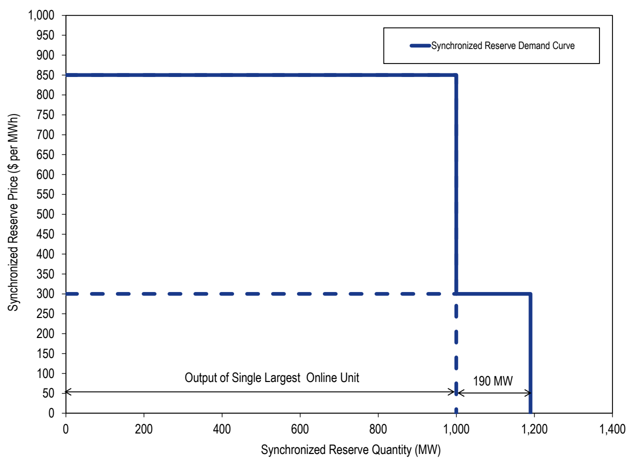
90 *See* PJM, "Capacity Market Seller Offer Cap Values," (March 15, 2019), *which can be accessed at* <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-cp-market-seller-offer-cap-values.ashx?la=en?>.

91 155 FERC ¶ 61,276 ("Order No. 825") at P 162.

92 *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).

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 $1,700 per MWh, which is the $850 per MWh price times two, for two reserve products (synchronized reserve and nonsynchronized reserve). The current market rules cap the additive reserve shortage penalty factors in MAD to the sum of the synchronized reserve penalty factor and the primary reserve penalty factor.[93]

Table 3-72 shows five example scenarios, under the current ORDC, 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, that results in the $1,700 per MWh scarcity adder in MAD and RTO. The $1,700 per MWh scarcity adder applies any time PJM initiates a manual load dump action or voltage reduction action.[94] 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 $1,700 per MWh scarcity adder, and a violated transmission constraint with a $2,000 per MWh penalty factor that results in a $3,750 per MWh LMP.[95]

In Scenario E, the energy component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in the $1,700 per MWh scarcity adder, and a violated transmission constraint with $2,000 per MWh penalty factor that results in a $5,700 per MWh LMP. The LMPs in Scenario E are not the highest possible LMPs in the PJM energy market under the current rules. If there are multiple violated transmission constraints, the transmission constraint penalty factor's contribution to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $5,700 per MWh. The extent to which each violated transmission penalty factor affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint.

93 *See* PJM Operating Agreement, Schedule 1, Section 3.2.3A(d)(ii). The cap on the additive reserve shortage penalty factors in MAD was not reflected in the prior report and the maximum in MAD was therefore overstated. See: *2020 Quarterly State of the Market Report for PJM: January through September*, p. 192.

94 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 112 (Jan. 5, 2021), 2.8 The Calculation of Locational Marginal Prices (LMPs) During Emergency Procedures.

95 The impact of the transmission constraint penalty factor at a pnode depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a single violated transmission constraint with dfax of 1.0. If there are multiple violated transmission constraints, the total impact at a pnode is the sum of the product of transmission constraint penalty factors and distribution factors.

Table 3-72 Additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

Scenario	Energy Component of LMP	Synchronized Reserve Penalty Factor RTO	Synchronized Reserve Penalty Factor MAD	Primary Reserve Penalty Factor RTO	Primary Reserve Penalty Factor MAD	Capped Reserve Shortage Penalty Factor	Transmission Constraint Penalty Factor	Total LMP in MAD	Total LMP outside MAD
A	$50	$850	$0	$0	$0	$850	$0	$900	$900
B	$50	$850	$850	$850	$850	$1,700	$0	$1,750	$1,750
C	$50	$850	$850	$850	$850	$1,700	$2,000	$3,750	$3,750
D	$1,000	$850	$850	$850	$850	$1,700	$2,000	$4,700	$4,700
E	$2,000	$850	$850	$850	$850	$1,700	$2,000	$5,700	$5,700

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 under most circumstances is only $1,000 per MWh. Only in the unusual circumstance when short run marginal costs exceed $1,000 per MWh is a higher ORDC price justified. When energy offers exceed $1,000 per MWh, they have to be verified and pre-approved by PJM and cannot exceed $2,000 per MWh, to be eligible to set LMP in the PJM energy market.

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 3-73 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 the 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. The $10,000 per MWh scarcity adder applies any time PJM initiates a manual load dump action or voltage reduction action. In scenario C, there is a reserve shortage for both primary and synchronized reserves in both the MAD and RTO Reserve Zones, a 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 results in a $12,050 per MWh LMP at a pnode in MAD.[96]

In Scenario E, the Energy Component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and a secondary reserve shortage, resulting in the $10,000 per MWh scarcity adder, and a violated transmission constraint with a $2,000 per MWh penalty factor that results in a $14,000 per MWh LMP at a pnode in MAD. The LMPs in Scenario E are not the highest possible LMPs in the PJM energy market under the ORDCs planned for implementation in 2022. If there are multiple violated transmission constraints, the transmission constraint penalty factors' contribution to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $14,000 per MWh. The extent to which each violated transmission penalty factor affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint.

96 The impact of the transmission constraint penalty factor at a pnode depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a single violated transmission constraint with dfax of 1.0. If there are multiple violated transmission constraints, the total impact at a pnode is sum of the product of transmission constraint penalty factors and distribution factors.

Table 3-73 Additive penalty factors under shortage conditions and transmission constraint violations

Scenario	Energy Component of LMP	Synchronized Reserve Penalty Factor RTO	Synchronized Reserve Penalty Factor MAD	Primary Reserve Penalty Factor RTO	Primary Reserve Penalty Factor MAD	Secondary Reserve Penalty Factor RTO	Transmission Constraint Penalty Factor	Total LMP in MAD	Total LMP outside MAD
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	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$14,000	$10,000

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 3-74 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 3-74 shows that, in 2020, PJM operators approved eight RT SCED solutions that indicated a shortage of reserves, from a total of 2,867 RT SCED solutions that indicated shortage. Among the eight approved RT SCED solutions with reserve shortage, seven were used in LPC for LMPs and reserve clearing prices. Among the seven RT SCED shortage solutions, two solutions were used in LPC for two consecutive five minute intervals in each instance, resulting in a total of nine five minute intervals with shortage prices in 2020. In 2019, PJM operators approved 47 solutions that indicated a shortage of reserves, from a total of 5,652 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 3-74 RT SCED cases with reserve shortage: 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%
Oct	32,429	481	2	2	1.5%	0.4%	0.4%
Nov	30,360	249	3	3	0.8%	1.2%	1.2%
Dec	31,859	229	1	1	0.7%	0.4%	0.4%
Total	429,864	2,867	8	7	0.7%	0.3%	0.2%

While there were 2,867 RT SCED solutions that indicated shortage, the number of RT SCED target times for which RT SCED indicated shortage was only 1,819. PJM solves multiple RT SCED cases with three solutions per case, for each five minute target time.[97 98]

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 3-75 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 3-75 shows that 1,819 target times, or 1.7 percent of all five minute target times in 2020, had at least one RT SCED solution showing a shortage of reserves, and 592 target times, or 0.6 percent of all five minute target times in 2020, had more than one RT SCED solution showing a shortage of reserves.

97 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.

98 PJM updated the RT SCED execution frequency to solve one case for each five minute target time beginning June 22, 2020.

Table 3-75 Five minute SCED target times and pricing intervals with shortage: 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 Oct	8,928	327	3.7%	91	1.0%	3	0.9%
2020 Nov	8,652	181	2.1%	44	0.5%	3	1.7%
2020 Dec	8,928	168	1.9%	41	0.5%	1	0.6%
2020 Total	105,408	1,819	1.7%	592	0.6%	9	0.5%

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 nine 5 minute intervals with shortage pricing that occurred in 2020, while there were 592 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. In 2019, out of 3,046 target times for which one or more RT SCED solutions indicated a shortage of reserves, there were 33 five minute intervals in LPC, or 1.1 percent, with shortage pricing. In 2020, out of 1,819 target times for which one or more RT SCED solutions indicated a shortage of reserves, there were nine five minute intervals in LPC, or 0.5 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 nine five minute intervals with shortage pricing in 2020, compared to 33 intervals in 2019, in PJM. Table 3-76 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 nine intervals with shortage pricing due to synchronized reserve shortage. Table 3-77 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD Reserve Subzone during the seven intervals with shortage pricing due to synchronized reserve shortage. Table 3-78 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO Reserve Zone during the one interval with shortage pricing due to primary reserve shortage. Table 3-79 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD Reserve Subzone during the one interval with shortage pricing due to primary reserve shortage.

PJM enforces an RTO wide reserve requirement and a supplemental reserve requirement for the MAD region. The MAD Reserve Subzone is nested within the RTO Reserve Zone. Resources located in the MAD Reserve Subzone can simultaneously satisfy the synchronized reserve requirement of the RTO Reserve Zone and the synchronized reserve requirement of the MAD Reserve Subzone. Resources located outside the MAD Reserve Subzone can satisfy the synchronized reserve requirement of the RTO Reserve Zone, and subject to transfer limits defined by transmission constraints, satisfy the reserve requirement of the MAD Subzone. The synchronized reserve clearing price of the RTO Reserve Zone is set by the shadow price of the binding reserve requirement constraint of the RTO Reserve Zone.[99] The synchronized reserve clearing price of the MAD Reserve Subzone, nested within the RTO Reserve Zone, is set by the sum of the shadow prices of the binding reserve requirement constraint of the RTO Reserve Zone and the shadow price of the binding reserve requirement constraint of the MAD Reserve Subzone.

In seven out of the nine intervals in 2020 with shortage pricing, both the RTO Zone and the MAD Subzone cleared with synchronized reserves less than their extended requirement. In four of the nine intervals, the synchronized reserves in the RTO Zone were short of the minimum reserve requirement, resulting in a $850 per MWh penalty factor. In five of the nine intervals, the synchronized reserves in the RTO zone were greater than or equal to the minimum reserve requirement but less than the 190 MW extended requirement. The clearing price for synchronized reserves in the RTO Zone is the sum of the shadow prices of the synchronized reserve constraint for the RTO Zone and the primary reserve constraint for the RTO Zone. The clearing price for synchronized reserves in the MAD Subzone is the sum of the shadow prices of the synchronized reserve constraints for the RTO Zone and MAD Subzone and the shadow prices of the primary reserve constraints in the RTO and MAD Subzone.

Table 3-76 RTO synchronized reserve shortage intervals: 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
12-Oct-20 00:35	1,537.3	1,273.6	263.7	$850.0
14-Oct-20 11:25	2,728.0	2,538.0	190.0	$874.4
14-Oct-20 11:30	2,728.0	2,538.0	190.0	$874.4
12-Nov-20 17:35	1,785.0	1,771.3	13.7	$300.0
13-Nov-20 17:55	1,783.0	1,727.6	55.4	$600.0
13-Nov-20 18:00	1,782.0	1,246.7	535.3	$1,700.0
16-Dec-20 11:45	1,860.0	1,735.5	124.5	$300.0

Table 3-77 MAD synchronized reserve shortage intervals: 2020

Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	MAD Synchronized Reserve Clearing Price ($/MWh)
12-Oct-20 00:35	1,537.3	1,273.6	263.7	$1,700.0
14-Oct-20 11:25	2,728.0	2,538.0	190.0	$1,662.2
14-Oct-20 11:30	2,728.0	2,538.0	190.0	$1,662.2
12-Nov-20 17:35	1,785.0	1,771.3	13.7	$600.0
13-Nov-20 17:55	1,783.0	1,727.6	55.4	$900.0
13-Nov-20 18:00	1,782.0	1,246.7	535.3	$1,700.0
16-Dec-20 11:45	1,860.0	1,735.5	124.5	$600.0

99 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set by the applicable operating reserve demand curve.

Table 3-78 RTO primary reserve shortage intervals: 2020

Interval (EPT)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	RTO Primary Reserve Clearing Price ($/MWh)
13-Nov-20 18:00	2,578.0	2,104.6	473.4	$850.0

Table 3-79 MAD primary reserve shortage intervals: 2020

Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	MAD Primary Reserve Clearing Price ($/MWh)
13-Nov-20 18:00	2,578.0	2,104.6	473.4	$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.[100] 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).[101] [102] 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.

Competitive Assessment

Market Structure

Market Concentration

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.

The HHI may not accurately capture market power issues in situations where, for example, there is moderate

100 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

101 *See* "PJM Manual 12: Balancing Operations," Rev. 41 (Nov. 19, 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.

102 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).

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 are an indicator of the ownership of incremental resources. But an aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power.

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.[103]

Analysis of supply curve segments of the PJM energy market in 2020 indicates low concentration in the base load segment, moderate concentration in the intermediate segment, and high concentration in the peaking segment.[104] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate a highly concentrated market structure. Given the low responsiveness of consumers to prices (inelastic demand), it is possible to have high markup even when HHI is low. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

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 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.

PJM HHI Results

Hourly HHIs indicate that by FERC standards, the PJM energy market during 2020 was unconcentrated on average, although there were 233 hours, or 2.7 percent of the hours in 2020 with HHI in the moderately concentrated range (Table 3-80).[105]

Table 3-80 Hourly energy market HHI: 2019 and 2020

By offering supplier	Hourly Market HHI (2019)	Hourly Market HHI (2020)
Average	781	790
Minimum	577	569
Maximum	1153	1166
Highest market share (One hour)	28%	28%
Average of the highest hourly market share	20%	20%
# Hours	8,760	8,784
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-81 includes HHI values by supply curve segment, including base, intermediate and peaking plants for 2019 and 2020. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking segment was highly concentrated.

Table 3-81 Generation segment HHI: 2019 and 2020

By offering	2019			2020		
supplier	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	659	818	1188	667	834	1203
Intermediate	701	1822	9105	743	1551	6815
Peak	716	5942	10000	651	5757	10000

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

104 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.

105 The HHI calculations use actual real time settled generation data for each unit in PJM. Each unit's output is assigned to the supplier that is responsible for offering the unit in the energy market. Prior to this report, each unit's generation was assigned to the supplier that was paid for the unit's output. For units that are jointly owned, the output was assigned to multiple suppliers using each supplier's share of the unit's output. The result of the new method is a slight increase in calculated HHIs.

Figure 3-52 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in 2020.[106]

Figure 3-52 Fuel source distribution in unit segments: 2020[107]

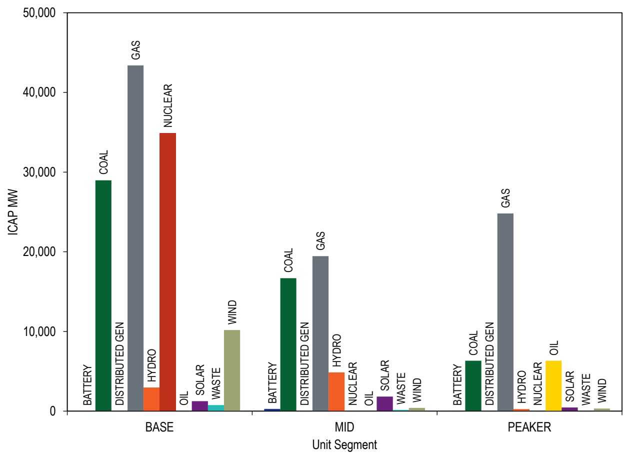


Figure 3-53 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking from 2016 through 2020. Figure 3-53 shows that the total ICAP of coal fired units in PJM that are classified as baseload has been steadily decreasing and the total ICAP of gas fired units in PJM that are classified as baseload has been steadily increasing, based on operating history for the period from 2016 through 2020. In 2019, the ICAP of gas fired units classified as baseload exceeded the ICAP of coal fired units classified as baseload for the first time.

Figure 3-53 Unit segment classification by fuel: 2016 through 2020

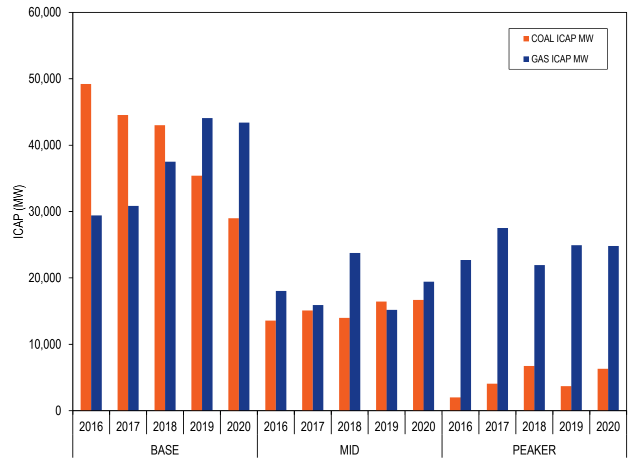
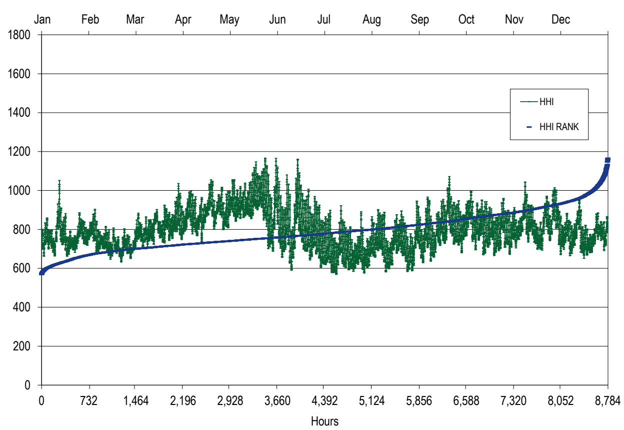


Figure 3-54 presents the hourly HHI values in chronological order and an HHI duration curve for 2020.

Figure 3-54 Hourly energy market HHI: 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,

106 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.

107 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>.

FERC relies on a rebuttable presumption that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.[108]

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).[109] 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.[110]

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."[111]

FERC applies tests set forth in the 1996 Merger Policy Statement.[112] [113]

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 evaluates a Competitive Analysis Screen.[114]

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.[115] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[116] FERC has considered the MMU's analysis in reviewing mergers.[117]

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 3-82 shows transactions that involved an entire generation unit or unit owner that were completed in 2020, as reported to the Commission. Table 3-83 shows transactions that involved transfers of partial unit ownership that were completed in 2020, as reported to the Commission.[118]

108 *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).

109 *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>.

110 *See* for example, "Protest of the Independent Market Monitor for PJM," Docket No. ER10-1556 (August 28, 2020).

111 18 U.S.C. § 824b.

112 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).

113 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.

114 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)

115 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).

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

117 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).

118 The transaction completion date is based on the notices of consummation submitted to the Commission.

Table 3-82 Completed transfers of entire resources: 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
Panda Hummel Station	Panda Power Funds	LS Power Development LLC	October 15, 2020	EC20-55
Tilton Energy	The Carlyle Group	Rockland Capital	November 17, 2020	EC20-100

Table 3-83 Completed transfers of partial ownership of resources: 2020

Generator or Geneation 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.[119] 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.[120] The MMU is developing an aggregate market power test for the day-ahead and real-time energy markets based on pivotal suppliers and will propose appropriate market power mitigation rules to address aggregate market power.

Day-Ahead Energy Market Aggregate Pivotal Suppliers

To assess the number of pivotal suppliers in the day-ahead energy market, the MMU determined, for each supplier, the MW available for economic commitment that were already running or were available to start between the close of the day-ahead energy market and the peak load hour of the operating day. The available supply is defined as MW offered at a price less than 150 percent of the applicable LMP because supply available at higher prices is not competing to meet the demand for energy.[121] Generating units, import transactions, economic demand response,

119 See 138 FERC ¶ 61,167 at P 19.

120 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).

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

and INCs, are included for each supplier. Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and DECs. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

Figure 3-55 shows the number of days in 2019 and 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 128 days in 2020. Three suppliers were jointly pivotal on 228 days in 2019 and on 301 days in 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 2020 compared to 2019.

Figure 3-55 Days with pivotal suppliers and numbers of pivotal suppliers in the day-ahead energy market by quarter

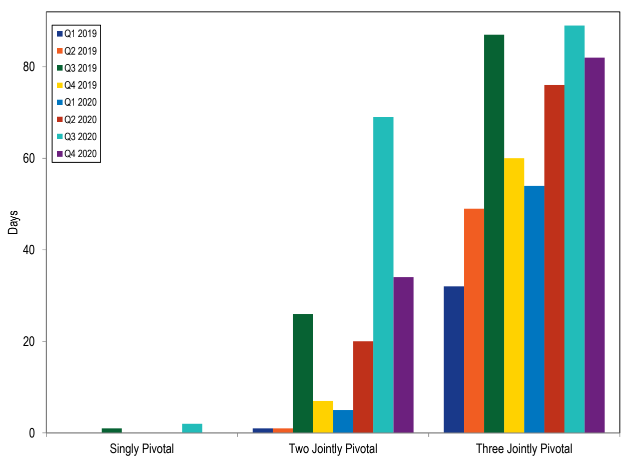


Table 3-84 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in 2020. The largest pivotal supplier was singly pivotal on two days in 2020. All of the top 10 suppliers were one of two pivotal suppliers on at least 14 days in 2020. All of the top 10 suppliers were one of three pivotal suppliers on at least 158 days in 2020.

Table 3-84 Day-ahead market pivotal supplier frequency: 2020

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	2	0.5%	121	33.1%	300	82.0%
2	0	0.0%	119	32.5%	300	82.0%
3	0	0.0%	113	30.9%	296	80.9%
4	0	0.0%	72	19.7%	271	74.0%
5	0	0.0%	61	16.7%	238	65.0%
6	0	0.0%	26	7.1%	212	57.9%
7	0	0.0%	25	6.8%	202	55.2%
8	0	0.0%	16	4.4%	164	44.8%
9	0	0.0%	15	4.1%	205	56.0%
10	0	0.0%	14	3.8%	158	43.2%

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.[122] 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-

122 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

based energy offers, defined by fuel cost policies, and have the option to submit market-based or price-based offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

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 2020, the 500 kV system, 10 zones, and MISO experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint (Table 3-85).[123] Table 3-85 shows that the 500 kV system, three zones and MISO experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from a binding interface constraint in every year from 2009 through 2020. Four Control Zones did not experience congestion resulting from one or more constraints binding for 100 or more hours or resulting from any binding interface constraint in any year from 2009 through 2020.

Table 3-85 Congestion hours resulting from one or more constraints binding for 100 or more hours or from an interface constraint: 2009 through 2020

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
500 kV System	4,468	6,789	6,109	1,468	3,002	1,596	777	1,487	994	1,120	4,186	2,577
AECO	149	172	234	0	208	0	394	439	0	500	108	0
AEP	1,045	1,636	2,510	0	2,611	2,710	1,274	796	469	1,878	808	1,361
APS	509	1,714	0	206	0	170	167	0	265	246	191	417
ATSI	157	0	0	208	270	489	242	141	1,113	2,856	1,405	306
BGE	152	470	1,041	2,970	1,760	6,255	9,601	11,434	2,178	3,135	812	9,491
ComEd	1,212	2,080	1,134	4,554	5,143	4,119	5,878	7,336	2,257	1,148	457	1,074
DAY	0	0	0	0	0	0	0	0	0	0	0	0
DEOK	0	0	0	109	0	0	112	0	0	0	0	0
DLCO	156	475	206	209	0	223	617	0	0	0	0	0
Dominion	468	905	1,179	1,020	664	0	1,172	459	436	136	196	891
DPL	0	122	0	1,542	639	3,071	2,066	2,719	673	1,117	0	106
EKPC	0	0	0	0	0	0	0	0	0	400	0	0
EXT	0	0	0	0	0	0	0	0	788	0	0	0
JCPL	0	0	0	0	0	0	0	0	0	0	0	0
Met-Ed	0	180	162	0	0	0	222	0	116	1,559	922	1,041
MISO	6,042	5,287	15,637	27,694	18,215	11,460	11,109	11,712	6,297	8,635	9,249	5,673
NYISO	0	0	0	0	167	143	834	2,130	332	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0	0	0
PECO	247	0	788	386	732	1,953	895	692	1,013	304	0	0
PENELEC	103	284	0	0	176	4,281	1,683	451	3,074	1,648	2,065	2,999
Pepco	149	1	0	143	245	41	0	0	0	0	0	0
PPL	176	118	40	350	452	148	266	936	2,044	436	1,124	891
PSEG	303	549	1,107	913	3,021	4,688	2,665	810	239	226	0	0
RECO	0	0	0	0	0	0	0	0	0	0	0	0

123 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, JCPK, 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.

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 2020.[124] While the real-time constraint hours include constraints that were binding in the five minute real-time pricing solution (LPC), IT SCED may contain different binding constraints because IT SCED looks ahead to 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 3-86 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 3-87 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 3-86 and Table 3-87 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 3-86 Three pivotal supplier test details for interface constraints: 2020

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	93	100	5	1	5
	Off Peak	108	100	6	0	6
AP South	Peak	370	688	19	7	11
	Off Peak	199	609	17	13	4
CPL - DOM	Peak	100	266	6	0	6
	Off Peak	85	197	6	0	5
PA Central	Peak	41	350	4	1	4
	Off Peak	64	351	4	0	4

Table 3-87 Three pivotal supplier test details for top 10 congested constraints: 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	83	145	13	5	8
	Off Peak	66	129	12	5	7
Lenox - North Meshoppen	Peak	12	35	2	0	2
	Off Peak	6	32	2	0	2
PA Central	Peak	41	350	4	1	4
	Off Peak	64	351	4	0	4
Sub 85 - Sub 18	Peak	24	11	2	0	2
	Off Peak	22	11	2	0	2
Graceton - Safe Harbor	Peak	82	136	13	6	7
	Off Peak	52	106	11	5	6
Three Mile Island	Peak	82	97	10	2	8
	Off Peak	92	130	11	3	8
East Towanda - Hillside	Peak	23	55	2	0	2
	Off Peak	11	57	2	0	2
Paradise - BR Tap	Peak	30	4	2	0	2
	Off Peak	31	4	2	0	2
East Moline	Peak	50	37	3	0	3
	Off Peak	46	29	3	0	3
Logtown - North Delphos	Peak	24	47	1	0	1
	Off Peak	28	36	1	0	1

124 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>.

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.[125] Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning November 1, 2017, with the introduction of hourly offers and intraday offer updates, certain online units whose commitment is extended beyond the day-ahead or real-time commitment, whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer.

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 3-88 shows that 0.5 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-88 shows that 7.1 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 3-88 Day-ahead committed units that cleared real-time: 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
2020	11,847	2,580,561	184,592	0.5%	7.1%

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 3-89 and Table 3-90 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.

125 If a steam unit were to lower its cost-based offer in real time, it would become eligible for offer capping based on the online TPS test.

Table 3-89 Summary of three pivotal supplier tests applied for interface constraints: 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
AEP - DOM	Peak	143	138	97%	9	6%	7%
	Off Peak	77	77	100%	0	0%	0%
AP South	Peak	81	69	85%	0	0%	0%
	Off Peak	32	32	100%	5	16%	16%
CPL - DOM	Peak	2,185	2,151	98%	2	0%	0%
	Off Peak	1,008	1,007	NA	1	NA	NA
PA Central	Peak	14,986	10,255	68%	2	0%	0%
	Off Peak	15,431	10,590	69%	4	0%	0%

Table 3-90 Summary of three pivotal supplier tests applied for top 10 congested constraints: 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	41,335	40,677	98%	314	1%	1%
	Off Peak	29,216	28,920	99%	151	1%	1%
Lenox - North Meshoppen	Peak	20,740	15,118	73%	2	0%	0%
	Off Peak	12,637	5,071	40%	0	0%	0%
PA Central	Peak	14,986	10,255	68%	2	0%	0%
	Off Peak	15,431	10,590	69%	4	0%	0%
Sub 85 - Sub 18	Peak	6,149	1,158	19%	0	0%	0%
	Off Peak	12,403	1,383	11%	0	0%	0%
Graceton - Safe Harbor	Peak	8,550	8,431	99%	40	0%	0%
	Off Peak	12,455	12,374	99%	77	1%	1%
Three Mile Island	Peak	14,719	14,031	95%	43	0%	0%
	Off Peak	4,853	4,674	96%	33	1%	1%
East Towanda - Hillside	Peak	6,022	4,371	73%	1	0%	0%
	Off Peak	3,314	1,569	47%	0	0%	0%
Paradise - BR Tap	Peak	4,721	1,712	36%	2	0%	0%
	Off Peak	2,613	1,080	41%	0	0%	0%
East Moline	Peak	3,982	889	22%	0	0%	0%
	Off Peak	4,165	744	18%	0	0%	0%
Logtown - North Delphos	Peak	6,641	99	1%	0	0%	0%
	Off Peak	5,250	65	1%	0	0%	0%

Offer Capping for Local Market Power

In the PJM energy market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the day-ahead and real-time energy markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market.

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.[126]

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

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 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

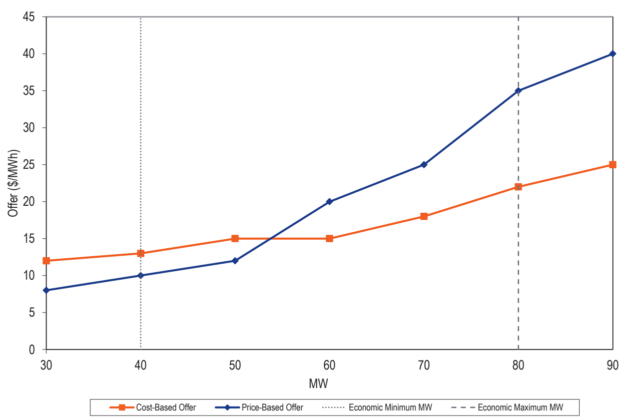


Table 3-91 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves in the PJM Day-Ahead and Real-Time Energy Markets, in 2020. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, and they may elect to offer price-based offers, but are not required to do so.

Table 3-91 Units offered with crossing curves in the day-ahead and real-time energy markets: 2020

	Day-Ahead			Real-Time		
2020	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%
Oct	106,687	845,496	12.6%	84,722	679,234	12.5%
Nov	92,129	818,139	11.3%	68,596	655,287	10.5%
Dec	89,793	839,400	10.7%	83,011	755,092	11.0%
Total	1,229,290	9,975,109	12.3%	1,104,128	8,908,166	12.4%

126 See PJM Operating Agreement Schedule 1 § 6.4.1(g).

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 3-92 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 3-92 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: 2020

	Day-Ahead			Real-Time		
2020	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%
Oct	32,664	845,496	3.9%	24,214	679,234	3.6%
Nov	32,012	818,139	3.9%	23,521	655,287	3.6%
Dec	35,919	839,400	4.3%	27,396	755,092	3.6%
Total	361,634	9,975,109	3.6%	289,120	8,908,166	3.2%

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

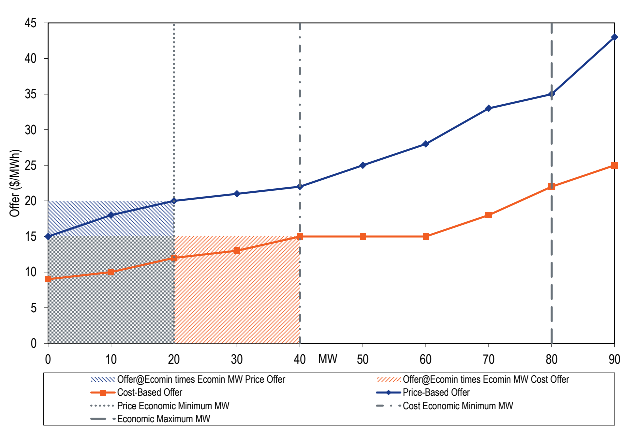


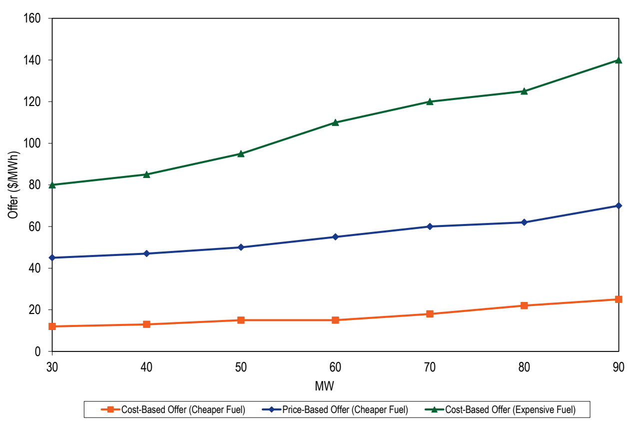
Table 3-93 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-93 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: 2020

	Day-Ahead			Real-Time		
2020	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%
Oct	120	845,496	0.0%	279	679,234	0.0%
Nov	265	818,139	0.0%	280	655,287	0.0%
Dec	907	839,400	0.1%	816	755,092	0.1%
Total	2,706	9,975,109	0.0%	2,714	8,908,166	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.[127] 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 3-95. 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

127 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.

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.[128] 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 3-94 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.[129] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real-time energy market for providing constraint relief, can be offer capped and dispatched on their cost-based offer subsequent to a real-time hourly offer update. This is reflected in the slightly higher rate of offer capping in the real-time energy market in since 2017.

Table 3-94 Offer capping statistics – energy only: 2016 to 2020

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2016	0.4%	0.2%	0.0%	0.0%
2017	0.3%	0.2%	0.0%	0.0%
2018	0.9%	0.5%	0.1%	0.1%
2019	1.7%	1.3%	1.3%	0.9%
2020	1.0%	1.1%	1.6%	1.3%

Table 3-95 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 3-94. 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 3-96.

Table 3-95 Offer capping statistics for energy and reliability: 2016 to 2020

	Real-Time		Day-Ahead	
Year	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%	0.2%
2018	1.0%	0.8%	0.2%	0.3%
2019	1.7%	1.3%	1.3%	0.9%
2020	1.0%	1.1%	1.6%	1.3%

Table 3-96 shows the offer capping percentages for units committed for reliability reasons, including units committed for reactive support. The low offer cap percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's rule results in the use of the price-based offer for commitment. However, the price-based offers have inflexible parameters such as longer minimum run times that may lead to higher total commitment cost if the unit was only needed for a shorter period that is less than its inflexible minimum run time.

Table 3-96 Offer capping statistics for reliability: 2016 to 2020

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2016	0.1%	0.1%	0.1%	0.1%
2017	0.1%	0.2%	0.1%	0.2%
2018	0.1%	0.3%	0.1%	0.2%
2019	0.0%	0.0%	0.0%	0.0%
2020	0.0%	0.0%	0.0%	0.0%

128 See OATT Attachment K Appendix § 6.4.1.

129 Prior to the *2018 Quarterly State of the Market Report for PJM: January through June*, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

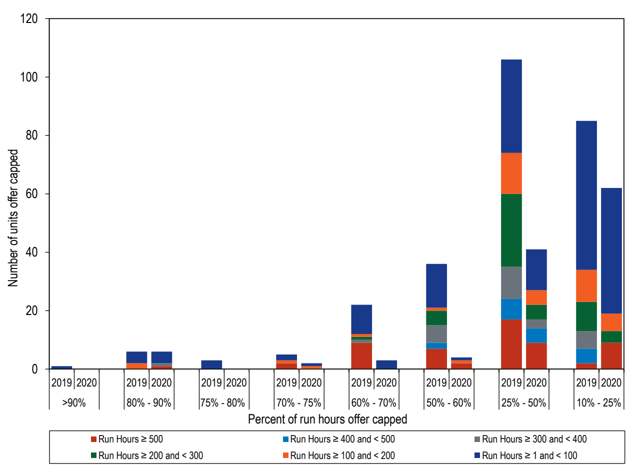
Table 3-97 presents data on the frequency with which units were offer capped in 2019 and 2020 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons. Table 3-97 shows that no units were offer capped for 90 percent or more of their run hours in 2020 compared to one unit in 2019.

Table 3-97 Real-time offer capped unit statistics: 2019 and 2020

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Year	Offer-Capped Hours: Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2019	0	0	0	0	0	1
	2020	0	0	0	0	0	0
80% and < 90%	2019	0	0	0	0	2	4
	2020	1	0	1	0	0	4
75% and < 80%	2019	0	0	0	0	0	3
	2020	0	0	0	0	0	0
70% and < 75%	2019	2	0	0	0	1	2
	2020	0	0	0	0	1	1
60% and < 70%	2019	9	0	1	1	1	10
	2020	0	0	0	0	0	3
50% and < 60%	2019	7	2	6	5	1	15
	2020	2	0	0	0	1	1
25% and < 50%	2019	17	7	11	25	14	32
	2020	9	5	3	5	5	14
10% and < 25%	2019	2	5	6	10	11	51
	2020	9	0	0	4	6	43

Figure 3-59 shows the frequency with which units were offer capped in 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: 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 (Price – Cost)/Price.[130] The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is higher than the cost-based offer price. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup Index

Table 3-98 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-99 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.[131] 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

130 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

131 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.

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-based offers. Actual market behavior reflects the fact that neither is part of a competitive offer and neither is a short run marginal cost.[132]

In 2020, 98.2 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 (-$1.26 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was positive ($0.15 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 2020, less than one percent had offer prices above $400 per MWh. Among the units that were marginal in 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 2020 was more than $450, and the highest markup in 2019 was more than $450.

Table 3-98 Average, real-time marginal unit markup index (By offer price category unadjusted): 2019 and 2020

	2019			2020		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.04	($1.69)	5.9%	(0.06)	($1.26)	15.0%
$10 to $15	0.02	$0.11	14.8%	0.03	$0.15	36.4%
$15 to $20	0.07	$0.94	31.7%	(0.01)	($0.46)	30.1%
$20 to $25	0.01	($0.04)	28.9%	0.02	($0.14)	11.7%
$25 to $50	0.07	$1.77	16.7%	0.09	$2.51	5.1%
$50 to $75	0.35	$19.10	0.9%	0.52	$30.46	0.4%
$75 to $100	0.55	$47.85	0.3%	0.53	$45.89	0.1%
$100 to $125	0.34	$37.04	0.2%	0.11	$12.95	0.5%
$125 to $150	0.45	$61.45	0.0%	0.02	$2.21	0.4%
$150 to $400	0.08	$15.35	0.4%	0.15	$25.29	0.3%
>= $400	0.02	$8.26	0.1%	0.96	>$400.00	0.0%

Table 3-99 Average, real-time marginal unit markup index (By offer price category adjusted): 2019 and 2020

	2019			2020		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.08	($1.37)	5.9%	0.00	($0.65)	15.0%
$10 to $15	0.10	$1.33	14.8%	0.11	$1.30	36.4%
$15 to $20	0.15	$2.46	31.7%	0.08	$1.15	30.1%
$20 to $25	0.10	$1.98	28.9%	0.10	$1.87	11.7%
$25 to $50	0.15	$4.32	16.7%	0.17	$5.02	5.1%
$50 to $75	0.40	$22.62	0.9%	0.56	$32.99	0.4%
$75 to $100	0.60	$51.21	0.3%	0.58	$49.64	0.1%
$100 to $125	0.41	$43.48	0.2%	0.20	$22.09	0.5%
$125 to $150	0.50	$68.18	0.0%	0.11	$14.37	0.4%
$150 to $400	0.17	$31.28	0.4%	0.23	$37.58	0.3%
>= $400	0.11	$47.71	0.1%	0.96	>$400.00	0.0%

132 See PJM. "Manual 15: Cost Development Guidelines," Rev. 37 (Dec. 9, 2020).

Table 3-100 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.[133] Table 3-101 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 2020, using unadjusted cost-based offers for coal units, 58.4 percent of marginal coal units had negative markups. In 2020, using adjusted cost-based offers for coal units, 34.8 percent of marginal coal units had negative markups.

Table 3-100 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): 2019 and 2020

	2019			2020		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	50.88%	26.41%	22.70%	58.40%	21.72%	19.88%
Gas	31.13%	12.52%	56.35%	38.51%	6.07%	55.42%
Oil	21.12%	77.66%	1.22%	3.99%	95.55%	0.46%

Table 3-101 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): 2019 and 2020

	2019			2020		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	35.09%	21.73%	43.17%	34.75%	17.85%	47.40%
Gas	12.76%	7.09%	80.15%	24.66%	4.48%	70.86%
Oil	0.32%	77.09%	22.58%	2.13%	73.80%	24.07%

Figure 3-60 shows the frequency distribution of hourly markups for all gas units offered in 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.[134] Of the gas units offered in the PJM market in 2020, 21.8 percent of gas unit-hours had a maximum markup that was negative. More than 10.3 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: 2019 and 2020

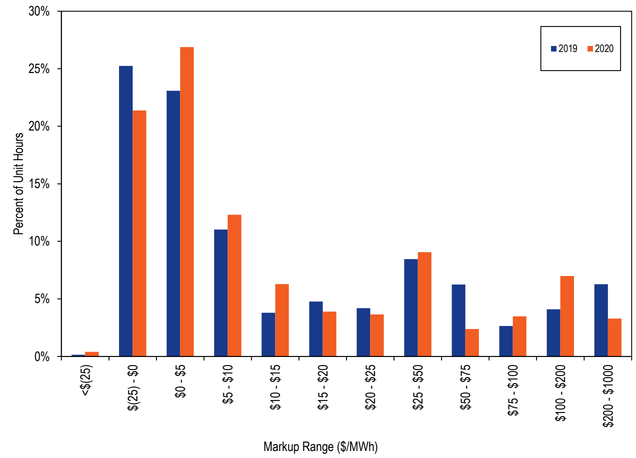


Figure 3-61 shows the frequency distribution of hourly markups for all coal units offered in 2019 and 2020 using unadjusted cost-based offers. Of the coal units offered in the PJM market in 2020, 47.7 percent of coal unit-hours had a maximum markup that was negative or equal to zero, increasing from 44.3 in 2019.

Figure 3-61 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: 2019 and 2020

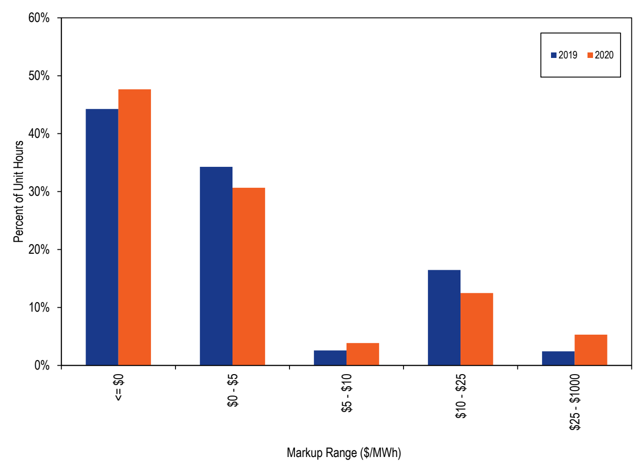
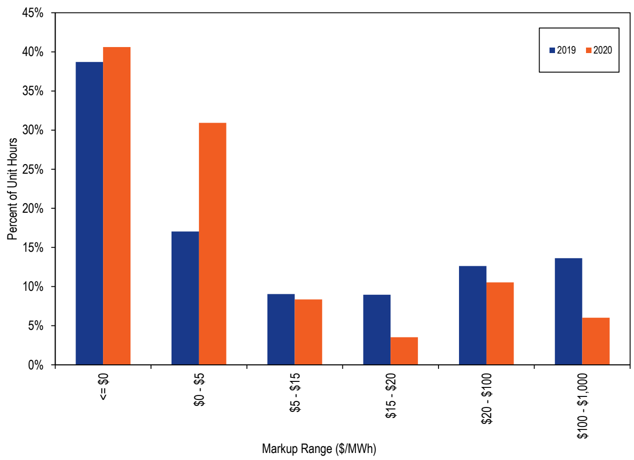


Figure 3-62 shows the frequency distribution of hourly markups for all offered oil units in 2019 and 2020 using unadjusted cost-based offers. Of the oil units offered in the PJM market in 2020, 40.6 percent of oil unit-hours had a maximum markup that was negative or equal to zero. More than 6.0 percent of oil fired unit-hours had

133 Other fuel types were excluded based on data confidentiality rules.
134 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

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: 2019 and 2020

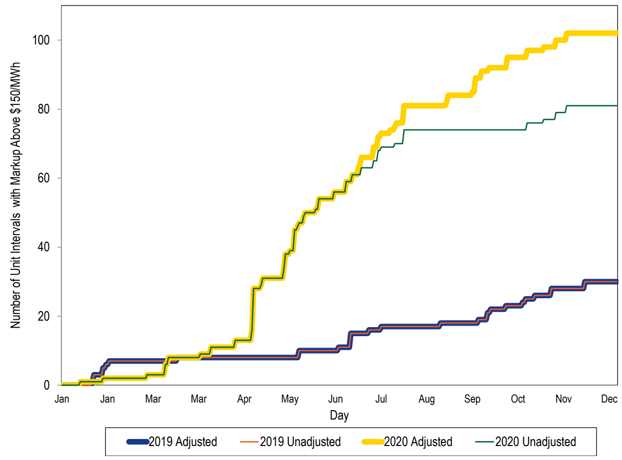


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 2020 and 2019 with markup above $150 per MWh. For several of the marginal unit intervals with markups above $150 per MWh, the units failed the TPS test for the hour. These exercise of market power are a result of PJM's failure to address the issues with the offer capping process identified by the MMU. If PJM adopted the MMU's recommendations, these exercises of market power would not occur.

Figure 3-63 Cumulative number of unit intervals with markups above $150 per MWh: 2019 and 2020



Day-Ahead Markup Index

Table 3-102 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 2020, 92.9 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 (-$1.88 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was positive ($0.75 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 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 2020 was more than $70 per MWh while the highest markup in 2019 was more than $90 per MWh.

Table 3-102 Average day-ahead marginal unit markup index (By offer price category, unadjusted): 2019 and 2020

	2019			2020		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.25	$0.15	2.9%	(0.05)	($1.88)	10.2%
$10 to $15	0.04	$0.38	9.2%	0.08	$0.75	30.5%
$15 to $20	0.13	$1.90	32.0%	0.08	$0.95	37.4%
$20 to $25	0.02	$0.09	32.8%	0.02	($0.04)	14.7%
$25 to $50	0.07	$1.83	21.8%	0.04	$0.98	6.3%
$50 to $75	0.19	$10.50	0.7%	0.18	$10.55	0.2%
$75 to $100	0.47	$41.28	0.1%	0.30	$24.65	0.0%
$100 to $125	0.52	$53.65	0.0%	(0.01)	($0.78)	0.1%
$125 to $150	0.32	$45.31	0.1%	0.00	$0.33	0.2%
>= $150	0.04	$5.94	0.5%	0.00	$0.69	0.3%

Table 3-103 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 2020, 37.4 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 0.30 in 2019, to 0.01 in 2020 in the offer price category less than $10.

Table 3-103 Average day-ahead marginal unit markup index (By offer price category, adjusted): 2019 and 2020

	2019			2020		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.30	$0.44	2.9%	0.01	($1.37)	10.2%
$10 to $15	0.12	$1.54	9.2%	0.15	$1.85	30.5%
$15 to $20	0.20	$3.33	32.0%	0.15	$2.43	37.4%
$20 to $25	0.10	$2.10	32.8%	0.10	$1.96	14.7%
$25 to $50	0.15	$4.36	21.8%	0.12	$3.64	6.3%
$50 to $75	0.26	$14.66	0.7%	0.25	$14.98	0.2%
$75 to $100	0.51	$45.55	0.1%	0.30	$25.30	0.0%
$100 to $125	0.56	$58.19	0.0%	0.01	$0.64	0.1%
$125 to $150	0.38	$53.81	0.1%	0.02	$2.61	0.2%
>= $150	0.12	$28.39	0.5%	0.08	$12.98	0.3%

No Load and Start Cost Markup

Generator energy offers in PJM are comprised of three parts, an incremental energy offer curve, no load cost and start cost. In cost-based offers, all three parts are capped at the level allowed by Schedule 2 of the Operating Agreement, the Cost Development Guidelines (Manual 15) and fuel cost policies approved by PJM. In price-based offers, the incremental energy offer curve is capped at $1,000 per MWh (unless the verified cost-based offer exceeds $1,000 per MWh, but cannot exceed $2,000 per MWh). Generators are allowed to choose whether to use price-based or cost-based no load cost and start costs twice a year. If price-based is selected, the no load and start costs do not have a cap, but the offers cannot be changed for six months (April through September and October through March). If cost-based is selected, the cap is the same as the cap of the no load and start costs in the cost-based offers, and the offers can be updated daily or hourly. Table 3-104 shows the caps on the three parts of cost-based and price-based offers.

Table 3-104 Cost-based and price-based offer caps

<table>
<tr><th>Offer Type</th><th>No Load and Start Cost Option</th><th>Incremental Offer Curve Cap</th><th>No Load Cost Cap</th><th>Start Cost Cap</th></tr>
<tr><td>Cost-Based</td><td>Cost-Based</td><td colspan="3">Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td></tr>
<tr><td rowspan="2">Price-Based</td><td>Cost-Based</td><td rowspan="2">$1,000/MWh or based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies if verified cost-based offer exceeds $1,000/MWh but no more than $2,000/MWh.</td><td>Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td><td>Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td></tr>
<tr><td>Price-Based</td><td>No cap but can only be changed twice a year.</td><td>No cap but can only be changed twice a year.</td></tr>
</table>

Table 3-105 shows the number of units that chose the cost-based option and the price-based option. In 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, seven percentage points higher than in 2019.

Table 3-105 Number of units selecting cost-based and price-based no load and start costs: 2019 and 2020

	2019		2020	
No Load and Start Cost Option	Number of units	Percent	Number of units	Percent
Cost-Based	498	84%	534	91%
Price-Based	94	16%	51	9%
Total	592	100%	585	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 3-106 shows the average markup in the no load and start costs in 2019 and 2020. Generators that selected the cost-based start and no load option offered on average with a negative markup on the no load cost (nine percent) and a negative markup on the start costs (six percent). The price-based offers were actually lower than the cost-based offers. Generators that selected the price-based start and no load option offered on average with a negative markup on the no load cost (two percent) but with very large positive markups on the start costs (683 percent).

Table 3-106 No load and start cost markup

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2019	Cost-Based	(9%)	(8%)	(7%)	(6%)
	Price-Based	(21%)	311%	358%	367%
2020	Cost-Based	(9%)	(6%)	(6%)	(6%)
	Price-Based	(2%)	568%	710%	772%

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 2020, 7.1 percent of the marginal units set prices based on cost-based offers, 3.2 percentage points less than in 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, a variable cost, is that the cost is "directly related to electric production."[135]

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.[136]

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 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.

135 See 167 FERC ¶ 61,030 (2019).
136 See OA Schedule 2(a).

Fuel Cost Policy Review

Table 3-107 shows the status of all fuel cost policies (FCP) as of December 31, 2020. As of December 31, 2020, 773 units (86 percent) had an FCP passed by the MMU, zero units had an FCP under MMU review (submitted) and 121 units (14 percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 23,386 MW. All units' FCPs were approved by PJM. The number of units with fuel cost policies passed by the MMU decreased by 433 in 2020 because solar and other units with zero short run marginal costs were not required to have fuel cost policies effective September 1, 2020.

Table 3-107 FCP Status for PJM generating units: December 31, 2020

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	0	0	0	0
Customer Input Required	0	0	0	0
Approved	773	0	121	894
Total	773	0	121	894

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.[137] Verifiable means that the FCP requires a market seller to provide a fuel price that can be calculated by the MMU after the fact with the same data available to the market seller at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the FCP must document a clearly defined quantitative method or methods for calculating fuel costs, including objective triggers for each method.[138] PJM and FERC did not agree that fuel cost policies should be algorithmic, although PJM's effectively requires algorithmic fuel cost policies by describing the requirements.[139] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs.

137 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) ("October 7th Filing") at P 11.
138 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) ("September 16th Filing") at P 8.
139 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).

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').[140]

FCPs are not verifiable and systematic if they are not algorithmic. The natural gas FCPs failed by the MMU and approved by PJM are not verifiable and systematic.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some fuel cost policies did not meet are:[141] 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 dollars per MWh or in dollars per MMBtu) that do not reflect the actual cost of fuel. The MMU determined that the terms used in these policies do not reflect the cost of fuel based on the information provided by the market sellers and information gathered by the MMU for similar units.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were the use of unverifiable fuel costs and the use of available market information that results in inaccurate expected costs.

Some of the failed fuel cost polices include unverifiable cost estimates. Some policies include options under which the estimate of the natural gas commodity cost can be calculated by the market seller without specifying a verifiable, systematic method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the market seller's organization. A fuel cost from discretionary and undocumented decision making within the market seller's organization is not verifiable. The point of FCPs is to eliminate such practices as the basis for fuel costs, as most companies have done. Verifiability requires that fuel cost estimates be transparently derived from market information and that PJM or the MMU could reproduce the same fuel cost estimates after the fact by applying the methods documented in the FCP to the same inputs. Verifiable is a key requirement of an FCP. If it is not verifiable, an FCP is meaningless and has no value. Unverifiable fuel costs permit the exercise of market power.

Some of the failed fuel cost polices include the use of available market information that results in inaccurate expected costs because the information does not represent a cleared market price. Some market sellers include the use of offers to sell natural gas on ICE as the sole basis for the cost of natural gas. An offer to sell is generally not a market clearing price and is not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions, often by a wide margin. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved noncompliant fuel cost policies. The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

Cost-Based Offer Penalties

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.[142] Penalties became effective May 15, 2017.

In 2020, 142 penalty cases were identified, 124 resulted in assessed cost-based offer penalties, five resulted in disagreement between the MMU and PJM, and 13 remain pending PJM's determination. These cases were from 124 units owned by 25 different companies. Table 3-109 shows the penalties by the year in which participants were notified.

140 September 16th Filing at P 8.
141 See PJM Operating Agreement Schedule 2 § 2.3 (a).
142 158 FERC ¶ 61,133 (2017).

Table 3-108 Cost-based offer penalty cases by year notified: May 2017 through December 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	142	124	5	13	124	25
Total	443	398	32	13	316	55

Since 2017, 443 penalty cases have been identified, 398 resulted in assessed cost-based offer penalties, 32 resulted in disagreement between the MMU and PJM, and 13 remain pending PJM's determination. The 398 cases were from 316 units owned by 55 different companies. The total penalties were $2.7 million, charged to units that totaled 82,180 available MW. The average penalty was $1.50 per available MW. This means that a 100 MW unit would have paid a penalty of $3,589.[143] Table 3-109 shows the total cost-based offer penalties since 2017 by year.

Table 3-109 Cost-based offer penalties by year: May 2017 through December 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	118	24	$364,600	19,109	$0.85
Total	416	58	$2,678,050	82,180	$1.50

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.[144]

The tariff revisions replaced the annual review process with a periodic review set by PJM. The revisions reinstated the periodic review process employed by the MMU prior to PJM's involvement in the review and approval of fuel cost policies. Monitoring participant behavior through the use of fuel cost policies is an ongoing process that necessitates frequent updates. Market sellers must revise their fuel cost policies whenever circumstances change that impact fuel pricing (e.g. different pricing points, dual fuel addition capability).

The tariff revisions removed the requirement for units with zero marginal cost to have an approved fuel cost policy but also included a zero offer cap for cost-based offers for units that do not have an approved fuel cost policy.

The tariff revisions allow a temporary cost offer method for units that do not have an approved fuel cost policy. The revisions allow units to submit nonzero cost-based offers without an approved fuel cost policy if they follow the temporary cost offer method. The use of the method results in cost-based offers that do not follow the fuel cost policy rules. The approach significantly weakens market power mitigation by allowing market sellers to make offers without an approved fuel cost policy. The proposed approach allows the use of an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy.

The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy.

The tariff revisions replace the fuel cost policy revocation provision with the ability for PJM to terminate fuel cost policies.

The tariff revisions reduce the penalties for noncompliant cost-based offers in two situations. When market sellers report their noncompliant cost-based offers, the penalty is reduced by 75 percent. When market sellers do not meet conditions defined to measure a potential market impact the penalty is reduced by 90 percent. The conditions include if the market seller failed the TPS test, if the unit was committed on its cost-based offer, if the unit was marginal or if the unit was paid uplift.

The tariff revisions eliminate penalties entirely when units submit noncompliant cost-based offers if PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based

143 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.
144 172 FERC ¶ 61,094.

offer. This new provision allows market sellers to not follow their fuel cost policy, submit cost-based offers that are not verifiable or systematic and not face any penalties for doing so.

The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced 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.[145] 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.[146] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[147] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory and effective market power mitigation and competitive market results.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start. The MMU converted all VOM costs into dollars per MWh using the units' heat rates, the average economic maximum and average minimum run time of the units in 2020.

The average variable operating and maintenance cost approved by PJM for combustion turbines and diesels for 2020 was 16 percent lower than the approved variable operating and maintenance cost approved by PJM in 2019.[148]

The average variable operating and maintenance cost approved by PJM for combined cycles for 2020 was seven percent higher than the approved variable operating and maintenance cost approved by PJM in 2019.

The average variable operating and maintenance cost approved by PJM for coal units for 2020 was 8 percent lower than the approved variable operating and maintenance cost approved by PJM in 2019.

Table 3-110 shows the amount of capacity offered within several ranges of VOM costs. Table 3-110 shows that 1,000 MW have an approved effective VOM above $100 per MWh and 3,146 MW have an approved effective VOM between $50 and $100 per MWh.

145 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
146 167 FERC ¶ 61,030.
147 168 FERC ¶ 61,134.
148 PJM reviews VOM once per year. The results reflect PJM's most recent review.

Table 3-110 2020 Approved effective VOM costs

Approved VOM Range ($/MWh)	Offered MW
$0 to $5 per MWh	71,068
$5 to $10 per MWh	30,635
$10 to $20 per MWh	16,035
$20 to $50 per MWh	4,938
$50 to $100 per MWh	3,146
Above $100 per MWh	1,000

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 CTs, CCs and coal units run for more hours, the VOM cost approved by PJM decreases. This is an indication that fixed costs are included in VOM costs. 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 accepted by PJM for inclusion in VOM depends on PJM's interpretation of the maintenance activities or expenses directly related to electricity production and the level of detailed support provided by market sellers to PJM.

PJM's VOM review is not adequate to determine whether all costs included in VOM are compliant. PJM's VOM review focuses only on the expenses submitted for the last year of up to 20 years of data 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.[149]

The flaws in PJM's review process for VOM are compounded by the ambiguity in the criteria used to determine if costs are includable. PJM's definition of allowable costs for cost-based offers, "costs resulting from electric production," is so broad as to be meaningless. Most costs incurred at a generating station result from electric production in one way or another. The generator itself would not exist but for the need for electric production. PJM's broad definition cannot identify which costs associated with electric production are includable in cost-based offers. The definition is not verifiable or systematic and permits wide discretion by PJM and generators.

The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics.

The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced.

The MMU understands that companies have different document retention policies but in order to be allowed to include maintenance costs, such costs must be verified, and they cannot be verified without documentation. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts. Market participants should be required to provide the operational data (e.g. run hours, MWh, MMBtu) that supports the maintenance cycle of the equipment being serviced/replaced. For example, if equipment is serviced every 5,000 run hours, the market participant must include at least 5,000 run hours of historical operation in its maintenance cost history.

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

149 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>.

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.[150]

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.

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.

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

150 The peak adder is equal to $300 times three divided by 5 MW.

August 2019.[151] One unit qualified for an FMU adder for the months of September and October, 2019. In 2020, five units qualified for an FMU adder in at least one month.

Table 3-111 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 3-111 Number of frequently mitigated units and associated units (By month): 2019 and 2020

	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	2	0	2	4
November	0	0	0	0	2	1	2	5
December	0	0	0	0	2	1	2	5

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 3-112 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[152] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2020, and summed by the parent company that offers the marginal resource into the real-time energy market. In 2020, the offers of one company resulted in 16.4 percent of the real-time, load-weighted PJM system LMP and the offers of the top four companies resulted in 44.4 percent of the real-time, load-weighted, average PJM system LMP. In 2020, the offers of one company resulted in 16.2 percent of the peak hour real-time, load-weighted PJM system LMP.

151 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).

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

Table 3-112 Marginal unit contribution to real-time, load-weighted LMP (By parent company): 2019 and 2020

2019						2020					
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	16.4%	16.4%	1	16.2%	16.2%
2	10.0%	22.8%	2	10.4%	24.1%	2	11.0%	27.4%	2	13.0%	29.2%
3	9.3%	32.1%	3	8.8%	32.9%	3	10.7%	38.1%	3	9.9%	39.1%
4	9.3%	41.5%	4	7.2%	40.1%	4	6.3%	44.4%	4	6.1%	45.2%
5	4.8%	46.3%	5	5.1%	45.2%	5	6.2%	50.6%	5	5.6%	50.8%
6	4.5%	50.8%	6	4.1%	49.3%	6	5.1%	55.8%	6	5.3%	56.1%
7	4.4%	55.3%	7	4.1%	53.4%	7	4.7%	60.5%	7	5.0%	61.1%
8	3.6%	58.9%	8	3.9%	57.2%	8	4.2%	64.6%	8	3.1%	64.2%
9	3.6%	62.5%	9	3.9%	61.1%	9	2.9%	67.6%	9	3.0%	67.2%
Other (74 companies)	37.5%	100.0%	Other (70 companies)	38.9%	100.0%	Other (75 companies)	32.4%	100.0%	Other (71 companies)	32.8%	100.0%

Figure 3-64 shows the marginal unit contribution to the real-time, load-weighted PJM system LMP summed by parent companies since 2011.

Figure 3-64 Marginal unit contribution to real-time, load-weighted LMP (By parent company): 2011 through 2020

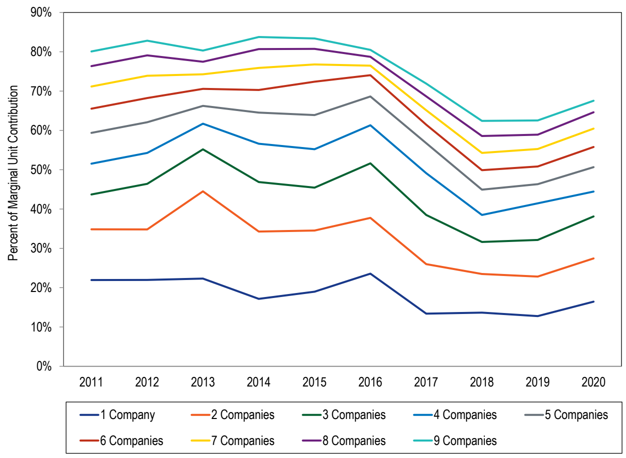


Table 3-113 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[153] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market. The results show that in 2020, the offers of one company contributed 10.5 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 31.3 percent of the day-ahead, load-weighted, average, PJM system LMP.

Table 3-113 Marginal resource contribution to day-ahead, load-weighted LMP (By parent company): 2019 and 2020

2019						2020					
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	11.9%	11.9%	1	10.5%	10.5%	1	10.9%	10.9%
2	7.8%	17.7%	2	6.6%	6.6%	2	10.4%	20.9%	2	9.5%	20.4%
3	5.9%	23.6%	3	5.7%	5.7%	3	5.7%	26.6%	3	8.8%	29.2%
4	5.8%	29.4%	4	5.4%	5.4%	4	4.8%	31.3%	4	5.3%	34.5%
5	5.6%	35.0%	5	4.8%	4.8%	5	4.5%	35.8%	5	5.0%	39.5%
6	4.4%	39.5%	6	4.3%	4.3%	6	4.3%	40.2%	6	4.4%	43.9%
7	4.1%	43.5%	7	3.8%	3.8%	7	3.9%	44.0%	7	4.1%	48.0%
8	3.5%	47.0%	8	3.3%	3.3%	8	3.7%	47.8%	8	3.3%	51.3%
9	3.0%	50.0%	9	3.0%	3.0%	9	3.7%	51.5%	9	3.0%	54.2%
Other (149 companies)	50.0%	100.0%	Other (137 companies)	51.1%	51.1%	Other (147 companies)	48.5%	100.0%	Other (144 companies)	45.8%	100.0%

Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup index of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus level impacts could also have different impacts on total system price. Markup can also affect prices when units with markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[154] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

The markup calculation is not based on a counterfactual redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost. A full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit

153 Id.

154 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.

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 3-114 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 $3.63 per MWh in 2019 to $2.19 per MWh in 2020. The adjusted markup contribution of coal units in 2020 was $0.24 per MWh. The adjusted markup component of gas fired units in 2020 was $1.98 per MWh, a decrease of $0.91 per MWh from 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 2020, among the wind units that were marginal, 92.8 percent had negative offer prices.

Table 3-114 Markup component of real-time, load-weighted, average LMP by primary fuel type and unit type: 2019 and 2020[155]

		2019		2020	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.08)	$0.77	($0.40)	$0.24
Gas	CC	$1.64	$2.62	$0.78	$1.61
Gas	CT	$0.17	$0.35	$0.24	$0.39
Gas	RICE	$0.02	$0.02	$0.02	$0.03
Gas	Steam	($0.17)	($0.11)	($0.10)	($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	($0.02)	($0.02)	($0.03)	($0.03)
Other	Steam	($0.00)	($0.00)	($0.00)	($0.00)
Wind	Wind	($0.01)	($0.01)	($0.00)	($0.00)
Total		$1.55	$3.63	$0.50	$2.19

Markup Component of Real-Time Price

Table 3-115 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-116 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In 2020, when using unadjusted cost-based offers, $0.50 per MWh of the PJM real-time, load-weighted, average LMP was attributable to markup. Using adjusted cost-based offers, $2.19 per MWh of the PJM real-time, load-weighted, average LMP was attributable to markup. In 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.

Table 3-115 Monthly markup components of real-time, load-weighted, LMP (Unadjusted): 2019 through 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	$0.09	$0.71	($0.57)
Nov	$1.12	$1.79	$0.51	($0.01)	$0.72	($0.68)
Dec	$0.19	$0.29	$0.08	$0.37	$0.37	$0.37
Total	$1.58	$2.16	$0.97	$0.50	$1.08	($0.10)

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

Table 3-116 Monthly markup components of real-time, load-weighted, LMP (Adjusted): 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	$1.76	$2.51	$0.95
Nov	$3.18	$3.95	$2.49	$1.68	$2.53	$0.88
Dec	$2.12	$2.38	$1.88	$2.46	$2.56	$2.37
Total	$3.64	$4.40	$2.86	$2.19	$2.90	$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 2020. Figure 3-66 shows the markup contribution to the hourly load-weighted, LMP using adjusted cost-based offers in 2019 and 2020.

Figure 3-65 Markup contribution to real-time, hourly, load-weighted LMP (Unadjusted): 2019 and 2020

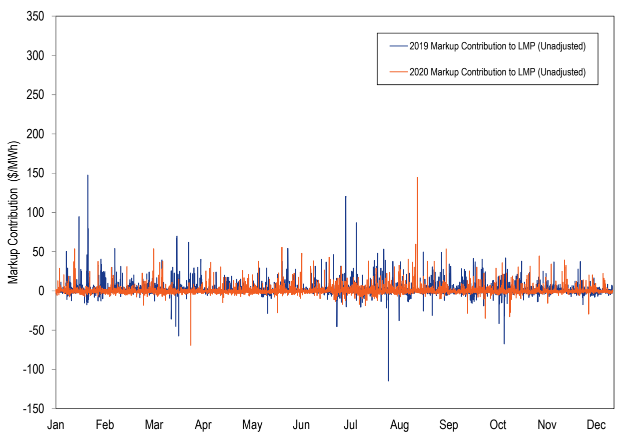
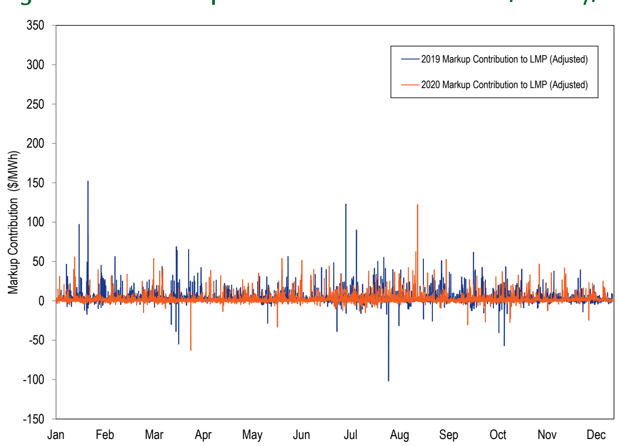


Figure 3-66 Markup contribution to real-time, hourly, load-weighted LMP (Adjusted): 2019 and 2020



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 2019 and 2020 in Table 3-117 and for adjusted offers in Table 3-118.[156] The smallest zonal all hours average markup component using unadjusted offers in 2020, was in the OVEC Control Zone, $0.26 per MWh, while the highest was in the BGE Control Zone, $0.97 per MWh. The smallest zonal on peak average markup component using unadjusted offers in 2020, was in the PPL Control Zone, $0.57 per MWh, while the highest was in the BGE Control Zone, $1.79 per MWh.

Table 3-117 Average, real-time, zonal markup component (Unadjusted): 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
AECO	$1.98	$2.45	$1.51	$0.35	$0.77	($0.09)
AEP	$1.56	$2.21	$0.90	$0.51	$1.10	($0.11)
APS	$1.54	$2.15	$0.92	$0.56	$1.20	($0.11)
ATSI	$1.66	$2.28	$1.00	$0.60	$1.24	($0.07)
BGE	$1.62	$2.41	$0.81	$0.97	$1.79	$0.11
ComEd	$0.78	$1.15	$0.38	$0.47	$1.10	($0.22)
DAY	$1.75	$2.51	$0.93	$0.58	$1.18	($0.06)
DEOK	$1.62	$2.33	$0.87	$0.53	$1.11	($0.09)
DLCO	$1.61	$2.20	$0.99	$0.66	$1.36	($0.09)
Dominion	$1.50	$2.12	$0.87	$0.60	$1.27	($0.09)
DPL	$2.06	$2.45	$1.66	$0.33	$0.75	($0.12)
EKPC	$1.50	$2.14	$0.85	$0.49	$1.08	($0.10)
JCPL	$1.90	$2.40	$1.36	$0.31	$0.69	($0.09)
Met-Ed	$1.69	$2.10	$1.26	$0.44	$0.83	$0.02
OVEC	$1.33	$2.01	$0.73	$0.26	$0.82	($0.24)
PECO	$2.00	$2.35	$1.64	$0.32	$0.75	($0.14)
PENELEC	$1.58	$2.08	$1.06	$0.35	$0.81	($0.13)
Pepco	$1.58	$2.29	$0.84	$0.71	$1.37	$0.00
PPL	$1.75	$2.13	$1.36	$0.29	$0.57	($0.00)
PSEG	$1.90	$2.45	$1.32	$0.29	$0.69	($0.14)
RECO	$1.74	$2.19	$1.23	$0.35	$0.77	($0.12)

Table 3-118 Average, real-time, zonal markup component (Adjusted): 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
AECO	$3.87	$4.47	$3.26	$1.94	$2.50	$1.37
AEP	$3.67	$4.50	$2.82	$2.21	$2.94	$1.46
APS	$3.66	$4.44	$2.86	$2.26	$3.06	$1.45
ATSI	$3.77	$4.59	$2.91	$2.31	$3.09	$1.48
BGE	$3.92	$4.91	$2.92	$2.84	$3.81	$1.83
ComEd	$2.77	$3.36	$2.14	$2.07	$2.86	$1.23
DAY	$3.94	$4.88	$2.92	$2.37	$3.11	$1.57
DEOK	$3.72	$4.62	$2.80	$2.24	$2.96	$1.48
DLCO	$3.69	$4.47	$2.88	$2.35	$3.22	$1.45
Dominion	$3.69	$4.50	$2.87	$2.34	$3.14	$1.53
DPL	$4.01	$4.54	$3.48	$1.98	$2.55	$1.40
EKPC	$3.62	$4.43	$2.81	$2.20	$2.92	$1.49
JCPL	$3.83	$4.47	$3.14	$1.93	$2.42	$1.40
Met-Ed	$3.66	$4.25	$3.05	$2.07	$2.59	$1.51
OVEC	$3.36	$4.21	$2.60	$1.91	$2.62	$1.29
PECO	$3.88	$4.37	$3.37	$1.89	$2.43	$1.31
PENELEC	$3.58	$4.23	$2.89	$1.98	$2.57	$1.35
Pepco	$3.83	$4.72	$2.89	$2.49	$3.29	$1.65
PPL	$3.66	$4.21	$3.09	$1.86	$2.25	$1.44
PSEG	$3.81	$4.50	$3.09	$1.89	$2.42	$1.33
RECO	$3.63	$4.22	$2.97	$1.98	$2.53	$1.36

156 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.

Markup by Real-Time Price Levels

Table 3-119 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 3-119 Real-time markup contribution (By load-weighted, LMP category, unadjusted): 2019 and 2020

	2019		2020	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($2.04)	0.3%	($1.05)	2.5%
$10 to $15	($0.29)	5.6%	($0.73)	21.7%
$15 to $20	($0.04)	23.3%	($0.80)	39.2%
$20 to $25	($0.16)	35.1%	$0.01	20.3%
$25 to $50	$2.55	32.3%	$3.69	13.6%
$50 to $75	$14.28	2.3%	$10.38	1.9%
$75 to $100	$22.27	0.5%	$13.70	0.6%
$100 to $125	$22.04	0.2%	$7.78	0.1%
$125 to $150	$22.89	0.1%	$2.42	0.0%
>= $150	$21.27	0.3%	$15.45	0.0%

Table 3-120 Real-time markup contribution (By load-weighted, LMP category, adjusted): 2019 and 2020

	2019		2020	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($1.11)	0.3%	($0.17)	2.5%
$10 to $15	$1.00	5.6%	$0.53	21.7%
$15 to $20	$1.60	23.3%	$0.84	39.1%
$20 to $25	$1.86	35.1%	$1.91	20.4%
$25 to $50	$4.94	32.3%	$5.77	13.6%
$50 to $75	$17.05	2.3%	$12.56	1.9%
$75 to $100	$25.74	0.5%	$15.85	0.6%
$100 to $125	$25.91	0.2%	$9.94	0.1%
$125 to $150	$26.13	0.1%	$4.09	0.0%
>= $150	$24.30	0.3%	$17.04	0.0%

Markup by Company

Table 3-121 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 2020, when using unadjusted cost-based offers, the markup of one company accounted for 1.8 percent of the load-weighted, average LMP, the markup of the top five companies accounted for 4.0 percent of the load-weighted, average LMP and the markup of all companies accounted for 2.3 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 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 2020. The markup contribution of a unit to the real-time, load-weighted, average LMP can be positive or negative.

Table 3-121 Markup component of real-time, load-weighted, average LMP by Company: 2019 and 2020

	2019				2020			
	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	$0.27	1.0%	$0.55	2.0%	$0.39	1.8%	$0.64	2.9%
Top 2 Companies	$0.52	1.9%	$1.01	3.7%	$0.55	2.5%	$0.88	4.0%
Top 3 Companies	$0.76	2.8%	$1.45	5.3%	$0.68	3.1%	$1.11	5.1%
Top 4 Companies	$0.99	3.6%	$1.82	6.6%	$0.79	3.6%	$1.31	6.0%
Top 5 Companies	$1.16	4.3%	$2.14	7.8%	$0.88	4.0%	$1.45	6.7%
All Companies	$1.55	5.7%	$3.63	13.3%	$0.50	2.3%	$2.19	10.0%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-122. INC, DEC and up to congestion transactions (UTC) have zero markups. UTCs were 51.4 percent of marginal resources, INCs were 13.2 percent of marginal resources and DECs were 18.8 percent of marginal resources in 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 3-122 shows the markup component of LMP for marginal generating resources. Generating resources were only 16.5 percent of marginal resources in 2020. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources decreased for coal fired steam units from $0.36 to $0.14 per MWh and decreased for gas fired CC units from $1.55 to $0.87 per MWh.

Table 3-122 Markup component of day-ahead, load-weighted, average LMP by primary fuel type and technology type: 2019 and 2020

		2019			2020		
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	($0.34)	$0.36	38.8%	($0.51)	$0.14	35.1%
Gas	CC	$1.03	$1.55	52.5%	$0.45	$0.87	53.4%
Gas	CT	$0.01	$0.01	1.1%	$0.03	$0.04	1.5%
Gas	RICE	($0.00)	($0.00)	0.6%	($0.00)	($0.00)	0.4%
Gas	Steam	($0.06)	($0.02)	3.9%	($0.07)	($0.04)	3.7%
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	0.8%
Oil	Steam	($0.05)	($0.04)	0.1%	($0.01)	($0.01)	0.1%
Other	Solar	$0.00	$0.00	0.1%	$0.00	$0.00	0.1%
Other	Steam	($0.00)	($0.00)	0.1%	($0.00)	($0.00)	0.3%
Uranium	Steam	$0.00	$0.00	1.0%	$0.00	$0.00	1.7%
Wind	Wind	$0.10	$0.10	1.1%	$0.01	$0.01	2.8%
Total		$0.70	$1.97	100.0%	($0.11)	$1.01	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 3-123 shows the markup component of average prices and of average monthly on peak and off peak prices using unadjusted cost-based offers. In 2020, when using unadjusted cost-based offers, -$0.11 per MWh of the PJM day-ahead load-weighted, average LMP was attributable to markup. In 2020, the peak markup component was highest in August, $0.70 per MWh using unadjusted cost-based offers.

Table 3-123 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: 2019 through 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	$0.15	$0.48	($0.21)
Nov	$1.71	$1.75	$1.68	($0.22)	$0.28	($0.70)
Dec	($0.34)	$0.21	($0.87)	$0.13	$0.37	($0.12)
Annual	$0.70	$1.10	$0.28	($0.11)	$0.19	($0.43)

Table 3-124 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In 2020, when using adjusted cost-based offers, $1.01 per MWh of the PJM day-ahead, load-weighted, average LMP was attributable to markup. In 2020, the peak markup component was highest in August, $1.77 per MWh using adjusted cost-based offers.

Table 3-124 Monthly markup components of day-ahead (Adjusted), load-weighted, LMP: 2019 through 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	$1.12	$1.37	$0.84
Nov	$2.92	$3.01	$2.84	$0.89	$1.29	$0.52
Dec	$1.12	$1.65	$0.61	$1.49	$1.68	$1.29
Annual	$1.97	$2.29	$1.62	$1.01	$1.29	$0.70

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 3-125. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-126. The smallest zonal all hours average markup component using adjusted cost-based offers for 2020 was in the Pepco Zone, $0.68 per MWh, while the highest was in the PPL Control Zone, $1.51 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the Pepco Control Zone, $0.85 per MWh, while the highest was in the OVEC Control Zone, $1.83 per MWh.

Table 3-125 Day-ahead, average, zonal markup component (Unadjusted): 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
AECO	$1.62	$2.58	$0.63	$0.22	$0.54	($0.11)
AEP	$0.53	$0.83	$0.21	($0.25)	$0.05	($0.56)
APS	$0.35	$0.68	$0.02	($0.26)	$0.02	($0.56)
ATSI	$0.98	$1.58	$0.33	($0.18)	$0.12	($0.51)
BGE	$0.70	$1.53	($0.16)	($0.34)	($0.02)	($0.67)
ComEd	$0.21	$0.12	$0.29	($0.20)	$0.13	($0.54)
DAY	$1.45	$2.54	$0.27	($0.07)	$0.43	($0.60)
DEOK	$1.05	$1.86	$0.19	($0.09)	$0.46	($0.68)
DLCO	$0.63	$1.09	$0.15	($0.30)	($0.06)	($0.57)
Dominion	$0.34	$0.72	($0.05)	($0.17)	$0.24	($0.60)
DPL	$1.25	$1.78	$0.71	$0.16	$0.39	($0.08)
EKPC	$0.59	$0.94	$0.24	($0.18)	$0.23	($0.59)
JCPL	$1.36	$1.97	$0.69	$0.14	$0.40	($0.14)
Met-Ed	$0.88	$1.20	$0.53	($0.02)	($0.04)	($0.01)
OVEC	($0.44)	$0.57	($1.39)	$0.22	$0.63	($0.31)
PECO	$1.37	$1.92	$0.80	$0.18	$0.43	($0.09)
PENELEC	$0.56	$0.75	$0.34	$0.06	$0.28	($0.21)
Pepco	$0.33	$0.80	($0.16)	($0.43)	($0.20)	($0.68)
PPL	$1.17	$1.51	$0.82	$0.47	$0.64	$0.28
PSEG	$1.22	$1.77	$0.63	$0.14	$0.36	($0.11)
RECO	$1.02	$1.50	$0.48	$0.17	$0.45	($0.15)

Table 3-126 Day-ahead, average, zonal markup component (Adjusted): 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
AECO	$2.81	$3.70	$1.90	$1.32	$1.64	$0.99
AEP	$1.80	$2.02	$1.58	$0.88	$1.13	$0.62
APS	$1.66	$1.91	$1.39	$0.84	$1.08	$0.58
ATSI	$2.28	$2.81	$1.70	$0.96	$1.25	$0.65
BGE	$2.07	$2.84	$1.27	$0.77	$1.03	$0.50
ComEd	$1.43	$1.33	$1.54	$0.91	$1.22	$0.57
DAY	$2.79	$3.81	$1.69	$1.13	$1.59	$0.63
DEOK	$2.37	$3.10	$1.58	$1.04	$1.53	$0.52
DLCO	$1.88	$2.22	$1.51	$0.78	$0.97	$0.58
Dominion	$1.66	$1.95	$1.36	$1.02	$1.49	$0.53
DPL	$2.44	$2.88	$1.98	$1.26	$1.46	$1.05
EKPC	$1.86	$2.13	$1.59	$0.94	$1.27	$0.60
JCPL	$2.59	$3.13	$2.00	$1.26	$1.51	$0.98
Met-Ed	$2.12	$2.38	$1.83	$1.02	$0.98	$1.07
OVEC	$0.66	$1.48	($0.11)	$1.36	$1.83	$0.74
PECO	$2.57	$3.04	$2.07	$1.26	$1.51	$1.00
PENELEC	$1.80	$1.91	$1.68	$1.07	$1.27	$0.84
Pepco	$1.70	$2.11	$1.26	$0.68	$0.85	$0.50
PPL	$2.37	$2.64	$2.08	$1.51	$1.67	$1.34
PSEG	$2.42	$2.88	$1.92	$1.23	$1.46	$1.00
RECO	$2.23	$2.60	$1.81	$1.25	$1.50	$0.97

Markup by Day-Ahead Price Levels

Table 3-127 and Table 3-128 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 3-127 Average, day-ahead markup component (By LMP category, unadjusted): 2019 and 2020

	2019		2020	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.00	0.1%	($0.01)	1.4%
$10 to $15	$0.01	3.9%	($0.08)	17.6%
$15 to $20	$0.01	21.1%	($0.19)	40.2%
$20 to $25	($0.00)	30.9%	($0.00)	24.2%
$25 to $50	$0.42	42.1%	$0.16	16.0%
$50 to $75	$0.23	1.4%	$0.01	0.6%
$75 to $100	$0.03	0.5%	$0.00	0.0%
$100 to $125	($0.02)	0.1%	$0.00	0.0%
$125 to $150	$0.01	0.0%	$0.00	0.0%
>= $150	$0.01	0.0%	$0.00	0.0%

Table 3-128 Average, day-ahead markup component (By LMP category, adjusted): 2019 and 2020

	2019		2020	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.00	0.1%	$0.00	1.4%
$10 to $15	$0.04	3.9%	$0.05	17.6%
$15 to $20	$0.23	21.1%	$0.27	40.2%
$20 to $25	$0.43	30.9%	$0.32	24.2%
$25 to $50	$0.98	42.1%	$0.34	16.0%
$50 to $75	$0.24	1.4%	$0.02	0.6%
$75 to $100	$0.04	0.5%	$0.00	0.0%
$100 to $125	($0.01)	0.1%	$0.00	0.0%
$125 to $150	$0.01	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 evaluates 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:[157]

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

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.[158] Using the Lerner Index,

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

158 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>.

the elasticities imply, for example, an average markup ranging from 25 to 50 percent at the unconcentrated to moderately concentrated threshold HHI of 1000:[159]

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

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 $21.27 per MWh and an average HHI of 790 in 2020, average PJM prices would theoretically range from $27 to $35 per MWh using the elasticity range of -0.2 to -0.4.[160] 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 $21.77 per MWh, and markups, at 2.3 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 3-129 categorizes real-time marginal unit intervals by markup level and TPS test status. In 2020, 5.2 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 of a marginal unit. The 5.2 percent of marginal unit intervals failing the TPS test with unmitigated positive markup exceeds the 3.8 percent of marginal unit intervals failing the TPS with zero markup. Marginal units with positive markup are mitigated less often than not.

Table 3-129 Percent of real-time marginal unit intervals with markup and local market power: 2019 and 2020

	2019			2020		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	24.1%	11.5%	35.6%	34.0%	6.5%	40.5%
Zero Markup	12.6%	6.7%	19.4%	11.3%	3.8%	15.1%
$0 to $5	24.3%	6.9%	31.2%	33.8%	4.5%	38.3%
$5 to $10	7.9%	1.7%	9.6%	3.5%	0.4%	3.9%
$10 to $15	1.2%	0.5%	1.7%	0.6%	0.2%	0.8%
$15 to $20	0.5%	0.3%	0.8%	0.3%	0.0%	0.3%
$20 to $25	0.3%	0.1%	0.4%	0.4%	0.0%	0.4%
$25 to $50	0.5%	0.2%	0.7%	0.4%	0.0%	0.4%
$50 to $75	0.2%	0.1%	0.3%	0.1%	0.0%	0.1%
$75 to $100	0.1%	0.0%	0.1%	0.1%	0.0%	0.1%
Above $100	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
Total Positive Markup	35.0%	10.0%	45.0%	39.2%	5.2%	44.4%
Total	71.8%	28.2%	100.0%	84.5%	15.5%	100.0%

The markup of marginal units was zero or negative in only 55.0 percent of marginal unit intervals in 2019 and 55.6 percent of marginal unit intervals in 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.

159 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.
160 The average HHI is found in Table 3-80. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3-64.

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. Effective November 1, 2020, UTC transactions are allocated day-ahead and real-time uplift charges, and are treated for uplift purposes as being equivalent to a decrement bid (DEC) at the sink point of the UTC.[2]

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.[3] [4] 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.

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.[5]

Overview

Energy Uplift Credits

- **Types of credits.** In 2020, energy uplift credits were $90.9 million, including $9.3 million in day-ahead generator credits, $58.2 million in balancing generator credits, $19.4 million in lost opportunity cost credits, and $3.4 million in local constraint control credits.
- **Types of units.** In 2020, coal units received 90.6 percent of all day-ahead generator credits. During the same time period, combustion turbines received 91.2 percent of all balancing generator credits and 95.1 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In 2020, 87.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.8 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2020, less than 0.1 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 74.4 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 17.0 percent of all credits. The top 10 organizations received 71.8 percent of all credits. The HHI for

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 172 FERC ¶ 61,046 (2020).

3 *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).

4 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.

5 Demand response payments are addressed in Section 6: Demand Response.

day-ahead operating reserves was 8387, the HHI for balancing operating reserves was 3582 and the HHI for lost opportunity cost was 5457, all of which are classified as highly concentrated.

- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $2.2 million or 12.9 percent, in 2020 compared to 2019, from $17.1 million to $19.4 million. Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 94.0 percent of the $19.4 million. The day-ahead generation paid LOC credits for this reason increased by 534.2 GWh or 70.3 percent during 2020, compared to 2019, from 759.9 GWh to 1,294.1 GWh.
- **Following Dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with proper offer parameters. Since 2018, the MMU has made cumulative resettlement requests that total $3.5 million, of which PJM has agreed and resettled 39.1 percent.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges increased by $2.4 million, or 2.7 percent, in 2020 compared to 2019, from $88.5 million to $90.9 million.
- **Energy Uplift Charges Categories.** The increase of $2.4 million in 2020 was comprised of a $6.2 million decrease in day-ahead operating reserve charges, an $8.8 million increase 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 $0.040 per MWh, a DEC paid $0.341 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.329 per MWh. In November and December 2020, which were the only months of the year that UTCs were allocated uplift charges, a UTC paid $0.305 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.012 per MWh, real-time load paid $0.030 per MWh, a DEC paid $0.296 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.285 per MWh in 2020. In November and December 2020, which were the only months of the year that UTCs were allocated uplift charges, a UTC paid $0.224 per MWh.
- **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 $0.008 per MWh, PPL had a rate of $0.004 per MWh, and EKPC had a rate of $0.004.

Geography of Charges and Credits

- In 2020, 89.1 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 3.8 percent by transactions at hubs and aggregates, and 7.2 percent by transactions at interchange interfaces.
- In 2020, generators in the Eastern Region received 36.3 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2020, generators in the Western Region received 61.1 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2020, external generators received 2.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 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 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 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. First reported Q3, 2020. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead 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 units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends 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.[6])
- 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

6 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.

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.[7])
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 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.)

7 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. 166 FERC ¶ 61,210. PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (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). Fast start pricing has been approved by FERC subject to a PJM compliance filing on the definition of fast start resources, and is expected to be implemented in 2021. Fast start pricing will affect uplift calculations.[8]

When units receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[9] 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.

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.[10] The uplift payments for UTCs began on November 1, 2020. Up to congestion transactions did not pay energy uplift charges in the first ten months of 2020.[11]

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. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. they do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make these units ineligible for uplift credits. Since 2018, the MMU has identified $3.5 million of incorrect uplift credits.

8 FERC Docket No. ER19-2722.

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

10 See 172 FERC ¶ 61,046.

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

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

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 2019 and 2020.[12] In 2020, energy uplift credits increased by $2.2 million or 2.4 percent compared to 2019.

Table 4-1 Energy uplift credits by category: 2019 and 2020[13]

Category	Type	2019 Credits (Millions)	2020 Credits (Millions)	Change	Percent Change	2019 Share	2020 Share
Day-Ahead	Generators	$15.5	$9.3	($6.2)	(40.2%)	17.5%	10.2%
	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	$52.1	$58.2	$6.0	11.6%	58.9%	64.0%
	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	$2.9	$3.4	$0.5	18.0%	3.3%	3.8%
	Lost Opportunity Cost	$17.1	$19.3	$2.2	12.9%	19.4%	21.3%
Reactive Services	Day-Ahead	$0.3	$0.1	($0.2)	(76.9%)	0.3%	0.1%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	($0.0)	(76.5%)	0.0%	0.0%
	Reactive Services	$0.3	$0.4	$0.1	32.6%	0.3%	0.4%
	Synchronous Condensing	$0.0	$0.0	($0.0)	(99.2%)	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)	(0.1%)	0.3%	0.2%
Total		$88.5	$90.9	$2.4	2.7%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-2 shows the distribution of total energy uplift credits by unit type for 2019 and 2020. Uplift credits decreased for most unit types, with the exception of combustion turbines and wind units. A combination of factors led to decreased uplift payments in the first nine months of 2020, but there were significant increases in the last three months. 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

12 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 12, 2021.

13 Year to year change is rounded to one tenth of a million, and includes values less than $0.05 million.

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 $5.5 million or 32.9 percent in 2020 compared with 2019. This decrease can largely be attributed to a small number of coal units in the BGE and Pepco Zones. Combustion turbines had the largest change in uplift credits with an increase of $10.0 million or 15.6 percent.

In 2020, uplift credits to wind units were $0.7 million, up by 175.8 percent compared to 2019.

Table 4-2 Total energy uplift credits by unit type: 2019 and 2020[14] [15]

Unit Type	2019 Credits (Millions)	2020 Credits (Millions)	Change	Percent Change	2019 Share	2020 Share
Combined Cycle	$3.2	$2.5	($0.8)	(24.4%)	3.7%	2.7%
Combustion Turbine	$64.3	$74.4	$10.0	15.6%	72.7%	81.8%
Diesel	$0.9	$0.8	($0.2)	(17.3%)	1.1%	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	$16.8	$11.3	($5.5)	(32.9%)	19.0%	12.4%
Steam - Other	$2.8	$1.3	($1.5)	(54.6%)	3.2%	1.4%
Wind	$0.2	$0.7	$0.4	188.1%	0.3%	0.7%
Total	$88.5	$90.9	$2.4	2.7%	100.0%	100.0%

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in 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, 95.0 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 91.2 percent of balancing credits and 93.8 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.

Table 4-3 Energy uplift credits by unit type: 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	3.0%	1.7%	0.0%	10.7%	3.4%	32.5%	0.0%	16.2%
Combustion Turbine	1.9%	91.2%	0.0%	74.8%	93.8%	56.6%	0.0%	83.7%
Diesel	0.1%	0.8%	0.0%	2.0%	1.4%	0.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.1%	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	90.6%	4.8%	0.0%	0.0%	0.3%	10.9%	0.0%	0.0%
Steam - Other	4.5%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	12.5%	0.9%	0.0%	0.0%	0.0%
Total (Millions)	$9.3	$58.2	$0.0	$3.4	$19.3	$0.4	$0.0	$0.2

14 Table 4-2 does not include balancing imports credits and load response credits in the total amounts.

15 Solar units should be ineligible for all uplift payments because they do not follow PJM's dispatch instructions. The MMU notified PJM of the discrepancy.

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.[16] 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.[17] 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 2020, 0.1 percent of the total day-ahead generation was committed for reliability by PJM, 0.2 percentage points lower than in 2019. The decrease in day-ahead generation committed for reliability by PJM was due to a reduction in the need to commit uneconomic units in the BGE and Pepco Zones for reliability.

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 $9.3 million. The top 10 units received $8.1 million or 87.6 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 2020, 74.4 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, of which 70.1 percent was paid as day-ahead operating reserve credits and the other 4.3 percent was paid as reactive services credits. The remaining 25.6 percent of the day-ahead generation committed for reliability by PJM was economic, meaning prices covered all resource operating costs.

Table 4-4 Day-ahead generation committed for reliability (GWh): 2019 and 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%	59,974	107	0.2%
Nov	63,347	8	0.0%	60,078	7	0.0%
Dec	69,808	61	0.1%	71,591	27	0.0%
Total	825,172	2,142	0.3%	804,363	666	0.1%

16 See OA Schedule 1 § 3.2.3(b).

17 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?la=en>.

Table 4-5 Day-ahead generation committed for reliability by category (GWh): 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
Oct	0.0	6.9	0.0	6.9
Nov	0.0	6.5	20.5	26.9
Dec	0.0	0.0	0.0	0.0
Total	23.8	391.7	143.2	558.7
Share	4.3%	70.1%	25.6%	100.0%

Total day-ahead operating reserve credits in 2020 were $9.3 million, of which $5.9 million or 63.5 percent was paid to units committed for reliability by PJM, and not scheduled to provide black start or reactive services. An additional 0.7 percent, or $0.1 million, was paid to units scheduled to provide black start or reactive services.

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 $53.0 million or 91.2 percent of all balancing operating reserve (BOR) credits in 2020. The majority of these credits, 98.2 percent, are paid to CTs that are committed in real time either without or outside of a day-ahead schedule.[18] 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. Units are disqualified from receiving uplift when the PJM dispatcher is able to identify units that are not following the dispatch signals, and after agreement with the generator, the dispatch reason is changed to self scheduled. PJM dispatchers should not be forced to 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, instead of relying on PJM dispatchers' manual determinations, to evaluate eligibility for receiving 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 increased by 11.6 percent from 2019 to 2020. Lower natural gas prices at the beginning of the year contributed to decreased LMPs and lower balancing operating reserve credits during the first nine months of 2020, but significantly higher balancing operating reserve credits in the last quarter offset the earlier decreases. Balancing operating reserve credits in the last quarter of 2020 constituted 45.4 percent of the 2020 total. Noneconomic generation by CTs in December 2020 increased sharply and caused balancing operating reserve credits to CTs that month to increase by 728.4 percent when compared to December 2019. The overall increase in credits in the AEP, ATSI, and ComEd Zones accounted for 76.1 percent of the total annual change in balancing operating reserve credits.

The credits paid to combustion turbines committed in real time without a day-ahead commitment occurs despite the fact that the total combustion turbine MW committed in the day-ahead energy market are similar 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 2020, generation by combustion turbines was 3.1 percent higher in the real-time energy market than in the day-ahead energy market, although this varied by month. Table 4-6 shows that only 2.1 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 29.6 percent of generation from combustion turbines in the real-time market was uneconomic and required $53.0 million in BOR credits.

18 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.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines: 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%)
Oct	1,326	3.6%	$0.0	1,550	43.2%	$6.2	14.5%
Nov	809	2.6%	$0.0	965	48.9%	$7.5	16.1%
Dec	353	1.8%	$0.0	885	58.4%	$11.4	60.1%
Total	15,210	2.1%	$0.2	15,693	29.6%	$53.0	3.1%

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 89.6 percent of total BOR credits.

Table 4-7 shows real-time generation by combustion turbines by day-ahead commitment status in 2020. CTs that operated on a day-ahead schedule constituted 69.4 percent of real-time generation by CTs, of which 22.1 percent was uneconomic in the real-time market and received $0.9 million in BOR credits.

In 2020, 30.6 percent of real-time generation by CTs was from CTs that operated outside of a day-ahead schedule, of which 46.6 percent was uneconomic in the real-time market and received $52.1 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: 2020

	Real-Time Generation Operating on a Day-Ahead Schedule				Real-Time Generation Operating Outside of a Day-Ahead Schedule			
Month	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)
Jan	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
Oct	1,030	66.5%	33.5%	$0.0	520	33.5%	62.4%	$6.2
Nov	611	63.3%	33.3%	$0.1	354	36.7%	75.7%	$7.4
Dec	262	29.6%	32.2%	$0.0	622	70.4%	69.5%	$11.3
Total	10,888	69.4%	22.1%	$0.9	4,805	30.6%	46.6%	$52.1

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. Such units are not actually forgoing an option to increase output because the reliability of the system and in some cases the generator depend on reducing output. This LOC is referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine 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 2019 and 2020. In 2020, LOC credits increased by $2.2 million or 12.9 percent compared to 2019. The increase of $2.2 million is comprised of a $1.8 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 2020, wind units received $0.2 million of real-time LOC, down by 0.7 percent compared to 2019. In 2020, real-time LOC credits to wind units accounted for 27.1 percent of the uplift payments to wind units. Wind units in the AEP and ComEd Zones received 99.8 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 2020, 14.6 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 2.2 percentage points higher than 2019. In 2020 compared to 2019, day-ahead generation by combustion turbines increased 31.3 percent, day-ahead generation not requested in real time increased by 54.5 percent, and day-ahead generation not requested in real time receiving lost opportunity costs increased by 70.3 percent. Unlike steam units, combustion turbines that clear the day-ahead energy market have to be instructed by PJM to come online in real time.

Table 4-8 Monthly lost opportunity cost credits (Millions): 2019 and 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	$4.4	$0.1	$4.5
Sep	$4.7	$0.2	$4.9	$1.6	$0.0	$1.7
Oct	$2.2	$0.1	$2.3	$0.9	$0.0	$0.9
Nov	$1.4	$0.1	$1.6	$0.8	$0.0	$0.8
Dec	$0.8	$0.0	$0.8	$0.4	$0.2	$0.5
Total	$16.4	$0.8	$17.1	$18.2	$1.2	$19.3
Share	95.5%	4.5%	100.0%	94.0%	6.0%	100.0%

Table 4-9 Day-ahead generation from combustion turbines and diesels (GWh): 2019 and 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	36
May	848	171	49	1,126	188	80
Jun	938	128	46	2,278	437	243
Jul	2,555	197	68	4,759	588	271
Aug	1,901	197	109	2,728	384	180
Sep	1,808	320	163	1,696	346	131
Oct	2,125	289	155	1,677	156	84
Nov	1,212	183	61	1,051	121	68
Dec	777	128	59	641	59	23
Total	14,369	1,789	760	18,867	2,763	1,294
Share	100.0%	12.4%	5.3%	100.0%	14.6%	6.9%

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.[19] 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.[20]

19 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
20 Resources do not recover their operating cost when market revenues for the day are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.

Table 4-10 Dispatch status, commitment status and uplift eligibility[21]

			Commitment Status	
Dispatch Status	Dispatch Description	Eligible to Set LMP	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 2020, 42.2 percent of generation in the day-ahead energy market was pool scheduled and 44.6 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 53.5 percent of real-time generation, are self scheduled.

Table 4-11 Day-ahead and real-time generation by offer status and eligibility to set LMP (GWh): 2020

	Self Scheduled			Pool Scheduled						Total Generation
	Dispatchable	Economic Minimum	Block Loaded	Dispatchable	Economic Minimum	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Eligible to Set Price
Day-Ahead Generation	81,941	183,192	199,769	151,048	166,955	21,458	804,363	339,461	464,902	232,989
Share of Day-Ahead	10.2%	22.8%	24.8%	18.8%	20.8%	2.7%	100.0%	42.2%	57.8%	29.0%
Real-Time Generation	72,473	174,699	199,763	151,686	181,824	25,819	806,264	359,328	446,936	224,159
Share of Real-Time	9.0%	21.7%	24.8%	18.8%	22.6%	3.2%	100.0%	44.6%	55.4%	27.8%

Economic and Noneconomic Generation[22]

Economic generation includes units scheduled day ahead by PJM 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 produce energy day ahead 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 as defined by PJM. In 2020, 87.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.8 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): 2020

Energy Market	Economic Generation	Noneconomic Generation	Total Eligible Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	297,501	41,960	339,461	87.6%	12.4%
Real-Time	203,306	100,875	304,181	66.8%	33.2%

21 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.

22 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 2020, 0.6 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.4 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-13 Generation receiving operating reserve credits (GWh): 2020

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	339,461	2,155	0.6%
Real-Time	304,181	4,141	1.4%

Uplift Resettlement

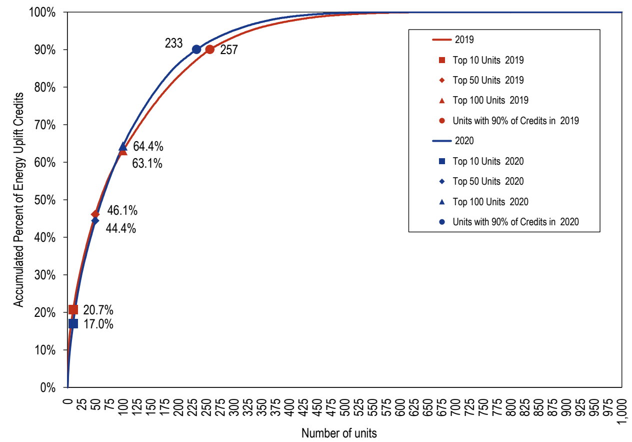
Some units have been incorrectly paid uplift despite not meeting uplift eligibility requirements, such as not following dispatch, not having the correct commitment status, or not operating with proper offer parameters. The MMU has requested that PJM correctly resettle the uplift payments in these cases. Since 2018, the cumulative resettlement requests totaled $3.5 million. Of that amount, PJM has agreed and resettled 39.1 percent of the requests, 53.5 percent remains pending. The remaining 7.5 percent occurred prior to January 2019 and would now require a directive from FERC for them to be resettled. The MMU continues to bring new cases to the attention of PJM.

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 full transparency has made it more difficult for competition to affect these payments.[23]

Figure 4-1 shows the concentration of energy uplift credits. The top 10 units received 17.0 percent of total energy uplift credits in 2020, compared to 20.7 percent in 2019. In 2020, 233 units received 90 percent of all energy uplift credits, compared to 257 units in 2019.

Figure 4-1 Cumulative share of energy uplift credits: 2019 and 2020 by unit



23 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.

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 2020.

Table 4-14 Top 10 units and organizations energy uplift credits: 2020

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$8.1	87.6%	$9.0	97.0%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$8.7	14.9%	$43.7	75.1%
	Local Constraints Control	$2.4	70.9%	$3.4	99.7%
	Lost Opportunity Cost	$4.5	23.2%	$15.5	80.2%
Reactive Services		$0.4	93.9%	$0.4	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	38.6%	$0.2	92.2%
Total		$15.5	17.0%	$65.3	71.8%

Table 4-15 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2020, 74.7 percent of all credits paid to these units were allocated to deviations while the remaining 25.3 percent were paid for reliability reasons.

Table 4-15 Balancing operating reserve credits to top 10 units by category and region: 2020

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$2.0	$0.2	$0.0	$5.5	$1.0	$0.0	$8.7
Share	23.2%	2.1%	0.0%	63.3%	11.4%	0.0%	100.0%

In 2020, concentration in all energy uplift credit categories was high.[24] [25] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category.[26] Table 4-16 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 8387, for balancing operating reserve credits to generators was 3582, for lost opportunity cost credits was 5457 and for reactive services credits was 9619. All of these HHI values are characterized as highly concentrated.

Table 4-16 Daily energy uplift credits HHI: 2020

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	8387	3265	10000	100.0%	51.1%
	Imports	10000	10000	10000	100.0%	55.5%
	Load Response	10000	10000	10000	100.0%	70.9%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	3582	794	10000	100.0%	27.1%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
	Lost Opportunity Cost	5457	1175	10000	100.0%	21.1%
Reactive Services		9619	5236	10000	100.0%	33.7%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9544	4930	10000	100.0%	25.5%
Total		3164	617	9864	99.3%	22.8%

24 See the *2020 State of the Market Report for PJM* Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
25 Table 4-16 excludes local constraint control categories.
26 The concentration is measured using the entity (or entities) to which the uplift credit is paid. This method differs from the method used in Section 3 "Energy Market," where the entity responsible for the energy offer is used rather than the entity receiving the uplift credit.

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 17.0 percent of all credits, with the top recipient receiving 3.6 percent. The top 10 units receiving day-ahead operating reserves received 87.6 percent. The top 10 recipients of balancing operating reserves received 14.9 percent of balancing operating reserve credits. The top 10 recipients of lost opportunity cost credits received 23.2 percent of total lost opportunity cost credits.

Table 4-17 Top 10 recipients of total uplift: 2020

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 1 F	BGE	$3,303,718	3.6%
2	BC BRANDON SHORES 2 F	BGE	$2,165,940	2.4%
3	DPL INDIAN RIVER 4 F	DPL	$1,936,008	2.1%
4	BC PERRYMAN 6 CT	BGE	$1,439,627	1.6%
5	VP MARSHRUN 1 CT	Dominion	$1,274,427	1.4%
6	VP MARSHRUN 3 CT	Dominion	$1,128,066	1.2%
7	VP MARSHRUN 2 CT	Dominion	$1,092,351	1.2%
8	VP LOUISA 5 CT	Dominion	$1,051,883	1.2%
9	PEP MORGANTOWN 1 F	Pepco	$1,048,167	1.2%
10	FE LEMOYNE 2 CT	ATSI	$1,040,365	1.1%
Total of Top 10			$15,480,552	17.0%
Total Uplift Credits			$90,877,619	100.0%

Table 4-18 Top 10 recipients of day-ahead generation credits: 2020

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 1 F	BGE	$2,948,379	31.8%
2	DPL INDIAN RIVER 4 F	DPL	$1,570,047	16.9%
3	BC BRANDON SHORES 2 F	BGE	$1,525,928	16.4%
4	PEP MORGANTOWN 1 F	Pepco	$805,646	8.7%
5	PEP MORGANTOWN 2 F	Pepco	$671,158	7.2%
6	PEP CHALKPOINT 2 F	Pepco	$145,113	1.6%
7	COM 3 POWERTON 5	ComEd	$136,128	1.5%
8	PL BRUNNER ISLAND 3 F	PPL	$128,535	1.4%
9	PEP CHALKPOINT 4 F	Pepco	$117,987	1.3%
10	PEP CHALKPOINT 3 F	Pepco	$79,282	0.9%
Total of Top 10			$8,128,203	87.6%
Total day-ahead operating reserve credits			$9,276,692	100.0%

Table 4-19 Top 10 recipients of balancing operating reserve credits: 2020

Rank	Unit Name	Zone	Balancing Operating Reserve Credit	Share of Balancing Operating Reserve Credits
1	VP MARSHRUN 1 CT	Dominion	$1,198,126	2.1%
2	VP MARSHRUN 3 CT	Dominion	$1,070,748	1.8%
3	VP MARSHRUN 2 CT	Dominion	$1,069,024	1.8%
4	VP LOUISA 5 CT	Dominion	$890,120	1.5%
5	FE LEMOYNE 2 CT	ATSI	$802,413	1.4%
6	FE LEMOYNE 3 CT	ATSI	$771,297	1.3%
7	AEP RIVERSIDE ZELDA 2 CT	AEP	$753,266	1.3%
8	AEP FOOT HILLS 2 CT	AEP	$740,867	1.3%
9	AEP RIVERSIDE ZELDA 3 CT	AEP	$711,988	1.2%
10	AEP RIVERSIDE ZELDA 1 CT	AEP	$680,397	1.2%
Total of Top 10			$8,688,247	14.9%
Total balancing operating reserve credits			$58,175,370	100.0%

Table 4-20 Top 10 recipients of lost opportunity cost credits: 2020

Rank	Unit Name	Zone	Lost Opportunity Cost Credit	Share of Lost Opportunity Cost Credits
1	BC PERRYMAN 6 CT	BGE	$832,449	4.3%
2	COM 900 ELWOOD 5 CT	ComEd	$542,655	2.8%
3	COM 900 ELWOOD 7 CT	ComEd	$514,222	2.7%
4	COM 900 ELWOOD 2 CT	ComEd	$450,058	2.3%
5	COM 900 ELWOOD 1 CT	ComEd	$411,750	2.1%
6	VP LADYSMYTH 4 CT	Dominion	$403,258	2.1%
7	COM 900 ELWOOD 6 CT	ComEd	$359,443	1.9%
8	COM 900 ELWOOD 4 CT	ComEd	$347,013	1.8%
9	VP DOSWELL 3 CT	Dominion	$343,465	1.8%
10	AEP CEREDO 1 CT	AEP	$280,239	1.4%
Total of Top 10			$4,484,552	23.2%
Total lost opportunity cost credits			$19,357,726	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 & UTCs	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids & UTCs	in RTO Region
Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits		→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids & UTCs	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC				
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-22 Reactive services, synchronous condensing and black start services credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:
		Reactive		
Resources Providing Reactive Service	Day-Ahead Operating Reserve Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Charge	Zonal Real-Time Load
			Reactive Services Local Constraint	Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Energy Uplift Charges Results

Energy Uplift Charges

Total energy uplift charges increased by $2.4 million or 2.7 percent in 2020 compared to 2019. Energy uplift charges in 2020 were $90.9 million.

Table 4-23 Total energy uplift charges: 2001 through 2020

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($175.3)	(56.2%)	0.4%
2017	$127.3	($9.4)	(6.9%)	0.3%
2018	$198.2	$70.9	55.7%	0.4%
2019	$88.5	($109.7)	(55.4%)	0.2%
2020	$90.9	$2.4	2.7%	0.3%

Table 4-24 shows total energy uplift charges by category in 2019 and 2020.[27] The increase of $2.4 million is comprised of a decrease of $6.2 million in day-ahead operating reserve charges, an increase of $8.8 million in balancing operating reserve charges and a decrease of $0.1 million in reactive service charges.

Table 4-24 Total energy uplift charges by category: 2019 and 2020

Category	2019 Charges (Millions)	2020 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$15.5	$9.3	($6.2)	(40.1%)
Balancing Operating Reserves	$72.2	$80.9	$8.8	12.1%
Reactive Services	$0.6	$0.4	($0.1)	(24.9%)
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.2	$0.2	$0.0	0.8%
Total	$88.5	$90.9	$2.4	2.7%
Energy Uplift as a Percent of Total PJM Billing	0.2%	0.3%	0.0%	19.8%

Table 4-25 compares monthly energy uplift charges by category for 2019 and 2020.

Table 4-25 Monthly energy uplift charges: 2019 and 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	$12.6	$0.0	$0.0	$0.0	$13.4
Sep	$1.7	$10.6	$0.0	$0.0	$0.0	$12.3	$2.1	$5.4	$0.0	$0.0	$0.0	$7.5
Oct	$0.9	$8.3	$0.0	$0.0	$0.0	$9.2	$1.1	$8.0	$0.0	$0.0	$0.1	$9.1
Nov	$0.2	$5.5	$0.0	$0.0	$0.0	$5.7	$0.6	$8.8	$0.0	$0.0	$0.0	$9.5
Dec	$0.5	$2.5	$0.1	$0.0	$0.0	$3.1	$0.5	$13.1	$0.0	$0.0	$0.0	$13.7
Total	$15.5	$72.2	$0.6	$0.0	$0.2	$88.5	$9.3	$80.9	$0.4	$0.0	$0.2	$90.9
Share	17.5%	81.6%	0.6%	0.0%	0.3%	100.0%	10.2%	89.1%	0.5%	0.0%	0.3%	100.0%

Table 4-26 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.[28] [29] Day-ahead operating reserve charges decreased by $6.2 million or 40.1 percent in 2020 compared to 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 nearly all of the total decrease in day-ahead operating reserve charges in 2020 compared to 2019.

Table 4-26 Day-ahead operating reserve charges: 2019 and 2020

Type	2019 Charges (Millions)	2020 Charges (Millions)	Change (Millions)	2019 Share	2020 Share
Day-Ahead Operating Reserve Charges	$15.5	$9.3	($6.2)	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$15.5	$9.3	($6.2)	100.0%	100.0%

27 Table 4-24 includes all categories of charges as defined in Table 4-21 and Table 4-22 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 12, 2021.

28 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.

29 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 charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $8.8 million or 12.1 percent in 2020 compared to 2019.

Table 4-27 Balancing operating reserve charges: 2019 and 2020

Type	2019 Charges (Millions)	2020 Charges (Millions)	Change (Millions)	2019 Share	2020 Share
Balancing Operating Reserve Reliability Charges	$21.0	$27.2	$6.1	29.2%	33.6%
Balancing Operating Reserve Deviation Charges	$48.2	$50.4	$2.1	66.8%	62.2%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$2.9	$3.4	$0.5	4.0%	4.2%
Total	$72.2	$80.9	$8.8	100.0%	100.0%

Table 4-28 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 2020, energy lost opportunity cost deviation charges increased by $2.2 million or 12.9 percent, and make whole deviation charges decreased by $0.1 million or 0.3 percent compared to 2019.

Table 4-28 Balancing operating reserve deviation charges: 2019 and 2020

Charge Attributable To	2019 Charges (Millions)	2020 Charges (Millions)	Change (Millions)	2019 Share	2020 Share
Make Whole Payments to Generators and Imports	$31.1	$31.0	($0.1)	64.5%	61.6%
Energy Lost Opportunity Cost	$17.1	$19.3	$2.2	35.5%	38.4%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$48.2	$50.4	$2.1	100.0%	100.0%

Table 4-29 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $0.1 million or 24.9 percent in 2020, compared to 2019.

Table 4-29 Additional energy uplift charges: 2019 and 2020

Type	2019 Charges (Millions)	2020 Charges (Millions)	Change (Millions)	2019 Share	2020 Share
Reactive Services Charges	$0.6	$0.4	($0.1)	71.6%	65.3%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.2	$0.2	$0.0	28.4%	34.7%
Total	$0.8	$0.7	($0.1)	100.0%	100.0%

Table 4-30 and Table 4-31 show the amount and shares of regional balancing charges in 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 2020, the largest share of regional charges was paid by real-time load which paid 33.3 percent of all regional balancing charges. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In 2020, regional balancing operating reserve charges increased by $8.2 million compared to 2019. Balancing operating reserve reliability charges increased by $6.1 million or 29.1 percent, and balancing operating reserve deviation charges increased by $2.1 million, or 4.3 percent.

Table 4-30 Regional balancing charges allocation (Millions): 2019

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$18.4	26.5%	$1.3	1.9%	$0.6	0.9%	$20.3	29.3%
	Real-Time Exports	$0.7	1.0%	$0.1	0.1%	$0.0	0.0%	$0.8	1.1%
	Total	$19.1	27.5%	$1.4	2.0%	$0.6	0.9%	$21.0	30.3%
Deviation Charges	Demand	$27.5	39.7%	$1.3	1.9%	$0.5	0.7%	$29.3	42.3%
	Supply	$8.0	11.5%	$0.4	0.6%	$0.1	0.2%	$8.6	12.4%
	Generator	$9.7	13.9%	$0.6	0.8%	$0.2	0.2%	$10.4	15.0%
	Total	$45.2	65.2%	$2.3	3.4%	$0.8	1.1%	$48.3	69.7%
Total Regional Balancing Charges		$64.3	92.7%	$3.7	5.3%	$1.4	2.0%	$69.4	100%

Table 4-31 Regional balancing charges allocation (Millions): 2020

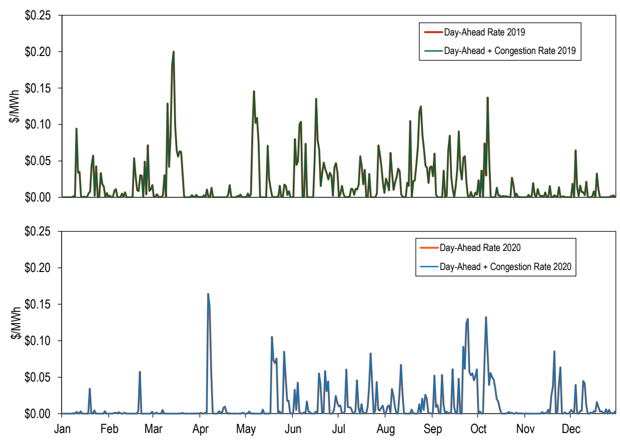
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$22.0	28.4%	$3.5	4.6%	$0.3	0.3%	$25.8	33.3%
	Real-Time Exports	$1.2	1.5%	$0.1	0.2%	$0.0	0.0%	$1.3	1.7%
	Total	$23.2	29.9%	$3.7	4.8%	$0.3	0.4%	$27.2	35.0%
Deviation Charges	Demand	$31.2	40.3%	$2.7	3.4%	$0.3	0.4%	$34.2	44.1%
	Supply	$5.7	7.3%	$0.5	0.7%	$0.1	0.1%	$6.3	8.1%
	Generator	$9.1	11.7%	$0.8	1.0%	$0.1	0.1%	$9.9	12.8%
	Total	$45.9	59.3%	$3.9	5.1%	$0.5	0.6%	$50.4	65.0%
Total Regional Balancing Charges		$69.1	89.2%	$7.6	9.9%	$0.8	1.0%	$77.5	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.[30]

Figure 4-2 shows the daily day-ahead operating reserve rate for 2019 and 2020. The average rate in 2020 was $0.012 per MWh, $0.007 per MWh lower than the average in 2019. The highest rate in 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 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 2020



30 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 2020. The average RTO reliability rate in 2020 was $0.030 per MWh. The highest RTO reliability rate in 2020 occurred on November 19 when the rate reached $0.457 per MWh, $0.089 per MWh higher than the $0.368 per MWh rate reached in 2019, on January 22.

Figure 4-3 Daily balancing operating reserve reliability rates ($/MWh): 2019 through 2020

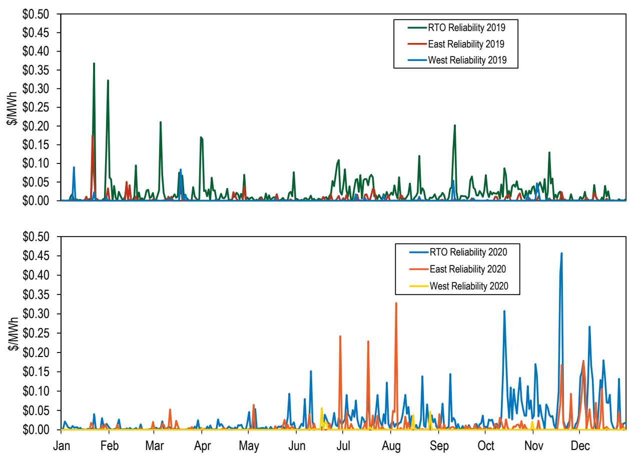


Figure 4-4 shows the RTO and regional deviation rates for 2019 and 2020. The average RTO deviation rate in 2020 was $0.162 per MWh. The highest daily rate in 2020 occurred on August 21, when the RTO deviation rate reached $1.222 per MWh, $0.004 per MWh less than the $1.226 per MWh rate reached in 2019, on July 9.

Figure 4-4 Daily balancing operating reserve deviation rates ($/MWh): 2019 through 2020

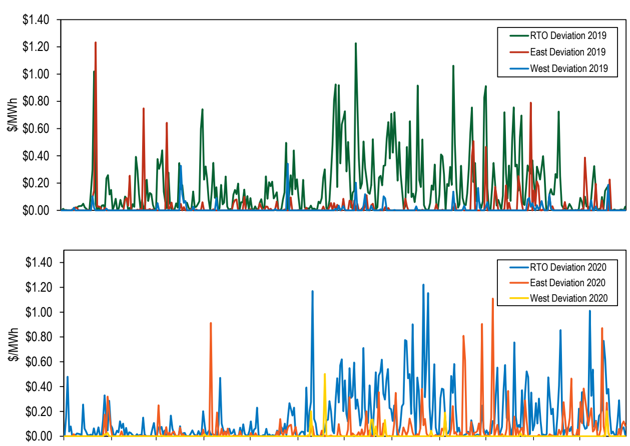


Figure 4-5 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2019 and 2020. The average lost opportunity cost rate in 2020 was $0.118 per MWh. The highest lost opportunity cost rate in 2020 occurred on June 3, when it reached $1.923 per MWh, $0.125 per MWh lower than 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 2020

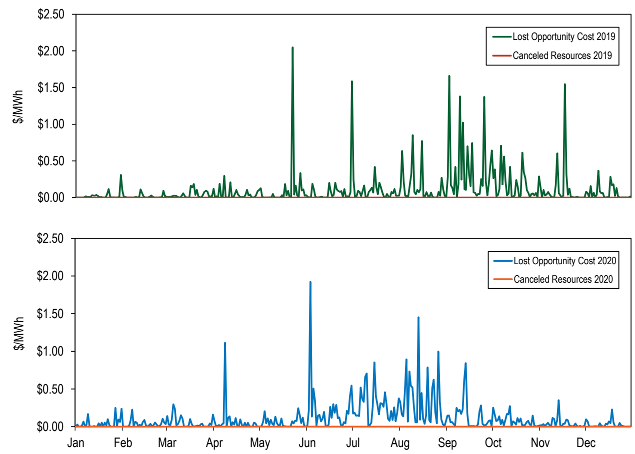


Table 4-32 shows the average rates for each region in each category for 2019 and 2020.

Table 4-32 Operating reserve rates ($/MWh): 2019 and 2020

Rate	2019 ($/MWh)	2020 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.019	0.012	(0.007)	(39.0%)
Day-Ahead with Unallocated Congestion	0.019	0.012	(0.007)	(39.0%)
RTO Reliability	0.024	0.030	0.006	25.0%
East Reliability	0.004	0.010	0.006	182.3%
West Reliability	0.001	0.001	(0.001)	(53.4%)
RTO Deviation	0.181	0.162	(0.020)	(10.9%)
East Deviation	0.030	0.050	0.020	66.6%
West Deviation	0.010	0.006	(0.005)	(44.4%)
Lost Opportunity Cost	0.111	0.118	0.007	5.9%
Canceled Resources	0.000	0.000	NA	NA

Table 4-33 shows the operating reserve cost of a one MW transaction in 2020. For example, in the Eastern Region a day-ahead withdrawal, such as a decrement bid or UTC, (if not offset by other transactions) paid an average rate of $0.341 per MWh with a maximum rate of $1.966 per MWh, a minimum rate of $0.001 per MWh and a standard deviation of $0.344 per MWh. The rates in Table 4-33 include all operating reserve charges including RTO deviation charges. The rates also include charges for UTCs, which were implemented on November 1, 2020 and which are treated similarly to DECs. Table 4-33 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels. In November and December 2020, the months in which UTCs were allocated uplift charges, the average rate for a UTC in the Eastern Region was 0.305 $/MWh, the maximum was 1.186 $/MWh, the minimum was 0.004 $/MWh, and the standard deviation was 0.282 $/MWh. In the Western Region, the average rate for a UTC was 0.224 $/MWh, the maximum was 1.020 $/MWh, the minimum was 0.003 $/MWh, and the standard deviation was 0.245 $/MWh. INCs, DECs, and UTCs have higher rates compared to real-time load because they always result in a deviation while day-ahead and real-time load do not always result in a deviation.

Table 4-33 Operating reserve rates statistics ($/MWh): 2020

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	1.961	0.329	<0.001	0.341
	DEC	1.966	0.341	0.001	0.344
	DA Load	0.164	0.012	<0.001	0.025
	RT Load	0.625	0.040	<0.001	0.068
	Deviation	1.961	0.329	<0.001	0.341
West	INC	1.961	0.285	<0.001	0.314
	DEC	1.966	0.296	<0.001	0.317
	DA Load	0.164	0.012	<0.001	0.025
	RT Load	0.457	0.030	<0.001	0.051
	Deviation	1.961	0.285	<0.001	0.314

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.[31] 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 4-34 shows the reactive services rates associated with local voltage support in 2019 and 2020. Table 4-34 shows that in 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 $0.008 per MWh for reactive services, and real-time load in the PPL Control Zone, where charges were the second highest, paid an average of $0.004 per MWh for reactive services.

Table 4-34 Local voltage support rates: 2019 and 2020

Control Zone	2019 ($/MWh)	2020 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	0.000	0.0%
AEP	0.000	0.000	(0.000)	(65.2%)
APS	0.000	0.000	(0.000)	(100.0%)
ATSI	0.000	0.000	(0.000)	(100.0%)
BGE	0.002	0.000	(0.002)	(100.0%)
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	0.006	0.000	(0.006)	(93.3%)
EKPC	0.001	0.004	0.003	221.1%
JCPL	0.000	0.008	0.008	NA
Met-Ed	0.000	0.000	0.000	16.9%
OVEC	0.000	0.000	0.000	0.0%
PECO	0.000	0.000	0.000	0.0%
PENELEC	0.008	0.000	(0.008)	(100.0%)
Pepco	0.000	0.000	0.000	0.0%
PPL	0.000	0.004	0.004	NA
PSEG	0.000	0.000	0.000	0.0%
RECO	0.000	0.000	0.000	0.0%

31 See *2019 State of the Market Report for PJM*, Volume 2, Section 10: Ancillary Service Markets.

Balancing Operating Reserve Determinants

Table 4-35 shows the determinants used to allocate the regional balancing operating reserve charges in 2019 and 2020. Total real-time load and real-time exports were 782,875 GWh, 2.7 percent lower in 2020 compared to 2019. Total deviations summed across the demand, supply, and generator categories were 164,551 GWh, 6.6 percent higher in 2020 compared to 2019.

Table 4-35 Balancing operating reserve determinants (GWh): 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
2019	RTO	771,929	32,874	804,803	92,739	28,251	33,392	154,382
	East	367,968	14,615	382,582	44,897	15,351	17,278	77,526
	West	403,961	18,259	422,221	47,187	12,356	16,114	75,657
2020	RTO	742,987	39,888	782,875	109,569	22,539	32,444	164,551
	East	355,089	13,276	368,364	51,071	12,132	15,353	78,556
	West	387,898	26,612	414,510	57,812	10,101	17,091	85,004
Difference	RTO	(28,942)	7,014	(21,928)	16,830	(5,713)	(948)	10,170
	East	(12,879)	(1,339)	(14,218)	6,173	(3,219)	(1,925)	1,030
	West	(16,063)	8,353	(7,710)	10,625	(2,254)	977	9,347

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, calculated between day-ahead and real-time generation, 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 4-36 shows the different categories by type of transactions that incurred deviations. In 2020, 37.3 percent of all RTO deviations were incurred by virtual transactions, or by a transaction that combines virtuals with exports or load. The volume of UTC deviations represents 31.5 percent of total deviations since November 1, 2020.

Table 4-36 Deviations by transaction type: 2020

Deviation		Deviation (GWh)			Share		
Category	Transaction	RTO	East	West	RTO	East	West
Demand	DECs Only	26,689	14,205	11,982	16.2%	18.1%	14.1%
	UTCs Only	11,444	3,344	7,916	7.0%	4.3%	9.3%
	Load Only	60,561	30,052	30,508	36.8%	38.3%	35.9%
	Exports Only	7,532	3,126	4,406	4.6%	4.0%	5.2%
	Combination of Load/Exports with DECs/UTCs	3,330	330	3,000	2.0%	0.4%	3.5%
	Combination of Load/Exports without DECs/UTCs	13	13	0	0.0%	0.0%	0.0%
Supply	INCs Only	19,667	9,837	9,524	12.0%	12.5%	11.2%
	Combination of Imports & INCs	197	195	2	0.1%	0.2%	0.0%
	Imports Only	2,675	2,100	575	1.6%	2.7%	0.7%
Generators		32,444	15,353	17,091	19.7%	19.5%	20.1%
Total		164,551	78,556	85,004	100.0%	100.0%	100.0%

Geography of Charges and Credits

Table 4-37 shows the geography of charges and credits in 2020. Table 4-37 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.

Table 4-37 Geography of regional charges and credits: 2020

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$1.3	$1.4	$0.1	1.4%	1.6%	0.0%	0.4%
	AEP	$11.8	$13.3	$1.5	13.6%	15.3%	0.0%	5.3%
	APS	$4.4	$2.0	($2.4)	5.0%	2.3%	8.3%	0.0%
	ATSI	$5.5	$4.9	($0.6)	6.3%	5.6%	2.1%	0.0%
	BGE	$3.6	$8.0	$4.4	4.2%	9.2%	0.0%	15.2%
	ComEd	$8.7	$20.1	$11.4	10.0%	23.1%	0.0%	39.2%
	DAY	$1.3	$2.5	$1.2	1.5%	2.9%	0.0%	4.0%
	DEOK	$2.4	$2.0	($0.4)	2.8%	2.3%	1.4%	0.0%
	DLCO	$1.2	$0.1	($1.1)	1.4%	0.1%	3.9%	0.0%
	Dominion	$9.7	$13.0	$3.3	11.1%	14.9%	0.0%	11.3%
	DPL	$2.2	$5.5	$3.3	2.6%	6.3%	0.0%	11.3%
	EKPC	$1.2	$3.0	$1.8	1.4%	3.5%	0.0%	6.2%
	External	$0.0	$2.0	$2.0	0.0%	2.3%	0.0%	7.0%
	JCPL	$2.4	$1.3	($1.0)	2.7%	1.5%	3.6%	0.0%
	Met-Ed	$1.9	$0.6	($1.2)	2.2%	0.7%	4.3%	0.0%
	OVEC	$0.3	$0.0	($0.3)	0.3%	0.0%	1.0%	0.0%
	PECO	$4.0	$0.1	($3.9)	4.6%	0.1%	13.5%	0.0%
	PENELEC	$2.8	$1.2	($1.6)	3.3%	1.4%	5.5%	0.0%
	Pepco	$3.3	$3.3	($0.0)	3.8%	3.8%	0.1%	0.0%
	PPL	$4.8	$1.2	($3.6)	5.5%	1.3%	12.5%	0.0%
	PSEG	$4.3	$1.4	($2.9)	4.9%	1.6%	10.1%	0.0%
	RECO	$0.4	$0.0	($0.4)	0.4%	0.0%	1.2%	0.0%
	All Zones	$77.3	$86.8	$9.5	89.1%	100.0%	67.3%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.7	$0.0	($0.7)	0.8%	0.0%	2.5%	0.0%
	Dominion	$0.3	$0.0	($0.3)	0.3%	0.0%	0.9%	0.0%
	Eastern	$0.2	$0.0	($0.2)	0.3%	0.0%	0.8%	0.0%
	New Jersey	$0.4	$0.0	($0.4)	0.4%	0.0%	1.3%	0.0%
	Ohio	$0.2	$0.0	($0.2)	0.3%	0.0%	0.8%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$1.4	$0.0	($1.4)	1.6%	0.0%	4.9%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$3.3	$0.0	($3.3)	3.8%	0.0%	11.2%	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	$0.4	$0.0	($0.4)	0.5%	0.0%	1.4%	0.0%
	IMO	$0.1	$0.0	($0.1)	0.1%	0.0%	0.3%	0.0%
	Linden	$0.4	$0.0	($0.4)	0.5%	0.0%	1.4%	0.0%
	MISO	$3.0	$0.0	($3.0)	3.5%	0.0%	10.5%	0.0%
	NCMPA Imp	$0.2	$0.0	($0.2)	0.2%	0.0%	0.6%	0.0%
	Neptune	$0.3	$0.0	($0.3)	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)	0.2%	0.0%	0.7%	0.0%
	NYIS	$0.6	$0.0	($0.6)	0.7%	0.0%	2.2%	0.0%
	South Exp	$0.6	$0.0	($0.6)	0.7%	0.0%	2.0%	0.0%
	South Imp	$0.3	$0.0	($0.3)	0.4%	0.0%	1.2%	0.0%
	All Interfaces	$6.2	$0.0	($6.2)	7.2%	0.0%	21.5%	0.0%
	Total	$86.8	$86.8	$0.0	100.0%	100.0%	100.0%	100.0%

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 1.3 percent of the corresponding credits. The PPL Control Zone received less operating reserve credits than operating reserve charges paid and had 12.5 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 4.2 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 9.2 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 15.2 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-37 also shows that 89.1 percent of all charges were allocated in control zones, 3.8 percent in hubs and aggregates and 7.2 percent in interfaces.

Energy Uplift Issues

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple segmented blocks of time during the operating day (intraday).[32] 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 4-38 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In 2019, balancing operating reserve credits would have been $13.3 million or 25.4 percent lower if they were calculated on a daily basis. In 2020, balancing operating reserve credits would have been $10.7 million or 18.5 percent lower if they were calculated on a daily basis.

Table 4-38 Intraday segments and daily balancing operating reserve credits: 2019 and 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	($3.0)
Aug	$5.1	$3.0	($2.0)	$8.1	$6.0	($2.1)
Sep	$5.7	$4.0	($1.7)	$3.7	$2.8	($0.9)
Oct	$5.9	$4.5	($1.4)	$6.8	$5.9	($0.9)
Nov	$3.9	$2.5	($1.4)	$7.8	$7.0	($0.8)
Dec	$1.7	$1.2	($0.5)	$11.8	$11.0	($0.9)
Total	$52.1	$38.9	($13.3)	$58.2	$47.4	($10.7)

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 4-39 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 2020, LOC credits would have been 7.1 percent lower if they had been settled on an hourly basis rather than on a five minute basis. For 2020, LOC credits would have been $3.4 million or 18.9 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute settlement.

32 See PJM "Manual 28: Operating Reserve Accounting," Rev. 83 (Dec. 3, 2019).

Table 4-39 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: 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	$4.4	$4.1	($0.3)	$3.8	($0.6)
Sep	$1.6	$1.4	($0.2)	$1.2	($0.5)
Oct	$0.9	$0.8	($0.0)	$0.7	($0.2)
Nov	$0.8	$0.8	($0.1)	$0.7	($0.1)
Dec	$0.4	$0.4	$0.0	$0.3	($0.1)
Total	$18.2	$16.9	($1.3)	$14.8	($3.4)

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.[33] 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 4-40 shows that during 2020, 61.2 percent of uplift credits were paid to units that were committed and dispatched on price offers without parameter limits, 10.3 percent to units committed on cost-based offers, 2.4 percent were committed on price-based offers with limited parameters (PLS) and 0.6 percent to units committed on a combination of price-based and cost-based offers.

Table 4-40 Operating Reserve Credits by Offer Type: 2020

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Balancing Operating Reserve Credits (Millions)	Day Ahead Reactive Credits (Millions)	Real Time Reactive Credits (Millions)	Total	Share of Total Operating Reserve Credits
Cost	$1.0	$8.0	$0.0	$0.3	$9.4	10.3%
Price	$8.1	$47.5	$0.0	$0.0	$55.6	61.2%
Price PLS	$0.2	$2.1	$0.0	$0.0	$2.2	2.4%
Cost & Price	$0.0	$0.5	$0.0	$0.0	$0.5	0.6%
Cost & PLS	$0.0	$0.1	$0.0	$0.0	$0.1	0.1%
Price & PLS	$0.0	$0.0	$0.0	$0.0	$0.0	0.0%
Total	$9.3	$58.1	$0.1	$0.4	$67.8	74.6%

Table 4-41 shows day-ahead operating reserve credits paid to units called on days with hot and cold weather alerts, classified by commitment schedule type. Of all the day-ahead credits received during days with weather alerts, 79.2 percent went to units that were committed on price schedules less flexible than PLS.

Table 4-41 Day-ahead operating reserve credits during weather alerts by commitment schedule: 2020

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share
Committed on cost (cost capped)	$11,824	1.1%
Committed on price schedule as flexible as PLS	$51,950	5.0%
Committed on price schedule less flexible than PLS	$821,403	79.2%
Committed on price PLS	$151,936	14.6%
Total	$1,037,113	100.0%

33 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]
- 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

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.

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 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 2020, RPM installed capacity decreased 486.0 MW or 0.3 percent, from 184,722.8 MW on January 1 to 184,236.8 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2020, 45.6 percent was gas; 27.0 percent was coal; 17.5 percent was nuclear; 4.8 percent was hydroelectric; 3.0 percent was oil; 1.2 percent was wind; 0.4 percent was solid waste; and 0.6 percent was solar.
- **Market Concentration.** In the 2020/2021 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test. 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, the submitted sell offer exceeded the defined offer cap,

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)(ii).

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

- **2020/2021 RPM Third Incremental Auction.** Of the 521 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for zero generation resources (0.0 percent).
- **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 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 2020 was 6.3 percent, an increase from 5.5 percent in 2019.[15]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in 2020 was 84.8 percent, an increase from 83.5 percent in 2019.

Recommendations[16]

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.[17 18] (Priority: High. First reported 2013. Status: Not adopted.)

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 February 1, 2021. 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.

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).

- 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.)
- 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

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.

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

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 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.)
- The MMU recommends that PJM update the values in the CRF table in the tariff when the components change. (Priority: High. New recommendation. 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.)

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).

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 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 15,882.6 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, 32,348.9 MW (77.1 percent) were based on market funding. Of the 2,711.8 MW of additional capacity that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years, 2,613.4 MW (96.4 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. These subsidy programs 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 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.

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).

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).

Subsidies are contagious. Competition in the markets could be replaced and is now being replaced by competition to receive 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.

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

The 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 when it replaces participation in the PJM markets.[32] 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 for payments to some renewable resources at above market prices.[33] 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.[34] [35] [36] [37] 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.

The MMU recognizes that both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC market would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would not be an

32 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%20Ohio_FRRs_20200717.pdf>.

33 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).

34 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).

35 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).

36 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).

37 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).

efficient outcome and would not serve the interests of customers or generators.

With the expected elimination of the current MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable or clean resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a demand curve for clean resources based on the quantity of such resources identified by one or more states and clear a market for clean resources as part of the capacity market clearing process.

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, but only if done correctly and only if all the required assumptions are made explicit and decided explicitly. Implementing ELCC incorrectly, based on average rather than marginal values, and locking in values for old technology for long periods regardless of market realities, and basing the results on incorrect assumptions about the dispatch of some resource types, would be a significant mistake and create new issues for the PJM capacity markets. The results could degrade reliability, impede innovation and the introduction of new technologies, and inefficiently displace 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.

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.[38]

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/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 Yadkin 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/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/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/Messages/IMM_Response_to_Grid_Strategies_Report_201909217.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_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

38 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).

Table 5-2 RPM related MMU reports: 2019 through 2020 (continued)

Date	Name
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. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_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. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_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. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_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. EO18080899 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO18080899_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
September 19, 2020	ELCC-IMM Comments https://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MRC_ELCC_IMM_Comments_20200919.pdf
September 30, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20200930.pdf
October 19, 2020	Issues with HVDC as Capacity https://www.monitoringanalytics.com/reports/Presentations/2020/IMM_HVDCSTF_Issues_with_HVDC_as_Capacity_20201019.pdf
October 19, 2020	IMM Answer re EAS Docket No. EL19-58-003 https://www.monitoringanalytics.com/filings/2020/IMM_Answer_Docket_No_EL19-58-003_20201019.pdf
November 5, 2020	PAI Settlement Issues https://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_PAI_Settlement_Issues_20201102.pdf
November 20, 2020	IMM Comments re ELCC Docket No. ER21-278 https://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER21-278_20201120.pdf
December 4, 2020	CRF Issues in the Capacity Market https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_CRF_Issues_in_the_Capacity_Market_20201204.pdf
December 14, 2020	IMM Answer and Motion for Consolidation re ELCC Docket No. ER21-278 https://www.monitoringanalytics.com/filings/2020/IMM_Answer_Docket_No_ER21-278_20201214.pdf
December 17, 2020	IMM Comments re PAI Docket No. ER15-623, et al https://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER15-623_et_al_20201217.pdf
December 18, 2020	IMM Answer re PJM ELCC Proposal Docket No. ER21-278 https://www.monitoringanalytics.com/filings/2020/IMM_Answer_Docket_No_ER21-278_20201218.pdf
December 29, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20201229.pdf

Installed Capacity

On January 1, 2020, RPM installed capacity was 184,722.8 MW (Table 5-3).[39] Over the next twelve months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 184,236.8 MW on December 31, 2020, a decrease of 486.0 MW or 0.3 percent from the January 1 level.[40] [41] The 486.0 MW decrease was the result of a decrease in imports (494.9 MW), an increase in exports (234.7 MW), derates (168.0 MW), and deactivations (3,226.3 MW), offset by new or reactivated generation (2,323.4 MW), and uprates (1,314.5 MW).

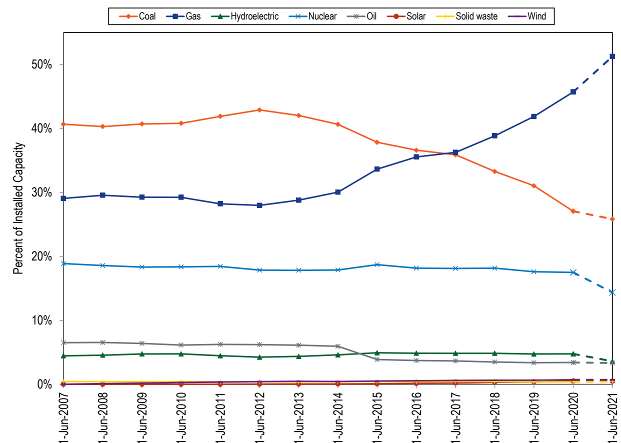
At the beginning of the new delivery year on June 1, 2020, RPM installed capacity was 184,583.3 MW, a decrease of 1,069.2 MW or 0.6 percent from the May 31, 2020, level of 185,652.5 MW.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2020

	01-Jan-20		31-May-20		01-Jun-20		31-Dec-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%	49,744.1	27.0%
Gas	82,313.9	44.6%	84,195.7	45.4%	84,355.1	45.7%	84,028.0	45.6%
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	17.5%
Oil	6,311.0	3.4%	6,282.8	3.4%	6,282.8	3.4%	5,512.6	3.0%
Solar	791.0	0.4%	791.0	0.4%	946.9	0.5%	1,014.7	0.6%
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%	2,177.1	1.2%
Total	184,722.8	100.0%	185,652.5	100.0%	184,583.3	100.0%	184,236.8	100.0%

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 December 31, 2020.[42] 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



39 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.

40 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.

41 Wind resources accounted for 2,177.1 MW, and solar resources accounted for 1,014.7 MW of installed capacity in PJM on December 31, 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).

42 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 December 31, 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 December 31, 2020

	01-Jan-20			31-May-20			01-Jun-20			31-Dec-20		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Exelon Corporation	21,165.8	12.4%	1	21,041.9	12.3%	1	20,801.8	12.1%	1	20,843.6	12.2%	1
Dominion Resources, Inc.	20,198.5	11.8%	2	20,198.5	11.8%	2	20,549.9	12.0%	2	19,533.2	11.4%	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	10,941.4	6.4%	4
LS Power Group	7,839.5	4.6%	7	8,709.5	5.1%	5	8,862.5	5.2%	5	8,829.5	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 December 31, 2020, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and December 31, 2020

	01-Jan-20		31-May-20		01-Jun-20		31-Dec-20	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	152,177.4	82.4%	153,111.1	82.5%	151,765.2	82.2%	152,403.5	82.7%
Nonmarket	32,545.4	17.6%	32,541.4	17.5%	32,818.1	17.8%	31,833.3	17.3%
Total	184,722.8	100.0%	185,652.5	100.0%	184,583.3	100.0%	184,236.8	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[43] 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.[44] 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.[45] The average FDI_c for 2020 decreased 1.3 percent compared to 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 4,763 MW of coal, CT and other capacity were identified as being at risk of retirement.[46] 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.[47] There are 4,163.9 MW of generation that have a requested retirement date after

43 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.

44 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.

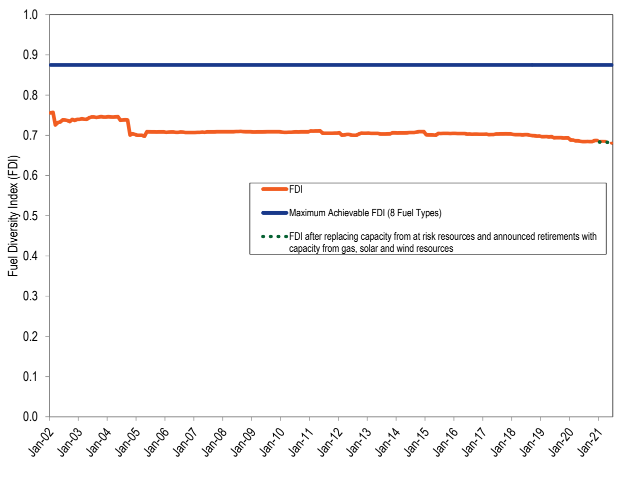
45 See the *2019 State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton Control Zones occurred in October 2004.

46 See Table 7-47 in the *2020 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

47 See OATT Part V § 113.1.

December 31, 2020.[48] 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, wind and solar capacity.[49] [50] The FDI_c under these assumptions would decrease by 0.2 percent on average from the expected FDI_c for the period January 1, 2021, through June 1, 2021.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2021



RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[51] In 2020, the 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted.[52]

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 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.

48 See *2020 State of the Market Report for PJM*, Section 12: Generation and Transmission Planning, Table 12-11.

49 It is assumed that 1,779.2 MW of replacement capacity is from solar units and 205.7 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 10,724.0 GWh of generation assuming the average capacity derate factors in the Planned Generation Additions subsection of Section 12 and the average capacity factors for wind and solar capacity resources in Table 8-27 and Table 8-30. This level of renewable generation represents the increase over 2020 levels of renewable generation that is required by RPS in 2021, assuming zero load growth. The split between solar and wind is based on queue data.

50 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 January 1, 2021.

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

52 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).

Future Changes in Generation Capacity[53]

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 (2,711.8 MW) and pending deactivations (3,081.4 MW), PJM capacity is expected to decrease by 1,005.1 MW for the 2020/2021 through 2021/2022 Delivery Years.

Table 5-6 Generation capacity changes: 2007/2008 through 2019/2020[54 55]

	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

Table 5-7 RPM reserve margin: June 1, 2016, to June 1, 2021[56 57]

										Reserve Margin in Excess of IRM			
	Generation and DR RPM Committed Less Deficiency UCAP (MW)	Forecast Peak Load	FRR Peak Load	PRD	RPM Peak Load	IRM	Pool Wide Average EFORd	Generation and DR RPM Committed Less Deficiency ICAP (MW)	Reserve Margin	Percent	ICAP (MW)	Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
01-Jun-16	160,883.3	152,356.6	12,511.6	0.0	139,845.0	16.4%	5.91%	170,988.7	22.3%	5.9%	8,209.2	0.0	22.3%
01-Jun-17	163,872.0	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,220.7	24.1%	7.5%	10,522.9	0.0	24.1%
01-Jun-18	161,242.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	171,662.5	22.9%	6.8%	9,499.8	0.0	22.9%
01-Jun-19	162,276.1	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	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%	5.78%	169,348.8	24.2%	8.7%	11,911.9	0.0	24.2%
01-Jun-21	164,267.3	149,482.9	11,717.7	510.0	137,255.2	14.7%	5.22%	173,314.3	26.3%	11.6%	15,882.6	6,818.8	21.0%

53 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).

54 The capacity changes in this report are calculated based on June 1 through May 31.

55 The calculated export MW for 2012/2013 were revised from the *2020 Quarterly State of the Market Report for PJM: January through March.*

56 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.

57 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

Sources of Funding[58]

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 26,798.1 MW from market funding and 8,179.1 MW from nonmarket funding. Uprates 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 5,550.8 MW from market funding and 1,451.4 MW from nonmarket funding. In summary, of the 41,979.4 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2019/2020 Delivery Years, 32,348.9 MW (77.1 percent) were based on market funding.

Of the 2,711.8 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2020/2021 through 2021/2022 delivery year, 2,226.8 MW are not yet in service. Of those 2,226.8 MW that have not yet gone into service, 2,207.8 MW have market funding and 19.0 MW have nonmarket funding. Applying the historical completion rates, 71.5 percent of all the projects in development are expected to go into service (1,577.7 MW of the 2,207.8 MW of market funded projects; 13.6 MW of the 19.0 MW of nonmarket funded projects). Together, 1,591.3 MW of the 2,226.8 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 485.0 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, 405.6 MW (83.6 percent) are based on market funding and 79.4 MW (16.4 percent) are based on nonmarket funding. In summary, 2,613.4 MW (96.4 percent) of the additional generation capacity (485.0 MW in service and 2,226.8 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 98.4 MW (3.6 percent) of proposed generation that cleared at least one RPM auction for the 2020/2021 through 2021/2022 Delivery Years.

58 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:

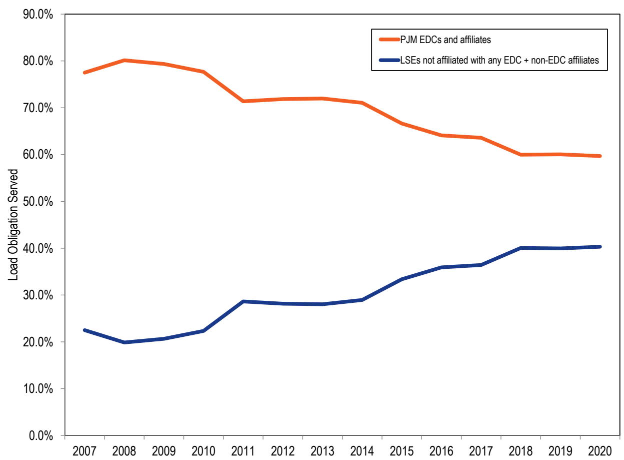
- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing 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.

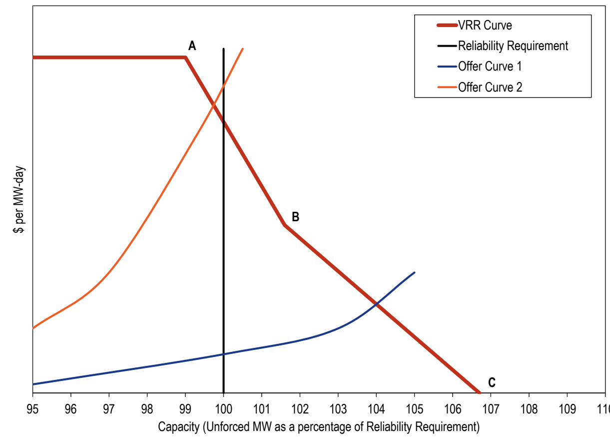
BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $6,734,907.

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 2020/2021 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test, and in the 2021/2022 RPM Second Incremental Auction two participants in the EMAAC LDA market passed the three pivotal supplier (TPS) test.[59] 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.[60 61 62]

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

59 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.

60 See OATT Attachment DD § 6.5.

61 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).

62 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).

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 Auctions[63]

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
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

63 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[64] 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."[65] 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.[66] 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

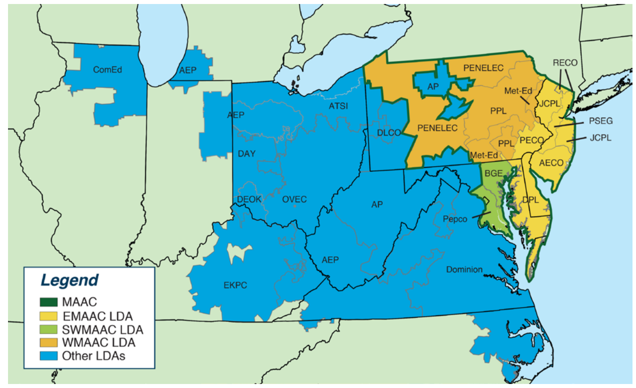


Figure 5-6 Map of RPM EMAAC subzonal LDAs

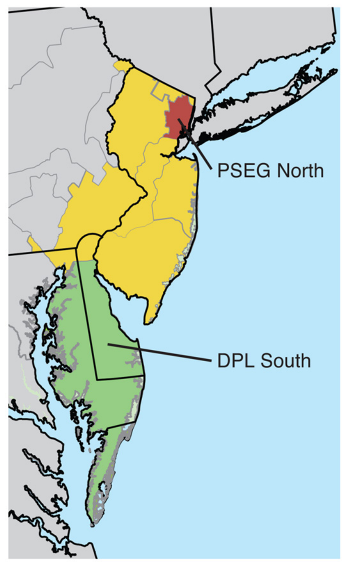
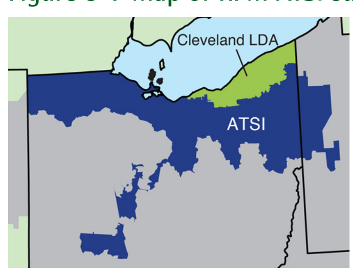


Figure 5-7 Map of RPM ATSI subzonal LDA



64 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.
65 OATT Attachment DD § 5.10 (a) (ii).
66 146 FERC ¶ 61,052 (2014).

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.[67]

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.[68] 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.[69]

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.[70] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

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.

67 OATT Attachment DD § 5.6.6(b).

68 147 FERC ¶ 61,060 (2014).

69 151 FERC ¶ 61,208 (2015).

70 161 FERC ¶ 61,197 (2017), *order denying reh'g*, 170 FERC ¶ 61,217 (2020).

Table 5-10 RPM imports: 2007/2008 through 2021/2022 RPM Base Residual Auctions

Base Residual Auction	UCAP (MW) MISO Offered	MISO Cleared	Non-MISO Offered	Non-MISO Cleared	Total Imports Offered	Total Imports 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:[71]

- **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.[72]

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:[73] [74]

- **Base Capacity Resources**
  - **Base Capacity Demand Resources.** A demand resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base capacity DR is required to be capable of maintaining each interruption for at least 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Base Capacity Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the base capacity energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the base capacity energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.
- **Capacity Performance Resources**
  - **Annual Demand Resources.** A demand resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only 10 hours during the hours of 10:00 a.m. to 10:00 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

71 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.

72 Letter Order, Docket No. ER10-366-000 (January 22, 2010).

73 151 FERC ¶ 61,208.

74 PJM Reliability Assurance Agreement Article 1.

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[75 76 77]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	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	184.7
	EE cleared	3,569.5	1,288.8	700.3	394.5	28.8	246.1	111.3	196.2	356.0	72.9	852.0	198.3	111.4	79.5	105.6
	DR net replacements	(2,399.5)	(858.7)	(369.0)	(176.5)	(29.7)	(136.5)	(89.0)	(53.3)	(121.1)	(36.2)	(314.5)	(123.2)	(171.0)	(66.1)	(27.5)
	EE net replacements	(29.7)	(0.5)	(0.3)	5.9	0.0	(6.3)	12.0	(0.6)	(0.2)	0.0	(0.1)	6.5	(5.2)	0.0	(5.0)
	RPM load management	10,586.0	3,258.7	1,499.9	709.7	71.7	442.3	187.0	378.6	1,186.4	268.6	2,194.7	331.1	551.8	254.9	257.8
01-Jun-21	DR cleared	11,419.8	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	220.5
	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	114.8
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	15,450.8	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	335.3

75 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.

76 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.

77 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[78 79 80]

	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[81 82]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5
01-Jun-20	3,569.5	0.0	(29.7)	3,539.8	(0.1)	3,539.7
01-Jun-21	4,031.0	0.0	0.0	4,031.0	0.0	4,031.0

78 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.

79 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.

80 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.

81 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.

82 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.[83] [84] [85] 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.[86] 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.[87] 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.[88]

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).[89] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Calculation of Offer Caps

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (Net ACR); and the resource's performance during performance assessment intervals (A) in the delivery year.[90]

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 OATT Attachment DD § 6.8 (b).

87 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).

88 OATT Attachment DD § 6.8(a).

89 151 FERC ¶ 61,208.

90 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.

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.[91]

The default offer cap defined in the PJM tariff, Net CONE times the average Balancing Ratio, is based on a number of assumptions:

1. The Net ACR of a resource is less than its expected energy only bonuses:

$$ACR \leq \sum_{i=1}^{H}(CPBR_i \times A_i)$$

$$or\ ACR \leq \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A})$$

2. The expected number of performance assessment intervals equals 360. (H = 360 intervals, or 12 hours)
3. The expected value of the bonus performance payment rate (CPBR) is equal to the nonperformance charge rate (PPR)
4. The average expected performance of the resource during performance assessment hours ($\bar{A}$)

The competitive offer of such a resource is:

$$p = \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A}))$$

In other words, the competitive offer of such a resource is the opportunity cost of taking on the capacity obligation which equals the sum of the energy only bonuses it would have earned ($CPBR \times H \times \bar{A})/12$) and the net nonperformance charges it would incur by taking on the capacity obligation ($PPR \times H \times (\bar{B} - \bar{A})/12)$. Both the components are proportional to the expected number of performance assessment intervals. If the expected number of performance assessment intervals (H) is significantly lower than the value used to determine the 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 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.[92] [93] 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 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.[94] 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

91 OATT Attachment DD § 10A (d).

92 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.

93 See Table 5-7.

94 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_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

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.[95] 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.[96]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[97] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exception process for those that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the transmission system; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from modeled LDAs only.

Effective December 8, 2017, FERC issued an order on remand rejecting PJM's MOPR proposal in Docket No. ER13-535, and as a result, the rules that were in effect prior to PJM's December 7, 2012, MOPR filing were reinstated. These changes include eliminating the Competitive Entry and Self Supply Exemptions and retaining only the Unit Specific Exception request; narrowing the region subject to MOPR from the entire RTO to only modeled LDAs; eliminating the 20.0 MW threshold for applicability; 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.[98]

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[99] 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 resources with state subsidies as 100 percent of the applicable net CONE or net ACR values. The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.[100] 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. The 2022/2023 BRA is scheduled to be run in May 2021.[101]

2020/2021 RPM Third Incremental Auction

As shown in Table 5-14, 521 generation resources submitted Capacity Performance offers in the 2020/2021 RPM Third Incremental Auction. Unit specific offer caps were calculated for zero generation resources (0.0

95 135 FERC ¶ 61,022 (2011).
96 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011).
97 143 FERC ¶ 61,090 (2013).
98 161 FERC ¶ 61,252 (2017).
99 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).
100 173 FERC ¶ 61,134 (2020).
101 174 FERC ¶ 61,036 (2021).

percent). Of the 521 generation resources, 447 generation resources had the net CONE times B offer cap (85.8 percent), 57 generation resources elected the offer cap option of 1.1 times the BRA clearing price (10.9 percent), seven Planned Generation Capacity Resources had uncapped offers (1.3 percent), and the remaining 10 generation resources were price takers (1.9 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

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 832.4 ICAP MW of MOPR Unit-Specific Exception requests for the 2020/2021 RPM Third Incremental Auction, requests for 832.4 MW were granted. 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 2020

	2020/2021 Third Incremental Auction		2021/2022 Second Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA	NA	NA
Unit specific ACR (APIR)	0	0.0%	0	0.0%
Unit specific ACR (APIR and CPQR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	0	0.0%
Opportunity cost input	0	0.0%	0	0.0%
Default ACR and opportunity cost	NA	NA	NA	NA
Net CONE times B	447	85.8%	241	87.3%
Offer cap of 1.1 times BRA clearing price elected	57	10.9%	NA	NA
Uncapped planned uprate and default ACR	NA	NA	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	0	0.0%	20	7.2%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	0	0.0%	NA	NA
Uncapped planned generation resources	7	1.3%	10	3.6%
Existing generation resources as price takers	10	1.9%	5	1.8%
Total Generation Capacity Resources offered	521	100.0%	276	100.0%

Table 5-15 MOPR statistics: RPM auctions conducted 2020[102]

		Number of Requests	ICAP (MW)			UCAP (MW)	
		(Company-Plant Level)	Requested	Granted	Offered	Offered	Cleared
2020/2021 Third Incremental Auction	Unit-Specific Exception	19	832.4	832.4	79.2	75.2	41.9
	Other MOPR Screened Generation Resources	0	0.0	0.0	113.3	112.8	0.0
	Total	19	832.4	832.4	192.5	188.0	41.9
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 Capacity[103]

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	(1,179.7)	168,298.3	0.0	168,298.3

Market Performance

Figure 5-8 shows cleared MW weighted average capacity market prices on a delivery year basis, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

Table 5-17 shows RPM clearing prices for all RPM auctions held through 2020, and Table 5-18 shows the RPM cleared MW for all RPM auctions held through 2020.

Figure 5-9 shows the RPM cleared MW weighted average prices for each LDA from the 2018/2019 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through 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 2020 based on the unforced MW cleared and the resource clearing prices. In the 2019/2020 Delivery Year RPM revenue was $7.1 billion. In the 2020/2021 Delivery Year, RPM revenue was $7.0 billion.

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through 2020. In 2018, RPM revenue was $10.3 billion. In 2019, RPM revenue was $8.7 billion.

102 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.

103 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).

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: 2019/2020 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: 2019/2020 through 2021/2022 RPM Auctions[104]

		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

104 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)			
LDA	2018/2019	2019/2020	2020/2021	2021/2022
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 2021/2022[105]

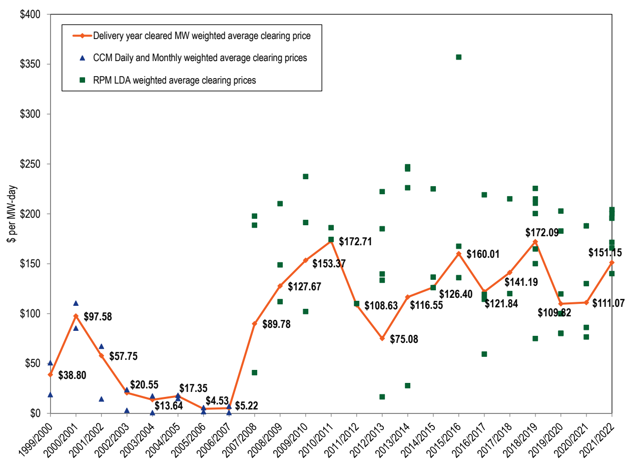
Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$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

105 The results for the ATSI Integration Auctions are not included in this table.

Table 5-21 RPM revenue by calendar year: 2007 through 2022[106]

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

Figure 5-8 History of capacity prices: 1999/2000 through 2021/2022[107]



106 The results for the ATSI Integration Auctions are not included in this table.

107 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 LDA clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-9 Map of RPM capacity prices: 2018/2019 through 2021/2022

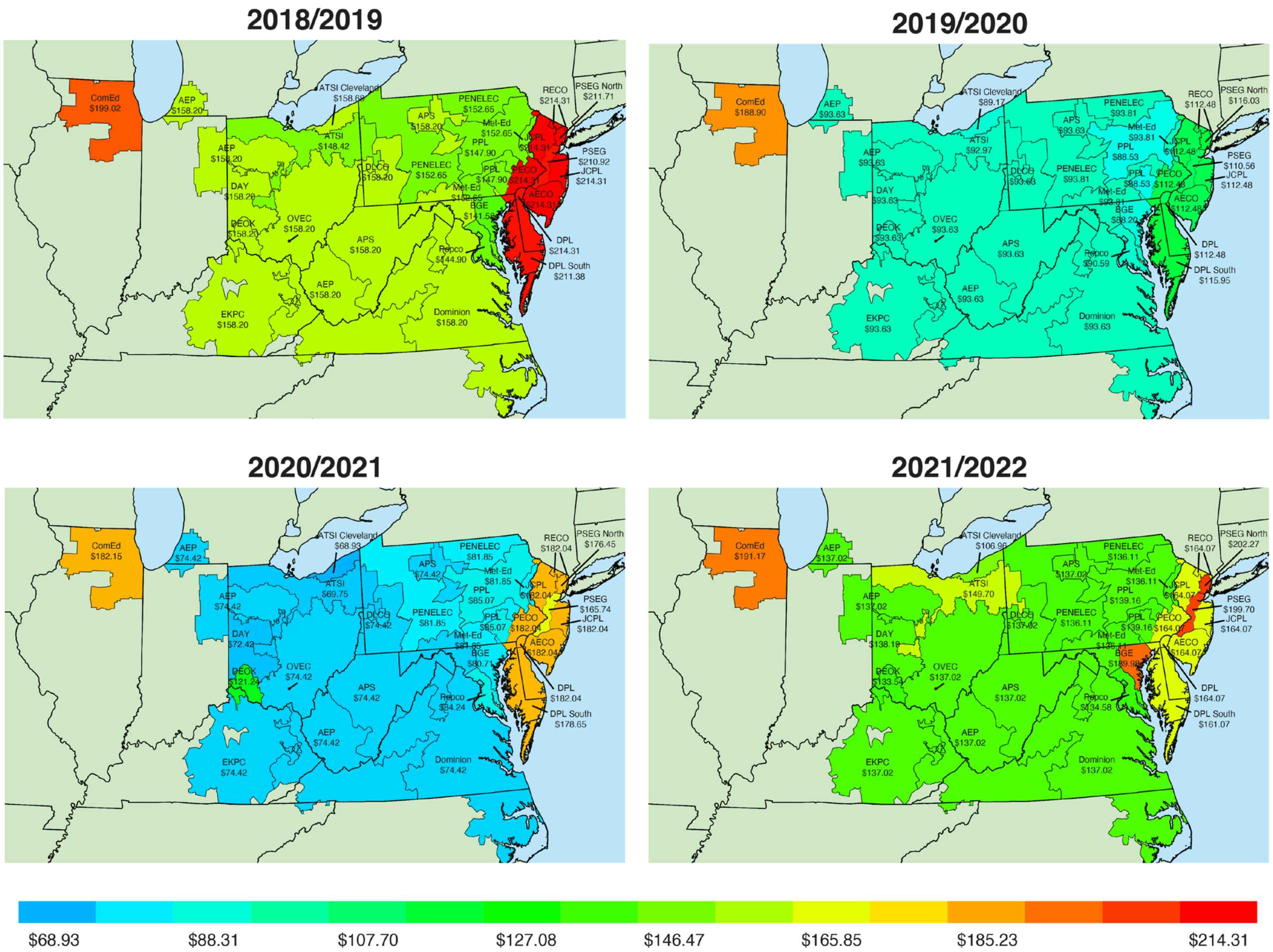


Table 5-22 RPM cost to load: 2019/2020 through 2021/2022 RPM Auctions[108 109 110]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2019/2020			
Rest of RTO	$98.07	89,185.9	$3,201,364,940
Rest of EMAAC	$115.58	24,415.1	$1,032,810,556
BGE	$97.79	7,595.2	$271,828,430
ComEd	$192.56	24,985.1	$1,760,892,086
Pepco	$92.90	7,330.3	$249,230,694
PSEG	$115.83	11,281.1	$478,247,326
Total		164,792.8	$6,994,374,033
2020/2021			
Rest of RTO	$77.31	69,073.7	$1,949,098,489
Rest of MAAC	$87.06	29,555.9	$939,246,366
EMAAC	$174.32	35,740.4	$2,274,098,760
ComEd	$189.92	23,744.7	$1,645,988,210
DEOK	$104.50	5,072.0	$193,459,838
Total		163,186.7	$7,001,891,663
2021/2022			
Rest of RTO	$142.71	81,244.5	$4,232,062,441
Rest of EMAAC	$164.89	23,999.1	$1,444,396,169
ATSI	$160.78	13,978.7	$820,348,098
BGE	$164.58	7,316.9	$439,530,736
ComEd	$198.71	23,149.9	$1,679,053,039
PSEG	$188.02	11,275.2	$773,794,246
Total		160,964.3	$9,389,184,729

CRF Issue

As a result of the significant changes to the federal tax code in December 2017, the CRF (capital recovery factor) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A are not correct. These tables should have been updated in 2018 and should be updated prior to the next capacity market auction. Correct CRFs will ensure that offer caps and offer floors in the capacity market are correct. The required changes are clear and unambiguous. An immediate filing to change the table based only on the known changes to the tax code would avoid potential uncertainty and confusion among market participants and would avoid any potential delay in running or finalizing the results of the capacity auctions. PJM could file the changes under FPA Section 205. The MMU issued a public statement on these issues.[111]

The current CRF table includes tax rates and depreciation provisions in the tax code that are no longer correct. The result is that the current tariff CRF values are significantly too high. A combination of modified depreciation rules and a reduction of the corporate tax rate has reduced the calculated CRF values required to provide the same return on and of capital as provided by the prior CRF values when the prior tax provisions were in effect. A reduced amount of revenue is required in order to provide full recovery on and of the relevant capital investment. Table 5-23 includes the new CRF values based solely on changes to the federal tax code.

108 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.

109 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.

110 The net load prices and obligation MW for 2021/2022 are not finalized.

111 *See* "CRF issues in the capacity market," December 4, 2020 <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_CRF_Issues_in_the_Capacity_Market_20201204.pdf>.

Table 5-23 Levelized CRF requests: 2022 through 2027

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF 2022	Levelized CRF 2023	Levelized CRF 2024	Levelized CRF 2025	Levelized CRF 2026	Levelized CRF 2027
1 to 5	30	0.082	0.087	0.091	0.095	0.099	0.103
6 to 10	25	0.088	0.092	0.096	0.100	0.105	0.109
11 to 15	20	0.096	0.101	0.105	0.110	0.114	0.119
16 to 20	15	0.111	0.116	0.121	0.126	0.131	0.136
21 to 25	10	0.144	0.151	0.158	0.165	0.172	0.179
25 Plus	5	0.246	0.259	0.273	0.286	0.300	0.313
Mandatory CapEx	4	0.297	0.314	0.331	0.349	0.366	0.383
40 Plus Alternative	1	1.100	1.100	1.100	1.100	1.100	1.100

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 issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[113]

Table 5-24 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through December 2020. Of the 77 deactivation requests submitted, 17 units (22.1 percent) deactivated an average of 232 days earlier than their initially requested date; 12 units (15.6 percent) deactivated an average of 95 days later than the originally requested deactivation date; and 25 units (32.5 percent) deactivated on their initially requested date. Twelve (15.6 percent) of the unit deactivations were cancelled an average of 435 days before their scheduled deactivation date, and 11 (14.3 percent) of the unit deactivations have not yet reached their target retirement date.

Table 5-24 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted 2018 through 2020

	Number of Units	Percent	Average Deviation from Originally Requested Date
Early	17	22.1%	(232)
Late	12	15.6%	95
On time	25	32.5%	0
Cancelled	12	15.6%	(435)
Pending	11	14.3%	-
Total	77	100.0%	-

112 OATT Attachment DD § 6.6(g).
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]

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]

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.*

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 5-25 shows units that have provided RMR service to PJM.

Table 5-25 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-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Only two of seven owners have used the deactivation avoidable cost rate approach. The other five owners used the cost of service recovery rate, despite the greater administrative expense.

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 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.

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.

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 5-26 shows the capacity factors by unit type in 2019 and 2020. In 2020, nuclear units had a capacity factor of 92.9 percent, compared to 92.3 percent in 2019; combined cycle units had a capacity factor of 52.4 percent in 2020, compared to a capacity factor of 53.7 percent in 2019; all steam units had a capacity factor of 23.4 percent in 2020, compared to 27.3 percent in 2019; coal units had a capacity factor of 25.6 percent in 2020, compared to 30.1 percent in 2019.

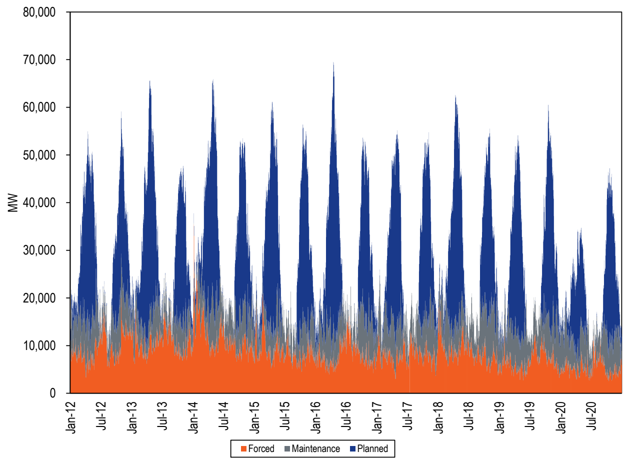
Table 5-26 Capacity factor (By unit type (GWh)): 2019 and 2020[130] [131]

	2019		2020		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in 2020 from 2019
Battery	18.8	0.6%	36.1	1.2%	0.6%
Combined Cycle	278,310.5	53.7%	294,736.1	52.4%	(1.3%)
Single Fuel	236,429.8	55.7%	252,301.6	54.3%	(1.4%)
Dual Fuel	41,880.7	44.4%	42,434.4	43.3%	(1.0%)
Combustion Turbine	16,351.6	5.4%	19,242.3	6.4%	1.0%
Single Fuel	11,063.7	5.1%	13,336.8	6.2%	1.1%
Dual Fuel	5,287.9	6.3%	5,905.4	7.0%	0.7%
Diesel	262.3	6.1%	282.5	6.2%	0.2%
Single Fuel	257.5	7.2%	273.5	7.3%	0.1%
Dual Fuel	4.8	0.6%	9.1	1.2%	0.5%
Diesel (Landfill gas)	1,656.6	42.8%	1,560.8	42.3%	(0.5%)
Fuel Cell	212.8	76.0%	226.6	80.7%	4.7%
Nuclear	278,904.6	92.3%	276,607.6	92.9%	0.5%
Pumped Storage Hydro	5,621.2	9.7%	6,049.3	10.4%	0.7%
Run of River Hydro	11,075.5	31.7%	10,374.0	29.6%	(2.1%)
Solar	2,725.4	18.5%	3,812.0	17.1%	(1.5%)
Steam	209,789.5	27.3%	170,400.7	23.4%	(4.0%)
Biomass	5,837.3	53.3%	5,533.8	52.7%	(0.6%)
Coal	197,730.2	30.1%	158,518.0	25.6%	(4.5%)
Single Fuel	193,837.5	30.9%	156,055.0	26.4%	(4.5%)
Dual Fuel	3,892.7	13.1%	2,463.0	8.8%	(4.3%)
Natural Gas	6,122.3	34.8%	6,262.9	35.3%	0.5%
Single Fuel	403.9	40.2%	426.7	40.7%	0.4%
Dual Fuel	5,718.4	21.2%	5,836.2	21.4%	0.2%
Oil	99.8	0.3%	86.0	0.5%	0.2%
Wind	24,166.7	28.8%	26,431.0	28.1%	(0.7%)
Total	829,099.8	39.6%	809,765.2	38.4%	(1.2%)

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.

Figure 5-10 Outages (MW): 2012 through 2020

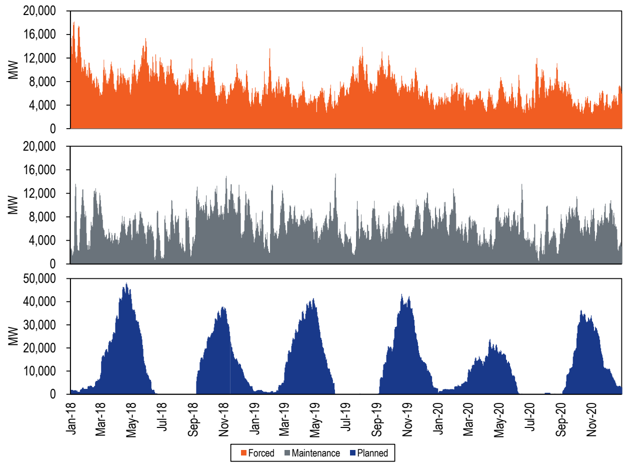


130 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

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.

In 2020, forced and planned outages were lower than in 2018 and 2019 (Figure 5-11). The MWh of planned outages in 2020 were 26 percent lower than in 2019 and the MWh of forced outages were 20 percent lower than in 2019. The MWh of maintenance outages were 7 percent lower than in 2019. Spring 2020 planned outages are expected to have been deferred to 2021 as a result of COVD related issues.

Figure 5-11 Outages (MW): Forced, maintenance and planned outages 2018 through 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 5-27.

Figure 5-12 Equivalent outage and availability factors: 2007 to 2020

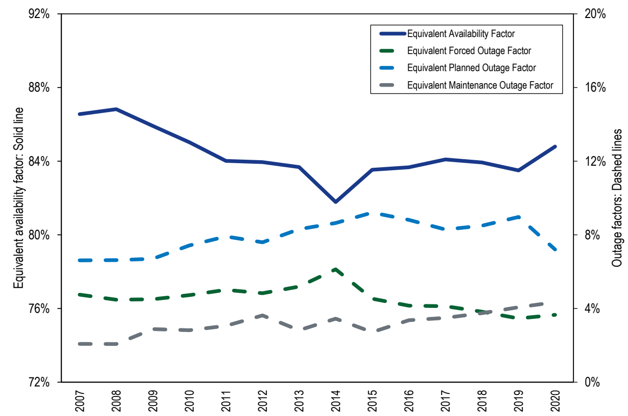


Table 5-27 EFOF, EPOF, EMOF and EAF by unit type: 2007 through 2020

	Coal				Combined Cycle				Combustion Turbine				Diesel			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7.3%	8.6%	2.7%	81.4%	2.5%	6.1%	1.7%	89.7%	4.4%	2.7%	2.5%	90.4%	10.2%	0.6%	1.6%	87.6%
2008	7.3%	7.1%	2.4%	83.1%	2.1%	6.2%	1.7%	90.0%	2.8%	4.5%	2.2%	90.5%	9.1%	1.0%	1.2%	88.7%
2009	6.6%	8.5%	3.6%	81.3%	2.8%	6.5%	3.3%	87.4%	1.7%	2.8%	2.5%	93.0%	6.6%	0.6%	1.1%	91.7%
2010	7.8%	8.9%	4.1%	79.2%	2.6%	8.4%	3.1%	85.9%	2.1%	2.8%	2.0%	93.1%	4.4%	0.4%	1.5%	93.6%
2011	8.2%	9.2%	4.4%	78.2%	2.5%	9.5%	2.3%	85.7%	2.2%	3.7%	2.4%	91.7%	3.3%	0.1%	1.8%	94.8%
2012	7.6%	9.0%	6.0%	77.4%	3.7%	7.9%	2.2%	86.1%	2.8%	3.4%	1.6%	92.2%	3.9%	0.7%	2.4%	93.0%
2013	8.4%	10.6%	4.5%	76.5%	1.9%	9.1%	2.4%	86.6%	5.3%	4.4%	1.5%	88.8%	6.1%	0.3%	1.4%	92.3%
2014	9.7%	9.8%	5.4%	75.1%	2.7%	10.0%	2.5%	84.7%	6.6%	4.2%	1.8%	87.4%	13.9%	0.4%	2.0%	83.6%
2015	7.7%	10.7%	3.9%	77.7%	2.3%	10.3%	2.0%	85.4%	2.8%	4.7%	1.9%	90.6%	7.7%	0.3%	2.7%	89.3%
2016	7.5%	9.3%	5.9%	77.3%	2.8%	10.6%	1.8%	84.7%	2.0%	5.8%	2.1%	90.1%	5.3%	0.2%	2.6%	92.0%
2017	8.9%	10.4%	6.4%	74.3%	2.1%	10.1%	1.7%	86.2%	1.4%	5.9%	1.9%	90.8%	5.9%	0.4%	2.1%	91.7%
2018	8.3%	11.7%	6.8%	73.2%	1.4%	9.3%	1.4%	87.9%	1.8%	5.6%	1.9%	90.7%	6.1%	0.9%	3.3%	89.6%
2019	7.4%	10.6%	8.0%	74.1%	1.9%	10.4%	1.9%	85.8%	1.8%	6.9%	1.7%	89.7%	7.0%	0.9%	3.0%	89.1%
2020	5.2%	8.9%	9.2%	76.6%	3.9%	7.8%	2.5%	85.8%	4.6%	6.0%	2.0%	87.4%	8.0%	0.1%	3.1%	88.8%

	Hydroelectric				Nuclear				Other			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1.3%	7.2%	1.4%	90.1%	1.4%	5.4%	0.3%	93.0%	5.3%	7.1%	3.3%	84.4%
2008	1.3%	7.8%	2.1%	88.8%	1.8%	5.1%	0.8%	92.3%	4.2%	11.0%	3.3%	81.4%
2009	2.3%	8.7%	2.3%	86.8%	4.2%	4.9%	0.6%	90.2%	3.1%	8.0%	5.0%	83.9%
2010	0.7%	8.6%	1.9%	88.8%	2.4%	5.6%	0.5%	91.6%	4.7%	10.5%	3.7%	81.2%
2011	1.7%	11.7%	1.9%	84.7%	2.7%	5.4%	1.2%	90.7%	5.0%	10.7%	3.3%	81.0%
2012	2.8%	6.3%	2.1%	88.9%	1.6%	6.3%	1.0%	91.1%	5.2%	11.8%	4.5%	78.5%
2013	2.3%	7.8%	1.9%	87.9%	0.9%	5.7%	0.6%	92.8%	6.6%	10.5%	3.5%	79.4%
2014	2.5%	9.3%	3.0%	85.3%	1.6%	5.5%	1.0%	92.0%	6.9%	16.3%	5.2%	71.5%
2015	3.7%	9.6%	1.5%	85.2%	1.4%	5.1%	1.4%	92.1%	6.0%	17.8%	4.2%	72.0%
2016	2.6%	7.7%	3.1%	86.6%	1.6%	5.5%	1.1%	91.8%	4.6%	16.6%	4.6%	74.2%
2017	2.3%	5.8%	3.1%	88.9%	0.5%	5.1%	0.7%	93.7%	4.7%	9.9%	5.7%	79.7%
2018	2.6%	9.0%	3.1%	85.3%	0.7%	4.7%	0.6%	94.0%	3.6%	9.1%	8.1%	79.2%
2019	1.5%	8.6%	3.7%	86.2%	0.6%	5.3%	0.9%	93.2%	3.5%	13.3%	6.7%	76.6%
2020	5.4%	7.4%	2.7%	84.4%	1.4%	4.8%	0.7%	93.0%	18.5%	7.8%	5.4%	68.2%

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.

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.

The average PJM EFORd in 2020 was 6.3 percent, an increase from 5.5 percent in 2019. Figure 5-13 shows the average EFORd since 1999 for all units in PJM.[133]

Figure 5-13 Trends in the equivalent demand forced outage rate (EFORd): 1999 through 2020

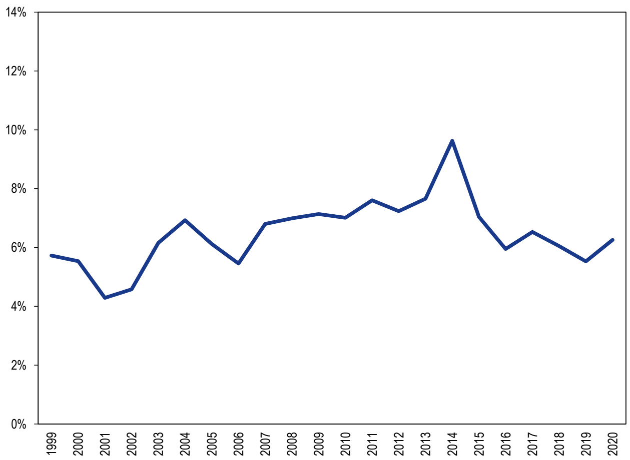


Table 5-28 shows the class average EFORd by unit type.

Table 5-28 EFORd by unit type: 2007 through 2020

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	8.4%	8.4%	8.2%	9.4%	10.5%	10.1%	10.9%	12.2%	9.4%	9.4%	11.4%	11.0%	10.1%	8.6%
Combined Cycle	4.0%	3.8%	4.3%	3.8%	3.5%	4.5%	2.6%	4.6%	3.0%	3.5%	2.7%	2.1%	2.7%	3.9%
Combustion Turbine	11.5%	11.7%	10.3%	9.7%	8.7%	8.3%	11.1%	16.5%	9.2%	5.6%	5.5%	6.2%	5.3%	4.6%
Diesel	11.7%	10.3%	9.3%	6.4%	9.3%	5.2%	6.7%	14.9%	9.0%	6.9%	7.0%	6.7%	7.6%	8.0%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	3.6%	3.8%	5.2%	3.7%	3.2%	3.3%	2.0%	5.4%
Nuclear	1.4%	2.0%	4.3%	2.6%	2.9%	1.8%	1.0%	1.8%	1.5%	1.8%	0.5%	0.8%	0.6%	1.4%
Other	9.3%	9.9%	8.4%	7.8%	10.0%	9.2%	11.3%	13.8%	13.2%	9.2%	13.4%	9.2%	9.0%	18.5%
Total	6.8%	7.0%	7.1%	7.0%	7.6%	7.2%	7.7%	9.6%	7.0%	6.0%	6.5%	6.1%	5.5%	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 3.7 percent in 2020. This means there was 3.7 percent lost availability because of forced outages. Table 5-29 shows that forced outages for boiler tube leaks, at 12.9 percent of the systemwide EFOF, were the largest single contributor to EFOF.

133 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2020 State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

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.

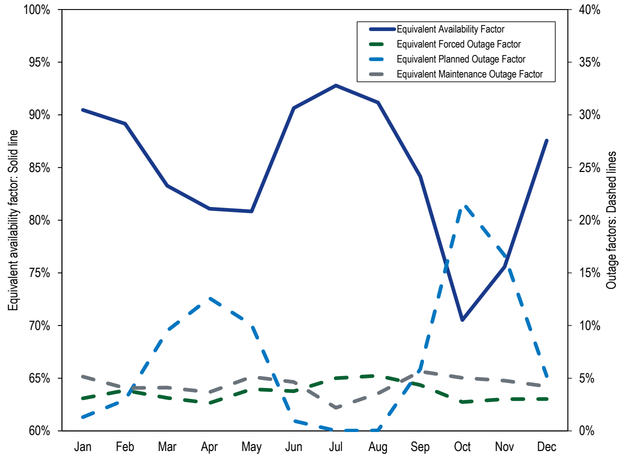
Table 5-29 Contribution to EFOF by unit type by cause: 2020

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	26.7%	1.7%	0.0%	0.0%	0.0%	0.0%	4.7%	12.9%
Electrical	4.0%	31.1%	11.1%	4.9%	4.7%	0.1%	1.2%	8.4%
Controls	2.5%	1.6%	0.9%	9.0%	1.9%	1.3%	31.5%	7.7%
Unit Testing	3.5%	6.2%	19.3%	23.8%	13.0%	0.6%	12.8%	7.3%
Catastrophe	2.0%	5.5%	1.2%	0.1%	39.7%	0.0%	6.1%	5.1%
High Pressure Turbine	11.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	4.8%
Generator	0.7%	19.4%	0.3%	3.4%	0.7%	4.1%	2.8%	4.5%
Boiler Air and Gas Systems	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	10.9%	3.8%
Feedwater System	6.7%	1.2%	0.0%	0.0%	0.0%	3.9%	0.9%	3.6%
Boiler Piping System	5.6%	2.1%	0.0%	0.0%	0.0%	0.0%	0.4%	2.9%
Miscellaneous (Steam Turbine)	0.9%	2.5%	0.0%	0.0%	0.0%	0.1%	9.8%	2.7%
Miscellaneous (Gas Turbine)	0.0%	4.3%	25.2%	0.0%	0.0%	0.0%	0.0%	2.6%
Turbine	0.0%	0.3%	14.9%	0.0%	21.9%	0.0%	0.0%	2.3%
Boiler Fuel Supply from Bunkers to Boiler	4.9%	0.1%	0.0%	0.0%	0.0%	0.0%	0.4%	2.3%
Economic	3.2%	0.2%	0.6%	3.7%	4.9%	0.0%	2.0%	2.1%
Steam Generators and Steam System	0.0%	0.0%	0.0%	0.0%	0.0%	30.4%	0.0%	2.1%
Wet Scrubbers	4.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%
Personnel or Procedure Errors	0.8%	0.1%	0.0%	2.4%	0.0%	2.9%	5.4%	1.6%
Auxiliary Systems	1.4%	2.3%	6.8%	0.0%	0.1%	0.1%	0.2%	1.5%
All Other Causes	18.0%	21.5%	19.7%	52.7%	13.1%	56.4%	10.9%	20.0%
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: 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 $131.4 million, 26.8 percent, from $490.5 million in 2019 to $359.1 million in 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 $128.2 million, 26.5 percent, from $483.3 million in 2019 to $355.1 million in 2020. This decrease consisted entirely of capacity market revenue.[2]

  Economic demand response revenue decreased by $0.7 million, 70.0 percent, from $1.0 million in 2019 to $0.3 million in 2020.[3] Demand response revenue in the synchronized reserve market decreased by $0.4 million, 14.3 percent, from $2.8 million in 2019 to $2.4 million in 2020. Demand response revenue in the regulation market decreased by $1.0 million, 41.7 percent, from $2.4 million in 2019 to $1.4 million in 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 2019 and 2020. The HHI for economic resource reductions increased by 796 points from 8261 in 2019 to 9056 in 2020. The ownership of emergency load response resources was highly concentrated in 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

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 January 12, 2021 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. 84 (Dec. 17 2020).

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

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

data at the site of the demand reductions.[6] (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends limited, extended summer and annual demand response event compliance be calculated on 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.)

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

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

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

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, 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. 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.

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

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

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

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

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.[12] This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

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.[13] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

FERC Order No. 719 required PJM and other RTOs to amend their market rules to accept bids from aggregators of retail customers of utilities unless the laws or regulations of the relevant electric retail regulatory authority ("RERRA") do not permit the customers aggregated in the bid to participate.[14] PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits end use customers' participation.[15] EDCs and their end use customers are categorized as small and large based on whether the EDC distributed more or less than 4 million MWh in the previous fiscal year. End use customers within a large EDC must provide verification of any other contractual obligations or laws or regulations that prohibit participation, but end use customers within a small EDC do not need to provide additional verification.[16] RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program.

12 577 U.S. 260 (2016).

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

14 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008), order on reh'g, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

15 The evidence supplied by LDCs must take the form of an order, resolution or ordinance of the RERRA, an opinion of the RERRA's legal counsel attesting to existence of an order, resolution, or ordinance, or an opinion of the state attorney general on behalf of the RERRA attesting to existence of an order, resolution or ordinance.

16 PJM Operating Agreement Schedule 1 § 1.5A.3.1.

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 Attachmend DD § 5.5A	Limited, Annual, Base, Capacity Performance,Summer-Period Capacity Performance OATT Attachmend DD § 5.5A		OATT Attachment K § 1.5A	
Market	Capacity Only OATT Attachemnt K § 8.1	Full Program Option (Capacity and Energy) OATT Attachemnt K § 8.1	Energy Only OATT Attachemnt K § 8.1	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	LSE PRD Credit RAA Schedule 6.1.G
Capacity Measurement and Verification	Firm Service Level Guaranteed Load Drop	Firm Service Level Guaranteed Load Drop	NA	NA	Firm Service Level
CBL	NA	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	NA
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment. OATT Attachment K § 3.3A	NA
Penalties	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	NA	NA	RPM event RAA Schedule 6.1.G Test compliance penalties RAA Schedule 6.1.L
Associate Manuals	Manual 18	Manual 11 Manual 18	Manual 11 Manual 18	Manual 11	Manual 18

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 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.[17] In 2020, total demand response revenue decreased by $131.4 million, 26.8 percent, from $490.5 million in 2019 to $359.1 million in 2020. Total emergency demand response revenue decreased by $129.3 million, 26.7 percent, from $484.4 million in 2019 to $355.1 million in 2020. This decrease consisted of capacity market revenue and emergency energy revenue.[18] In 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.

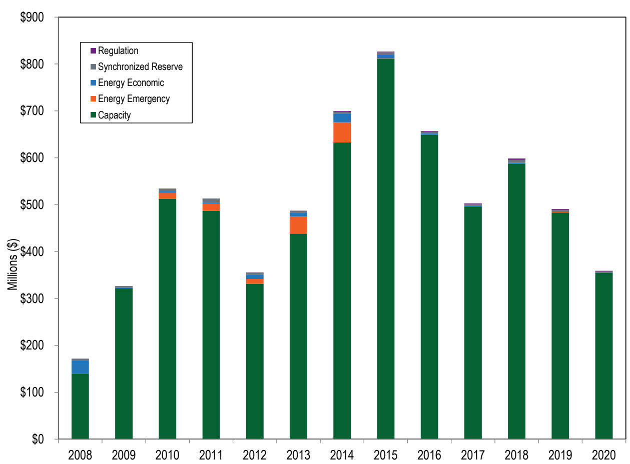
17 This includes both capacity market revenue and emergency energy revenue for capacity resources.

18 The total credits and MWh for demand resources were calculated as of January 21, 2021 and may change as a result of continued PJM billing updates.

Economic demand response revenue decreased by $0.7 million, 70.0 percent, from $1.0 million in 2019 to $0.3 million in 2020.[19] Demand response revenue in the synchronized reserve market decreased by $0.3 million, 14.3 percent, from $2.8 million in 2019 to $2.4 million in 2020. Demand response revenue in the regulation market decreased by $1.0 million, 41.7 percent, from $2.4 million in 2019 to $1.4 million in 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: 2008 through 2020



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.[20] Under current rules, PJM will declare an emergency if pre-emergency or emergency demand response is dispatched. In all demand response programs, CSPs are companies that sign up customers that have the ability to reduce load. CSPs satsify cleared RPM commitments registerting customers as Nominated MW. After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response programs, but a participant can register as a PJM special member and become a CSP without any additional cost.

The emergency and pre-emergency load response programs consist of the base and capacity performance demand response products. Full implementation of the Capacity Performance design in the 2020/2021 Delivery Year requires all emergency or pre-emergency demand resources to be registered as annual capacity resources. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement of the CP design.[21]

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.

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.

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

20 OA Schedule 1 § 8.5.

21 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.

Demand resources are also not required to meet the same must offer requirements a 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.[22]

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 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.

22 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014), "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

Table 6-2 HHI value for committed UCAP MW by LDA by delivery year: 2019/2020 and 2020/2021 Delivery Years[23]

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 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: 2007/2008 through 2020/2021 Delivery Years

	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%

23 The RTO LDA refers to the rest of RTO.

Table 6-4 shows zonal monthly capacity market revenue to demand resources for 2020. Capacity market revenue decreased in 2020 by $128.2 million, 26.5 percent, from $483.3 million in 2019 to $355.1 million in 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 2019 is from the 2018/2019 and 2019/2020 RPM auction clearing prices and the capacity revenue in 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 demand resource capacity revenue: 2020

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$451,066	$421,965	$451,066	$436,515	$451,066	$353,042	$364,810	$364,810	$353,042	$364,810	$353,042	$364,810	$4,730,043
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	$3,309,544	$3,202,784	$3,309,544	$42,443,899
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	$1,790,204	$1,732,456	$1,790,204	$23,936,118
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	$1,882,518	$1,821,792	$1,882,518	$24,873,700
BGE	$651,153	$609,143	$651,153	$630,148	$651,153	$453,083	$468,186	$468,186	$453,083	$468,186	$453,083	$468,186	$6,424,738
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	$8,465,782	$8,192,692	$8,465,782	$107,283,274
DAY	$551,678	$516,086	$551,678	$533,882	$551,678	$450,951	$465,983	$465,983	$450,951	$465,983	$450,951	$465,983	$5,921,790
DEOK	$628,567	$588,015	$628,567	$608,291	$628,567	$567,208	$586,115	$586,115	$567,208	$586,115	$567,208	$586,115	$7,128,089
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	$1,791,652	$1,733,857	$1,791,652	$21,286,129
Dominion	$1,171,216	$1,095,654	$1,171,216	$1,133,435	$1,171,216	$940,665	$972,021	$972,021	$940,665	$972,021	$940,665	$972,021	$12,452,817
DPL	$619,442	$579,478	$619,442	$599,460	$619,442	$370,874	$383,237	$383,237	$370,874	$383,237	$370,874	$383,237	$5,682,835
JCPL	$626,062	$585,671	$626,062	$605,867	$626,062	$791,309	$817,686	$817,686	$791,309	$817,686	$791,309	$817,686	$8,714,395
Met-Ed	$801,598	$749,882	$801,598	$775,740	$801,598	$624,134	$644,939	$644,939	$624,134	$644,939	$624,134	$644,939	$8,382,575
OVEC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$3	$6
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	$2,133,013	$2,064,206	$2,133,013	$22,744,968
PENELEC	$857,760	$802,420	$857,760	$830,090	$857,760	$800,092	$826,762	$826,762	$800,092	$826,762	$800,092	$826,762	$9,913,114
Pepco	$147,322	$137,817	$147,322	$142,570	$147,322	$418,494	$432,443	$432,443	$418,494	$432,443	$418,494	$432,443	$3,707,608
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	$1,594,416	$1,542,983	$1,594,416	$20,136,550
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	$1,901,994	$1,840,639	$1,901,994	$18,994,254
RECO	$31,919	$29,860	$31,919	$30,889	$31,919	$21,883	$22,613	$22,613	$21,883	$22,613	$21,883	$22,613	$312,605
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	$28,853,919	$27,923,148	$28,853,921	$355,069,506

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.[24] 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.[25] 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.

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 Performance	Pre-Emergency Total	Base	Capacity Performance	Emergency Total	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 Performance	Pre-Emergency Total	Base	Capacity Performance	Emergency Total	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

24 See "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 46 (Nov. 19, 2020).
25 See "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 46 (Nov. 19, 2020).

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 Performance	Pre-Emergency Total	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	4,097.2	4,097.2	240.6	240.6	4,337.9
Short Lead (60 Minutes)	326.9	326.9	28.8	28.8	355.7
Long Lead (120 Minutes)	3,043.0	3,043.0	150.0	150.0	3,192.9
Total	7,467.1	7,467.1	419.4	419.4	7,886.5
	Pre-Emergency Locations		Emergency Locations		
Lead Type	Capacity Performance	Pre-Emergency Total	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	10,995	10,995	472	472	11,467
Short Lead (60 Minutes)	315	315	39	39	354
Long Lead (120 Minutes)	2,476	2,476	275	275	2,751
Total	13,786	13,786	786	786	14,572

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).[26] The Guaranteed Load Drop (GLD) method measures the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the PLC minus the real-time load multiplied by the loss factor. The comparison load estimates what the load would have been if PJM did not declare a Load Management Event, similar to a CBL, by using a comparable day, same day, customer baseline, regression analysis or backup generation method. Limiting the GLD method to the minimum of the two calculations ensures reductions occur below the PLC, thus avoiding double counting of load reductions.[27] 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.[28] 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.[29]

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.[30] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[31] 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

26 Real-time load is hourly metered load.
27 135 FERC ¶ 61,212.

28 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 46 (Nov. 19, 2020).
29 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev.46 (Nov. 19, 2020).
30 OATT Attachment DD.5.11.
31 OATT Attachment M-2.

months effective June 1, 2017.[32] The MMU recommends setting the baseline for measuring capacity compliance under summer and winter compliance at the customer's PLC, similar to GLD, to avoid double counting, to avoid under counting and to ensure that a customer's purchase of capacity is calculated correctly. The FSL and GLD equations for calculating load reductions are:

$$FSL\ Compliance_{Summer} = PLC - (Load \cdot LF)$$

$$FSL\ Compliance_{Non-Summer} = (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)$$

$$GLD\ Compliance_{Summer} = Minimum\{(comparison\ load - Load) \cdot LF; PLC - (Load \cdot LF)\}$$

$$GLD\ Compliance_{Non-Summer} = Minimum\{(comparison\ load - Load) \cdot LF; (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)\}$$

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.

Table 6-7 Reduction MW by each demand response method: 2019/2020 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Batteries and Plug Load MW	Total	Percent by type
Firm Service Level	1,202.7	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

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,225.3	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

	2019/2020	
Fuel Type	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%

32 162 FERC ¶ 61,159 (2018).

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

	2020/2021	
Fuel Type	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.[33] 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_BLKRIVER, PENELEC_ERIC, APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, and JCPL_REDBANK.[34] 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.[35]

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.[36] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR would not otherwise set price under the fundamental LMP logic. Of the 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of allowing emergency DR to set price.[37] The closed loop interfaces created for the purpose of allowing emergency DR to set price are located in the 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 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

33 OATT Attachment DD, Section 11.

34 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed January 21, 2020).

35 OATT Attachment DD, Section 10A.

36 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software, Docket No. AD10-12-006 (June 23, 2015) <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf>.

37 See the *2018 State of the Market Report for PJM*, Volume 2, Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.

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.[38]

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).[39] 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.[40]

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).[41] [42] A CAA, or EAA, is an electrically connected area that has the same capacity market price. This changes the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch. The multiple zone approach is even less locational than the zonal and subzonal

38 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 46 (Nov. 19, 2020).

39 OATT § 1 (Performance Assessment Hour).

40 *2018 State of the Market Report for PJM*, Volume 2, Section 5: Capacity, Table 5-7.

41 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.

42 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 46 (Nov. 19, 2020).

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.[43]

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.[44] The compliance values PJM reports for demand response events are different than the actual compliance values accounting for both increases and decreases in load from demand resources that are called on and paid under the program.

The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations.

Demand resources that are also registered as economic resources have a calculated CBL for the emergency

43 OA Schedule 1 § 8.9.

44 OA Schedule 1 § 8.9.

event days. Demand resources that are not registered as Economic Resources use the three day CBL type with the symmetrical additive adjustment for measuring energy reductions without the requirements of a Relative Root Mean Squared Error (RRMSE) Test required for all economic resources.[45] The CBL must use the RRMSE test to verify that it is a good approximation for real-time load usage. The MMU recommends 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 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."[46] 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.[47] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

The metering requirement for demand resources is outdated, and has not kept up with the changes to PJM's market design. PJM moved to five minute settlements, but the metering requirement for demand resources remained at an hourly interval meter. It is impossible to measure energy usage on a five minute basis using an hourly interval meter. PJM will estimate real-time usage by prorating the hourly interval meter and assume if load is less than the CBL, that the reduction occurred during the required dispatch window. The meter reading is not telemetered to PJM in real time. The resource is allowed up to 60 days to report the data to PJM. The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions so that they can accurately measure compliance.[48]

45 157 FERC ¶ 61,067 (2016).

46 OA Schedule 1 § 8.2.

47 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>.

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

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment.[49] 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.[50] 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

	2015/2016			2016/2017			2017/2018			2018/2019			2019/2020		
Product Type	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty
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.[51] 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 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

49 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. 46 (Nov. 19 2020).

50 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.

51 *Id.*

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."[52] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2019/2020 Delivery Year.[53] [54] 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.[55] 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.[56]

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

52 161 FERC ¶ 61,153 at P 8 (2017).
53 139 FERC ¶ 61,057 (2012).
54 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.
55 OATT Attachment K Appendix Section 1.10.1A Day-Ahead Energy Market Scheduling (d) (x).
56 "PJM Manual 15: Cost Development Guidelines," § 8.1, Rev. 37 (Dec. 9, 2020).

PRD

The PRD rules are more aligned with the Capacity Performance construct effective December 30, 2019, although the rules still fall short.[57] PJM's initial filing was rejected by the Commission based on the MMU's comments and PJM's modified filing was accepted.[58] 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.[59]

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.[60] 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.[61]

Economic Load Response Program

The Economic Load Response Program is for demand response customers that offer into the day-ahead or real-time energy market. The estimated load reduction is paid the zonal LMP, as long as the zonal LMP is greater than the monthly Net Benefits Test threshold.

Market Structure

Table 6-15 shows the average hourly HHI for each month and the average hourly HHI for 2019, through, 2020. The ownership of economic demand response resources was highly concentrated in 2019 and 2020.[62] 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 2020, 82.7 percent of all economic DR reported reductions and 82.1 percent of economic DR revenue were attributable to the four largest CSPs. The HHI for economic demand response was highly concentrated for 2020. The HHI for economic demand response increased by 796 from 8261 for 2019 to 9065 for 2020.

57 See "Compliance Filing Regarding Price Responsive Demand Rules," Docket No. ER20-271-001 (February 28, 2020).

58 See "Order Rejecting Tariff Revisions," Docket No. ER19-1012-000 (June 27, 2019).

59 October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).

60 The Demand Response Subcommittee (DRS) is currently working to align PRD with the CP designed products.

61 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>.

62 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: 2019 through 2020[63]

	Average Hourly MWh HHI			Top Four CSPs Share of Reduction			Top Four CSPs Share of Credit		
Month	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%	90.2%	4.1%
Aug	9390	8344	(11.1%)	99.9%	93.5%	(6.4%)	100.0%	93.1%	(6.8%)
Sep	9513	8893	(6.5%)	99.5%	100.0%	0.5%	99.6%	100.0%	0.4%
Oct	9400	9439	0.4%	99.9%			99.6%		
Nov	8121	9925	22.2%	96.3%	100.0%	3.7%	95.4%	100.0%	4.6%
Dec	7745	10000	29.1%	93.8%			90.9%		
Total	8261	9056	9.6%	81.5%	82.7%	1.2%	74.0%	82.1%	8.1%

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 2010 through 2020. The average credits per MWh paid decreased by $4.71 per MWh, 11.7 percent, from $40.29 per MWh in 2019 to $35.58 per MWh in 2020. The PJM real-time, load-weighted, average LMP was 21.3 percent lower in 2020 than in 2019, $27.24 per MWh versus $21.44 per MWh. Curtailed energy for the economic program decreased by 14,371 MWh, 63.2 percent, from 24,306 MWh in 2019 to 8,935 MWh in 2020. Total credits paid for the economic load response program in 2020 decreased by $0.7 million, 70.4 percent, from $1.0 million in 2019 to $0.3 million in 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 the opportunity for economic load response. 2020 had the least amount of economic load response since 2010.

Table 6-16 Credits paid to economic program participants: 2019 through 2020

	Total MWh	Total Credits	$/MWh
2010	72,757	$3,088,049	$42.44
2011	17,398	$2,052,996	$118.00
2012	144,285	$9,278,942	$64.31
2013	133,963	$8,711,873	$65.03
2014	146,301	$17,820,063	$121.80
2015	121,129	$7,983,488	$65.91
2016	81,908	$3,550,535	$43.35
2017	62,622	$2,709,335	$43.27
2018	49,441	$2,548,575	$51.55
2019	24,306	$979,348	$40.29
2020	8,935	$289,804	$32.44

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.[64] 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.[65] 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 April, May, June and December 2020 reduction and credit share percent are redacted based on confidentiality rules.
64 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 112 (Jan. 5, 2021).
65 FERC Order No. 831.

Figure 6-2 shows monthly economic demand response credits and MWh, from 2010 through 2020.

Figure 6-2 Economic program credits and MWh by month: 2010 through 2020

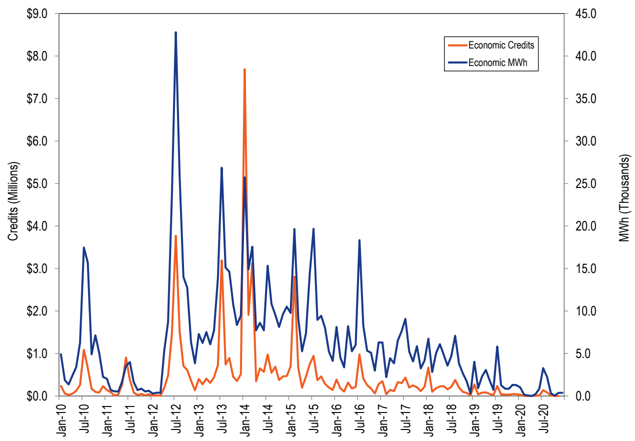


Table 6-17 shows performance for 2019 and 2020 in the economic program by control zone. Total reported reductions under the economic program decreased by 14,994 MWh, 63.8 percent, from 23,487 MWh in 2019 to 8,493 MWh in 2020. Total revenue under the economic program decreased by $0.7 million, 69.8 percent, from $0.9 million in 2019 to $0.3 million in 2020.[66]

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.[67] The zonal allocation is shown in Table 6-17.

Table 6-17 Economic program participation by zone: 2019 and 2020

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2019	2020	Percent Change	2019	2020	Percent Change	2019	2020	Percent Change
AECO	$1,353.78	$0.00	NA	41	0	NA	$33.27	NA	NA
AEP	$8,361.94	$880.95	(89.5%)	119	18	(84.9%)	$70.23	$48.95	(30.3%)
APS	$1,344.96	$12,356.22	818.7%	30	210	595.2%	$44.45	$58.74	32.2%
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	$7,269.74	$125,412.82	1,625.1%	296	3,899	1,218.2%	$24.58	$32.16	30.9%
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	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DPL	$4,916.92	$10,800.39	119.7%	150	138	(8.2%)	$32.74	$78.37	139.3%
JCPL	$16,793.13	$12,898.56	(23.2%)	338	305	(9.7%)	$49.66	$42.25	(14.9%)
Met-Ed	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	$140,676.59	$10,021.03	(92.9%)	2,422	311	(87.2%)	$58.08	$32.21	(44.5%)
PENELEC	$189,181.78	$29,035.12	(84.7%)	6,018	1,717	(71.5%)	$31.44	$16.91	(46.2%)
Pepco	$10,239.62	$97.49	(99.0%)	316	2	(99.5%)	$32.44	$60.39	86.2%
PPL	$156,475.67	$3,716.95	(97.6%)	2,476	76	(96.9%)	$63.21	$49.12	(22.3%)
PSEG	$293,912.59	$42,105.95	(85.7%)	8,674	1,516	(82.5%)	$33.88	$27.77	(18.0%)
RECO	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Total	$943,260.09	$273,496.18	(71.0%)	23,487	8,493	(63.8%)	$40.16	$32.20	(19.8%)

66 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-17. Payments for Economic demand response reductions are settled monthly.

67 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 84 (Dec. 17, 2020).

Table 6-18 shows average reported MWh reductions and credits by hour for 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 2019, 90.7 percent of the reported reductions and 87.1 percent of credits occurred in hours ending 0900 to 2100, and in 2020, 97.9 percent of the reported reductions and 98.2 percent of credits occurred in hours ending 0900 to 2100.

Table 6-18 Hourly frequency distribution of economic program reported MWh reductions and credits: 2019 and 2020

	MWh Reductions			Program Credits			Average LMP during Load Response		
Hour Ending (EPT)	2019	2020	Percent Change	2019	2020	Percent Change	2019	2020	Percent Change
1 through 6	533	(1)	(100%)	$32,397	($12)	(100%)	$53.54	$23.90	(55%)
7	288	18	(94%)	$18,693	$451	(98%)	$64.53	$39.77	(38%)
8	498	125	(75%)	$31,107	$3,642	(88%)	$71.36	$41.09	(42%)
9	938	193	(79%)	$38,180	$3,492	(91%)	$42.09	$28.96	(31%)
10	1,128	222	(80%)	$40,342	$3,933	(90%)	$35.69	$26.53	(26%)
11	1,324	240	(82%)	$47,994	$4,326	(91%)	$35.04	$27.22	(22%)
12	1,402	539	(62%)	$43,556	$12,644	(71%)	$34.26	$27.41	(20%)
13	1,432	764	(47%)	$47,095	$19,416	(59%)	$33.58	$29.83	(11%)
14	1,765	907	(49%)	$60,420	$28,263	(53%)	$34.00	$33.51	(1%)
15	1,841	1,084	(41%)	$62,146	$35,022	(44%)	$35.08	$37.03	6%
16	2,058	1,101	(46%)	$73,741	$37,702	(49%)	$36.75	$38.37	4%
17	2,423	1,225	(49%)	$96,600	$48,114	(50%)	$41.15	$43.00	4%
18	2,468	1,189	(52%)	$124,517	$50,531	(59%)	$44.89	$43.49	(3%)
19	2,141	930	(57%)	$88,869	$31,436	(65%)	$40.66	$36.11	(11%)
20	1,661	239	(86%)	$66,530	$6,427	(90%)	$37.30	$27.64	(26%)
21	1,454	110	(92%)	$62,797	$3,183	(95%)	$37.95	$26.67	(30%)
22	619	35	(94%)	$28,327	$990	(97%)	$38.35	$27.17	(29%)
23 through 24	334	13	(96%)	$16,038	$246	(98%)	$36.29	$37.33	3%
Total	24,306	8,935	(63%)	$979,348	$289,804	(70%)	$41.81	$33.06	(18%)

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 2019 and 2020. In 2020, 0.7 percent of reported MWh reductions and 4.2 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): 2019 through 2020

	MWh Reductions			Program Credits		
LMP	2019	2020	Percent Change	2019	2020	Percent Change
$0 to $25	6,387	3,673	(42%)	$163,200	$83,131	(49%)
$25 to $50	13,738	4,043	(71%)	$501,212	$137,363	(73%)
$50 to $75	2,337	706	(70%)	$140,207	$31,088	(78%)
$75 to $100	816	185	(77%)	$61,912	$5,233	(92%)
$100 to $125	474	149	(69%)	$43,454	$8,565	(80%)
$125 to $150	181	68	(63%)	$15,619	$8,792	(44%)
$150 to $175	135	46	(66%)	$16,222	$3,368	(79%)
> $175	238	65	(73%)	$37,523	$12,263	(67%)
Total	24,306	8,935	(63%)	$979,348	$289,804	(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 2020.

Table 6-20 Zonal Economic Load Response charge: 2020

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$307	$22	$12	$2	$53	$228	$2,043	$1,160	$167	$6	$0	$0	$4,001
AEP	$4,802	$459	$191	$31	$1,004	$2,311	$19,229	$12,532	$1,535	$108	$2	$0	$42,203
APS	$1,908	$180	$74	$13	$386	$917	$7,600	$4,913	$573	$41	$1	$0	$16,605
ATSI	$2,392	$229	$103	$16	$547	$1,219	$10,584	$6,779	$814	$59	$1	$0	$22,743
BGE	$1,244	$110	$40	$8	$236	$745	$5,554	$3,445	$433	$25	$1	$0	$11,841
ComEd	$3,134	$256	$141	$24	$654	$1,852	$16,491	$9,534	$1,134	$81	$2	$0	$33,303
DAY	$725	$64	$26	$4	$141	$350	$2,803	$1,773	$225	$15	$0	$0	$6,126
DEOK	$945	$94	$39	$6	$224	$542	$4,407	$2,762	$359	$22	$0	$0	$9,401
DLCO	$468	$45	$20	$3	$118	$276	$2,370	$1,515	$172	$11	$0	$0	$4,999
Dominion	$3,927	$364	$133	$25	$792	$2,134	$17,423	$10,897	$1,465	$80	$2	$0	$37,242
DPL	$698	$50	$24	$3	$97	$386	$3,345	$1,854	$274	$12	$0	$0	$6,745
EKPC	$526	$53	$18	$3	$98	$236	$1,931	$1,243	$161	$11	$0	$0	$4,280
JCPL	$762	$61	$30	$4	$170	$544	$4,680	$2,710	$357	$15	$0	$0	$9,333
Met-Ed	$587	$46	$22	$4	$115	$344	$2,531	$1,661	$197	$11	$0	$0	$5,519
OVEC	$4	$0	$0	$0	$1	$2	$12	$8	$1	$0	$0	$0	$28
PECO	$1,374	$93	$53	$7	$230	$804	$6,804	$3,878	$539	$27	$1	$0	$13,810
PENELEC	$574	$56	$25	$5	$134	$306	$2,540	$1,628	$193	$15	$0	$0	$5,477
Pepco	$1,146	$102	$39	$7	$210	$646	$4,968	$3,133	$407	$23	$1	$0	$10,682
PPL	$1,319	$113	$59	$11	$296	$825	$6,248	$4,041	$481	$30	$1	$0	$13,426
PSEG	$1,456	$123	$59	$8	$318	$927	$7,906	$4,689	$615	$29	$1	$0	$16,132
RECO	$47	$4	$2	$0	$12	$35	$317	$183	$22	$1	$0	$0	$623
Exports	$1,955	$127	$62	$11	$325	$967	$6,772	$4,488	$539	$39	$1	$0	$15,287
Total	$30,300	$2,651	$1,173	$197	$6,161	$16,596	$136,560	$84,827	$10,665	$661	$14	$0	$289,805

Table 6-21 shows the total zonal Economic Load Response charge per GWh of real-time load and exports in 2020.

Table 6-21 Zonal economic load response charge per GWh of load and exports: 2020

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Zonal Average
AECO	$0.401	$0.033	$0.018	$0.309	$0.086	$0.263	$0.309	$0.000	$0.000	$0.000	$0.000	$0.000	$0.118
AEP	$0.430	$0.044	$0.019	$0.314	$0.113	$0.234	$0.314	$0.000	$0.000	$0.000	$0.000	$0.000	$0.122
APS	$0.431	$0.044	$0.019	$0.319	$0.112	$0.243	$0.319	$0.000	$0.000	$0.000	$0.000	$0.000	$0.124
ATSI	$0.426	$0.044	$0.020	$0.317	$0.120	$0.229	$0.317	$0.000	$0.000	$0.000	$0.000	$0.000	$0.123
BGE	$0.464	$0.045	$0.018	$0.328	$0.113	$0.287	$0.328	$0.000	$0.000	$0.000	$0.000	$0.000	$0.132
ComEd	$0.392	$0.034	$0.020	$0.303	$0.100	$0.227	$0.303	$0.000	$0.000	$0.000	$0.000	$0.000	$0.115
DAY	$0.490	$0.045	$0.020	$0.325	$0.121	$0.245	$0.325	$0.000	$0.000	$0.000	$0.000	$0.000	$0.131
DEOK	$0.421	$0.044	$0.020	$0.314	$0.120	$0.241	$0.314	$0.000	$0.000	$0.000	$0.000	$0.000	$0.123
DLCO	$0.424	$0.044	$0.020	$0.321	$0.125	$0.244	$0.321	$0.000	$0.000	$0.000	$0.000	$0.000	$0.125
Dominion	$0.447	$0.046	$0.018	$0.052	$0.111	$0.000	$0.052	$0.000	$0.000	$0.000	$0.000	$0.000	$0.060
DPL	$0.437	$0.035	$0.018	$0.308	$0.080	$0.248	$0.308	$0.000	$0.000	$0.000	$0.000	$0.000	$0.120
EKPC	$0.437	$0.045	$0.019	$0.319	$0.112	$0.241	$0.319	$0.000	$0.000	$0.000	$0.000	$0.000	$0.124
JCPL	$0.424	$0.038	$0.019	$0.334	$0.116	$0.275	$0.334	$0.000	$0.000	$0.000	$0.000	$0.000	$0.128
Met-Ed	$0.427	$0.037	$0.019	$0.317	$0.109	$0.274	$0.317	$0.000	$0.000	$0.000	$0.000	$0.000	$0.125
OVEC	$0.372	$0.033	$0.018	$0.262	$0.090	$0.198	$0.262	$0.000	$0.000	$0.000	$0.000	$0.000	$0.103
PECO	$0.413	$0.031	$0.018	$0.301	$0.088	$0.246	$0.301	$0.000	$0.000	$0.000	$0.000	$0.000	$0.117
PENELEC	$0.376	$0.039	$0.019	$0.305	$0.109	$0.233	$0.305	$0.000	$0.000	$0.000	$0.000	$0.000	$0.115
Pepco	$0.461	$0.046	$0.019	$0.324	$0.111	$0.273	$0.324	$0.000	$0.000	$0.000	$0.000	$0.000	$0.130
PPL	$0.354	$0.033	$0.019	$0.306	$0.105	$0.259	$0.306	$0.000	$0.000	$0.000	$0.000	$0.000	$0.115
PSEG	$0.418	$0.039	$0.019	$0.311	$0.111	$0.248	$0.311	$0.000	$0.000	$0.000	$0.000	$0.000	$0.121
RECO	$0.419	$0.041	$0.020	$0.341	$0.120	$0.262	$0.341	$0.000	$0.000	$0.000	$0.000	$0.000	$0.129
Exports	$0.616	$0.044	$0.017	$0.290	$0.080	$0.206	$0.290	$0.000	$0.000	$0.000	$0.000	$0.000	$0.128
Monthly Average	$0.431	$0.040	$0.019	$0.301	$0.107	$0.235	$0.301	$0.000	$0.000	$0.000	$0.000	$0.000	$0.119

Table 6-22 shows the monthly day-ahead and real-time Economic Load Response charges for 2019 through 2020. The day-ahead Economic Load Response charges decreased by $0.4 million, 66.0 percent, from $0.6 million in 2019 to $0.2 million in 2020. The real-time Economic Load Response charges decreased $0.3 million, 78.5 percent, from $0.3 million in 2019 to $0.1 million in 2020.

Table 6-22 Monthly day-ahead and real-time economic load response charge: 2019 through 2020

	Day-ahead Economic Load Response Charge			Real-time Economic Load Response Charge		
Month	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	$87,384	12.8%	$160,398	$49,176	(69.3%)
Aug	$34,048	$70,100	105.9%	$5,473	$14,727	169.1%
Sep	$24,599	$10,140	(58.8%)	$9,105	$525	(94.2%)
Oct	$25,008	$330	(98.7%)	$5,206	$331	(93.6%)
Nov	$43,272			$1,405	$14	(99.0%)
Dec	$34,892			$9,547		
Total	$633,937	$215,568	(66.0%)	$345,412	$74,236	(78.5%)

Table 6-23 shows registered sites and MW for the last day of each month for the period 2015, through 2020. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations decreased by 57, 15.2 percent, from 373 in 2019 to 316 in 2020. Average monthly registered MW decreased by 815 MW, 28.5 percent, from 2,855 MW in 2019 to 2,040 MW in 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 98 economic registrations and 107 capacity registrations in the emergency program that share the same location ids in both programs. There are 804 nominated economic MW and 517 nominated capacity MW in the emergency program that share the same location ids in both programs

Table 6-23 Economic program registrations on the last day of the month: 2015 through 2020[68]

	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	285	1,418
Jul	870	2,609	519	2,421	589	1,548	374	2,591	376	2,899	283	1,453
Aug	869	2,609	805	2,569	590	1,541	382	2,609	360	2,885	292	1,482
Sep	867	2,608	831	2,608	588	1,663	378	2,580	368	2,954	297	1,566
Oct	858	2,568	822	2,564	574	1,660	382	2,584	375	2,909	275	1,361
Nov	851	2,566	820	2,564	559	1,662	381	2,581	379	3,051	280	1,375
Dec	850	2,566	807	2,561	556	1,659	392	2,671	383	3,070	282	1,327
Avg	974	2,788	774	2,547	706	2,000	438	2,606	373	2,855	316	2,040

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 2010, through 2020. The monthly peak is the sum of each registration's monthly noncoincident peak

68 Data for years 2010 through 2014 are available in the *2018 State of the Market Report for PJM*.

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 634.4 MW, 76.4 percent, from 830 MW in 2019 to 196 MW in 2020.[69] The peak dispatched MW in 2020, 135 MW, were 2,140 MW less than the average MW registered in 2020, 2,275 MW.

Table 6-24 Sum of peak MW reported reductions for all registrations per month: 2010 through 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	31
Oct	118	81	242	168	214	136	150	88	69	29	9
Nov	111	86	165	155	166	127	116	81	54	35	12
Dec	114	88	98	168	155	122	147	83	11	31	5
Annual	1,202	840	1,942	1,486	1,739	1,858	1,451	1,217	758	830	196

Table 6-25 shows total settlements submitted for 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: 2010 through 2020

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Number of Settlements	3,781	732	5,835	2,846	3,014	2,173	1,958	1,884	1,524	1,066	520

Table 6-26 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for 2010 through 2020. The number of active participants decreased by 24, 45.3 percent, from 53 in 2019 to 29 in 2020. All participants must be registered through a CSP.

Table 6-26 Participants and CSPs submitting settlements in the economic program by year: 2010 through 2020

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Active CSPs	16	15	22	20	18	18	12	13	14	13	11
Active Participants	258	203	428	276	165	116	58	72	59	53	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 FERC Order No. 831. Demand resources should not be permitted to make offers above $1,000 per MWh without the same verification requirements applied to economic resources or generation resources. The MMU recommends that the rules for maximum offer for the emergency and pre-emergency program match the maximum offer for generation resources.

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefits test (NBT) price threshold is exceeded. This approach replaced

69 The total credits and MWh numbers for demand resources were calculated as of January 21, 2021 and may change as a result of continued PJM billing updates.
70 157 FERC ¶ 61,115 at P 139 (2016).
71 *Id.* at 8.

the payment of LMP minus the charges for wholesale power and transmission included in customers' tariff rates. Following FERC Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price 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.

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 FERC Order No. 745 was implemented in PJM, through December 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 December 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	$17.25
Nov	$36.83		$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89	$21.11	$18.35
Dec	$37.04		$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35	$22.24	$19.47
Average	$36.32	$37.51	$24.80	$28.09	$30.91	$23.97	$23.99	$27.34	$24.54	$21.64	$16.87

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 2020, the highest zonal LMP in PJM was higher than the NBT threshold price 7,389 hours out of 8,784 hours, or 84.1 percent of all hours. Reductions occurred in 1,176 hours, 15.9 percent, of those 7,389 hours in 2020. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for 2019 through 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 2020, and 0.1 percent (1 hour) of the hours in which LMP was below the NBT threshold price in 2019.

72 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 112 (Jan. 5, 2021).

Table 6-28 Hours with price higher than NBT and economic load response occurrences in those hours: 2019 through 2020

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with Economic Load Response		
Month	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%	7.4%	(24.8%)
Oct	744	744	637	676	6.1%	29.5%	3.3%	(26.3%)
Nov	721	721	664	607	(8.6%)	31.8%	14.2%	(17.6%)
Dec	744	744	506	712	40.7%	37.5%	12.1%	(25.5%)
Total	8,760	8,784	7,090	7,389		38.9%	19.1%	

Energy Efficiency

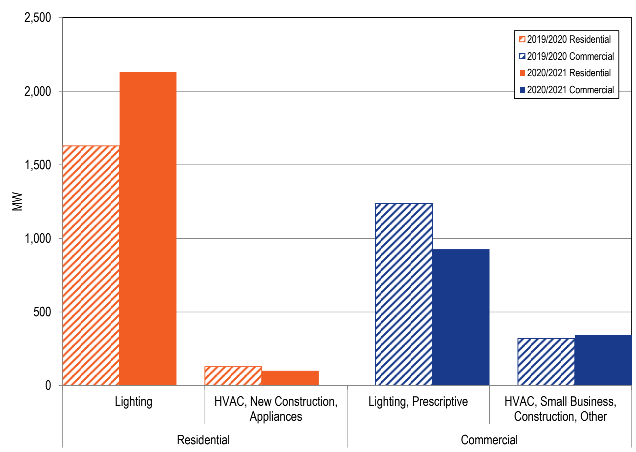
Calculating the Nominated MW value for Energy Efficiency (EE) resources is different than calculating the Nominated MW value for other capacity resources. The maximum amount of Nominated MW a generator can offer into the capacity market is based on the maximum output of a generator. EE resources do not 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 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.

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

73 PJM. "Manual 18: PJM Capacity Market," § 4.4, Rev. 46 (Nov. 19, 2020).

74 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 4 (August 22, 2019).

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.

percent from 2,296.3 MW in the 2019/2020 Delivery Year to 2,528.5 MW in the 2020/2021 Delivery Year.[77]

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] [80] 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 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.

77 See the *2019 State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market, Table 5-13.

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).

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 2020 than in 2019.
- In 2020, average energy market net revenues decreased by 17 percent for a new combustion turbine (CT), 19 percent for a new combined cycle (CC), 51 percent for a new coal plant (CP), 22 percent for a new nuclear plant, 49 percent for a new diesel (DS), 27 percent for a new onshore wind installation, 22 percent for a new offshore wind installation and 25 percent for a new solar installation compared to 2019.
- The prices of natural gas, coal, and oil fell in 2020. The marginal costs of a new CC and a new CT were less than the marginal cost of a new CP in 2020.
- Based on Western Hub prices, the spark spread in 2020 decreased by 1 percent while the spark spread standard deviation decreased by 46 percent. The dark spread decreased by 17 percent while the dark spread standard deviation decreased by 46 percent, and the quark spread decreased by 27 percent while the quark spread standard deviation decreased by 46 percent.
- In 2020, capacity market revenue accounted for 55 percent of total net revenues for a new CT, 44 percent for a new CC, 82 percent for a new CP, 20 percent for a new nuclear plant, 88 percent for a new DS, 10 percent for a new onshore wind installation, 19 percent for a new offshore wind installation and 8 percent for a new solar installation.
- In 2020, no new CT, CC, CP, nuclear, or DS units would have received sufficient net revenue to cover levelized total costs in any zone as a result of lower energy prices.
- In 2020, a new entrant onshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the four zones analyzed. Net revenues would have covered between 34 and 37 percent of levelized total costs of a new entrant onshore wind installation in AEP, APS, ComEd and PENELEC. Renewable energy credits accounted for at least 29 percent of the total net revenue of an onshore wind installation.
- In 2020, a new entrant offshore wind installation in AECO would not have received sufficient net revenue to cover levelized total costs. Net revenues would have covered 19 percent of levelized total costs. Renewable energy credits accounted for 30 percent of the total net revenue of an offshore wind installation.
- In 2020, a new entrant solar installation would have covered more than 100 percent of levelized total costs in four of the five zones analyzed. Renewable energy credits accounted for at least 68 percent of the total net revenue of a solar installation.
- In 2020, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2020, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal units and some nuclear units.
- Using a forward analysis, a total of 4,751 MW of coal, CT, diesel, and oil fired capacity are at risk of retirement, in addition to the units that are currently planning to retire. The 4,751 MW at risk of retirement include 2,361 MW of coal, 227 MW of CT, and 2,841 MW of other capacity.
- 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]

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.

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.)

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.

Net Revenue

When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and to maintain existing generation in PJM markets. Net revenue equals total revenue received by generators from PJM energy, capacity and ancillary service markets and from the provision of black start and reactive services, 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.

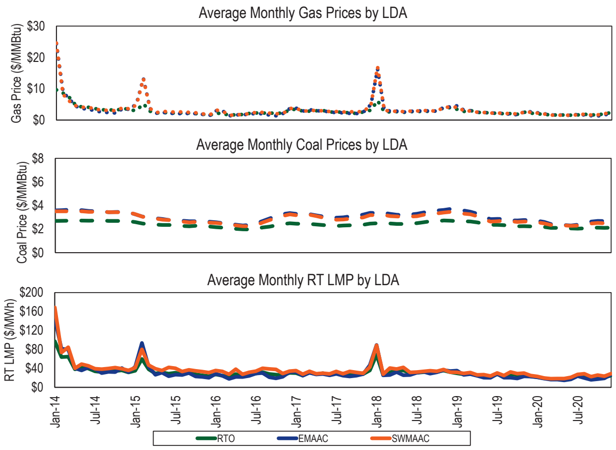
In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the annualized fixed and avoidable costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets that contribute 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 2020. The load-weighted, average real-time LMP was 20.3 percent lower in 2020 than in 2019, $21.77 per MWh versus $27.32 per MWh. Gas prices and coal prices also decreased in 2020. The price of Northern Appalachian coal was 18.2 percent lower; the price of Central Appalachian coal was 23.9 percent lower; the price of Powder River Basin coal was

2 Avoidable costs are sometimes referred to as going forward costs.

1.8 percent lower; the price of eastern natural gas was 30.9 percent lower; and the price of western natural gas was 24.6 percent lower (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2014 through 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.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{MMBtu}\right) * Heat\ Rate\left(\frac{MMBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative. Spreads are generally lower in 2020 than in 2019 and the standard deviation is uniformly 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

	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	$16.70	$14.48	$22.16	$9.48	$15.95	$16.54	$9.33	$3.83	$14.86	$13.10	$10.58	$18.26

Table 7-2 Peak hour spread standard deviation ($/MWh): 2014 through 2020

	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	$23.3	$23.4	$23.3	$13.5	$13.6	$13.6	$12.2	$12.8	$12.8	$15.5	$15.5	$15.5

Figure 7-2 shows the hourly spark spread for peak hours for BGE, ComEd, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2018 through 2020[3]

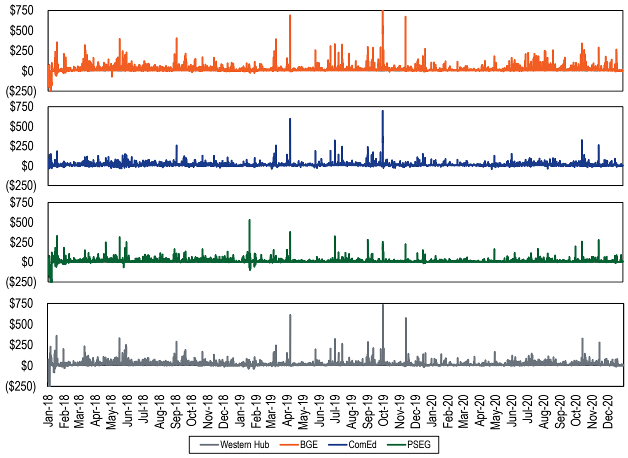


Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2018 through 2020[4]

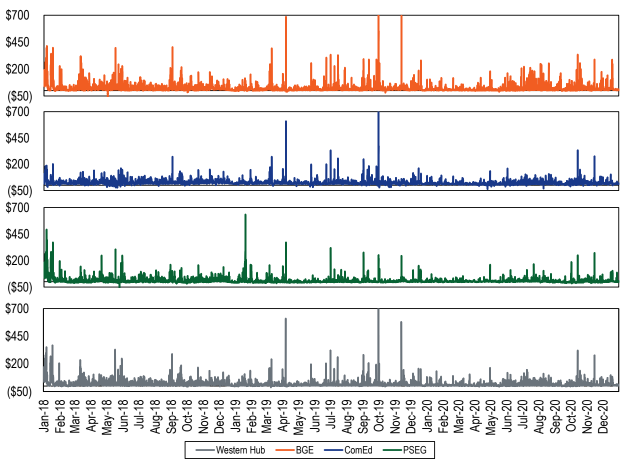
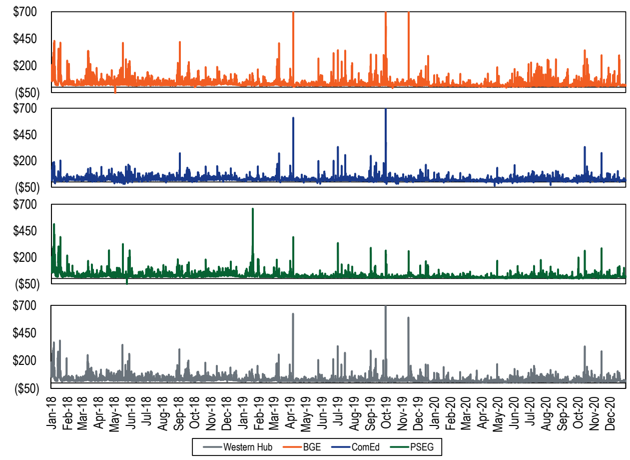


Figure 7-4 Hourly quark spread (uranium) for selected zones ($/MWh): 2018 through 2020[5]



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 eight power plant configurations:

- The CT plant is a single GE Frame 7HA.02 CT with an installed capacity of 360.1 MW, equipped with evaporative coolers, and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant includes two 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.

3 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for ComEd, Zone 6 non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

4 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.

5 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium (U_3O_8) prices.

- 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.[6 7] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost.[8] CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[9]

The class average equivalent availability factor for each type of plant was calculated from PJM data and incorporated into all revenue calculations.[10] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day annual planned outage in the fall season.

CT revenues for the provision of reactive services include both real-time reactive service revenues and reactive capability revenues. Reactive service revenues for CTs are based on the average reactive service revenue per MW-year received by all CTs with 20 or fewer operating years. Reactive service revenues for CC, CP, and DS units are based on the average reactive service revenue per MW-year received by all generators of that unit type. Table 7-3 includes reactive service revenues plus reactive capability revenue of $3,350/MW-year for all unit types plus reactive service revenue.[11]

Table 7-3 New entrant reactive revenue (Dollars per MW-year)

	Reactive				
	CT	CC	CP	Diesel	Nuclear
2014	$3,721	$4,046	$3,574	$3,350	$3,350
2015	$3,673	$4,911	$3,386	$3,350	$3,350
2016	$3,436	$4,573	$3,470	$3,350	$3,350
2017	$3,885	$3,591	$3,438	$3,350	$3,350
2018	$4,150	$3,350	$4,929	$3,350	$3,350
2019	$3,519	$3,350	$3,629	$3,350	$3,350
2020	$8,907	$3,784	$3,676	$3,365	$3,350

Zonal net revenues reflect average zonal LMP and fuel costs based on locational fuel indices and zone specific delivery charges.[12] 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.[13] 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.[14] Net revenues are calculated for all zones except OVEC.[15]

Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[16 17] Average short run marginal costs are shown, including all components, in Table 7-4 and the short run marginal component of VOM is also shown separately.

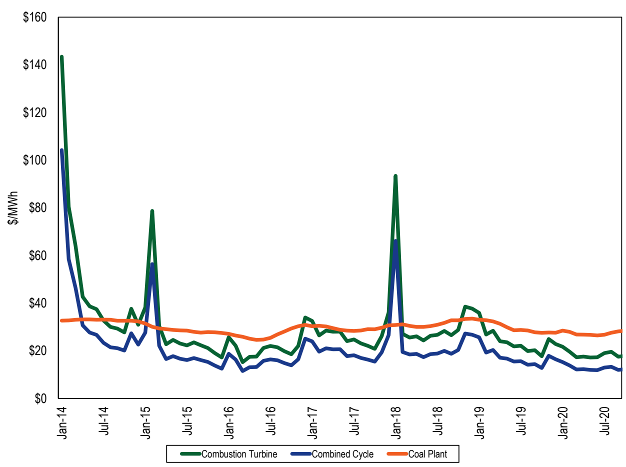
6 Hourly ambient conditions supplied by DTN.
7 Heat rates provided by Pasteris Energy, Inc. No load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.
8 CO_2 emission allowance costs only included for states participating in RGGI, including New Jersey.
9 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
10 Outage figures obtained from the PJM eGADS database.
11 The value of $3,350/MW-year is the average of reactive capability payments of selected units obtained from FERC filings.
12 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.
13 Gas daily cash prices obtained from Platts.
14 Coal prompt month prices obtained from Platts.
15 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.
16 Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid.
17 VOM rates provided by Pasteris Energy, Inc.

Table 7-4 Average short run marginal costs: 2020

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$19.38	9,241	$0.36
CC	$13.41	6,296	$1.41
CP	$27.63	9,250	$4.21
DS	$96.01	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

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 2020.

Figure 7-5 Average short run marginal costs: 2014 through 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 7-5 shows the average run hours by a new entrant unit.

Table 7-5 Average run hours: 2014 through 2020

	CT	CC	CP	DS	Nuclear
2014	4,722	7,908	6,693	153	8,760
2015	6,266	8,133	5,605	141	8,760
2016	6,337	8,264	5,025	44	8,784
2017	4,974	8,230	4,520	38	8,760
2018	4,925	8,190	4,971	116	8,760
2019	4,944	8,143	2,867	33	8,760
2020	4,716	8,097	1,511	44	8,784

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the energy and ancillary service markets. In the PJM market design, the sale of capacity provides an important source of revenues that contribute to covering generator avoidable costs and fixed costs. Capacity revenue for 2020 includes five months of the 2019/2020 capacity market clearing price and seven months of the 2020/2021 RPM capacity market clearing price.[18]

Table 7-6 Capacity revenue by zone (Dollars per MW-year): 2014 through 2020[19]

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	$66,206	$56,448	$50,948	$43,669	$65,655	$58,103	$57,650
AEP	$31,149	$48,128	$33,377	$34,645	$53,235	$45,873	$31,371
APS	$31,149	$48,128	$33,377	$34,645	$53,216	$45,948	$31,425
ATSI	$31,149	$95,422	$78,709	$42,929	$53,124	$45,781	$31,351
BGE	$63,360	$56,448	$50,948	$43,669	$52,953	$45,651	$33,380
ComEd	$31,149	$48,128	$33,377	$34,645	$63,994	$75,508	$70,901
DAY	$31,149	$48,128	$33,377	$34,645	$52,760	$44,969	$30,957
DEOK	$31,149	$48,128	$33,377	$34,645	$52,338	$44,515	$42,289
DLCO	$31,149	$48,128	$33,377	$34,645	$53,045	$45,567	$31,239
Dominion	$31,149	$48,128	$33,377	$34,645	$53,219	$45,665	$31,221
DPL	$66,206	$56,448	$50,948	$43,669	$65,106	$57,607	$57,573
EKPC	$31,149	$48,128	$33,377	$34,645	$52,400	$44,611	$30,883
JCPL	$66,206	$56,448	$50,948	$43,669	$64,763	$56,462	$56,932
Met-Ed	$63,360	$56,448	$50,948	$43,669	$53,353	$46,138	$33,526
PECO	$66,206	$56,448	$50,948	$43,669	$65,707	$58,548	$57,940
PENELEC	$63,360	$56,448	$50,945	$43,667	$53,154	$45,760	$33,376
Pepco	$66,529	$56,448	$50,948	$43,669	$53,323	$46,207	$33,590
PPL	$63,360	$56,448	$50,948	$43,669	$52,218	$45,398	$33,569
PSEG	$72,567	$60,936	$67,224	$73,401	$79,190	$59,582	$58,370
RECO	$72,567	$60,936	$67,224	$73,401	$79,190	$59,582	$58,370
PJM	$46,247	$54,646	$48,568	$44,809	$58,432	$52,008	$42,199

18 The RPM revenue values for PJM are load-weighted, average clearing prices across the relevant base residual auctions. Differences in capacity market revenues reflect differences in clearing prices across LDAs.

19 See the *2020 State of the Market Report for PJM*, Appendix A: "PJM Geography," for details on the expansion of the PJM footprint.

Net Revenue Adequacy

When total net revenues exceed the annual, nominal levelized total costs for the technology, that technology is covering all its costs including a return on and of capital and all the expenses of operating the facility.

The extent to which net revenues cover the levelized total costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue. Table 7-7 includes new entrant levelized total costs for selected technologies.

Net revenues include net revenues from the PJM energy market, from the PJM Capacity Market and from any applicable ancillary services plus RECs for wind installations and SRECs for solar installations.

Levelized Total Costs

Table 7-7 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[20 21]

	20-Year Levelized Total Cost						
	2014	2015	2016	2017	2018	2019	2020
Combustion Turbine	$122,604	$120,675	$119,346	$114,557	$118,116	$121,612	$120,720
Combined Cycle	$146,443	$146,300	$148,327	$129,731	$113,641	$116,781	$119,180
Coal Plant	$504,050	$517,017	$523,540	$528,701	$562,747	$581,567	$599,912
Diesel Plant	$161,746	$170,500	$173,182	$158,817	$154,683	$169,859	$177,843
Nuclear Plant	$880,770	$935,659	$963,107	$1,349,850	$1,178,607	$1,383,428	$1,383,428
On Shore Wind Installation (with 1603 grant)	$198,033	$202,874	$231,310	$188,747	$214,780	$214,618	$208,167
Off Shore Wind Installation (with 1603 grant)	-	-	-	-	$683,771	$710,472	$707,739
Solar Installation (with 1603 grant)	$236,289	$234,151	$218,937	$200,931	$232,230	$243,936	$189,391

Levelized Cost of Energy

The levelized cost of energy is a measure of the total cost per MWh of energy from a technology, including all fixed and variable costs. If a unit's revenues cover its levelized cost of energy, it is covering all its costs and earning the target rate of return. Table 7-8 shows the levelized cost of energy for a new entrant unit by technology type operating at the capacity factor for the new entrant unit type. CCs had a low levelized cost of energy in 2020 because they had a high capacity factor, which increases the MWh over which costs are spread. DS units had a high levelized cost of energy because DS units had a very low capacity factor, which decreases the MWh over which costs are spread. The levelized costs of onshore wind, offshore wind and solar are higher than for a CT or CC and lower than for a CP or DS.

The levelized cost of all units is sensitive to the capacity factor used. The LCOE of a solar installation is shown using a capacity factor of 16 percent. The LCOE of a solar installation is $133/MWh if a capacity factor of 21 percent is used because the costs are distributed over a greater number of MWh.

Table 7-8 Levelized cost of energy: 2020

	CT	CC	CP	DS	Nuclear	Wind (On Shore)	Wind (Off Shore)	Solar
Levelized cost ($/MW-year)	$121,612	$116,781	$581,567	$169,859	$1,383,428	$214,618	$710,472	$243,936
Short run marginal costs ($/MWh)	$19.38	$13.41	$27.63	$96.01	$0.00	$0.00	$0.00	$0.00
Capacity factor (%)	48%	76%	13%	1%	93%	26%	45%	16%
Levelized cost of energy ($/MWh)	$48	$31	$529	$2,255	$170	$96	$180	$170

20 Levelized total costs provided by Pasteris Energy, Inc.

21 Under Section 1603 of the American Recovery and Reinvestment Tax Act of 2009, the United States Department of the Treasury makes payments to owners who place in service specified energy property and apply for such payments. The purpose of the payment is to reimburse eligible applicants for a portion of the capital cost of such property. Solar and wind energy properties are eligible for a 30 percent payment of the total eligible capital cost of the project. This 30 percent payment reduced the calculated fixed nominal levelized revenue requirements of the solar and wind technologies.

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 five zones in 2020 (Table 7-9).

Table 7-9 Energy net revenue for a new entrant gas fired CT under economic dispatch: 2014 through 2020 (Dollars per installed MW-year)[22]

Zone	2014	2015	2016	2017	2018	2019	2020	Change in 2020 from 2019
AECO	$84,836	$50,794	$52,699	$28,997	$34,625	$24,051	$9,052	(62%)
AEP	$74,978	$69,424	$55,360	$36,440	$72,928	$44,651	$33,410	(25%)
APS	$101,376	$97,467	$61,544	$48,564	$71,758	$24,930	$19,200	(23%)
ATSI	$55,573	$59,263	$53,052	$38,949	$86,415	$45,733	$33,690	(26%)
BGE	$99,953	$79,092	$92,965	$40,064	$52,362	$33,157	$31,522	(5%)
ComEd	$34,672	$32,378	$34,109	$22,162	$32,571	$23,501	$18,530	(21%)
DAY	$49,905	$57,180	$51,652	$37,682	$81,172	$51,092	$40,100	(22%)
DEOK	$44,998	$54,542	$48,954	$36,051	$88,626	$46,495	$36,049	(22%)
DLCO	$52,029	$81,445	$72,284	$46,308	$57,854	$30,516	$31,432	3%
Dominion	$67,601	$68,742	$64,140	$37,075	$57,676	$35,826	$28,998	(19%)
DPL	$65,984	$33,315	$26,615	$19,853	$28,229	$14,604	$14,297	(2%)
EKPC	$65,277	$56,514	$48,036	$30,024	$55,351	$37,022	$29,760	(20%)
JCPL	$85,599	$48,957	$48,143	$32,391	$32,118	$23,755	$9,133	(62%)
Met-Ed	$87,153	$87,946	$71,178	$55,484	$44,929	$29,492	$36,074	22%
PECO	$89,208	$86,138	$66,527	$46,494	$38,961	$22,037	$26,723	21%
PENELEC	$139,617	$140,467	$89,309	$63,620	$83,911	$41,273	$44,218	7%
Pepco	$70,396	$50,496	$46,753	$25,829	$42,134	$21,041	$14,094	(33%)
PPL	$212,119	$155,947	$72,532	$59,248	$81,558	$28,443	$30,634	8%
PSEG	$108,432	$99,278	$71,988	$54,477	$44,574	$24,808	$9,575	(61%)
RECO	$80,365	$55,796	$53,746	$34,467	$35,019	$25,217	$11,413	(55%)
PJM	$58,381	$73,259	$59,079	$39,709	$56,138	$31,382	$25,395	(19%)

In 2020, a new CT would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-10).

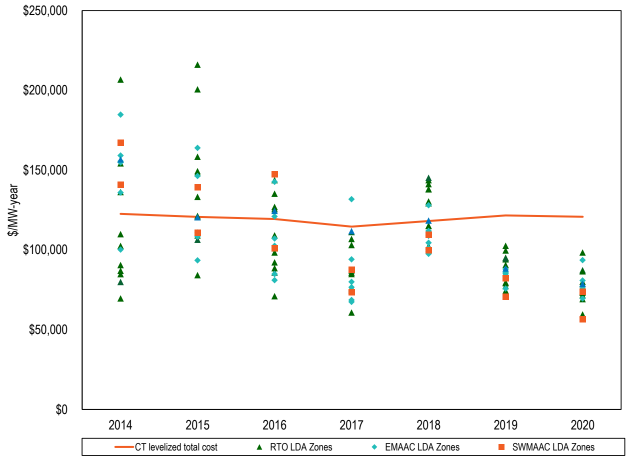
Table 7-10 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue: 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	126%	92%	90%	67%	88%	70%	63%
AEP	90%	100%	77%	65%	110%	77%	61%
APS	111%	124%	82%	76%	109%	61%	49%
ATSI	74%	131%	113%	75%	122%	78%	61%
BGE	136%	115%	123%	76%	93%	68%	61%
ComEd	57%	70%	59%	53%	85%	84%	81%
DAY	69%	90%	74%	67%	117%	82%	66%
DEOK	65%	88%	72%	65%	123%	78%	72%
DLCO	71%	110%	91%	74%	97%	65%	59%
Dominion	84%	100%	85%	66%	97%	70%	57%
DPL	111%	77%	68%	59%	83%	62%	67%
EKPC	82%	90%	71%	60%	95%	70%	58%
JCPL	127%	90%	86%	70%	86%	69%	62%
Met-Ed	126%	123%	105%	90%	87%	65%	65%
PECO	130%	121%	101%	82%	92%	69%	78%
PENELEC	169%	166%	120%	97%	120%	74%	72%
Pepco	115%	92%	85%	64%	84%	58%	47%
PPL	228%	179%	106%	93%	117%	64%	61%
PSEG	151%	136%	120%	115%	108%	72%	64%
RECO	128%	100%	104%	98%	100%	73%	65%
PJM	88%	109%	93%	77%	101%	71%	63%

22 The energy net revenues presented for the PJM area in this section are calculated using the zonal average LMP.

Figure 7-6 shows zonal net revenue and the annual levelized total cost for the new entrant CT by LDA.

Figure 7-6 New entrant CT net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2020



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.[23] 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 2020 as a result of lower energy prices (Table 7-11).

Table 7-11 Energy net revenue for a new entrant CC under economic dispatch: 2014 through 2020 (Dollars per installed MW-year)[24]

Zone	2014	2015	2016	2017	2018	2019	2020	Change in 2020 from 2019
AECO	$126,626	$74,716	$68,004	$50,259	$67,427	$51,977	$30,319	(42%)
AEP	$109,036	$96,826	$76,488	$59,550	$109,104	$75,511	$55,507	(26%)
APS	$154,231	$140,352	$98,353	$76,282	$117,114	$64,967	$54,578	(16%)
ATSI	$82,670	$87,902	$74,459	$60,987	$120,740	$76,430	$55,795	(27%)
BGE	$155,871	$125,088	$129,148	$71,490	$98,258	$75,145	$67,980	(10%)
ComEd	$47,229	$54,134	$53,187	$38,278	$56,006	$45,701	$34,513	(24%)
DAY	$76,213	$86,691	$73,887	$61,188	$117,206	$82,157	$63,218	(23%)
DEOK	$66,685	$82,518	$70,201	$57,922	$122,183	$77,203	$58,414	(24%)
DLCO	$82,827	$95,948	$86,877	$64,871	$91,162	$58,222	$53,223	(9%)
Dominion	$106,993	$98,562	$86,903	$60,969	$92,066	$68,337	$51,053	(25%)
DPL	$109,317	$50,497	$43,345	$27,674	$47,707	$21,780	$17,669	(19%)
EKPC	$94,596	$84,530	$68,479	$52,705	$91,178	$67,735	$51,526	(24%)
JCPL	$129,943	$73,929	$63,904	$53,388	$64,877	$52,372	$30,694	(41%)
Met-Ed	$125,883	$104,606	$82,491	$71,970	$78,513	$58,243	$54,319	(7%)
PECO	$130,722	$105,080	$77,959	$64,772	$74,100	$49,311	$45,284	(8%)
PENELEC	$177,418	$147,403	$99,614	$78,602	$118,315	$70,955	$63,114	(11%)
Pepco	$116,024	$96,499	$85,838	$54,535	$84,100	$58,997	$39,576	(33%)
PPL	$232,421	$155,117	$83,707	$73,720	$108,706	$54,943	$49,351	(10%)
PSEG	$157,086	$118,918	$83,897	$72,328	$81,207	$54,350	$33,449	(38%)
RECO	$125,098	$79,151	$68,279	$55,405	$66,816	$54,423	$34,227	(37%)
PJM	$100,026	$97,923	$78,751	$60,345	$90,339	$60,938	$47,190	(23%)

23 All starts associated with combined cycle units are assumed to be warm starts.
24 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

In 2020, a new CC would not have received sufficient net revenue to cover levelized total costs any zones (Table 7-12).

Table 7-12 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue: 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	134%	93%	83%	75%	120%	97%	77%
AEP	98%	102%	77%	75%	146%	107%	76%
APS	129%	132%	92%	88%	153%	98%	75%
ATSI	80%	129%	106%	83%	156%	108%	76%
BGE	152%	127%	125%	92%	136%	106%	88%
ComEd	56%	73%	61%	59%	109%	107%	92%
DAY	76%	96%	75%	77%	153%	112%	82%
DEOK	70%	93%	73%	74%	157%	107%	88%
DLCO	81%	102%	84%	79%	130%	92%	74%
Dominion	97%	104%	84%	76%	131%	100%	72%
DPL	123%	76%	67%	58%	102%	71%	66%
EKPC	89%	94%	72%	70%	129%	99%	72%
JCPL	137%	92%	81%	78%	117%	96%	77%
Met-Ed	132%	113%	93%	92%	119%	92%	77%
PECO	137%	114%	90%	86%	126%	95%	90%
PENELEC	167%	143%	105%	97%	154%	103%	84%
Pepco	127%	108%	95%	78%	124%	93%	65%
PPL	205%	148%	94%	93%	145%	89%	73%
PSEG	160%	126%	105%	115%	144%	100%	80%
RECO	138%	99%	94%	102%	131%	100%	81%
PJM	103%	108%	89%	84%	134%	100%	78%

Figure 7-7 shows zonal net revenue and the annual levelized total cost for the new entrant CC by LDA.

Figure 7-7 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2020

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 7-13).

Table 7-13 Energy net revenue for a new entrant CP: 2014 through 2020 (Dollars per installed MW-year)[25]

Zone	2014	2015	2016	2017	2018	2019	2020	Change in 2020 from 2019
AECO	$115,697	$48,138	$10,643	$7,601	$31,260	$4,279	$1,176	(73%)
AEP	$113,144	$51,079	$38,517	$35,658	$63,698	$19,004	$7,807	(59%)
APS	$105,457	$42,147	$14,995	$17,879	$43,519	$5,688	$2,413	(58%)
ATSI	$124,565	$51,785	$34,262	$35,618	$66,002	$14,847	$4,630	(69%)
BGE	$167,855	$84,957	$46,952	$18,903	$51,185	$9,970	$6,209	(38%)
ComEd	$112,699	$39,698	$28,732	$26,632	$37,054	$12,822	$2,983	(77%)
DAY	$117,447	$50,088	$31,524	$34,467	$62,462	$18,807	$9,763	(48%)
DEOK	$106,048	$46,117	$28,460	$31,389	$67,260	$16,583	$8,587	(48%)
DLCO	$98,952	$40,461	$29,819	$32,250	$65,589	$13,181	$5,229	(60%)
Dominion	$156,315	$90,406	$44,653	$27,496	$64,695	$17,805	$9,438	(47%)
DPL	$167,509	$71,672	$21,952	$16,869	$50,348	$10,285	$6,805	(34%)
EKPC	$102,305	$38,208	$24,436	$25,144	$43,091	$12,475	$6,577	(47%)
JCPL	$119,656	$46,725	$7,933	$8,452	$30,416	$4,074	$1,386	(66%)
Met-Ed	$153,809	$64,861	$19,709	$20,908	$49,202	$9,800	$6,897	(30%)
PECO	$111,207	$44,763	$8,709	$7,691	$29,007	$4,053	$871	(79%)
PENELEC	$129,578	$59,867	$23,206	$16,790	$46,051	$9,533	$5,186	(46%)
Pepco	$114,167	$41,146	$10,499	$6,142	$29,304	$4,342	$1,347	(69%)
PPL	$110,250	$43,645	$7,050	$7,770	$28,732	$3,234	$1,069	(67%)
PSEG	$174,390	$72,812	$13,651	$12,882	$35,986	$6,201	$489	(92%)
RECO	$170,401	$73,077	$13,238	$12,236	$35,919	$7,234	$1,279	(82%)
PJM	$128,573	$55,083	$22,947	$20,139	$46,539	$10,211	$4,507	(56%)

In 2020, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-14). This has been the consistent result for a new CP since 2009.

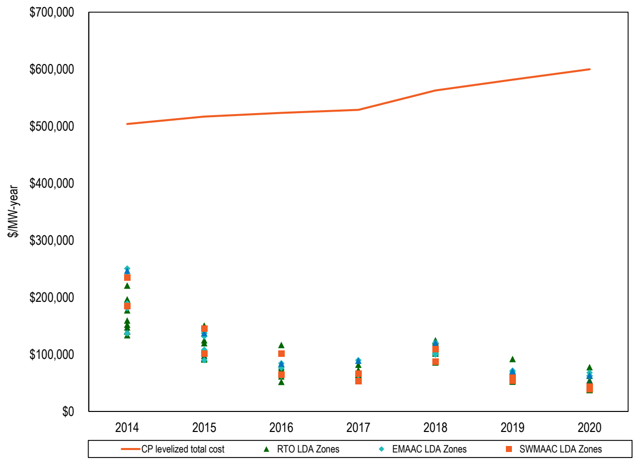
Table 7-14 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue: 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	37%	21%	12%	10%	18%	11%	10%
AEP	29%	20%	14%	14%	22%	12%	7%
APS	28%	18%	10%	11%	18%	10%	6%
ATSI	32%	29%	22%	16%	22%	11%	7%
BGE	47%	28%	19%	12%	19%	10%	7%
ComEd	29%	18%	13%	12%	19%	16%	13%
DAY	30%	20%	13%	14%	21%	12%	7%
DEOK	28%	19%	12%	13%	22%	11%	9%
DLCO	27%	18%	13%	13%	22%	11%	7%
Dominion	38%	27%	16%	12%	22%	12%	7%
DPL	47%	25%	15%	12%	21%	12%	11%
EKPC	27%	17%	12%	12%	18%	10%	7%
JCPL	38%	21%	12%	11%	18%	11%	10%
Met-Ed	44%	24%	14%	13%	19%	10%	7%
PECO	36%	20%	12%	10%	18%	11%	10%
PENELEC	39%	23%	15%	12%	19%	10%	7%
Pepco	37%	20%	12%	10%	16%	9%	6%
PPL	35%	20%	12%	10%	15%	9%	6%
PSEG	50%	27%	16%	17%	21%	12%	10%
RECO	49%	27%	16%	17%	21%	12%	11%
PJM	35%	22%	14%	13%	20%	11%	8%

25 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

Figure 7-8 shows zonal net revenue and the annual levelized total cost for the new entrant CP by LDA.

Figure 7-8 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2020



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.[26]

New entrant nuclear plant energy market net revenues were lower in all zones as a result of lower energy prices (Table 7-15).

Table 7-15 Energy net revenue for a new entrant nuclear plant: 2014 through 2020 (Dollars per installed MW-year)[27 28]

Zone	2014	2015	2016	2017	2018	2019	2020	Change in 2020 from 2019
AECO	$430,088	$273,691	$200,584	$226,845	$285,185	$192,221	$147,168	(23%)
AEP	$358,889	$259,420	$226,969	$241,589	$291,370	$217,407	$170,937	(21%)
APS	$383,546	$282,041	$231,832	$245,633	$302,994	$216,401	$170,914	(21%)
ATSI	$371,823	$262,859	$228,329	$246,859	$305,160	$219,369	$170,965	(22%)
BGE	$482,796	$352,161	$296,138	$268,966	$332,101	$237,019	$194,052	(18%)
ComEd	$322,257	$225,655	$213,368	$221,193	$235,676	$191,318	$154,963	(19%)
DAY	$361,855	$261,380	$228,084	$246,977	$301,482	$226,472	$179,830	(21%)
DEOK	$347,738	$256,348	$223,698	$242,729	$307,041	$220,799	$174,520	(21%)
DLCO	$340,525	$249,258	$222,416	$242,278	$304,190	$216,018	$171,585	(21%)
Dominion	$430,421	$311,499	$250,271	$260,185	$323,948	$225,667	$176,991	(22%)
DPL	$467,506	$301,832	$224,906	$245,767	$314,185	$203,224	$159,794	(21%)
EKPC	$343,061	$246,594	$218,753	$234,319	$274,749	$214,080	$170,356	(20%)
JCPL	$434,325	$272,261	$195,704	$231,523	$282,490	$192,909	$147,714	(23%)
Met-Ed	$417,516	$265,313	$198,714	$236,723	$282,769	$199,556	$155,273	(22%)
PECO	$421,701	$266,837	$193,380	$226,787	$277,512	$188,645	$145,298	(23%)
PENELEC	$394,697	$271,023	$215,556	$236,980	$291,292	$207,398	$162,672	(22%)
Pepco	$467,154	$328,709	$266,428	$263,124	$323,833	$230,232	$180,809	(21%)
PPL	$418,032	$265,864	$195,230	$228,451	$273,036	$188,993	$146,492	(22%)
PSEG	$456,679	$283,287	$200,257	$237,187	$286,834	$194,920	$149,103	(24%)
RECO	$451,926	$284,922	$201,343	$237,924	$289,049	$199,553	$153,187	(23%)
PJM	$405,127	$276,048	$221,598	$241,102	$294,245	$209,110	$164,131	(22%)

26 The annual class average equivalent availability factor was used in the calculation of energy market net revenues.

27 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.

28 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.

In 2020, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-16). This has been the consistent result for a new nuclear plant for the entire period of the analysis.

Table 7-16 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue: 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	57%	36%	26%	20%	30%	18%	15%
AEP	45%	33%	27%	21%	30%	19%	15%
APS	47%	36%	28%	21%	31%	19%	15%
ATSI	46%	39%	32%	22%	31%	19%	15%
BGE	62%	44%	36%	23%	33%	21%	17%
ComEd	41%	30%	26%	19%	26%	20%	17%
DAY	45%	33%	27%	21%	30%	20%	15%
DEOK	43%	33%	27%	21%	31%	19%	16%
DLCO	43%	32%	27%	21%	31%	19%	15%
Dominion	53%	39%	30%	22%	32%	20%	15%
DPL	61%	39%	29%	22%	32%	19%	16%
EKPC	43%	32%	27%	20%	28%	19%	15%
JCPL	57%	35%	26%	21%	30%	18%	15%
Met-Ed	55%	35%	26%	21%	29%	18%	14%
PECO	56%	35%	26%	20%	29%	18%	15%
PENELEC	52%	35%	28%	21%	30%	19%	14%
Pepco	61%	42%	33%	23%	32%	20%	16%
PPL	55%	35%	26%	20%	28%	17%	13%
PSEG	60%	37%	28%	23%	31%	19%	15%
RECO	60%	37%	28%	23%	32%	19%	16%
PJM	52%	36%	28%	21%	30%	19%	15%

Figure 7-9 New entrant nuclear plant net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2020

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 two zones in 2020 (Table 7-17).

Table 7-17 Energy market net revenue for a new entrant DS: 2014 through 2020 (Dollars per installed MW-year)

Zone	2014	2015	2016	2017	2018	2019	2020	Change in 2020 from 2019
AECO	$33,114	$13,159	$2,416	$2,554	$10,312	$2,029	$835	(59%)
AEP	$14,469	$3,968	$987	$1,420	$4,154	$5,138	$1,182	(77%)
APS	$18,020	$7,423	$1,051	$1,343	$6,675	$4,662	$2,092	(55%)
ATSI	$14,114	$3,675	$2,090	$1,773	$7,209	$4,537	$2,548	(44%)
BGE	$50,096	$18,305	$8,329	$3,202	$12,785	$6,899	$4,980	(28%)
ComEd	$11,320	$2,327	$748	$1,333	$730	$3,476	$821	(76%)
DAY	$14,288	$3,772	$1,044	$1,670	$3,946	$5,570	$1,146	(79%)
DEOK	$13,467	$3,288	$1,415	$3,069	$6,675	$5,441	$1,013	(81%)
DLCO	$13,132	$3,179	$2,416	$1,517	$9,248	$4,493	$3,973	(12%)
Dominion	$42,609	$12,064	$2,596	$2,765	$15,094	$5,841	$1,863	(68%)
DPL	$38,453	$19,925	$3,691	$5,637	$14,261	$6,375	$8,788	38%
EKPC	$14,483	$2,970	$1,054	$972	$1,922	$4,868	$1,003	(79%)
JCPL	$33,066	$13,042	$923	$2,848	$11,134	$2,085	$1,614	(23%)
Met-Ed	$31,992	$13,020	$908	$3,794	$10,974	$2,670	$3,020	13%
PECO	$32,360	$12,429	$875	$2,839	$9,838	$2,077	$1,421	(32%)
PENELEC	$15,964	$6,436	$904	$1,699	$5,539	$2,906	$1,355	(53%)
Pepco	$51,396	$12,842	$3,551	$2,497	$12,363	$6,314	$1,884	(70%)
PPL	$32,931	$13,062	$796	$2,988	$8,799	$1,650	$1,194	(28%)
PSEG	$32,550	$12,650	$1,064	$3,284	$10,325	$2,437	$730	(70%)
RECO	$30,724	$13,740	$1,247	$3,031	$9,703	$2,627	$1,785	(32%)
PJM	$29,787	$9,564	$1,905	$2,512	$8,584	$4,105	$2,162	(47%)

In 2020, the new entrant DS would not have received sufficient net revenue to cover levelized total costs in any zone. This has been the consistent result for a new DS for the entire period of the analysis.

Table 7-18 Percent of 20-year levelized total costs recovered by DS energy and capacity net revenue: 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	63%	43%	33%	31%	51%	37%	35%
AEP	30%	33%	22%	25%	39%	32%	20%
APS	32%	35%	22%	25%	41%	32%	21%
ATSI	30%	60%	49%	30%	41%	32%	21%
BGE	72%	46%	36%	32%	45%	33%	23%
ComEd	28%	32%	22%	25%	44%	48%	42%
DAY	30%	32%	22%	25%	39%	32%	20%
DEOK	30%	32%	22%	26%	40%	31%	26%
DLCO	29%	32%	23%	25%	42%	31%	22%
Dominion	48%	37%	23%	26%	46%	32%	20%
DPL	67%	47%	33%	33%	53%	40%	39%
EKPC	30%	32%	22%	25%	37%	31%	20%
JCPL	63%	43%	32%	31%	51%	36%	35%
Met-Ed	61%	43%	32%	32%	44%	31%	22%
PECO	63%	42%	32%	31%	51%	38%	35%
PENELEC	51%	39%	32%	31%	40%	31%	21%
Pepco	75%	43%	33%	31%	45%	33%	22%
PPL	62%	43%	32%	31%	42%	30%	21%
PSEG	67%	45%	41%	50%	60%	38%	35%
RECO	66%	46%	41%	50%	60%	39%	36%
PJM	49%	40%	31%	32%	45%	35%	27%

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).[29]

Onshore wind energy market net revenues were lower as a result of lower energy prices.

Table 7-19 Energy market net revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020	Change in 2020 from 2019
AEP	$106,499	$78,929	$67,826	$71,312	$93,621	$70,434	$47,589	(32%)
APS	$108,148	$72,504	$62,352	$71,867	$95,329	$58,628	$47,685	(19%)
ComEd	$95,745	$67,842	$58,915	$68,278	$65,111	$59,836	$39,899	(33%)
PENELEC	$129,612	$85,543	$65,204	$73,843	$95,776	$55,603	$42,652	(23%)

The new entrant onshore wind installation analysis is based on a 17.6 percent capacity factor for purposes of participating in the capacity market.[30]

Table 7-20 Capacity market net revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AEP	$5,482	$8,471	$5,874	$6,097	$9,369	$8,074	$5,521
APS	$5,482	$8,471	$5,874	$6,097	$9,366	$8,087	$5,531
ComEd	$5,482	$8,471	$5,874	$6,097	$11,263	$13,289	$12,479
PENELEC	$11,151	$9,935	$8,966	$7,685	$9,355	$8,054	$5,874

Wind units in the four zones were assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[31] Renewable energy credits were approximately 30 percent of the total net revenue of an onshore wind installation.

Table 7-21 RECs revenue for an onshore wind installation (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AEP	$37,956	$41,971	$30,518	$12,681	$15,679	$18,030	$23,127
APS	$36,437	$33,539	$26,854	$12,202	$15,350	$14,957	$22,491
ComEd	$40,539	$41,676	$28,828	$13,526	$15,102	$18,602	$23,227
PENELEC	$41,808	$39,913	$30,101	$12,811	$15,746	$14,956	$21,621

In 2020, a new onshore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the four zones analyzed. This has been the consistent result for a new wind installation for the entire period of the analysis.

Wind projects that are currently operating or under construction may have a different financing structure, require a lower rate of return, or have other factors that are not captured in the new entrant analysis presented in this section.

Table 7-22 Percent of 20-year levelized total costs recovered by onshore wind net revenue (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AEP	76%	64%	45%	48%	55%	45%	37%
APS	76%	56%	41%	48%	56%	38%	36%
ComEd	72%	58%	40%	47%	43%	43%	36%
PENELEC	92%	67%	45%	50%	56%	37%	34%

29 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.

30 PJM Planning. Class Average Capacity Factors Wind and Solar Resources. (Eff. June 1, 2017). <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.

31 RECs prices obtained from Evolution Markets, Inc.

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 7-23 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020	Change in 2020 from 2019
AECO	$201,681	$129,548	$96,525	$109,649	$137,203	$93,518	$72,895	(22%)

The new entrant offshore wind installation is based on a 45 percent capacity factor for purposes of participating in the capacity market.[32]

Table 7-24 Capacity market net revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	$29,793	$25,402	$22,926	$19,651	$29,545	$26,146	$25,943

The offshore wind unit was assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[33] Renewable energy credits accounted for 18 percent of the total net revenue of an off shore wind installation.

Table 7-25 RECs revenue for an offshore wind installation (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	$62,616	$62,607	$46,082	$19,225	$23,931	$26,087	$37,914

In 2020, a new offshore wind installation would not have received sufficient net revenue to cover levelized total costs.

Table 7-26 Percent of 20-year levelized total costs recovered by offshore wind net revenue (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	43%	32%	24%	22%	28%	21%	19%

32 Lazard. Levelized Cost of Energy. Version 13.0. November 2019 <https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf>.
33 RECs prices obtained from Evolution Markets, Inc.

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).[34]

Solar energy market net revenues were lower as a result of lower energy prices.

Table 7-27 Energy market net revenue for a solar installation (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020	Change in 2020 from 2019
AECO	$67,446	$48,285	$38,762	$38,022	$41,772	$32,636	$23,716	(27%)
Dominion	-	-	$70,026	$68,150	$78,189	$59,472	$45,177	(24%)
DPL	-	-	$45,546	$50,740	$61,773	$44,687	$33,323	(25%)
JCPL	$61,850	$41,551	$33,986	$36,414	$39,433	$30,189	$23,599	(22%)
PSEG	$61,548	$47,830	$39,380	$40,979	$43,469	$34,047	$25,767	(24%)

The new entrant solar installation analysis is based on a 42.0 percent capacity factor for purposes of participating in the capacity market.[35]

Table 7-28 Capacity market net revenue for a solar installation (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	$27,807	$23,708	$21,398	$18,341	$27,575	$24,403	$24,213
Dominion	-	-	$14,018	$14,551	$22,352	$19,179	$13,113
DPL	-	-	$21,398	$18,341	$27,345	$24,195	$24,181
JCPL	$27,807	$23,708	$21,398	$18,341	$27,200	$23,714	$23,911
PSEG	$30,478	$25,593	$28,234	$30,828	$33,260	$25,025	$24,515

The solar installation was assumed to receive the highest of the DC, MD or NJ Solar REC, based on locational eligibility, for the purposes of calculating RECs revenue.[36] Renewable energy credits ranged from 68 percent of the total net revenue of a solar installation in DPL to 86 percent of the total net revenue of a solar installation in AECO, JCPL, and PSEG.

Table 7-29 RECs revenue for a solar installation (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	$240,050	$325,643	$373,683	$285,895	$273,161	$313,056	$292,165
Dominion	-	-	$101,679	$20,760	$18,364	$99,084	$150,493
DPL	-	-	$74,619	$17,514	$15,804	$85,624	$121,982
JCPL	$222,593	$280,457	$332,265	$267,345	$258,291	$286,300	$281,980
PSEG	$213,746	$303,612	$379,054	$294,273	$279,286	$319,285	$312,318

In 2020, a new solar installation would have received sufficient net revenue to cover levelized total costs in AECO, Dominion, JCPL and PSEG as a result of high RECs revenue and would not have received sufficient net revenue to cover levelized total costs in Dominion or DPL.

Solar projects that are currently operating or under construction may have a different financing structure, require a lower rate of return, or have other factors that are not captured in the new entrant analysis presented in this section.

Table 7-30 Percent of 20-year levelized total costs recovered by solar net revenue (Dollars per installed MW-year): 2014 through 2020

Zone	2014	2015	2016	2017	2018	2019	2020
AECO	142%	170%	198%	170%	147%	152%	180%
Dominion	-	-	85%	51%	51%	73%	110%
DPL	-	-	65%	43%	45%	63%	95%
JCPL	132%	148%	177%	160%	140%	139%	174%
PSEG	129%	161%	204%	182%	153%	155%	191%

34 The 1603 payment is a direct payment of 30 percent of the project cost.
35 PJM Planning. Class Average Capacity Factors Wind and Solar Resources. (Eff. June 1, 2017). <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>.
36 RECs prices obtained from Evolution Markets, Inc.

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 PSEG Zone and 99 percent of total costs in the BGE Zone 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.

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 7-10 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 7-10 Historical new entrant CC revenue adequacy: 2007 through 2020 and 2012 through 2020[37]

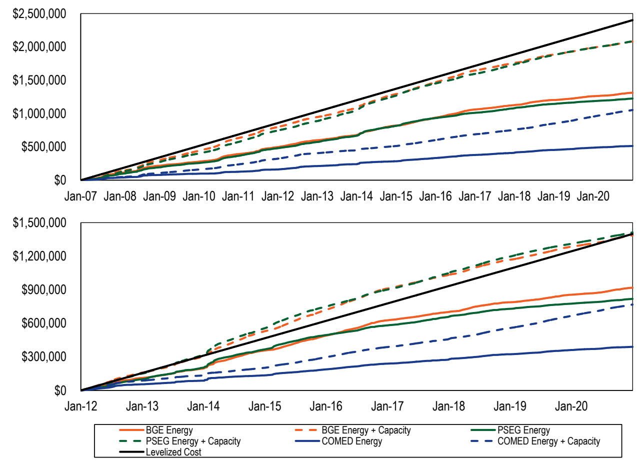


Table 7-31 shows the percent of levelized total costs recovered.

Table 7-31 Percent of levelized total costs recovered

	2007 CC	2012 CC
BGE	87%	99%
ComEd	44%	55%
PSEG	87%	101%

Assumptions used for this analysis are shown in Table 7-32.

Table 7-32 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%

37 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.

Factors in Net Revenue Adequacy

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed and variable costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2020, the average short run marginal cost of the CC and CT were lower than the average short run marginal cost of the CP in every month. (Figure 7-5)

The net revenue results illustrate some fundamentals of the PJM wholesale power market. Lower energy prices, lower gas prices, and lower coal prices meant that units ran with lower margins and sometimes for fewer hours than in prior years. High demand hours result in less efficient units setting prices, which results in higher net revenues for more efficient units. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue in the PJM design. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market.

However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which is generally an inaccurate estimate of actual net revenues in the current operating year and an inaccurate estimate of expected net revenues for the forward capacity market. A forward looking estimate of expected energy and ancillary services net revenues is a preferred method for defining the offset in the capacity market. Capacity market prices and revenues have a substantial impact on the profitability of investing in new and existing units.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized total costs from Table 7-7. The results are shown in Table 7-33.[38]

Table 7-33 Internal rate of return sensitivity for CT and CC generators

	CT		CC	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$124,370	13.4%	$124,655	13.4%
Base Case	$120,720	12.0%	$119,180	12.0%
Sensitivity 2	$117,070	10.5%	$113,705	10.5%
Sensitivity 3	$113,420	8.9%	$108,230	8.8%
Sensitivity 4	$109,770	7.1%	$102,755	6.9%
Sensitivity 5	$106,120	5.1%	$97,280	4.7%
Sensitivity 6	$102,470	2.6%	$91,805	1.9%

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 7-34 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR falls.

Table 7-34 Debt to equity ratio sensitivity for CT and CC assuming 20-year debt term and 12 percent internal rate of return

	Equity as a percent of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$126,663	$126,362
Sensitivity 2	55%	$123,680	$122,748
Base Case	50%	$120,720	$119,180
Sensitivity 3	45%	$117,783	$115,658
Sensitivity 4	40%	$114,869	$112,181
Sensitivity 5	35%	$111,977	$108,750
Sensitivity 6	30%	$109,108	$105,365

38 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt to equity capital structure with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC plant. An annual rate of cost inflation of 2.5 percent was used in all calculations.

Table 7-35 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly affect the profitability of investing in peaking and midmerit generation technologies at a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant CC has a higher energy output over which to spread the costs than the new entrant CT.

Table 7-35 Interconnection cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$0	0.0%	$118,341	$0	0.0%	$116,625
Sensitivity 2	$3,705	1.3%	$119,531	$11,702	1.2%	$117,903
Base Case	$7,410	2.6%	$120,720	$23,403	2.4%	$119,180
Sensitivity 3	$11,115	3.9%	$121,910	$35,105	3.5%	$120,458
Sensitivity 4	$14,820	5.2%	$123,100	$46,806	4.7%	$121,736
Sensitivity 5	$18,525	6.5%	$124,289	$58,508	5.9%	$123,013
Sensitivity 6	$22,262	7.8%	$125,479	$70,209	7.1%	$124,291

Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational to operate a unit whenever the price is greater than its short run marginal costs. It is rational for an owner to continue to operate a unit rather than retire the unit if the unit is covering or is expected to cover its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit rather than retire the unit if the unit is not covering and is not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of incremental investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs in this analysis, the actual avoidable costs are adjusted to exclude APIR. Existing APIR is a sunk cost and a rational decision about retirement would ignore such sunk costs. For example, APIR may reflect investments in environmental technology which were made in prior years to keep units in service. These costs are sunk costs.

The MMU calculated actual unit specific energy and ancillary service net revenues for a range of technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM energy and ancillary service markets alone provide sufficient incentive for continued operations in PJM markets. Energy and ancillary service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include day-ahead and balancing market energy revenues, less short run marginal costs, plus any applicable day-ahead or balancing operating reserve credits. Ancillary service revenues include actual unit credits for regulation services, synchronized reserves, black start service, and reactive revenues.

The MMU calculated avoidable costs by unit type in dollars per MW-year.[39]

39 Avoidable costs provided by Pasteris Energy, Inc.

The PJM capacity market design provides supplemental signals to the market based on the locational and forward looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2019/2020 and 2020/2021 Delivery Years, reflecting commitments made in base residual auctions (BRA) and subsequent incremental auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM markets in 2020. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[40] For units exporting capacity, the applicable BRA clearing price was applied.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the capacity market. The analysis is on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. As required by FERC, net revenues for units other than nuclear are calculated using units' price-based offers for technologies, unless the unit is cost-capped or the price-based offer is less than fuel plus environmental costs.[41] For nuclear units, public data on revenues and costs are used.

The unit specific energy and ancillary net revenues, avoidable costs and capacity revenues, on which the class averages shown in Table 7-36 are based, include a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile.

Table 7-36 shows energy and ancillary service net revenues by quartile for select technology classes.[42] Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivered costs for input fuels. Unlike the other technologies, nuclear data is from public sources in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP from the relevant node as shown in Table 7-39, adjusted by the class average equivalent availability factor. Nuclear unit capacity revenue assumes that the unit cleared its full installed capacity at the BRA locational clearing price as shown in Table 7-40.

Table 7-36 also includes new entrant theoretical energy market net revenue from Table 7-9, Table 7-11, Table 7-13, Table 7-15, and Table 7-17 for comparison purposes. As an example, for the CC plants, the predominant form of new entry in PJM, existing resources in the top quartile of net revenue, earn net revenues that are comparable to the theoretical new entrant net revenues. This supports the conclusion that the theoretical new entrant results are a good representation of the performance of actual new entrants and existing plants with comparable technologies. The results for existing units vary based on location, technology and actual performance.

Table 7-36 Net revenue by quartile for select technologies: 2020

		($/MW-Yr)										
	Total	Energy and ancillary service net revenue				Capacity revenue			Energy, ancillary, and capacity revenue			
Technology	Installed Capacity (ICAP)	New entrant	First quartile	Median	Third quartile	First quartile	Median	Third quartile	New entrant	First quartile	Median	Third quartile
CC - Combined Cycle	30,264	$50,975	$5,660	$22,927	$54,225	$17,083	$30,186	$54,692	$93,174	$47,414	$64,221	$89,838
CT - Aero Derivative	5,646	$34,303	$3,023	$10,492	$34,635	$30,481	$48,181	$57,717	$76,502	$40,305	$65,081	$93,634
CT - Industrial Frame	21,533	-	($208)	$1,751	$8,067	$25,183	$31,121	$55,382	-	$25,564	$40,812	$68,860
Coal Fired	46,148	$8,183	($7,477)	($1,681)	$0	$17,220	$27,446	$30,727	$50,382	$9,751	$21,390	$30,389
Diesel	296	$5,528	($361)	$1,004	$17,905	$18,722	$30,683	$51,135	$47,727	$18,722	$29,772	$70,529
Hydro	1,483	-	$57,227	$90,647	$155,741	$20,553	$30,680	$42,855	-	$77,081	$112,840	$210,919
Nuclear	30,351	$167,481	$141,290	$148,397	$167,014	$31,299	$57,895	$70,453	$209,680	$199,461	$201,455	$215,557
Oil or Gas Steam	9,848	-	($3,384)	($1,132)	$5,599	$28,848	$36,291	$46,523	-	$20,468	$35,556	$47,192
Pumped Storage	4,721	-	$34,815	$68,765	$68,765	$28,885	$46,445	$53,418	-	$71,317	$88,365	$115,504
Solar	3,644	$30,317	$20,854	$24,917	$35,219	$971	$2,234	$3,735	$52,303	$21,589	$25,621	$35,976
Wind	11,172	$44,456	$37,336	$42,080	$49,700	$217	$506	$1,132	$51,808	$37,457	$42,332	$50,243

40 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

41 154 FERC ¶ 61,151 at P 59.

42 The quartile numbers in the table are the dividing lines between the quartiles. The first quartile result means that 25 percent of units have lower net revenues, the median result means that 50 percent of units have lower net revenues and the third quartile result means that 75 percent of units have lower net revenues.

Table 7-37 shows the percent of avoidable costs covered by net revenue from PJM energy and ancillary services markets by quartiles. In 2020, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone. After including capacity revenues, net revenues from all markets cover avoidable costs for even the first quartile of most technology types, although this is not the case for every individual unit and it is not the case for coal or nuclear units.

The analysis of nuclear plants includes publicly available data on energy market prices, capacity prices, and an estimate of annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's average across all U.S. nuclear plants.[43] [44] The NEI annual avoidable costs used in the analysis are for 2019, the most recent data available.

Table 7-37 Avoidable cost recovery by quartile: 2020

	Total Installed	Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
Technology	Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	30,264	41%	166%	393%	343%	465%	651%
CT - Aero Derivative	5,646	23%	86%	206%	304%	454%	660%
CT - Industrial Frame	21,533	(1%)	14%	61%	213%	341%	612%
Coal Fired	46,148	(12%)	(2%)	0%	14%	29%	47%
Diesel	296	(3%)	8%	151%	158%	251%	594%
Hydro	1,483	178%	282%	485%	240%	352%	657%
Nuclear	30,351	58%	63%	71%	86%	87%	93%
Oil or Gas Steam	9,848	(9%)	(3%)	6%	34%	80%	125%
Pumped Storage	4,721	371%	732%	732%	760%	941%	1,230%
Solar	3,644	401%	479%	678%	415%	493%	692%
Wind	11,172	108%	121%	143%	108%	122%	145%

Table 7-38 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets from 2011 through 2020. In 2020, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of coal and nuclear units.[45]

Table 7-38 Proportion of units recovering avoidable costs: 2011 through 2020

	Units with full recovery from energy and ancillary net revenue										Units with full recovery from all markets									
Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	57%	66%	64%	67%	85%	79%	79%	95%	88%	93%	89%	98%	90%	93%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	10%	30%	46%	42%	100%	96%	76%	98%	100%	99%	100%	99%	96%	96%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	3%	21%	30%	21%	99%	98%	83%	100%	100%	100%	100%	96%	92%	86%
Coal Fired	31%	17%	27%	78%	16%	15%	12%	11%	2%	2%	82%	36%	54%	83%	64%	40%	36%	63%	31%	5%
Diesel	48%	42%	37%	69%	56%	33%	32%	39%	11%	37%	100%	100%	77%	100%	100%	100%	100%	97%	91%	89%
Hydro	74%	61%	95%	97%	81%	79%	95%	94%	90%	72%	81%	77%	97%	98%	100%	100%	97%	98%	100%	74%
Nuclear	-	-	50%	94%	17%	6%	17%	53%	0%	0%	-	-	61%	100%	56%	17%	50%	88%	81%	0%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	0%	10%	73%	6%	92%	78%	86%	85%	91%	88%	81%	76%	66%	34%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Solar	-	95%	97%	99%	97%	95%	95%	98%	96%	95%	-	95%	97%	99%	97%	95%	95%	98%	96%	95%
Wind	88%	85%	96%	93%	92%	89%	93%	91%	88%	79%	88%	85%	96%	93%	92%	89%	93%	91%	89%	79%

43 Operating costs from: Nuclear Energy Institute (October, 2020). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Nuclear-Costs-in-Context.pdf>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

44 The NEI costs for Hope Creek and Salem plants were both treated as those associated with a two unit configuration because all three units are located in the same area.

45 Analysis excludes Catawba 1 which joined PJM with the integration of DEOK.

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.[46] [47] 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).[48] 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).[49] 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.[50] When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. In 2016, PJM energy prices were then at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs based on current year prices.[51] 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. Energy prices in 2020 were lower than 2019 prices, but forward energy prices for 2021 through 2023 are at or above 2019 energy prices. The result is that nuclear plant energy revenues based on forward period prices are expected to be similar to or higher than 2019 energy revenues. The results for nuclear plants are also sensitive to changes in costs and whether actual unit costs are less than or greater than the benchmark NEI data.

Table 7-39 includes the publicly available data on energy market prices, Table 7-40 and Table 7-41 show capacity market prices and Table 7-42 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.[52] 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.[53] 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.

46 Operating costs from: Nuclear Energy Institute (October, 2020). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Nuclear-Costs-in-Context.pdf>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

47 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.

48 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.

49 Capital expenditures have decreased 46.0 percent since 2012 for single unit plants and 44.5 percent for multiple unit plants.

50 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.

51 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.*

52 Installed capacity is from NEI, "Map of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.

53 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?la=en>.

Table 7-39 Nuclear unit day-ahead LMP: 2008 through 2020

	ICAP	Average DA LMP ($/MWh)												
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Beaver Valley	1,808	$49.46	$31.51	$35.59	$37.43	$30.34	$34.24	$41.86	$30.35	$27.07	$29.11	$36.35	$26.22	$20.33
Braidwood	2,337	$48.10	$27.76	$31.48	$32.02	$27.51	$30.26	$37.34	$25.97	$24.30	$24.99	$27.11	$22.88	$18.23
Byron	2,300	$47.61	$23.98	$28.49	$28.09	$24.25	$29.22	$35.05	$21.00	$17.94	$23.79	$26.96	$22.19	$17.66
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	$21.88
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44	$26.33	$20.54
Dresden	1,797	$48.76	$28.27	$32.73	$33.07	$28.42	$31.82	$39.22	$27.45	$25.89	$26.35	$28.25	$23.41	$18.73
Hope Creek	1,172	$73.34	$39.43	$48.03	$45.52	$33.07	$37.43	$51.99	$32.41	$23.20	$26.78	$32.93	$22.45	$17.32
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	$18.14
Limerick	2,242	$73.49	$39.49	$48.23	$45.27	$33.09	$37.28	$51.71	$32.65	$23.37	$26.99	$33.08	$22.68	$17.31
North Anna	1,892	$75.14	$39.89	$50.59	$45.47	$33.87	$38.55	$53.37	$38.05	$30.50	$31.27	$38.44	$27.39	$21.06
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	$18.07
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	$16.93
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24	$26.76	$20.49
Quad Cities	1,819	$47.28	$24.81	$27.53	$26.79	$20.43	$25.94	$30.71	$19.47	$18.04	$23.09	$25.54	$21.13	$15.95
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	$17.32
Surry	1,676	$71.96	$39.02	$49.30	$45.01	$33.62	$37.98	$51.75	$37.91	$30.08	$31.08	$38.50	$26.65	$20.41
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	$16.03
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	$19.07

Table 7-40 BRA capacity market clearing prices ($/MW-Day): 2008 through 2021[54]

	ICAP	BRA Capacity Price ($/MW-Day)														
	(MW)	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
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

54 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. 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 7-41 Nuclear unit capacity market revenue ($/MWh): 2008 through 2021[55] [56]

	ICAP	Capacity Revenue ($/MWh)													
	(MW)	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

Table 7-42 Nuclear unit costs: 2008 through 2019[57] [58]

	ICAP	NEI Costs ($/MWh)											
	(MW)	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

55 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.

56 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. 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>.

57 Operating costs from: Nuclear Energy Institute (October, 2020). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>.

58 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>.

Table 7-43 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.[59] The surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.[60] 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 Auction[61] and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear in the 2019/2020 Auction.[62] Three Mile Island and Quad Cities did not clear in the 2020/2021 Auction.[63] Three Mile Island, Dresden, and most of Byron did not clear in the 2021/2022 Auction.[64] Beaver Valley, Davis Besse, and Perry did not clear in the 2021/2022 Auction.[65]

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 1.7 percent in 2020.[66]

In 2020, no nuclear plants covered their fuel costs, operating costs, and capital expenditures as a result of lower energy prices, based on current year prices.

59 Talen Energy Investor Day, February 12, 2019.

60 Installed capacity is from NEI. "Maps of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.

61 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

62 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

63 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.

64 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>.

65 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>.

66 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.

Table 7-43 Nuclear unit surplus (shortfall) based on public data: 2008 through 2020[67]

	ICAP	Surplus (Shortfall) ($/MWh)												
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
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	($4.0)
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	($1.3)
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	($1.9)
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	($2.2)
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.2)	($13.8)
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	($0.7)
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	($3.6)
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	$3.8	($1.5)
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	($3.9)
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	($3.3)
Oyster Creek	608	$47.5	$8.4	$15.9	$7.2	($8.2)	$3.3	$16.4	($4.7)	($11.6)	($9.9)	NA	NA	NA
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	($4.1)
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.3)	$1.9	($5.8)	($13.9)
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	($3.7)
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	($3.9)
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	($4.0)
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)	($8.0)
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($3.8)	NA	NA

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2021, 2022 and 2023 and known capacity market prices for 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. Nuclear plants may sell their output at a range of forward prices and for a range of future years.

Table 7-44 shows PJM energy prices (LMP), annual fuel, and operating and capital expenditures used for the analysis of the period 2021 through 2023. Capacity revenues are not presented for calendar year 2022 and 2023 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.[68] Forward prices are as of January 4, 2021. The capacity prices are known based on PJM capacity auction results.

Table 7-44 Forward prices in PJM energy markets, capacity revenue, and annual costs[69]

		Average Forward LMP ($/MWh)			Ancillary Revenue ($/MWh)	Capacity Revenue ($/MWh)	2019 NEI Costs ($/MWh)		
	ICAP (MW)	2021	2022	2023	Reactive	2021	Fuel	Operating	Capital
Beaver Valley	1,808	$26.23	$28.09	$27.56	$0.24	$5.03	$6.06	$17.00	$5.32
Braidwood	2,337	$23.67	$25.42	$24.93	$0.24	$8.52	$6.06	$17.00	$5.32
Byron	2,300	$22.88	$24.57	$24.10	$0.21	$8.52	$6.06	$17.00	$5.32
Calvert Cliffs	1,708	$27.51	$29.41	$28.85	$0.20	$5.21	$6.06	$17.00	$5.32
Davis Besse	894	$26.48	$28.36	$27.83	$0.24	$5.85	$6.50	$24.60	$7.30
Dresden	1,797	$24.34	$26.11	$25.62	$0.32	$8.52	$6.06	$17.00	$5.32
Hope Creek	1,172	$23.32	$25.12	$24.67	$0.43	$7.74	$6.06	$17.00	$5.32
LaSalle	2,271	$23.59	$25.32	$24.84	$0.18	$8.52	$6.06	$17.00	$5.32
Limerick	2,242	$23.26	$25.07	$24.62	$0.14	$7.74	$6.06	$17.00	$5.32
North Anna	1,892	$26.79	$28.66	$28.11	$0.17	$5.03	$6.06	$17.00	$5.32
Peach Bottom	2,347	$22.99	$24.80	$24.36	$0.29	$7.74	$6.06	$17.00	$5.32
Perry	1,240	$26.41	$28.29	$27.76	$0.24	$5.85	$6.50	$24.60	$7.30
Quad Cities	1,819	$21.01	$22.53	$22.10	$0.18	$8.52	$6.06	$17.00	$5.32
Salem	2,328	$23.32	$25.12	$24.67	$0.12	$7.74	$6.06	$17.00	$5.32
Surry	1,676	$25.87	$27.63	$27.10	$0.17	$5.03	$6.06	$17.00	$5.32
Susquehanna	2,520	$21.56	$23.01	$22.58	$0.28	$5.21	$6.06	$17.00	$5.32

67 The values for 2016 through 2019 have changed slightly from previous values to account for reactive supply and voltage control revenues.

68 Forward prices on January 4, 2021. 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 2020 data.

69 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>.

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.[70] 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.

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.[71] 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.

In Table 7-45, 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 unit's ICAP multiplied by the average forward LMP multiplied by the class average equivalent availability factor. Total expected ancillary services revenue is reactive capability revenue.[72] 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.

In Table 7-45, for 2022, using forward prices as of January 4, 2021, the capacity price required to cover avoidable costs ranges from $0/MW-day for a multiple unit plant to $220.02/MW-day for a single unit plant for NEI data as reported including capex as a proxy for major maintenance, and from $0/MW-day for multiple unit plants to $57.26/MW-day for a single unit plant, excluding capital expenditures as a proxy for major maintenance.

Table 7-45 Net ACR

		Net ACR ($/MWh)			Net ACR ($/MW-Day)			Net ACR Excluding Capital ($/MW-Day)		
	ICAP (MW)	2021	2022	2023	2021	2022	2023	2021	2022	2023
Beaver Valley	1,808	$1.91	$0.04	$0.57	$42.48	$0.94	$12.76	$0.00	$0.00	$0.00
Braidwood	2,337	$4.47	$2.72	$3.21	$99.65	$60.67	$71.53	$0.00	$0.00	$0.00
Byron	2,300	$5.29	$3.60	$4.06	$117.84	$80.29	$90.61	$0.00	$0.00	$0.00
Calvert Cliffs	1,708	$0.67	$0.00	$0.00	$14.93	$0.00	$0.00	$0.00	$0.00	$0.00
Davis Besse	894	$11.68	$9.80	$10.33	$260.39	$218.44	$230.30	$97.63	$55.68	$67.54
Dresden	1,797	$3.71	$1.94	$2.43	$82.82	$43.35	$54.28	$0.00	$0.00	$0.00
Hope Creek	1,172	$4.64	$2.83	$3.28	$103.36	$63.15	$73.24	$0.00	$0.00	$0.00
LaSalle	2,271	$4.61	$2.87	$3.36	$102.84	$64.10	$74.84	$0.00	$0.00	$0.00
Limerick	2,242	$4.99	$3.17	$3.62	$111.15	$70.78	$80.80	$0.00	$0.00	$0.00
North Anna	1,892	$1.42	$0.00	$0.10	$31.77	$0.00	$2.18	$0.00	$0.00	$0.00
Peach Bottom	2,347	$5.10	$3.30	$3.74	$113.74	$73.53	$83.36	$0.00	$0.00	$0.00
Perry	1,240	$11.75	$9.87	$10.40	$262.00	$220.02	$231.89	$99.24	$57.26	$69.13
Quad Cities	1,819	$7.19	$5.67	$6.10	$160.32	$126.37	$136.07	$41.70	$7.75	$17.45
Salem	2,328	$4.94	$3.14	$3.59	$110.13	$69.94	$80.03	$0.00	$0.00	$0.00
Surry	1,676	$2.34	$0.58	$1.11	$52.27	$13.02	$24.76	$0.00	$0.00	$0.00
Susquehanna	2,520	$6.54	$5.09	$5.52	$145.75	$113.54	$123.01	$27.13	$0.00	$4.40

70 See 169 FERC ¶ 61,239 at P 148.
71 See 167 FERC ¶ 61,030 at P 41.
72 Reactive Supply & Voltage Control Revenue Requirements available from PJM <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx>.

Table 7-46 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 7-46 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 only three plants, Davis Besse, Perry, and Susquehanna would not cover their annual avoidable costs in 2021. Two of these plants, Davis Besse and Perry, are single unit sites which have higher operating costs per MWh than multiple unit plants and show an annual shortfall of $5.83 and $5.90 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. Susquehanna has reduced its operating costs below the NEI average costs and is not operating at a loss when the unit specific information is accounted for.[73]

Table 7-46 Nuclear unit forward annual surplus (shortfall)

		Surplus (Shortfall) ($/MWh)	Surplus (Shortfall) ($ in millions)
	ICAP (MW)	2021	2021
Beaver Valley	1,808	$3.13	$47.4
Braidwood	2,337	$4.05	$79.0
Byron	2,300	$3.23	$62.4
Calvert Cliffs	1,708	$4.54	$64.5
Davis Besse	894	($5.83)	($41.7)
Dresden	1,797	$4.81	$71.8
Hope Creek	1,172	$3.11	$30.6
LaSalle	2,271	$3.91	$74.1
Limerick	2,242	$2.76	$52.1
North Anna	1,892	$3.61	$57.0
Peach Bottom	2,347	$2.64	$52.3
Perry	1,240	($5.90)	($58.6)
Quad Cities	1,819	$1.33	$21.1
Salem	2,328	$2.80	$54.9
Surry	1,676	$2.69	$38.0
Susquehanna	2,520	($1.33)	($25.6)

73 Bank of America Global Research, October 26, 2020.

Units At Risk

The definition of units at risk of retirement is units that are not expected to recover their avoidable costs from market revenues.

Unit revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover and are expected to continue to fail to recover avoidable costs from total market revenues, including capacity market revenues, are at risk of retirement.[74] Units that failed to clear the most recent capacity auction(s) are at increased risk of retirement if this result is outside the control of the plant owner and is expected to continue. The profile of units that are not expected to cover their avoidable costs over the next three years is shown in Table 7-47. These units are considered at risk of retirement.[75]

The analysis compares expected energy and capacity market revenues to ACR values over the period 2021-2023. Bus level forward LMPs are based on forward prices with a basis adjustment for the specific plant locations.[76] Forward prices are as of January 4, 2021. The capacity revenues for 2021 are carried forward for calendar year 2022 and 2023 because neither the 2022/2023 nor the 2023/2024 auctions have been run.

Based on these criteria, a total of 4,751 MW of coal, CT, diesel, and oil fired capacity are at risk of retirement, in addition to the units that are currently planning to retire. The 4,763 MW considered to be at risk of retirement includes 2,361 MW of coal, 1,829 MW of CT and 574 MW of other capacity.[77]

No nuclear plants are considered to be at risk of retirement. The maximum Net ACR for a multiple unit plant in 2022 or 2023 is $90.61/MW-Day,[78] which is below the five year historical average BRA clearing price. The single site nuclear plants, Davis Besse and Perry, receive a subsidy and are not expected to retire.

74 FRR units and units that have either already started the deactivation process or requested deactivation review are excluded from the at risk analysis.

75 Units expected to continue operations for reasons not directly related to market prices are not considered at risk of retirement.

76 Forward prices on January 4, 2021. 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 2020 data.

77 Units at risk of retirement analysis is based on the default unit type ACR provided by Pasteris Energy, Inc.

78 The average of $90.61/MW-Day excludes Quad Cities and Susquehanna. Quad Cities receives a subsidy and is not expected to retire. Susquehanna has costs below the NEI average and has a significantly lower Net ACR than is shown. Bank of America Global Research, October 26, 2020.

Table 7-47 Profile of units at risk of retirement

Technology	No. Units	ACR ($/MW-Day)	ICAP (MW)	Avg. 2020 Run Hours	Avg. Unit Age (Yrs)	Avg. Heat Rate (Btu/Mwh)
Coal Fired	7	$118.68	2,361	5,354	43	10,558
CT	50	$98.46	1,829	381	45	15,160
Other	7	$55.96	574	2,841	47	10,785
Total	64	-	4,763	-	-	-

If unit capacity revenues for the 2022/2023 and 2023/2024 Delivery Years are 25 percent higher than the revenues received for the 2021/2022 Delivery Year, then 3,945 MW will be at risk of retirement, consisting of 2,326 MW of coal, 1,056 MW of CT, and 563 MW of other generation.

If unit capacity revenues for the 2022/2023 and 2023/2024 Delivery Years are 25 percent lower than the revenues received for the 2021/2022 Delivery Year, then 7,590 MW will be at risk of retirement, consisting of 4,245 MW of coal, 2,761 MW of CT, and 585 MW of other generation.

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 SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[4] On October 15, 2020, the EPA proposed to revise upward the good neighbor obligations under the 2008 ozone NAAQS for 12 states, including 10 PJM states.[5]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[6] 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.[7] 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

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 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. [EPA-HQ-OAR-2020-0272; FRL-10013-42- OAR, 85 Fed. Reg. 68964 (Oct. 30, 2020).

6 *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).

7 See 40 CFR § 63.6640(f).

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 January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's Affordable Clean Energy (ACE) rule which would have permitted more CO_2 emissions than under the Clean Power Plan, which ACE had replaced.[8]
- **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]
- **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 CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont that applies to power generation facilities. New Jersey rejoined on January 1, 2020.[12] Virginia joined RGGI on January 1, 2021, and Pennsylvania is preparing to join.[13] [14] The auction price in the December 2, 2020, auction for the 2018/2020 compliance period was $7.41 per ton, or $8.17 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 126.5 percent for a new combustion turbine (CT) unit, $16.71 per MWh or 124.6 percent for a new combined cycle (CC) unit and $43.15 per MWh or 156.2 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 December 31, 2020, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia had a voluntary RPS in 2020, but a new mandatory RPS became effective on January 1, 2021. 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.

8 American Lung Association et al. v. EPA, No. 19-1140.

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).

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 "Statement on Virginia Greenhouse Gas Rule," RGGI, (July 8, 2020) <https://www.rggi.org/news-releases/rggi-releases>.

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/>.

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 December 31, 2020, 93.9 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 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 3.7 percent of total generation in PJM in 2020. RPS Tier I generation was 5.2 percent of total generation in PJM and RPS Tier II generation was 2.1 percent of total generation in PJM in 2020. Only Tier I generation is defined to be renewable but Tier 1 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 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.)

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 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

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.").

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 $6.17 per tonne in Washington, DC to $18.36 per tonne in New Jersey. The price of carbon implied by SREC prices ranges from $60.97 per tonne in Pennsylvania to $883.41 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in December 2020 of $8.17 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 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

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.

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.[18] 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 $7.41 per short ton and emissions levels were five percent below 2020 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 $16.6 billion if the carbon price were $50 per short ton and emission levels were five percent below 2020 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 $7.41 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.

18 Several states that have compliance periods that align with the PJM capacity market have not released compliance reports for the period June 1, 2019 through May 31, 2020.

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.[19]

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.[20 21]

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.[22] Regulation of coal ash or coal combustion residuals affects coal fired power plants.

The EPA's actions have affected and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

CAA: NESHAP/MATS

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the EPA issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified

19 For more details, see the *2019 State of the Market Report for PJM*, Vol. 2, Appendix H: "Environmental and Renewable Energy Regulations."

20 42 U.S.C. § 7401 et seq. (2000).

21 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.

22 42 U.S.C. §§ 6901 *et seq.*

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.[23] 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.[24] 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.[25] [26] 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.[27] 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.[28] The rule allows four refuse coal plants, 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 SO_2.[29] 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.[30]

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, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).

In January 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states. CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS. CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[31]

On October 15, 2020, in response to a court holding in *Wisconsin v. EPA*,[32] the EPA proposed to revise upward the good neighbor obligations under the 2008 ozone NAAQS for 12 states.[33] Ten of the affected states are PJM states, including Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia. For these states, projected 2021 emissions were found to contribute at or above a threshold of 1 percent of the NAAQS (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states.[34] Starting with the 2021 ozone season, the EPA proposes to issue new or amended Federal Implementation Plans (FIPs) for the affected

23 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.

24 *Id.* at 31299.

25 Michigan v. EPA, 135 S.Ct. 2699 (2015) (reversed EPA determination that cost does not have to be read into the definition of "appropriate").

26 85 Fed. Reg. at 31288.

27 *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)."

28 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).

29 *Id.* at 20841.

30 *Id.* at 20847.

31 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).

32 Wisconsin v. EPA, 938 F.3d 303, 318–20 (D.C. Cir. 2019).

33 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. [EPA-HQ-OAR-2020-0272; FRL-10013-42- OAR, 85 Fed. Reg. 68964 (Oct. 30, 2020).

34 *Id.* at 68989.

states.[35] The proposed FIPs would require power plants in the affected states (also including Louisiana and New York) to participate in a new CSAPR NO_x Ozone Season Group 3 Trading Program.[36] Participation in the more stringent new program would replace the obligation to participate in the existing CSAPR NO_x Ozone Season Group 2 Trading Program.[37]

The EPA's current and proposed emissions budgets for each PJM state for each ozone season for 2021 through 2024, and beyond are shown in Table 8-1.

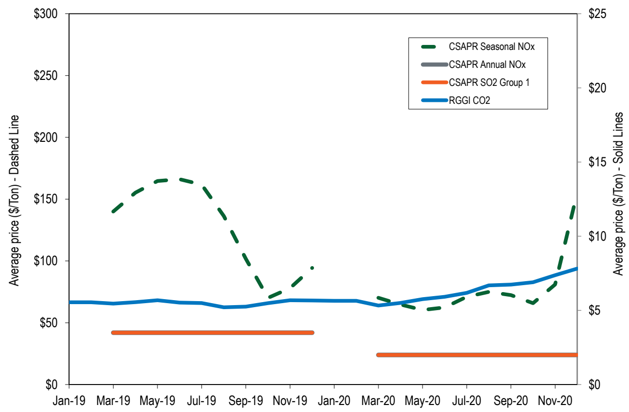
Table 8-1 CSAPR NO_X ozone season group 3 state budgets, variability limits, and assurance levels: 2021 through 2024[38 39]

	Emissions Budget (Tons)							
	Current				Proposed			
PJM State	2021	2022	2023	2024+	2021	2022	2023	2024+
Illinois	9,688	9,652	8,599	8,599	9,444	9,415	8,397	8,397
Indiana	15,586	15, 383	15,383	12,755	12,500	11,998	11,998	9,447
Kentucky	15,588	15,588	15,588	15, 588	14,384	11,936	11,936	11,936
Maryland	1,565	1,565	1,565	1,565	1,522	1,498	1,498	1,498
Michigan	13,893	13,893	11,056	10,841	12,727	11,767	9,803	9,614
New Jersey	1,346	1,346	1,346	1,346	1,253	1,253	1,253	1,253
Ohio	15,832	15,917	15,917	15,917	9,605	9676	9,676	9,676
Pennsylvania	11,570	11,570	11,570	11,570	8,076	8,076	8,076	8,076
Virginia	4,592	4,175	4,175	3,912	4,544	3,656	3,656	3,395
West Virginia	15,165	15,165	13,407	13,407	13,686	12,813	11,810	11,810

Figure 8-1 shows average, monthly settled prices for NO_X, CO_2 and SO_2 emissions allowances including CSAPR related allowances for 2020. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In 2020, CSAPR annual NO_X prices were 42.9 percent lower than in 2019. In 2020, CSAPR Seasonal NO_X prices were 38.7 percent lower than in 2019.

Figure 8-1 Spot monthly average emission price comparison: 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.[40] 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.[41]

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

35 *Id.* at 69009.
36 *Id.* at 69010.
37 *Id.*
38 *Id.* at 69010–69011(Table VIII.C.2–1–4).
39 See "Proposed State Budgets under the Revised Cross-State Air Pollution Rule Update", EPA, <https://www.epa.gov/csapr/proposed-state-budgets-under-revised-cross-state-air-pollution-rule-update>.

40 42 U.S.C § 7470 et seq.
41 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.

test.[42] 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.

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.[43] [44] 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,"[45] the policy precludes 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.[46] Under PJM rules, an EEA2 is automatically triggered when PJM initiates an emergency load response event. Demand resources that rely on RICE to provide load reductions are constrained to a maximum of 100 hours.

PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it does not meet emissions standards. Emergency RICE with a limit of 100 hours per year cannot comply with the requirement to be available during the entire delivery year to be a capacity resource. PJM should not allow locations that rely upon emergency stationary RICE to register individually or in portfolios. Registration of DR should be based on a finding that registered locations are capable of providing load reductions without an hourly limit. Reliance on the prospect of penalties to deter registration of ineligible resources as DR in lieu of a substantive ex ante review is not appropriate.

CAA: Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[47] [48]

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

42 *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).

43 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").

44 See 40 CFR § 52.21(b)(11); 40 CFR § 52.21(a)(2)(iii).

45 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…").

46 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).

47 See CAA § 111.

48 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.

in analyses known as the "Social Costs of Carbon."[49] 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.[50] 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 CO_2 that new, modified or reconstructed fossil fuel fired steam power plants would be allowed to emit based on the best system of emission reductions (BSER) determined by the EPA (2015 GHG NSR Rule).[51] 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.[52]

On January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's Affordable Clean Energy (ACE) rule which would have permitted more CO_2 emissions than under the Clean Power Plan, which ACE had replaced.

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).[53] [54]

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.[55] 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.[56]

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").[57] 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.[58] Environmental groups have filed complaints seeking to overturn the NWPR, including in federal district court in Maryland.[59]

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.[60] Groundwater is not itself WOTUS. However, if pollutants pass through groundwater from a point source to WOTUS, a permit may be required.[61] 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.[62] The EPA may not interpret the CWA to require a direct discharge.[63] The Court held that discharge into groundwater "is the functional equivalent of a direct discharge."[64] The existence of a functional discharge will depend on an analysis including time and distance, and other factors.[65] Additional litigation or administrative action may clarify the functional

49 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).

50 *Id.*

51 *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.

52 *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").

53 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.").

54 For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix H: "Environmental and Renewable Energy Regulations."

55 The stay was issued by the U.S. Court of Appeals for the Sixth Circuit on October 9, 2015.

56 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).

57 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.

58 *Id.* at 22251–22252.

59 See Chesapeake Bay Foundation et al. v. Wheeler et al., Case 1:20-cv-01064-GLR (USDC Dist. of Md.).

60 Slip. Op. No. 18–260 (April 23, 2020).

61 *Id.*

62 *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).

63 Slip. Op. No. 18–260 at 5.

64 *Id.* at 1.

65 *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.").

discharge analysis.[66] County of Maui reduces the importance of the precise definition of WOTUS because WOTUS is generally part of the watershed.[67]

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.[68]

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[69] 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.[70] CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

In 2016, RCRA was amended to establish a permitting scheme allowing states to apply to the EPA for approval to operate a permit program that implements the CCR rule. Such state programs could include alternative state standards, provided that EPA determines that they are ‘‘at least as protective as’’ the EPA CCR regulations.[71]

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR (“2018 CCRR Revisions”) partly in response to the 2016 amendments.[72]

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.

The U.S. Court of Appeals for the D.C. Circuit invalidated certain provisions of the 2015 CCRR and remanded it to the EPA.[73] On July 29, 2020, the EPA finalized revisions to CCRR in compliance with the court orders (“Revised CCRR”).[74] 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.[75] Impoundment facilities unable to meet the earliest deadline would be able to obtain extensions until an alternative can be “technically feasibly

66 *Id.*

67 *See id.* at 5 (“Virtually all water, polluted or not, eventually makes its way to navigable water. This is just as true for groundwater.”).

68 For more details, see the *2019 State of the Market Report for PJM*, Volume 2, Appendix H: "Environmental and Renewable Energy Regulations."

69 42 U.S.C. §§ 6901 *et seq.*

70 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

71 The Water Infrastructure Improvements for the Nation Act (WIIN Act).

72 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).

73 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).

74 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).

75 *Id.* at 53516–53517, 53536.

implemented."[76] Utilities had until November 30, 2020, to obtain an automatic extension upon certification of need for additional time.[77] [78] Upon receipt of required documentation satisfying certain criteria, the EPA could grant certain extensions, including to as late as October 17, 2028, for a facility with a surface impoundment of 40 acres or greater that commits to a deadline for ending operations of its boiler.[79]

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.[80] 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.[81] In 2019, Virginia enacted legislation directing the closure of coal ash ponds located in the Chesapeake Bay Watershed and owned by Dominion Energy.[82] 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,[83] the Illinois Environmental Protection Agency (Illinois EPA) proposed rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.[84] 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.[85] 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.[86] The Illinois EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.[87]

The North Carolina Department of Environmental Quality (NCDEQ) has initiated a rule making on rules for the disposal or recycling of coal combustion residuals. None of the affected power stations or power station impoundments are located in the PJM Dominion Zone (which includes a portion of northeast coastal North Carolina).

The Maryland Department of Environment (MDE) indicated in April 2020, that it would require GenOn Holdings Inc. to meet a November 1, 2020, deadline for compliance with effluent guidelines at Chalk Point Generating Station, Dickerson Generating Station and Morgantown Generating Station.[88] On May 15, 2020, GenOn announced its decision to retire the Dickerson Generating Station.[89] Dickerson Generating Station was retired effective August 13, 2020. On August 10, 2020, Genon announced that the Chalk Point coal units would retire on June 1, 2021.[90] On December 18, 2020, GenOn reported that it would retire its Morgantown coal fired unit by October 1, 2027.[91]

76 *Id.* at 53546.
77 *Id.* at 65942.
78 A number of plants in PJM timely filed for extensions.
79 *Id.*
80 *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).
81 The following Virginia power stations host coal ash ponds: Bremo 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.
82 Va. Code § 10.1-1402.03.
83 Ill. Public Act 101-171 (a.k.a. SB 09).
84 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.
85 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").
86 Proposed Illinois Rules at 3.
87 *Id.* at 3.
88 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/>.
89 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>.
90 See "GenOn Holdings, Inc. Announces Retirement of Chalk Point Coal Units" (August 10, 2020) <https://www.genon.com/genon-news/genon-holdings-inc-announces-retirement-of-chalk-point-coal-units>.
91 See "GenOn Holdings, Inc. Announces Retirement of Morgantown Coal Units," (December 18, 2020) <https://www.genon.com/genon-news/genon-holdings-inc-announces-retirement-of-morgantown-coal-units>.

State Environmental Regulation

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[92]

- **New Jersey HEDD.** Units that run only during peak demand periods have relatively low annual emissions, and have less reason to make such investments under the EPA transport rules. New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days. New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.
- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS). MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

State Regulation of Greenhouse Gas Emissions

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.[93] 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.[94] 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.[95]

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 CO_2 emissions from power generation facilities.[96]

Delaware, Maryland and New Jersey are the only PJM states that were members of RGGI in 2020. New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.[97] Other PJM states have expressed interest in joining RGGI. Virginia's RGGI rules were finalized in July 2020 and Virginia will begin participating in RGGI on January 1, 2021.[98] Pennsylvania Governor Tom Wolf issued an executive order on October 3, 2019, directing the Pennsylvania Department of Environmental Protection (DEP) to develop a proposal to limit carbon emissions from fossil fuel generators that is consistent with RGGI.[99] 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.[100] 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."

92 For more details, see the *2019 State of the Market Report for PJM*, Volume 2, Appendix H: "Environmental and Renewable Energy Regulations."

93 Va. HB 1526/SB 851.

94 See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).

95 *Id.*

96 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>.

97 "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>.

98 "RGGI States Welcome Virginia as Its CO_2 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>.

99 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/>.

100 "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>.

Table 8-2 shows the RGGI CO_2 auction clearing prices and quantities for the 2015/2018 compliance period and the 2018/2020 compliance period auctions held as of December 2, 2020, in short tons and metric tonnes.[101] Prices for auctions held December 2, 2020, were $7.41 per allowance (equal to one short ton of CO_2).[102] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The December auction clearing price increased 8.7 percent over the last auction clearing price of $6.82 in September 2020.

Table 8-2 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2015/2018 and 2018/2020 Compliance Periods[103]

	Short Tons			Metric Tonnes		
Auction Date	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
December 2, 2020	$7.41	16,237,495	16,237,495	$8.17	14,730,412	14,730,412

RGGI auctions generated $416.3 million in auction revenue in 2020 and have generated $3.8 billion in auction revenue since 2008.[104] 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.[105]

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 2020 CO_2 emission levels and the RGGI clearing price for the December 2020 auction ranges from $1.3 billion per year to $2.5 billion per year depending on associated reductions in carbon emission levels (Table 8-3).[106] Table 8-3 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2020 CO_2 emission levels ranging from five to 50 percent. A power plant owner must acquire an allowance for each ton of CO_2 emissions and the revenue values in Table 8-3 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2020 actual emissions level. States that participate in RGGI choose their emission cap. For example, New Jersey chose an emission cap of 18,000,000 short tons for reentry into RGGI in 2020, 5.3 percent below New Jersey's 2018 CO_2 emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.[107]

101 The September 3, 2015, auction included additional Cost Containment Reserves (CCRs) since the clearing price for allowances was above the CCR trigger price of $6.00 per ton in 2015. The auctions on March 5, 2014, and September 3, 2015, were the only auctions to use CRRs.

102 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).

103 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 23, 2020).

104 See Auction Results at <https://www.rggi.org/>.

105 The Investment of RGGI Proceeds in 2017, The Regional Greenhouse Gas Initiative (RGGI), October 2019, <https://www.rggi.org/investments/proceeds-investments>.

106 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.

107 "Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative," State of New Jersey, Governor Phil Murphy Press Release, June 17, 2019 <https://nj.gov/governor/news/news/562019/approved/20190617a.shtml>.

Table 8-3 Estimated CO_2 allowance revenue at December 2020 RGGI price level[108 109]

		Estimated CO_2 allowance revenue ($ millions), carbon price $7.41 per short ton					
Jurisdiction	2020 power generation CO_2 emissions (short tons)	5 percent reduction below 2020 emission levels	10 percent reduction below 2020 emission levels	15 percent reduction below 2020 emission levels	20 percent reduction below 2020 emission levels	25 percent reduction below 2020 emission levels	50 percent reduction below 2020 emission levels
Delaware	2,055,837.3	$14.5	$13.7	$12.9	$12.2	$11.4	$7.6
Illinois	18,797,514.2	$132.3	$125.4	$118.4	$111.4	$104.5	$69.6
Indiana	32,621,089.9	$229.6	$217.6	$205.5	$193.4	$181.3	$120.9
Kentucky	28,595,734.2	$201.3	$190.7	$180.1	$169.5	$158.9	$105.9
Maryland	10,160,364.6	$71.5	$67.8	$64.0	$60.2	$56.5	$37.6
Michigan	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	11,765,032.5	$82.8	$78.5	$74.1	$69.7	$65.4	$43.6
North Carolina	40,388.7	$0.3	$0.3	$0.3	$0.2	$0.2	$0.1
Ohio	80,279,155.3	$565.1	$535.4	$505.6	$475.9	$446.2	$297.4
Pennsylvania	77,857,196.9	$548.1	$519.2	$490.4	$461.5	$432.7	$288.5
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	32,755,841.7	$230.6	$218.4	$206.3	$194.2	$182.0	$121.4
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	53,818,573.2	$378.9	$358.9	$339.0	$319.0	$299.1	$199.4
Total	348,746,728.4	$2,455.0	$2,325.8	$2,196.6	$2,067.4	$1,938.2	$1,292.1

The RGGI emissions cap is the sum of CO_2 allowances issued by each state. Table 8-4 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.[110] At the end of the first control period, 57,449,495 banked allowances were held by market participants.[111] 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.[112] A second cap adjustment, 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.[113] The RGGI clearing price since 2014 has been on average 108.3 percent higher than the prices prior to the emission cap adjustments.

Table 8-4 RGGI emissions cap history[114 115]

	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	1st	$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	2nd	$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	3rd	$4.47	86,506,875	(2.5%)	64,615,467	(3.3%)
2017		$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018		$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019	4th	$5.43	80,179,708	(2.5%)	58,288,301	(3.4%)
2020		$6.41	96,175,215	19.9%	74,283,807	27.4%

108 The 2020 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from generators located within the PJM footprint.

109 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.

110 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.

111 "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>.

112 *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.

113 "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>.

114 See Regional Greenhouse Gas Initiative, "Elements of RGGI" and "Auction Results," <https://www.rggi.org/> (Accessed June 25, 2019).

115 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.

If higher carbon prices were implemented in PJM, the associated revenues flowing to states would also increase. Table 8-5 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 $16.6 billion if the carbon price were $50 per short ton and emission levels were five percent below 2020 levels. Allowance revenues to states would be $1.7 billion if the carbon price were $10 per short ton and emission levels were 50 percent below 2020.

Table 8-5 Estimated CO_2 allowance revenue at various carbon prices

	Estimated CO_2 allowance revenue ($ millions)					
	5 percent reduction below 2020 emission levels	10 percent reduction below 2020 emission levels	15 percent reduction below 2020 emission levels	20 percent reduction below 2020 emission levels	25 percent reduction below 2020 emission levels	50 percent reduction below 2020 emission levels
Jurisdiction		Carbon Price ($ per short ton)			$10.00	
Delaware	$19.5	$18.5	$17.5	$16.4	$15.4	$10.3
Illinois	$178.6	$169.2	$159.8	$150.4	$141.0	$94.0
Indiana	$309.9	$293.6	$277.3	$261.0	$244.7	$163.1
Kentucky	$271.7	$257.4	$243.1	$228.8	$214.5	$143.0
Maryland	$96.5	$91.4	$86.4	$81.3	$76.2	$50.8
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$111.8	$105.9	$100.0	$94.1	$88.2	$58.8
North Carolina	$0.4	$0.4	$0.3	$0.3	$0.3	$0.2
Ohio	$762.7	$722.5	$682.4	$642.2	$602.1	$401.4
Pennsylvania	$739.6	$700.7	$661.8	$622.9	$583.9	$389.3
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$311.2	$294.8	$278.4	$262.0	$245.7	$163.8
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$511.3	$484.4	$457.5	$430.5	$403.6	$269.1
Total	$3,313.1	$3,138.7	$2,964.3	$2,790.0	$2,615.6	$1,743.7
		Carbon Price ($ per short ton)			$25.00	
Delaware	$48.8	$46.3	$43.7	$41.1	$38.5	$25.7
Illinois	$446.4	$422.9	$399.4	$376.0	$352.5	$235.0
Indiana	$774.8	$734.0	$693.2	$652.4	$611.6	$407.8
Kentucky	$679.1	$643.4	$607.7	$571.9	$536.2	$357.4
Maryland	$241.3	$228.6	$215.9	$203.2	$190.5	$127.0
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$279.4	$264.7	$250.0	$235.3	$220.6	$147.1
North Carolina	$1.0	$0.9	$0.9	$0.8	$0.8	$0.5
Ohio	$1,906.6	$1,806.3	$1,705.9	$1,605.6	$1,505.2	$1,003.5
Pennsylvania	$1,849.1	$1,751.8	$1,654.5	$1,557.1	$1,459.8	$973.2
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$778.0	$737.0	$696.1	$655.1	$614.2	$409.4
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,278.2	$1,210.9	$1,143.6	$1,076.4	$1,009.1	$672.7
Total	$8,282.7	$7,846.8	$7,410.9	$6,974.9	$6,539.0	$4,359.3
		Carbon Price ($ per short ton)			$50.00	
Delaware	$97.7	$92.5	$87.4	$82.2	$77.1	$51.4
Illinois	$892.9	$845.9	$798.9	$751.9	$704.9	$469.9
Indiana	$1,549.5	$1,467.9	$1,386.4	$1,304.8	$1,223.3	$815.5
Kentucky	$1,358.3	$1,286.8	$1,215.3	$1,143.8	$1,072.3	$714.9
Maryland	$482.6	$457.2	$431.8	$406.4	$381.0	$254.0
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$558.8	$529.4	$500.0	$470.6	$441.2	$294.1
North Carolina	$1.9	$1.8	$1.7	$1.6	$1.5	$1.0
Ohio	$3,813.3	$3,612.6	$3,411.9	$3,211.2	$3,010.5	$2,007.0
Pennsylvania	$3,698.2	$3,503.6	$3,308.9	$3,114.3	$2,919.6	$1,946.4
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,555.9	$1,474.0	$1,392.1	$1,310.2	$1,228.3	$818.9
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$2,556.4	$2,421.8	$2,287.3	$2,152.7	$2,018.2	$1,345.5
Total	$16,565.5	$15,693.6	$14,821.7	$13,949.9	$13,078.0	$8,718.7

Table 8-6 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 2020 would have increased by 7.1 percent.[116]

Table 8-6 Estimated impact of carbon price on LMP: 2019 and 2020

		2019			2020		
Scenario	Carbon Price ($/Metric Ton)	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change
Scenario 1	$5.00	$27.32	$28.94	5.9%	$21.77	$23.32	7.1%
Scenario 2	$10.00	$27.32	$30.71	12.4%	$21.77	$25.08	15.2%
Scenario 3	$15.00	$27.32	$32.48	18.9%	$21.77	$26.85	23.3%
Scenario 4	$25.00	$27.32	$36.02	31.9%	$21.77	$30.37	39.5%
Scenario 5	$50.00	$27.32	$44.88	64.3%	$21.77	$39.17	79.9%

Table 8-7 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[117] [118] 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 8-7 Carbon price per MWh by unit type

	Carbon Price per MWh						
Unit Type	Carbon $5/tonne	Carbon $10/tonne	Carbon $15/tonne	Carbon $50/tonne	Carbon $100/tonne	Carbon $200/tonne	Carbon $400/tonne
CT	$2.45	$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 $185.53 per MWh for 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 8-8. The carbon price implied by the average REC price for 2020 in Washington, DC is $6.17 per tonne which is lower than the average 2020 RGGI clearing price of $7.06 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.[119] 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.

116 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>.

117 Heat rates from: *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Table 7-4.

118 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).

119 "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 8-8 Implied carbon price based on REC and SREC prices: 2009 through 2020[120]

	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	$17.76	$17.73
New Jersey	$13.34	$17.74	$8.58	$4.74	$13.09	$21.04	$25.29	$26.93	$24.01	$22.01	$19.19	$18.36
Ohio						$10.16	$8.52	$5.29	$6.27	$11.17	$14.00	$14.66
Pennsylvania	$6.82	$8.13	$3.33	$4.29	$15.87	$26.66	$28.88	$26.35	$23.35	$21.47	$17.91	$17.87
Washington, D.C.							$3.19	$4.04	$4.88	$4.68	$5.50	$6.17
Jurisdiction with Solar REC	**Carbon Price ($ 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	$83.93	$85.32
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	$378.31
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	$48.30	$60.97
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	$883.41
Regional Greenhouse Gas Initiative	**CO_2 Allowance Price ($ 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	$7.06

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).[121] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of December 31, 2020, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of December 31, 2020, Virginia and Indiana had voluntary renewable portfolio standards that do not require participation and do not include noncompliance penalties.[122] Incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. The voluntary standard was enacted by the Indiana legislature in 2011, but no load serving entities have volunteered to participate in the program.[123]

As of December 31, 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

120 There were no trades in 2018 and 2019 for Ohio SRECs available in the Evomarkets data.

121 Renewable Energy Explained, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 23, 2019).

122 Effective January 1, 2021 the Virginia voluntary RPS is being replaced with a mandatory RPS.

123 See the Indiana Utility Regulatory Commission's "2020 Annual Report," at 41 (Oct. 2020) <https://www.in.gov/iurc/2981.htm>.

with respect to the total cost for the RPS, where the RECs originated that fulfill the RPS requirements, and if the state fulfilled the RPS goals. Pennsylvania and Maryland both provide more information than other states and serve as a model for other states. The MMU recommends that jurisdictions with a renewable portfolio standard make the compliance data and cost data available in a more complete and transparent manner.

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year for use toward satisfying their REC obligation in either of the two subsequent reporting years.[124]

Table 8-9 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 8-9 Renewable and alternative energy standards of PJM jurisdictions: 2020 to 2030[125] [126]

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.[127] 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.[128] [129] Intermediate RPS targets begin in 2021 with a 6.0 percent standard for phase I utilities and a 14.0 percent standard for phase II utilities. Eligible RPS resources include wind, solar, hydroelectric, landfill gas and biomass resources.

In 2018, New Jersey passed legislation that included provisions promoting the development of solar power in the state.[130] 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

124 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).

125 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.

126 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.

127 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.

128 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).

129 APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS

130 N.J. S. 2314/A. 3723.

within three years. The statute targets the development of 600 MW of electric storage by 2021 and 2,000 MW by 2030. Table 8-10 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington, DC.

Table 8-10 Recent changes in RPS rules[131 132 133 134]

Jurisdiction	Legislation	Effective Date	Summary of changes
Virginia	Virginia Clean Economy Act	April 11, 2020	Replaces the voluntary RPS with a mandartory RPS beginning in January 2021. The legislation requires 100 percent clean energy by 2050 for phase I utilities and 100 percent clean energy by 2045 for phase II utilities. Intermiate target levels begin in 2021 with 6 percent for phase I utilities and 14 percent for phase II utilities.
Ohio	House Bill 6	October 22, 2019	Reduced the RPS percent for each year beginning in 2020. The 2020 standard was reduced from 6.5 percent to 5.5 percent; the 2026 standard was reduced from 12.5 percent to 8.5 percent. The legislation also removed language that had previously indicated that the standard would remain at the 2026 level for each year after 2026. The solar carve out was removed for compliance year 2020 and beyond. Prior to the recent legislation, the solar carve out was 0.26 percent for 2020, increased to 0.50 percent for 2026, and remained at 0.50 percent for subsequent years.
Maryland	Clean Energy Jobs Act	May 25, 2019	Established a new Tier I target of 50.0 percent in 2030; previously the 2030 Tier I standard was 25.0 percent. The 2019 Tier I standard increased from 20.4 percent to 20.7. The solar carve out percent for 2019 increased from 1.95 percent to 5.50 percent. The solar carve out percent for 2030 increased from 2.5 percent to 14.5 percent. The 2.5 percent Tier II standard, scheduled to end in 2018, was extended through 2020.
Washington, D.C.	CleanEnergy DC Omnibus Amendment Act of 2018	March 22, 2019	Established a 100 percent Tier I renewable standard by 2032. Previously, the 2032 target was 50.0 percent. Tier I increases start in 2020, going from 20.0 percent to 26.25 percent. The 2020 solar carve out will increase from 1.58 percent to 2.175 percent. The 2041 target for the solar carve out is 10.0 percent.

New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[135] 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).[136] 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.[137] 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.[138 139]

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.[140] 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.[141] In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.[142]

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.[143] Although there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic,

131 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.

132 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>.

133 See Maryland State Legislature, Senate Bill No. 516, "Clean Energy Jobs," Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.

134 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>.

135 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.

136 N.J. S. 2314/A. 3723.

137 Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.

138 BPU Docket No. QO18080851.

139 "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>.

140 "Orsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ORSTED Press Release (August 10, 2018).

141 "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>.

142 "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>.

143 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.

solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources. Table 8-11 shows the Tier I standards for PJM states.[144] All eligible technologies for the RPS standards in Table 8-11 satisfy the EIA definition of renewable energy.[145]

Table 8-11 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.[146]

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.

Figure 8-2 shows the average Tier I REC price by jurisdiction from January 1, 2009, through December 31, 2020. Tier I REC prices are lower than SREC prices. For example, the average SREC price in Washington, DC in 2020 was $433.24 and the average Tier I price in Washington, DC in 2020 was $3.02.

Figure 8-2 Average Tier I REC price by jurisdiction: January 2009 through December 2020

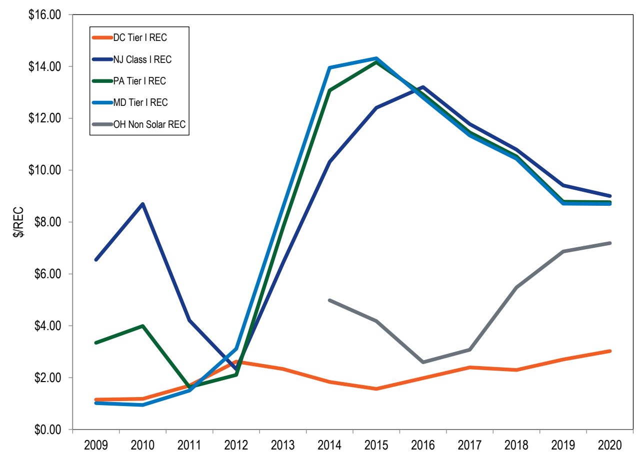


Figure 8-3 and Table 8-12 show the fulfillment of Tier I equivalent RPS requirement for 2016 through 2019 by state and by import and internal RECs and by carbon producing and noncarbon producing RECs.[147] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Noncarbon 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 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 8-12

144 This includes New Jersey's Class I renewable standard.

145 Renewable Energy Explained, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 17, 2019).

146 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.

147 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 21, 2020).

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 75.8 percent imported RECs, and 24.2 percent State RECs for the 2019 compliance year. Pennsylvania met its Tier I target using 71.1 percent noncarbon producing RECs, and 28.9 percent carbon producing RECs for the 2019 compliance year. Illinois met its Tier I target using 29.5 percent imported RECs, and 70.5 percent State RECs for the 2019 compliance year. Illinois met its Tier I target using 100.0 percent noncarbon producing RECs for the 2019 compliance year.

Figure 8-3 State fulfillment of Tier I equivalent RPS: 2016 through 2019

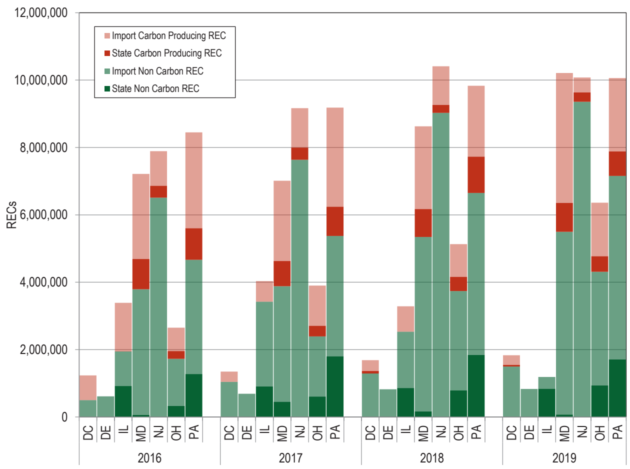
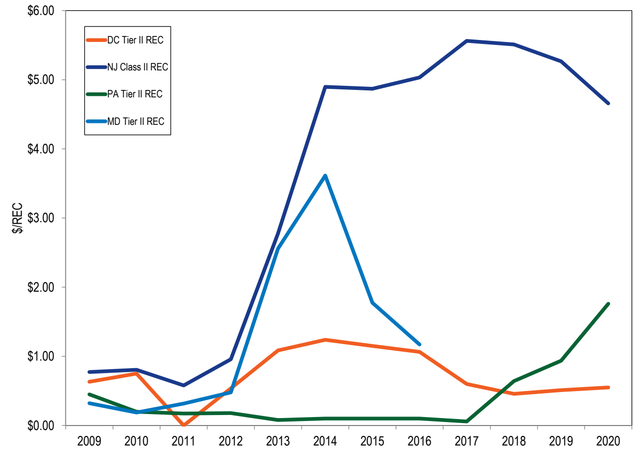


Table 8-12 State fulfillment of Tier I equivalent RPS: 2016 through 2019

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%
2019	DE New Eligible	0.3%	99.7%	0.0%	0.0%
	DC Tier I	0.0%	81.5%	2.8%	15.7%
	OH Renewable Energy Source	14.7%	53.0%	7.3%	25.0%
	IL Renewable	70.5%	29.5%	0.0%	0.0%
	MD Tier I	0.7%	53.2%	8.4%	37.8%
	NJ Class I	0.1%	92.7%	2.8%	4.4%
	PA Tier I	17.0%	54.2%	7.2%	21.7%

Table 8-13 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 8-13 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-13 are included in the total RPS requirements presented in Table 8-9. 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.[148]

Figure 8-4 Average Tier II REC price by jurisdiction: 2009 through December 2020



Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-11 but must be met by solar RECs (SRECs) only. Table 8-14 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 or have had 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.[150] 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 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

Table 8-13 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%

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 December 31, 2020. Washington D.C. had the lowest average Tier II REC prices at $0.55 per REC while New Jersey had the highest average Tier II REC prices at $4.66 per REC.[149]

148 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>.

149 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed January 21, 2020).

150 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).

to 4.3 percent for 2018, 5.1 percent for 2020 through 2022 and the solar standard decreases to 1.1 percent for 2032.[151] 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.[152]

Table 8-14 Solar renewable standards by percent of electric load for PJM jurisdictions: 2020 to 2030[153]

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 December 31, 2020. The average NJ SREC prices dropped from $673 per SREC in 2009 to $186 per SREC in 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 was $433 per SREC in 2020.[154]

Figure 8-5 Average SREC price by jurisdiction: January 2009 through December 2020

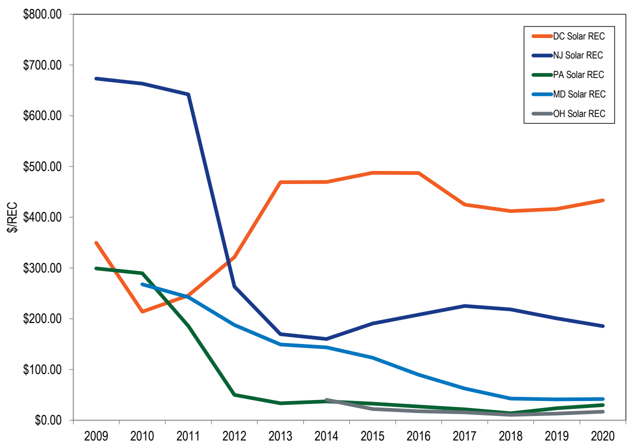


Figure 8-6 and Table 8-15 shows where the SRECs originated that are used to satisfy the states' solar requirement by retiring RECs for 2016 through 2019.[155] Depending on the state, the solar RPS requirement can be fulfilled by in state or out of state SRECs. The SRECs purchased in some states are imported from other PJM states and from non PJM states. Table 8-15 shows the percent of imported and local SRECs used to meet the RPS requirements. Illinois, Maryland and New Jersey met their solar requirements using 100 percent in-state SRECs in 2019.

151 "Assembly, No. 3723," State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.
152 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>.
153 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.
154 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed October 21, 2020).
155 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 21, 2020).

Figure 8-6 State fulfillment of Solar RPS: 2016 through 2019

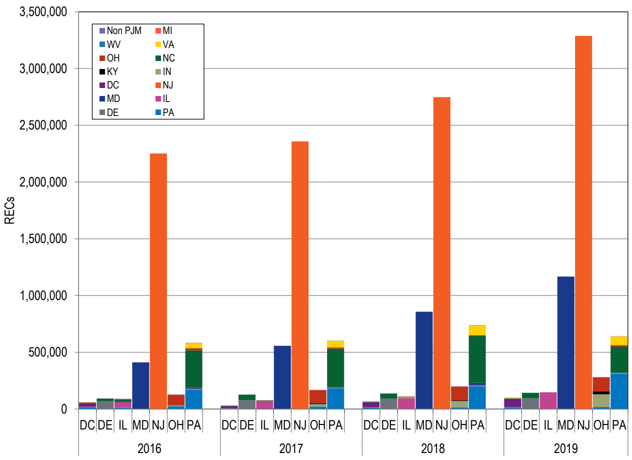
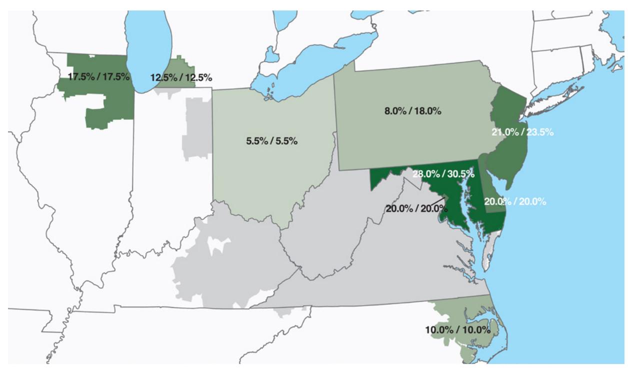


Table 8-15 State fulfillment of Solar RPS: 2016 through 2019

		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	27.1%	72.9%
2019	DC Solar	72.4%	27.6%
	DE Solar Eligible	66.4%	33.6%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	43.5%	56.5%
	PA Solar	48.8%	51.2%

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: 2020[156]



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 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 2020, 7.3 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 8-16. If the proportion of load among states remains constant, 17.5 percent of

156 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.

PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2030 under currently defined RPS rules. Approximately 9.6 percent of PJM load should have been served by Tier I or renewable energy resources in 2020. In 2020, 5.2 percent of PJM generation was Tier I or renewable energy. The current REC production from PJM generation resources was not enough to meet the 2020 state renewable requirements, and LSEs purchased RECs from outside the PJM footprint. LSEs that are unable to meet the RPS with RECs may use alternative compliance payments for unmet goals based on each state's requirements. If the proportion of load among states remains constant, 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 8-16 shows generation by jurisdiction and resource type for 2020. Wind output was 26,427.6 GWh of 41,729.9 Tier I GWh, or 63.3 percent, in the PJM footprint. As shown in Table 8-16, 59,058.7 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 70.7 percent. Total wind and solar generation (noncarbon producing) was 3.7 percent of total generation in PJM for 2020. Tier I generation was 5.2 percent of total generation in PJM and Tier II was 2.1 percent of total generation in PJM for 2020. Biofuel, landfill gas, solid waste and waste coal (carbon producing) were 12,512.2 GWh, or 21.2 percent of the total Tier I and Tier II.

Figure 8-8 shows the average hourly output by fuel type for 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.[157]

Figure 8-8 Average hourly output by fuel type: 2014 through 2020

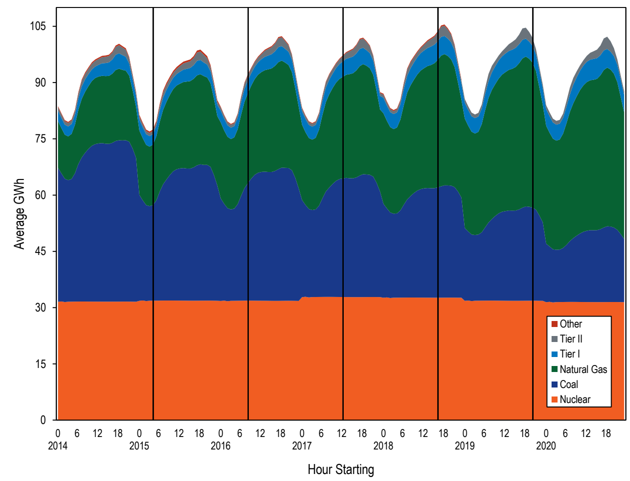


Table 8-16 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): 2020

	Tier I						Tier II					
Jurisdiction	Biofuel	Landfill Gas	Tier I Hydro	Solar	Wind	Total Tier I Credit	Tier II Hydro	Pumped-Storage Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	0.0	43.1	0.0	0.0	0.0	43.1	0.0	0.0	0.0	0.0	0.0	43.1
Illinois	0.0	119.7	0.0	14.2	11,984.3	12,118.2	0.0	0.0	0.0	0.0	0.0	12,118.2
Indiana	0.0	20.8	33.0	14.3	5,477.7	5,545.8	0.0	0.0	0.0	0.0	0.0	5,545.8
Kentucky	0.0	0.0	360.0	0.0	0.0	360.0	0.0	0.0	0.0	0.0	0.0	360.0
Maryland	0.0	59.7	0.0	411.4	719.7	1,190.8	0.0	0.0	588.7	0.0	588.7	1,779.6
Michigan	0.0	61.0	61.7	4.9	0.0	127.7	0.0	0.0	0.0	0.0	0.0	127.7
New Jersey	0.0	162.9	15.3	813.1	12.1	1,003.4	0.0	250.4	1,350.3	0.0	1,600.7	2,604.1
North Carolina	0.0	0.0	772.9	1,329.1	546.6	2,648.6	0.0	0.0	0.0	0.0	0.0	2,648.6
Ohio	0.0	346.3	817.2	25.7	2,182.9	3,372.2	0.0	0.0	1.9	0.0	1.9	3,374.1
Pennsylvania	0.0	565.0	4,211.5	75.2	3,731.5	8,583.2	0.0	1,918.1	1,563.3	4,610.9	8,092.3	16,675.4
Tennessee	87.2	0.0	0.0	0.0	0.0	87.2	1,628.1	0.0	0.0	0.0	1,628.1	1,715.3
Virginia	827.1	531.8	1,580.7	974.4	40.1	3,954.1	1,098.9	2,781.9	918.9	0.0	4,799.8	8,753.8
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	36.2	893.6	33.3	1,732.8	2,695.8	0.0	0.0	0.0	617.3	617.3	3,313.0
Total	914.3	1,946.5	8,745.9	3,695.7	26,427.6	41,729.9	2,727.0	4,950.4	4,423.1	5,228.2	17,328.8	59,058.7

157 See the *2020 State of the Market Report for PJM*, Section 3: Energy Market, Table 3-45.

Table 8-17 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. Virginia has the largest amount of solar capacity in PJM, 831.2 MW, or 28.2 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 6,588.2 MW, or 64.9 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.[158] 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.[159] As of January 1, 2021, the derated capacity eligible for compensation in the PJM Capacity Market totaled 2,177.1 MW for wind generators and 1,014.7 MW for solar generators. This compares to installed wind capacity of 10,144.2 MW and installed solar capacity of 2,942.3 MW in Table 8-17. 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.[160]

Table 8-17 Renewable capacity by jurisdiction (MW): December 31, 2020

Jurisdiction	Biofuel	Coal / Biofuel	Hydro	Landfill Gas	Natural Gas / Biofuel	Natural Gas / Landfill Gas	Other Gas	Oil / Biofuel	Oil / Landfill Gas	Pumped-Storage Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	0.0	0.0	8.1	1,797.0	0.0	0.0	0.0	13.0	0.0	0.0	0.0	0.0	0.0	1,818.1
Illinois	0.0	0.0	0.0	39.2	0.0	360.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	4,435.8	4,844.0
Indiana	0.0	0.0	8.2	3.2	0.0	0.0	0.0	0.0	0.0	0.0	10.1	0.0	0.0	2,152.5	2,174.0
Kentucky	0.0	0.0	132.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	132.7
Maryland	0.0	0.0	0.4	22.3	0.0	0.0	0.0	69.0	0.0	0.0	299.5	128.2	0.0	245.2	764.6
Michigan	0.0	0.0	13.9	12.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	11.0	70.3	0.0	0.0	0.0	0.0	0.0	453.0	685.9	204.6	0.0	4.5	1,429.2
North Carolina	0.0	0.0	325.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	817.5	0.0	0.0	208.0	1,350.5
Ohio	0.0	4,846.0	194.4	58.2	0.0	0.0	1.0	136.0	0.0	0.0	151.1	0.0	0.0	795.8	6,182.5
Pennsylvania	54.0	0.0	1,387.3	196.8	2,346.0	0.0	0.0	0.0	0.0	1,269.0	104.3	209.2	1,347.0	1,457.2	8,370.8
Tennessee	50.0	0.0	296.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	346.6
Virginia	241.9	585.0	436.4	127.7	0.0	0.0	88.0	17.0	0.0	5,386.0	831.2	123.0	0.0	12.0	7,848.1
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	209.9	8.0	0.0	0.0	0.0	0.0	0.0	0.0	29.1	0.0	96.0	687.3	1,030.2
PJM Total	345.9	5,431.0	3,015.6	545.7	4,143.0	360.0	89.0	222.0	13.0	7,108.0	2,942.3	665.0	1,443.0	10,144.2	36,467.7

There are three classes of solar generators with capacity factors ranging from 39.0 percent to 60.0 percent.[161]

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.[162] 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

158 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>.
159 See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <https://pjm.com/-/media/documents/manuals/m21.ashx>.
160 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>.
161 Id.
162 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>.

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.[163] 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.[164] 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 lock ins 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.

Table 8-18 shows renewable capacity registered in the PJM generation attribute tracking system (GATS).[165] These resources are not PJM resources even though most are located in PJM states. For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM units. This includes solar capacity of 7,138.6 MW of which 2,618.6 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 1,496.4 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.

163 "ELCC IMM Proposal," Monitoring Analytics, LLC, August 7, 2000. <http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_CCSTF_ELCC_IMM_Proposal_20200807.pdf>.

164 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>.

165 PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits. GATS publishes details on every renewable generator registered within the PJM footprint and aggregate emissions of renewable generation, but does not publish generation data by unit and does not make unit data available to the MMU.

Table 8-18 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): December 31, 2020[166]

Jurisdiction	Biofuel	Coal / Biofuel	Fuel Cell	Geothermal	Hydro	Landfill Gas	Natural Gas/ Distributed Generation	Other Gas	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Alabama	54.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.0
Delaware	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	128.2	0.0	0.0	0.0	2.0	132.4
Georgia	0.0	0.0	0.0	0.0	0.0	27.1	0.0	0.0	152.2	0.0	0.0	0.0	0.0	179.3
Illinois	0.0	0.0	0.0	0.0	21.4	55.4	0.0	2.1	537.7	0.0	0.0	0.0	598.4	1,214.9
Indiana	0.0	0.0	0.0	0.0	0.0	46.4	0.0	5.2	125.5	0.0	0.0	94.6	180.0	451.6
Iowa	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	2.1	0.0	0.0	0.0	336.8	340.5
Kentucky	93.0	600.0	0.0	0.0	162.2	20.2	0.0	0.4	38.1	0.0	0.0	0.0	0.0	913.9
Maryland	3.8	65.0	0.0	2.0	0.0	12.7	0.0	0.0	1,121.5	10.0	0.0	0.0	0.3	1,215.3
Michigan	31.0	0.0	0.0	0.0	1.3	16.6	0.0	0.0	4.7	0.0	0.0	0.0	80.6	134.2
Missouri	0.0	0.0	0.0	0.0	0.0	5.6	0.0	0.0	61.2	0.0	0.0	0.0	451.0	517.8
New Jersey	0.0	0.0	0.0	0.0	0.0	45.8	0.0	11.4	2,618.6	0.0	0.0	0.0	4.7	2,680.5
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.4
North Carolina	151.5	0.0	0.0	0.0	520.4	0.0	0.0	0.0	1,197.0	0.0	0.0	0.0	0.0	1,868.9
North Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0	360.0
Ohio	92.8	0.0	0.0	0.0	6.6	19.7	0.0	61.1	235.5	0.0	0.0	33.0	54.7	503.4
Pennsylvania	8.6	109.7	0.8	0.0	31.5	45.2	8.0	99.6	453.2	0.2	109.2	0.0	3.2	869.2
South Carolina	0.0	0.0	0.0	0.0	0.0	30.8	0.0	0.0	91.3	0.0	0.0	0.0	0.0	122.1
Tennessee	0.0	0.0	0.0	0.0	99.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	99.6
Virginia	287.6	0.0	0.0	0.0	30.8	11.3	0.0	2.6	250.0	0.0	0.0	0.0	0.0	582.3
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	49.4	117.1	0.0	0.0	13.5	0.0	180.1
West Virginia	0.0	0.0	0.0	0.0	102.0	0.0	0.0	0.0	4.1	0.0	0.0	0.0	0.0	106.1
Wisconsin	44.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	44.8
Total	766.9	774.7	0.8	2.0	975.8	340.5	8.0	231.7	7,138.6	10.2	109.2	141.1	2,071.7	12,571.3

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.[167] RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. Revenues from RECs markets are revenues for PJM resources earned in addition to revenues earned from the sale of the same MWh in PJM markets.

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.[168] 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 8-19 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.

166 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 19, 2021).

167 See *WSPP, Inc.*, 139 FERC ¶ 61,051 at P 18 (2012) ("we conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA"); citing *American Ref-Fuel Company, et al.*, 105 FERC ¶ 61,004 at PP 23–24 (2003) ("American Ref-Fuel, 105 FERC ¶ 61,004 at PP 23-24 ("RECs are created by the States. They exist outside the confines of PURPA... And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, ... do not control the ownership of RECs."); see also *Williams Solar LLC and Allco Finance Limited*, 156 FERC ¶ 61,042 (2016).

168 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed November 3, 2018).

Table 8-19 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 8-20 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 8-20 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, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio.
Pennsylvania	Yes	RECs must be purchased from resources located within PJM. All SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania.
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.
State with Voluntary Standard		
Indiana	Yes	At least 50 percent of RECs must be purchased from resources located within Indiana.
Virginia	No	RECs must be purchased from the RTO or control area in which the participating utility is a member.

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.[169] 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 $74.00 per MWh for reporting year ending May 31, 2020. Figure 8-9 shows the historical relationship between SREC prices and ACP levels. The SREC price is represented by a solid line in the figure and the corresponding ACP level is represented by a dashed line. For each jurisdiction, the ACP is an upper bound for the price level. In Michigan and North Carolina, there are no defined values for ACPs. The public utility commissions in Michigan and North Carolina have discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

Table 8-21 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-21 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions: 2020[170] [171]

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		

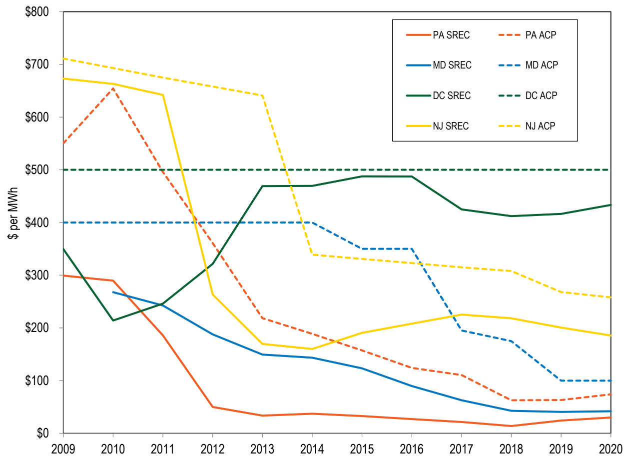
Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission.

169 N.J. S. 2314/A. 3723.

170 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/>.

171 The entry for Pennsylvania reflects the solar ACP for the compliance year ending May 31, 2020. See "Pricing," <https://www.pennaeps.com/reports/> (Accessed October 22, 2020).

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.[172] 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 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 99,061 SRECs, 1,834,067 Tier I RECs and 54,953 Tier II RECs were retired during the 2019 compliance year. ACPs decreased from $18.7 million for 2018 to $12.1 million for 2019.[173]

The Public Service Commission of Maryland reported that 1,167,329 SRECs were retired in 2019, an increase of 36.2 percent over the 2018 level. Tier 1 REC retirements increased to 10,210,275, 18.3 percent higher than in 2018, and 55,879 Tier 2 RECs were retired in 2019, a 96.5 percent decrease below the 2018 level.[174] ACPs totaled $7.7 million for 2019, up from $67,797 in 2018.[175]

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.[176]

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 719,261 credits for the compliance year ending May 31, 2020, with zero ACPs.[177] Delmarva Power satisfied their solar REC obligation of 135,771 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.[178]

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).[179] Dominion also met its solar, poultry

172 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2019," (September 2020), <https://www.pennaeps.com/wp-content/uploads/2020/09/2019-AEPS-Annual-Report.pdf>.

173 "Renewable Energy Portfolio Standard, A Report for Compliance Year 2019," Public Service Commission of the District of Columbia (May 1, 2020), <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.

174 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (October 2020) at 9, <https://www.psc.state.md.us/commission-reports/>.

175 *Id.* at 9.

176 "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>.

177 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2019–May 31, 2020," Delmarva Power, (Sept. 25, 2020), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.

178 "Annual Report Fiscal Year 2018," Illinois Power Agency (Feb. 15, 2019) at 46, <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.

179 "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>.

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.[180]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2019.[181] 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 8-22 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.[182] The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost by type in Table 8-22 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.[183] The average RPS compliance cost per year 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.

180 "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>.

181 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>.

182 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.

183 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.

Table 8-22 RPS Compliance Cost[184 185 186 187 188 189 190 191 192 193 194]

Jurisdiction with RPS		2014	2015	2016	2017	2018	2019
Delaware	Total RPS		$16,013,421	$18,409,631	$18,772,855	$18,341,916	$19,401,476
	Solar		$7,070,254	$7,748,073	$7,105,726	$6,565,240	$8,121,914
	Non-Solar		$8,943,167	$10,661,557	$11,667,129	$11,776,676	$11,279,562
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	$134,545,520
	Solar	$29,372,737	$39,055,714	$45,556,987	$21,275,664	$27,351,388	$55,166,116
	Tier I	$70,630,620	$85,054,001	$88,200,121	$50,045,621	$56,406,247	$79,320,505
	Tier II	$3,987,557	$2,617,917	$1,441,416	$687,785	$1,049,293	$58,899
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	$57,300,000
	Solar	$25,145,143	$36,526,662	$44,897,161	$38,571,061	$45,673,261	$51,982,914
	Tier I	$2,140,860	$1,899,232	$2,132,072	$3,960,018	$4,809,857	$5,262,354
	Tier II	$86,966	$114,738	$134,119	$147,734	$126,583	$54,733
PJM	Total RPS	$678,387,871	$888,389,738	$986,186,949	$925,417,144	$986,947,843	$211,246,996

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.[195] 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.[196 197]

184 Several states that have compliance periods that align with the PJM capacity market have not released compliance reports for the period June 1, 2019 through May 31, 2020.

185 "Delmarva Power & Light's 2018 RPS Compliance Report," Delmarva Power (Sept. 23, 2019), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.

186 "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.

187 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (Dec. 2019) at 8, <https://www.psc.state.md.us/commission-reports/>.

188 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.

189 "RPS Report Summary 2005-2019," New Jersey's Clean Energy Program, February 12, 2020, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.

190 "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>.

191 "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>.

192 "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://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.

193 "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.

194 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.

195 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 7, 2020).

196 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).

197 On April 9, 2020, the EPA created a new subcategory of six coal refuse power plants in Pennsylvania and West Virginia with reduced limits of HCl and SO_2 emissions under MATS. These units were all compliant with the previous MATS rules. "Mercury and Air Toxics Standards," <https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_coal_refuse_2060-au48_final_rule.pdf> (Accessed May 7, 2020)

Table 8-23 shows SO_2 emission controls by fossil fuel fired units in PJM.[198] [199] [200] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[201] Of the current 59,153.1 MW of coal capacity in PJM, 55,544.8MW of capacity, 93.9 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-23 SO_2 emission controls by fuel type (MW): December 31, 2020[202]

	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	73,747.9	73,747.9	0.0%
Other	325.0	3,959.7	4,284.7	7.6%
Total	55,869.8	86,575.5	142,445.3	39.2%

Table 8-24 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, 58,941.6MW 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, 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.[203]

198 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed May 7, 2020).

199 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.

200 The total MW are less than the 184,236.8 reported in Section 5: Capacity Market, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed May 7, 2020).

201 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA, "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A, Section 72.2," <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&mc=true&node=se40.18.72_12&rgn=div8> (Accessed May 7, 2020).

202 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.

203 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed May 7, 2020).

Table 8-24 NO_X emission controls by fuel type (MW): As of December 31, 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	72,748.3	999.6	73,747.9	98.6%
Other	1,805.7	2,479.0	4,284.7	42.1%
Total	135,069.2	7,376.1	142,445.3	94.8%

Table 8-25 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 (51.0 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[204] 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, 59,068.1MW 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.

Table 8-25 Particulate emission controls by fuel type (MW): As of December 31, 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	70,961.9	73,747.9	3.8%
Other	2,184.5	2,100.2	4,284.7	51.0%
Total	64,038.6	78,406.7	142,445.3	45.0%

Emissions

Figure 8-10 shows the total CO_2 emissions and the CO_2 emissions per MWh within PJM for all CO_2 emitting units, for each quarter from 1999 to the fourth quarter of 2020. Figure 8-10 also shows the CO_2 emissions per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the fourth quarter of

204 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed May 7, 2020).

2020.[205 206] For the period from the first quarter of 1999 through the fourth quarter of 2020, the minimum CO_2 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 194,930.8 GWh in the fourth quarter of 2019 to 194,878.5 GWh in the fourth quarter of 2020, while CO_2 produced decreased from 84.2 million short tons in the fourth quarter of 2019 to 83.5 million short tons in the fourth quarter of 2020.[207] The reduction in total CO_2 emissions was primarily the result of a decrease in the use of coal and an increase in the use of natural gas for generation.

Figure 8-10 CO_2 emissions by quarter (millions of short tons), by PJM units: 1999 through 2020[208 209]

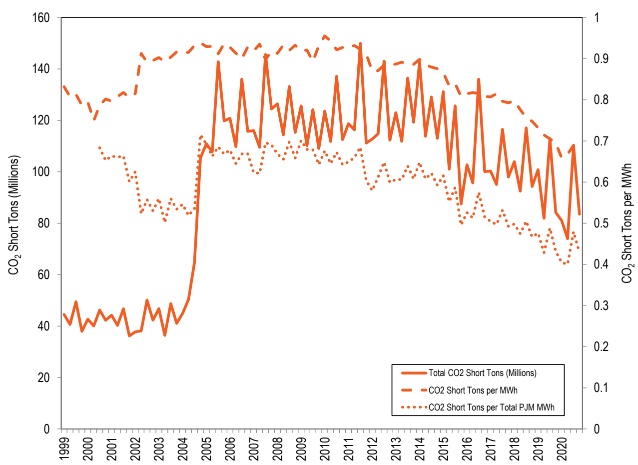


Figure 8-11 shows the total CO_2 emissions on peak and off peak and the CO_2 emissions per MWh for all CO_2 emitting units. Since the first quarter of 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.66 short tons per MWh in the first quarter of 2020, and a maximum of 0.97 short tons per MWh in the second quarter of 2010. Since the first quarter of 1999 the amount of CO_2 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. In the fourth quarter of 2020, CO_2 emissions were 0.70 short tons per MWh for off peak hours and 0.69 for on peak hours.

Figure 8-11 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: 1999 through 2020[210]

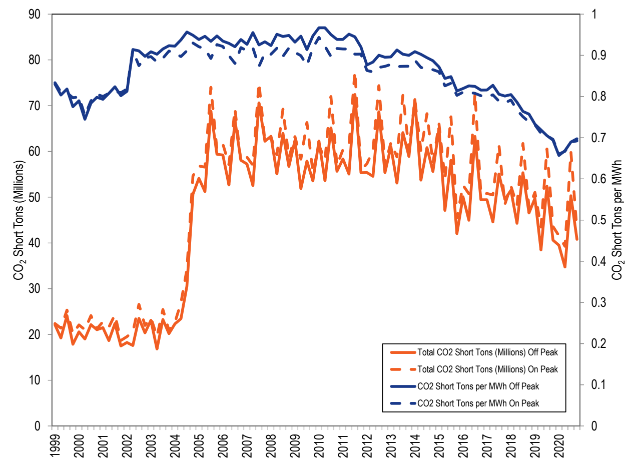


Figure 8-12 shows the total SO_2 and NO_X emissions and the short ton emissions per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emissions per MWh of total PJM generation. For the period from the first quarter of 1999 through the fourth quarter of 2020, the minimum SO_2 produced per 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 fourth 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 in the first quarter of 2005. In the fourth quarter of 2020, SO_2 emissions were 0.000427 short tons per MWh and NO_X emissions were 0.000334 short tons per MWh. The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal, an

205 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.

206 Emissions data for the fourth 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.

207 See the *2019 Quarterly State of the Market Report for PJM* Section 3: Energy Market, Table 3-10.

208 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

209 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).

210 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

increase in the use of natural gas, and the installation of environmental controls from 2006 to 2020.[211] [212]

Figure 8-12 SO_2 and NO_X emissions by quarter (thousands of short tons), by PJM units: 1999 through 2020[213]

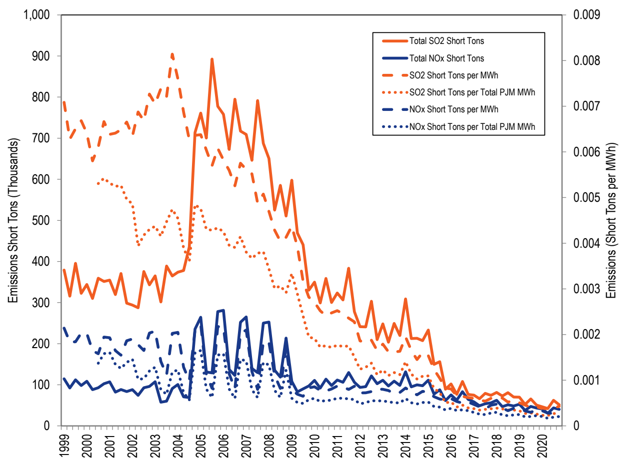
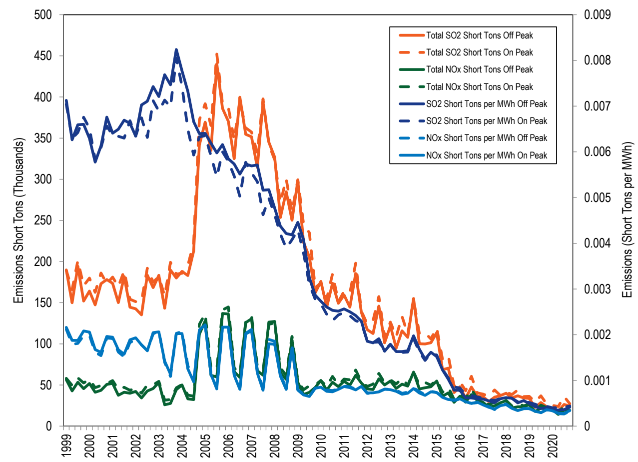


Figure 8-13 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emissions per MWh from emitting resources for all SO_2 and NO_X emitting units. For the period from the first quarter of 1999 through the fourth quarter of 2020, the minimum SO_2 produced per MWh during off peak 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 fourth 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 fourth quarter of 2020, the minimum NO_X produced per MWh during off peak hours was 0.000267 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 fourth 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 fourth quarter of 2020, SO_2 emissions were 0.000414 short tons per MWh and 0.000440 short tons per MWh for off and on peak hours. In the fourth quarter of 2020, NO_X emissions were 0.000329 short tons per MWh and 0.000339 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 2020[214]



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 2020. Of the top 100 load hours in PJM in 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

211 See EIA, "Changes in coal sector led to less SO_2 and NO_x emissions from electric power industry," <https://www.eia.gov/todayinenergy/detail.php?id=37752> (Accessed October 25, 2019).

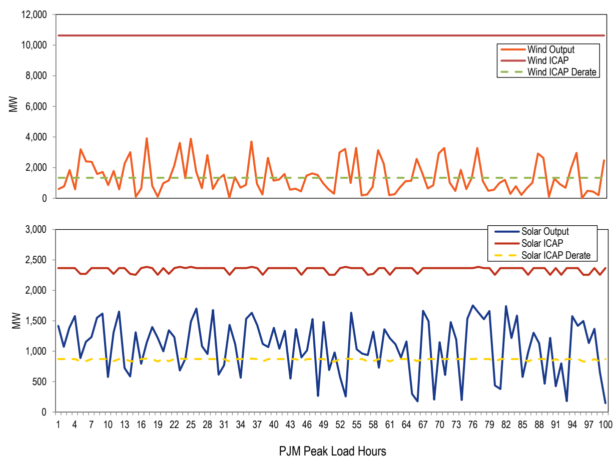
212 See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <https://www.eia.gov/todayinenergy/detail.php?id=29812> (Accessed October 25, 2019).

213 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

214 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

capacity market.[215] 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 2020 was 13.1 percent. Wind output was above the derated ICAP for 6,163 hours and below the derated ICAP for 2,621 hours in 2020. The wind capacity factor in 2020 was 28.1 percent. Solar output was above the derated ICAP for 72 hours and below the derated ICAP for 28 hours of the top 100 load hours in 2020. The solar capacity factor for the top 100 load hours in 2020 was 46.3 percent. Solar output was above the derated ICAP for 1,953 hours and below the derated ICAP for 6,831 hours in of 2020. The solar capacity factor in 2020 was 20.9 percent.

Figure 8-14 Wind and solar output during the top 100 load hours: 2020



Wind Units

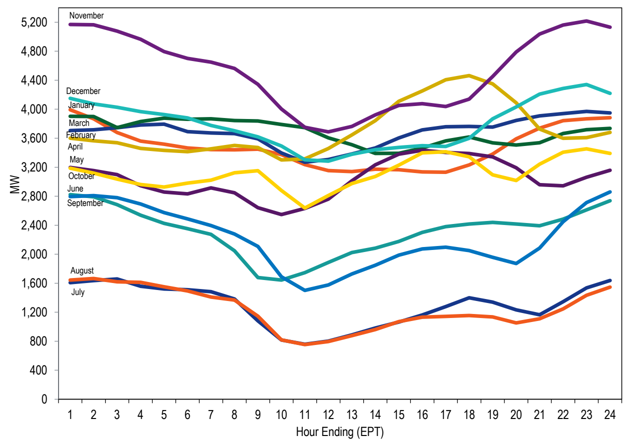
Table 8-26 shows the capacity factors of wind units in PJM. In 2020, the capacity factor of wind units in PJM was 28.1 percent. Wind units that were capacity resources had a capacity factor of 28.9 percent and an installed capacity of 8,599 MW. Wind units that were energy only had a capacity factor of 25.0 percent and an installed capacity of 2,768 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.[216]

Table 8-26 Capacity factor of wind units: 2020[217]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	25.0%	2,768
Capacity Resource	28.9%	8,599
All Units	28.1%	11,367

Figure 8-15 shows the average hourly real-time generation of wind units in PJM, by month for 2020. The hour with the highest average output, 5,216.7 MW, occurred in November, and the hour with the lowest average output, 753.5 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: 2020



215 PJM used derating factors of 13 and 38 percent until June 1, 2017. The current derating factors depend on installation type. PJM, Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed Oct. 17, 2019).

216 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed October 17, 2019).

217 Capacity factor is calculated based on online date of the resource.

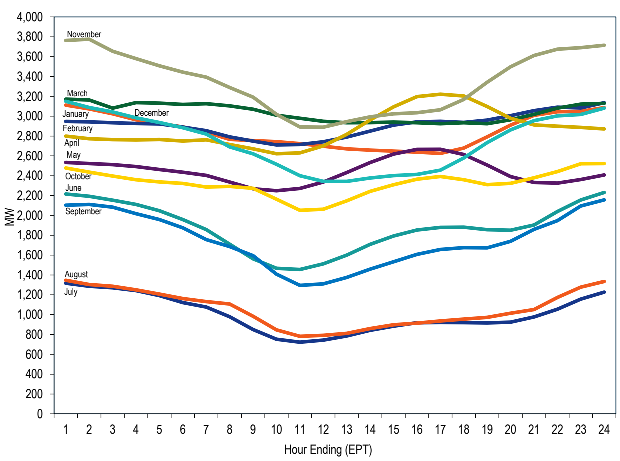
Table 8-27 shows the generation and capacity factor of wind units by month for 2019 and 2020.

Table 8-27 Capacity factor of wind units in PJM by month: 2019 and 2020

	2019		2020	
Month	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%	2,322,150.1	29.0%
November	2,157,505.1	30.6%	3,271,536.3	41.1%
December	2,855,933.5	37.7%	2,851,142.4	33.8%
Annual	24,166,659.8	28.8%	26,431,001.9	28.1%

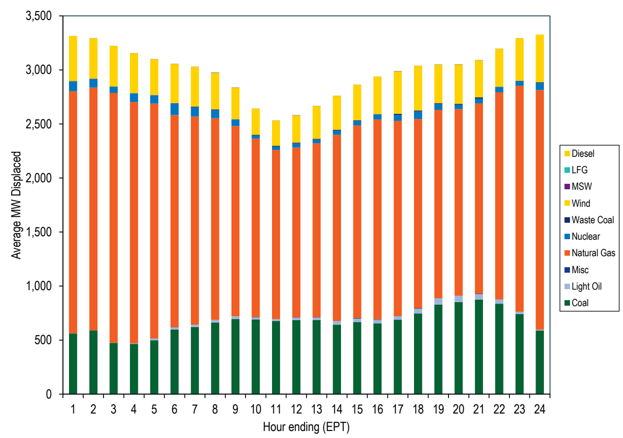
Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-16 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

Figure 8-16 Average hourly day-ahead generation of wind units: 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.[218] Figure 8-17 and Table 8-28 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in 2020. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. In 2020, the dispatch instruction for marginal wind resources was to reduce output for 66.9 percent of the unit intervals. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours, if the dispatch instruction was to lower the generation. The level of wind displaced by wind is thus overstated.

Figure 8-17 Marginal fuel at time of wind generation: 2020



218 The measure is based on the principle that any incremental change in the wind output is balanced by the change in the output of marginal generators, while holding everything else equal.

Table 8-28 Marginal fuel MW at time of wind generation: 2020

Hour	Coal	Light Oil	Misc	Natural Gas	Nuclear	Waste Coal	Wind	MSW	LFG	Diesel	Solar	Heavy Oil	Total
0	562.0	0.6	0.4	2,239.4	90.4	4.2	418.6	0.0	0.0	0.0	0.0	0.0	3,315.7
1	590.3	0.0	0.9	2,245.4	77.9	4.6	374.2	0.6	0.0	0.0	0.0	0.0	3,293.9
2	473.3	1.2	0.3	2,312.5	57.5	1.6	375.7	0.0	0.8	0.0	0.0	0.0	3,222.9
3	465.3	5.0	0.4	2,232.0	78.2	4.4	369.7	0.4	0.0	0.0	0.0	0.0	3,155.4
4	498.9	15.1	1.8	2,172.3	76.8	2.2	332.4	0.7	0.0	0.0	0.0	0.0	3,100.4
5	598.4	19.2	2.0	1,963.0	103.7	6.8	361.7	0.8	1.2	0.2	0.0	0.0	3,057.1
6	621.2	20.5	0.0	1,926.1	84.5	8.0	367.2	1.2	1.1	0.0	1.1	0.0	3,031.0
7	662.2	24.5	0.0	1,866.6	74.3	7.3	339.0	1.8	2.4	1.1	2.0	0.0	2,981.2
8	695.4	24.5	0.0	1,760.7	58.9	3.9	293.6	1.3	0.0	0.0	10.6	0.0	2,849.0
9	691.8	17.5	2.9	1,652.2	28.5	6.6	240.7	0.5	0.0	0.0	15.6	0.0	2,656.5
10	678.0	16.2	0.4	1,565.1	30.0	7.9	234.0	0.5	0.0	0.0	32.9	0.0	2,565.1
11	685.1	21.5	3.8	1,571.5	36.5	9.1	251.6	1.7	1.6	0.0	23.1	0.0	2,605.5
12	685.0	23.9	2.4	1,610.3	34.7	5.8	303.8	0.8	0.0	0.9	37.7	0.0	2,705.1
13	642.0	33.5	2.5	1,722.0	37.1	9.1	312.8	0.9	0.0	2.4	33.4	0.0	2,795.6
14	666.5	32.6	4.4	1,783.2	40.6	6.3	328.5	0.3	0.0	1.0	39.3	0.0	2,902.8
15	654.9	31.7	4.7	1,849.5	47.4	2.9	345.0	0.4	0.0	3.2	38.7	0.0	2,978.3
16	688.9	31.5	1.7	1,807.1	51.5	13.9	391.3	2.2	0.0	1.7	21.6	0.2	3,011.7
17	746.8	44.8	3.2	1,751.6	67.9	10.5	411.9	1.1	0.0	0.3	10.2	0.5	3,048.8
18	828.0	59.2	0.9	1,742.3	52.8	9.9	353.5	0.7	2.2	3.1	1.5	0.2	3,054.4
19	851.1	60.0	0.0	1,726.8	39.5	9.9	361.7	1.9	0.5	1.6	0.0	0.2	3,053.1
20	874.8	50.4	3.4	1,761.6	42.5	13.7	342.5	2.1	0.3	0.8	0.3	0.4	3,092.8
21	836.7	37.7	1.5	1,916.6	48.0	3.9	351.0	1.3	0.0	0.7	0.0	0.0	3,197.5
22	741.8	21.4	0.2	2,089.2	42.4	4.9	394.1	0.0	0.5	0.0	0.0	0.0	3,294.6
23	588.2	8.4	0.0	2,217.4	66.3	5.5	442.0	0.0	0.0	0.0	0.0	0.0	3,327.8
Average	667.8	25.0	1.6	1,895.2	57.0	6.8	345.7	0.9	0.4	0.7	11.2	0.1	3,012.3

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 8-17, there are 2,942.3 MW capacity of solar registered in GATS that are PJM units. As shown in Table 8-18, there are 7,138.6 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 8-29 shows the capacity factor of solar units in PJM. The capacity factor of solar units in PJM was 20.9 percent in 2020. Solar units that were capacity resources had a capacity factor of 22.5 percent and an installed capacity of 1,867 MW. Solar units that were energy only had a capacity factor of 15.3 percent and an installed capacity of 1,897 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.[219]

Table 8-29 Capacity factor of solar units: 2020

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	15.3%	1,897
Capacity Resource	22.5%	1,867
All Units	20.9%	3,764

219 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed October 17, 2019).

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, 1,510.5 MW, occurred in July, and the hour with the lowest peak average output, 905.7 MW, occurred in January. Solar output in PJM is generally higher during peak hours and lower during off peak hours.

Figure 8-18 Average hourly real-time generation of solar units: 2020

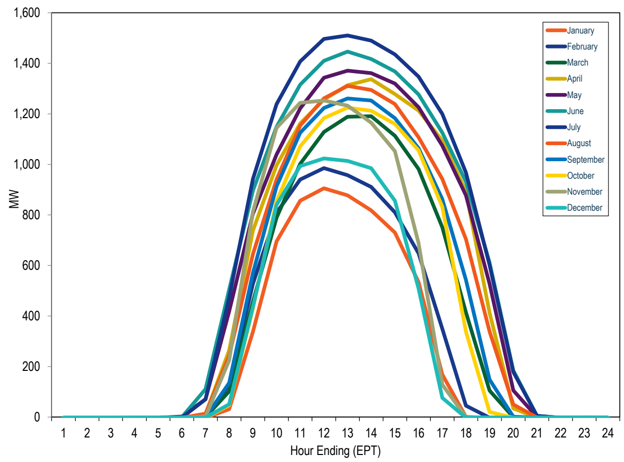


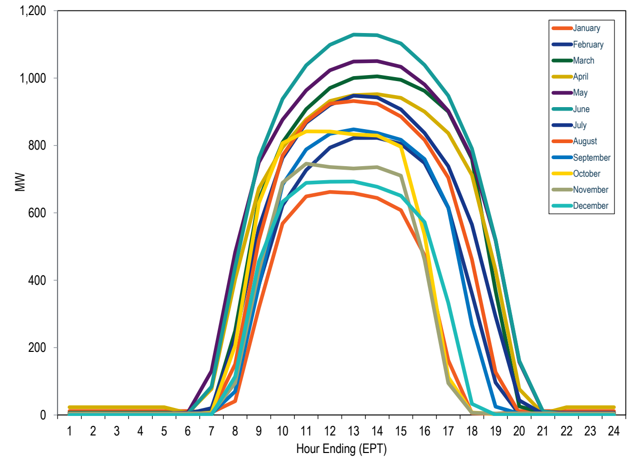
Table 8-30 shows the generation and capacity factor of solar units by month for 2019 and 2020.

Table 8-30 Capacity factor of solar units by month: 2019 and 2020

	2019		2020	
Month	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%	223,815.2	18.8%
November	157,567.3	15.8%	196,975.3	17.1%
December	127,723.7	11.6%	148,473.2	12.7%
Annual	2,542,985.4	22.5%	3,166,919.5	22.5%

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.[220]

Figure 8-19 Average hourly day-ahead generation of solar units: 2020



220 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 2020, PJM was a monthly net exporter of energy in the real-time energy market in all months.[1] In 2020, the real-time net interchange was -41,630.2 GWh. The real-time net interchange in 2019 was -31,674.1 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2020, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In 2020, the total day-ahead net interchange was -15,414.6 GWh. The day-ahead net interchange in 2019 was -7,174.9 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2020, gross imports in the day-ahead energy market were 538.7 percent of gross imports in the real-time energy market (492.5 percent in 2019). In 2020, gross exports in the day-ahead energy market were 104.4 percent of the gross exports in the real-time energy market (138.5 percent in 2019).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2020, there were net scheduled exports at 15 of PJM's 19 interfaces in the real-time energy market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 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 2020, there were net scheduled exports at 15 of PJM's 19 interfaces in the day-ahead energy market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 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 2020, up to congestion transactions were net exports at four of PJM's 18 interface pricing points eligible for day-ahead transactions in the day-ahead energy market.[5]
- **Inadvertent Interchange.** In 2020, net scheduled interchange was -41,630 GWh and net actual interchange was -41,716 GWh, a difference of 86 GWh. In 2019, the difference was 128 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 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 -11,906 GWh of net actual interchange, a difference of 10,283 GWh. In 2020, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,433 GWh of net scheduled interchange and 24,369 GWh of net actual interchange, a difference of 20,936 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 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 67.9 percent of the hours.

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. On October 1, 2020, PJM retired the Northwest interface pricing point. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points. These retirements reduced the number of real-time interface pricing points to 10.

4 On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points. On October 1, 2020, PJM retired the Northwest interface pricing point. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points. These retirements reduced the number of day-ahead interface pricing points to 10.

5 On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points. On October 1, 2020, PJM retired the Northwest interface pricing point. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points. These retirements reduced the number of day-ahead interface pricing points to 10.

- **PJM and New York ISO Interface Prices.** In 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 49.9 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 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 70.0 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 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 61.4 percent of the hours.
- **Hudson DC Line.** In 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 58.5 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued two TLRs of level 3a or higher in 2020, compared to two such TLRs issued in 2019.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market decreased by 6.6 percent, from 52,046 bids per day in 2019 to 48,618 bids per day in 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 12.5 percent, from 500,819 MWh per day in 2019, to 438,170 MWh per day in 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: Adopted Q4, 2020.)
- 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: Adopted Q4, 2020.)

- 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 NISPCO 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.

In 2020, PJM terminated a number of interface pricing points, consistent with longstanding MMU recommendations. On June 1, 2020, PJM terminated the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP interface pricing points. It was not clear why PJM did not also terminate the NCMPAIMP and NCMPAEXP interface pricing points at that time. On October 1, 2020, PJM terminated the Northwest interface pricing point. But following this termination, PJM failed to correctly map the pricing points to transactions that had been mapped to the Northwest pricing point to pricing points that are consistent with electrical impacts on the PJM system. 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 electrical impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. On November 3, 2020, PJM terminated the NCMPAIMP and NCMPAEXP interface pricing points. The MMU continues to recommend the termination of the Southeast and Southwest interface pricing points, and the Ontario interface pricing point. These pricing points can either 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.[6]

6 For an explanation and current rate for each billing line item, see "*Quick Reference Guide to Market Settlements By Type of Business*" (November 1, 2020) <https://pjm.com/markets-and-operations/~/media/0FE1D93C5E61457185BB7652F2F18668.ashx>.

Table 9-1 Charges and credits applied to interchange transactions

	Real-Time Transactions				Day-Ahead Transactions				
Billing Item	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Up to Congestion
Firm or Non-Firm Point-to-Point Transmission Service	X		X[1]	X[1]	X		X[1]	X[1]	
Spot Import Service		X[2]				X[2]			
Day-ahead Spot Market Energy					X	X	X		
Balancing Spot Market Energy	X	X	X						
Day-ahead Transmission Congestion					X	X	X	X	X
Balancing Transmission Congestion	X	X	X	X					X
Day-ahead Transmission Losses					X	X	X	X	X
Balancing Transmission Losses	X	X	X	X					X
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	X		X	X	X		X	X	
PJM Scheduling, System Control and Dispatch Service - Market Support	X	X	X		X	X	X		X
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	X	X	X	X	X	X	X	X	X
PJM Scheduling, System Control and Dispatch Service - Market Support Offset	X	X	X		X	X	X		X
PJM Settlement, Inc.	X	X	X		X	X	X		X
Market Monitoring Unit (MMU) Funding	X	X	X		X	X	X		X
FERC Annual Recovery	X		X	X	X		X	X	
Organization of PJM States, Inc. (OPSI) Funding	X		X	X	X		X	X	
Synchronous Condensing			X				X		
Transmission Owner Scheduling, System Control and Dispatch Service	X		X	X	X		X	X	
Reactive Supply and Voltage Control from Generation and Other Sources Service	X		X	X	X		X	X	
Day-ahead Operating Reserve					X	X	X		X
Balancing Operating Reserve	X	X	X						X
Black Start Service	X		X	X	X		X	X	
Marginal Loss Surplus Allocation (for those paying for transmission service only)			X				X		

[1] No charge if Point of Delivery is MISO

[2] No charge for spot in transmission

Aggregate Imports and Exports

Table 9-2 shows the real-time and day-ahead scheduled interchange totals for 2019 and 2020. In 2020, gross imports in the day-ahead energy market were 538.7 percent of gross imports in the real-time energy market (492.5 percent in 2019). In 2020, gross exports in the day-ahead energy market were 104.4 percent of gross exports in the real-time energy market (138.5 percent in 2019).

Table 9-2 Real-time and day-ahead scheduled interchange volumes (GWh): 2019 and 2020

Category	2019	2020	Percent Change
Real-Time Gross Imports	10,370.4	6,462.4	(37.7%)
Real-Time Gross Exports	42,044.6	48,092.6	14.4%
Real-Time Net Interchange	(31,674.1)	(41,630.2)	31.4%
Day-Ahead Gross Imports	51,070.4	34,815.4	(31.8%)
Day-Ahead Gross Exports	58,245.4	50,230.0	(13.8%)
Day-Ahead Net Interchange	(7,174.9)	(15,414.6)	114.8%
Monthly Average Real-Time Gross Exports	3,503.7	4,007.7	14.4%
Monthly Average Real-Time Gross Imports	864.2	538.5	(37.7%)
Monthly Average Day-Ahead Gross Exports	4,853.8	4,185.8	(13.8%)
Monthly Average Day-Ahead Gross Imports	4,255.9	2,901.3	(31.8%)

In 2020, PJM was a monthly net exporter of energy in the real-time energy market in all months. In 2020, PJM was a monthly net exporter of energy in the day-ahead energy market in all months (Figure 9-1).[7]

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.

7 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.

Transactions in the day-ahead energy market create financial obligations to deliver in the real-time energy market and to pay operating reserve charges based on differences between the transaction MWh in the day-ahead and real-time energy markets times the applicable operating reserve rates. Up to congestion transactions also create financial obligations to deliver in real time, but did not pay operating reserve charges until November 1, 2020. In 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: 2020

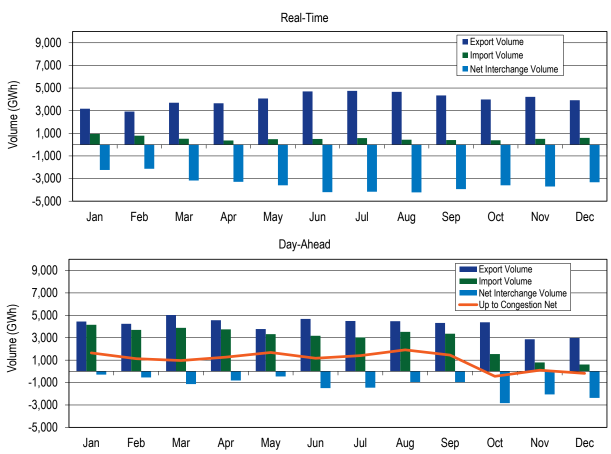
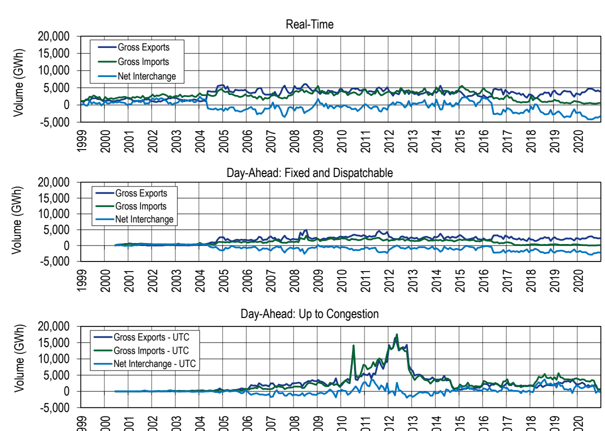


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from January 1999 through December 2020. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the real-time and day-ahead energy markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and 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.[8] As a result, the volume of import and export up to congestion transactions increased, contributing to PJM becoming a net importer in the day-ahead energy market starting in March 2018. On July 16, 2020, FERC issued an order directing PJM to revise uplift allocation rules to allocate uplift to up to congestion transactions.[9] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. As a result, the volume of up to congestion transactions decreased.

Figure 9-2 Scheduled import and export transaction volume history: January 1, 1999 through December 31, 2020



8 162 FERC ¶ 61,139.
9 172 FERC ¶ 61,046 (2020).

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 2020. Figure 9-3 shows the approximate geographic location of the interfaces. In 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. 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 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 2020, there were net scheduled exports at 15 of PJM's 19 interfaces. The top three net exporting interfaces in the real-time energy market accounted for 51.1 percent of the total net scheduled exports: PJM/Cinergy (CIN) with 26.6 percent, PJM/MidAmerican Energy Company (MEC) with 12.8 percent and PJM/Alliant Energy - East (ALTE) with 11.7 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 22.9 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 75.1 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in 2020, there were net scheduled imports at three of PJM's 19 interfaces. The top two importing interfaces in the real-time energy market accounted for 98.9 percent of the total net scheduled imports: PJM/Duke Energy Corp. (DUK) with 78.4 percent and PJM/Carolina Power and Light East (CPLE) with 20.5 percent of the net scheduled import volume.[10] 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): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	50.4	78.1	197.3	82.2	112.5	14.6	(1.9)	(19.6)	(61.7)	22.8	59.1	(116.8)	417.0
CPLW	9.6	0.0	0.0	1.2	11.3	0.0	0.0	0.0	0.0	0.1	0.0	0.0	22.3
DUK	352.5	274.6	5.2	(0.7)	22.8	148.3	257.7	164.9	127.8	65.1	115.5	61.3	1,595.0
LGEE	(62.3)	(65.2)	(75.4)	(34.2)	(34.8)	(80.5)	(85.9)	(68.9)	(57.3)	(48.1)	(85.8)	(81.0)	(779.5)
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)	(2,869.2)	(3,052.0)	(2,035.6)	(32,813.0)
ALTE	(353.2)	(330.2)	(518.7)	(581.9)	(408.5)	(454.4)	(331.4)	(352.3)	(407.2)	(597.4)	(562.4)	(219.7)	(5,117.3)
ALTW	(0.6)	(89.2)	(175.7)	(167.5)	(201.4)	(213.1)	(280.9)	(293.8)	(166.9)	(145.6)	(124.4)	(41.4)	(1,900.6)
AMIL	(32.2)	(40.7)	(48.5)	(57.0)	(66.2)	(52.6)	(45.1)	(25.3)	(49.0)	(69.7)	(85.6)	(22.2)	(594.1)
CIN	(516.6)	(447.4)	(637.8)	(885.2)	(1,044.8)	(1,282.6)	(1,485.8)	(1,175.2)	(1,332.0)	(992.6)	(1,124.7)	(701.7)	(11,626.2)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(42.9)	(89.7)	(134.8)	(119.5)	(160.5)	(122.7)	(128.8)	(140.1)	(119.9)	(136.5)	(199.2)	(72.7)	(1,467.4)
MEC	(466.4)	(436.0)	(505.8)	(356.3)	(515.4)	(427.1)	(449.0)	(454.5)	(436.5)	(463.4)	(495.8)	(583.4)	(5,589.6)
MECS	(132.7)	(211.3)	(368.4)	(370.9)	(391.2)	(336.7)	(306.8)	(392.6)	(393.4)	(402.6)	(407.3)	(343.5)	(4,057.4)
NIPS	(245.8)	(134.7)	(291.9)	(289.4)	(331.0)	(322.8)	(7.1)	0.0	0.0	0.0	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)	(61.3)	(52.6)	(51.1)	(837.7)
NYISO	(863.7)	(673.5)	(573.7)	(427.8)	(530.5)	(936.4)	(1,137.1)	(1,332.6)	(966.2)	(706.3)	(645.1)	(1,195.3)	(9,988.2)
HUDS	(163.6)	(115.2)	(62.0)	(14.3)	(30.3)	(88.3)	(116.4)	(145.4)	(133.0)	(73.0)	(128.8)	(218.1)	(1,288.5)
LIND	(140.4)	(111.4)	(85.9)	(52.3)	(63.7)	(111.7)	(153.0)	(191.7)	(186.3)	(189.1)	(130.4)	(224.2)	(1,640.1)
NEPT	(426.5)	(386.2)	(395.6)	(386.0)	(375.9)	(445.2)	(487.1)	(473.6)	(277.3)	(281.1)	(266.2)	(220.3)	(4,421.0)
NYIS	(133.2)	(60.7)	(30.2)	24.8	(60.6)	(291.2)	(380.6)	(521.8)	(369.6)	(163.1)	(119.7)	(532.7)	(2,638.6)
TVA	187.0	124.2	23.0	(27.6)	1.3	(58.3)	(103.2)	(75.3)	(23.9)	(64.9)	(100.5)	34.6	(83.7)
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)	(3,600.6)	(3,708.7)	(3,332.8)	(41,630.2)

10 In the real-time energy market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)). CWLP is a balancing authority on the western side of MISO.

Table 9-4 Real-time scheduled gross import volume by interface (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	85.2	158.6	253.7	162.9	173.4	109.1	54.7	36.8	9.1	90.0	133.3	13.4	1,280.2
CPLW	9.6	0.0	0.0	1.2	11.3	0.0	0.0	0.0	0.0	0.1	0.0	0.0	22.3
DUK	369.5	295.5	23.1	5.5	36.9	176.7	285.4	196.6	176.1	111.5	156.3	173.4	2,006.5
LGEE	24.0	14.4	1.1	1.8	2.1	2.0	4.5	8.1	1.4	2.7	3.7	15.9	81.5
MISO	104.8	47.8	27.4	24.4	28.5	59.1	65.1	34.5	49.9	37.0	48.8	157.3	684.6
ALTE	2.9	1.3	0.4	0.7	4.0	12.7	4.6	1.0	3.5	2.2	0.7	34.1	68.1
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	5.1	0.2	0.0	0.0	0.0	0.0	3.5	0.2	0.3	0.1	0.1	0.0	9.3
CIN	10.6	7.9	5.0	1.8	3.5	8.8	14.5	10.9	21.6	5.6	4.2	27.4	121.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	4.2	0.5	0.4	0.1	0.4	1.4	3.9	0.3	0.0	0.4	0.4	16.3	28.2
MEC	12.8	19.8	19.2	17.7	13.6	31.6	22.5	18.0	20.7	21.3	33.3	22.4	253.0
MECS	62.0	16.6	2.3	4.1	6.7	4.5	15.7	4.1	3.7	2.5	6.1	56.0	184.3
NIPS	0.0	0.0	0.0	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	4.9	4.1	1.1	19.9
NYISO	124.8	112.5	135.1	137.3	124.8	130.7	141.4	122.3	117.0	124.2	141.2	123.3	1,534.5
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
LIND	0.9	0.4	0.2	1.2	0.4	0.5	1.0	0.3	0.0	0.6	8.5	0.1	14.2
NEPT	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.3
NYIS	123.8	112.0	135.0	136.1	124.3	130.2	140.3	121.9	116.9	123.5	132.8	123.1	1,519.9
TVA	216.6	151.7	78.5	24.8	98.9	19.6	24.5	34.4	50.5	18.9	27.0	107.4	852.7
Total	934.3	780.5	518.9	358.0	475.9	497.1	575.5	432.7	404.0	384.4	510.4	590.7	6,462.4

Table 9-5 Real-time scheduled gross export volume by interface (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	34.8	80.5	56.4	80.7	61.0	94.4	56.6	56.5	70.8	67.2	74.1	130.1	863.2
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	16.9	20.9	17.9	6.2	14.1	28.4	27.8	31.7	48.3	46.4	40.9	112.1	411.6
LGEE	86.3	79.6	76.5	36.0	36.9	82.4	90.4	77.0	58.7	50.9	89.5	96.9	861.0
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	2,906.2	3,100.8	2,192.9	33,497.6
ALTE	356.1	331.5	519.0	582.6	412.5	467.2	335.9	353.3	410.8	599.6	563.1	253.8	5,185.4
ALTW	0.6	89.2	175.7	167.5	201.4	213.1	280.9	293.8	166.9	145.6	124.4	41.4	1,900.6
AMIL	37.3	40.9	48.5	57.0	66.2	52.6	48.5	25.5	49.2	69.9	85.7	22.2	603.4
CIN	527.2	455.2	642.8	887.0	1,048.4	1,291.4	1,500.3	1,186.1	1,353.6	998.2	1,128.8	729.1	11,748.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	47.1	90.2	135.2	119.6	160.9	124.1	132.7	140.4	119.9	136.9	199.6	89.0	1,495.6
MEC	479.3	455.8	525.0	374.0	529.0	458.7	471.5	472.5	457.2	484.7	529.1	605.8	5,842.6
MECS	194.6	227.9	370.7	375.0	397.9	341.2	322.5	396.7	397.2	405.1	413.4	399.5	4,241.7
NIPS	245.8	134.7	291.9	289.4	331.0	322.8	7.1	0.0	0.0	0.0	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	66.2	56.7	52.2	857.5
NYISO	988.5	786.0	708.9	565.2	655.3	1,067.1	1,278.5	1,454.8	1,083.2	830.5	786.3	1,318.6	11,522.8
HUDS	163.6	115.2	62.0	14.3	30.3	88.3	116.4	145.4	133.0	73.0	128.8	218.2	1,288.7
LIND	141.4	111.9	86.1	53.5	64.1	112.1	154.0	192.0	186.3	189.8	138.9	224.3	1,654.3
NEPT	426.6	386.2	395.6	386.0	376.0	445.2	487.1	473.7	277.3	281.1	266.2	220.4	4,421.3
NYIS	256.9	172.7	165.1	111.4	184.9	421.4	520.9	643.7	486.6	286.6	252.5	655.8	4,158.5
TVA	29.6	27.5	55.5	52.4	97.7	77.9	127.7	109.7	74.4	83.8	127.5	72.8	936.4
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	3,985.0	4,219.1	3,923.5	48,092.6

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.[11] 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,

11 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.

the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the PJM/MISO Interface based on the scheduled path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the PJM/MISO Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the 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.[12]

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.[13] 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 2020. On October 21, 2020, PJM updated the mappings of external balancing authorities to individual pricing points. Figure 9-4 shows a map of the default interface pricing point assignments for all external balancing authorities. Figure 9-4 shows that the balancing authorities in the Western Interconnection are mapped to either the MISO interface pricing point or the SouthIMP/EXP interface pricing point. This determination was made by PJM based on geographic location rather than the electrical impact on the PJM system. When power is scheduled across a DC tie line, its effects on the PJM system are as if a generator is located at the point in the Eastern Interconnection where the DC tie line connects. The electrical impact on PJM tie lines from sources in the Western Interconnection differ based on the relevant DC tie line and could vary from the MISO interface pricing point to the 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 rather than geographical location.

The MMU recommended 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. On October 1, 2020, PJM terminated the Northwest interface pricing point and reassigned the default pricing points for Saskatchewan Power Company and Manitoba Hydro balancing authorities to MISO. The MMU recommends that PJM review these mappings at least annually to reflect the fact that changes to the system topology can affect the electrical impact of external power sources on PJM.

The 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.[14] 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

12 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.

13 See "Interface Pricing Point Assignment Methodology," (October 21, 2020) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>. PJM periodically updates these definitions on its website.

14 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario interface pricing point.

determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions which have since expired.[15] [16]

In the real-time energy market, in 2020, there were net scheduled exports at 10 of PJM's 17 interface pricing points eligible for real-time transactions.[17] [18] The top three net exporting interface pricing points in the real-time energy market accounted for 87.8 percent of the total net scheduled exports: PJM/MISO with 71.6 percent, PJM/NEPTUNE with 9.6 percent and PJM/SouthEXP with 6.6 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 21.7 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in 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 93.5 percent of the total net scheduled imports: PJM/SouthIMP with 76.5 percent and PJM/NCMPAIMP with 16.9 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.[19]

Table 9-6 Real-time scheduled net interchange volume by interface pricing point (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	62.1	17.2	2.0	4.2	6.7	8.9	16.0	2.7	4.1	1.3	5.5	71.9	202.7
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)	(2,866.4)	(3,049.4)	(2,102.0)	(33,001.6)
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)	(706.3)	(645.1)	(1,195.3)	(9,986.1)
HUDSONTP	(163.6)	(115.2)	(62.0)	(14.3)	(30.3)	(88.3)	(116.4)	(145.4)	(133.0)	(73.0)	(128.8)	(218.1)	(1,288.5)
LINDENVFT	(140.4)	(111.4)	(85.9)	(52.3)	(63.7)	(111.7)	(153.0)	(191.7)	(186.3)	(189.1)	(130.4)	(224.2)	(1,640.1)
NEPTUNE	(426.5)	(386.2)	(395.6)	(386.0)	(375.9)	(445.2)	(487.1)	(473.6)	(277.3)	(281.1)	(266.2)	(220.3)	(4,421.0)
NYIS	(133.2)	(60.7)	(30.2)	24.7	(60.6)	(291.1)	(378.9)	(521.3)	(369.8)	(163.1)	(119.7)	(532.6)	(2,636.5)
Southern Imports	723.9	623.5	356.5	196.3	322.7	307.4	372.2	275.9	238.1	228.5	325.2	311.5	4,281.7
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	68.5	13.4		759.2
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	587.9	524.0	227.0	143.1	245.7	223.5	317.3	205.3	175.3	160.1	311.9	311.5	3,432.6
Southern Exports	(168.9)	(209.5)	(208.9)	(180.0)	(214.2)	(287.9)	(304.4)	(274.9)	(255.5)	(257.7)	(345.0)	(418.7)	(3,125.8)
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	0.0	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	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(159.0)	(192.2)	(185.9)	(170.3)	(209.3)	(287.9)	(304.4)	(274.9)	(255.5)	(257.7)	(345.0)	(418.7)	(3,060.9)
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)	(3,600.6)	(3,708.7)	(3,332.8)	(41,630.2)

15 Use of the Southwest pricing point for grandfathered transactions is not appropriate, and the MMU recommends that no further such agreements be entered into.

16 On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP interface pricing points. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points.

17 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.

18 On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP, DUKEXP and NIPSCO interface pricing points. On October 1, 2020, PJM retired the Northwest interface pricing point. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points. These retirements reduced the number of real-time interface pricing points to 10.

19 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): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	62.2	17.3	2.0	4.2	6.7	9.0	17.9	4.8	4.1	1.3	5.5	73.3	208.5
MISO	23.5	27.2	25.3	20.3	21.8	50.0	44.1	29.9	44.9	30.3	38.3	82.6	438.2
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	124.2	141.2	123.3	1,534.0
HUDSONTP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
LINDENVFT	0.9	0.4	0.2	1.2	0.4	0.5	1.0	0.3	0.0	0.6	8.5	0.1	14.2
NEPTUNE	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.3
NYIS	123.8	112.0	134.9	136.0	124.3	130.2	140.3	121.7	116.8	123.5	132.8	123.1	1,519.3
Southern Imports	723.9	623.5	356.5	196.3	322.7	307.4	372.2	275.9	238.1	228.5	325.2	311.5	4,281.7
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	68.5	13.4		759.2
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	587.9	524.0	227.0	143.1	245.7	223.5	317.3	205.3	175.3	160.1	311.9	311.5	3,432.6
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0								0.0
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	0.0		0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	934.3	780.5	518.9	358.0	475.9	497.1	575.5	432.7	404.0	384.4	510.4	590.7	6,462.4

Table 9-8 Real-time scheduled gross export volume by interface pricing point (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	0.1	0.2	0.0	0.0	0.0	0.1	1.9	2.1	0.0	0.0	0.0	1.5	5.8
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	2,896.8	3,087.7	2,184.7	33,439.8
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	830.5	786.3	1,318.6	11,520.2
HUDSONTP	163.6	115.2	62.0	14.3	30.3	88.3	116.4	145.4	133.0	73.0	128.8	218.2	1,288.7
LINDENVFT	141.4	111.9	86.1	53.5	64.1	112.1	154.0	192.0	186.3	189.8	138.9	224.3	1,654.3
NEPTUNE	426.6	386.2	395.6	386.0	376.0	445.2	487.1	473.7	277.3	281.1	266.2	220.4	4,421.3
NYIS	256.9	172.7	165.1	111.4	184.9	421.3	519.1	643.0	486.6	286.6	252.5	655.7	4,155.9
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0								0.0
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	0.0		0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	168.9	209.5	208.9	180.0	214.2	287.9	304.4	274.9	255.5	257.7	345.0	418.7	3,125.8
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	0.0	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	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	159.0	192.2	185.9	170.3	209.3	287.9	304.4	274.9	255.5	257.7	345.0	418.7	3,060.9
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	3,985.0	4,219.1	3,923.5	48,092.6

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.[20] 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

20 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.

also submitted in the real-time energy market. In the day-ahead energy market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up to congestion; and dispatchable.[21]

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 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 2020, there were net scheduled exports at 15 of PJM's 19 interfaces. The top three net exporting interfaces in the day-ahead energy market accounted for 51.8 percent of the total net scheduled exports: PJM/ MidAmerican Energy Company (MEC) with 19.8 percent, PJM/Neptune (NEPT) with 16.0 percent and PJM/Alliant Energy - East (ALTE) with 16.0 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 30.0 percent of the total net PJM scheduled exports in the day-ahead energy market. In 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 65.8 percent of the total net PJM exports in the day-ahead energy market.

In the day-ahead energy market, in 2020, there were net scheduled imports at two of PJM's 19 interfaces. The top net importing interface in the day-ahead energy market accounted for 98.1 percent of the total net scheduled imports: PJM/Duke Energy Corp. (DUK) with 98.1 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 2020, there were net imports in the day-ahead energy market at none of the 10 separate interfaces that connect PJM to MISO.[22]

21 See the *2010 State of the Market Report for PJM*, Volume 2, Section 4, "Interchange Transactions," for details.

22 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)).

Table 9-9 Day-ahead scheduled net interchange volume by interface (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	25.8	8.3	125.0	52.8	57.4	(40.1)	(40.0)	(34.8)	(56.7)	(20.8)	10.7	(90.3)	(2.7)
CPLW	0.0	0.0	0.0	1.4	7.8	0.0	0.0	0.0	0.0	0.0	0.3	0.0	9.5
DUK	196.9	122.4	22.5	4.4	25.1	(3.5)	34.2	4.9	37.2	(5.1)	27.9	26.6	493.5
LGEE	(118.5)	(135.7)	(109.7)	(52.2)	(25.3)	(74.4)	(89.8)	(78.4)	(55.4)	(47.1)	(87.8)	(90.7)	(965.0)
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)	(1,757.6)	(1,578.3)	(1,199.6)	(18,420.2)
ALTE	(337.9)	(260.1)	(432.9)	(510.5)	(360.0)	(417.1)	(320.4)	(293.9)	(361.7)	(549.1)	(450.8)	(177.5)	(4,471.9)
ALTW	(1.2)	(94.0)	(171.8)	(175.5)	(203.6)	(214.1)	(282.4)	(302.2)	(169.0)	(145.3)	(115.6)	(40.4)	(1,915.2)
AMIL	(16.8)	0.0	(0.8)	0.0	0.0	(6.1)	(7.6)	(0.6)	(0.9)	0.0	0.0	(0.7)	(33.5)
CIN	(158.6)	(92.3)	(133.4)	(167.1)	(185.3)	(195.3)	(555.6)	(525.3)	(521.8)	(507.4)	(479.7)	(438.2)	(3,960.1)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	(0.9)	0.0	(1.0)	0.0	0.0	0.0	(1.9)
MEC	(482.3)	(451.0)	(460.0)	(379.3)	(478.3)	(458.4)	(470.7)	(472.4)	(457.0)	(476.6)	(464.6)	(491.8)	(5,542.5)
MECS	9.6	5.9	(15.8)	(18.0)	(27.8)	(24.5)	(14.4)	(13.1)	(19.1)	(17.0)	(18.1)	0.1	(152.3)
NIPS	(257.8)	(139.8)	(293.4)	(295.1)	(334.4)	(323.6)	(7.0)	0.0	0.0	0.0	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)	(62.1)	(49.5)	(51.1)	(691.9)
NYISO	(746.2)	(596.9)	(560.9)	(466.9)	(534.0)	(829.3)	(982.2)	(1,076.6)	(730.9)	(551.8)	(514.8)	(820.0)	(8,410.5)
HUDS	(119.4)	(89.8)	(45.1)	(9.0)	(14.8)	(10.9)	(15.8)	(22.9)	(22.8)	(22.9)	(51.5)	(70.4)	(495.1)
LIND	0.0	0.0	0.0	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)	(285.7)	(268.9)	(222.9)	(4,478.8)
NYIS	(196.7)	(120.3)	(124.9)	(80.5)	(143.1)	(362.6)	(475.8)	(554.5)	(414.0)	(243.2)	(194.4)	(526.6)	(3,436.6)
TVA	13.6	8.1	(4.9)	(13.9)	(19.9)	(21.7)	(63.1)	(26.1)	(26.7)	(10.6)	(23.1)	(19.4)	(207.6)
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)	(2,392.9)	(2,165.1)	(2,193.4)	(27,503.0)
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	(443.8)	101.0	(180.6)	12,088.4
Total	(297.1)	(549.3)	(1,143.2)	(816.0)	(454.6)	(1,500.0)	(1,460.0)	(956.8)	(962.8)	(2,836.7)	(2,064.1)	(2,374.0)	(15,414.6)

Table 9-10 Day-ahead scheduled gross import volume by interface (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	55.2	69.3	158.0	115.5	106.5	40.4	10.4	15.3	6.8	35.9	75.3	6.3	695.0
CPLW	0.0	0.0	0.0	1.4	7.8	0.0	0.0	0.0	0.0	0.0	0.3	0.0	9.5
DUK	198.4	129.9	27.2	6.6	30.8	4.8	34.3	10.1	44.1	2.0	32.0	42.3	562.6
LGEE	0.2	0.0	0.0	0.0	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	0.3	0.4	48.8	105.7
ALTE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	24.2	24.4
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	1.2	1.0	0.0	0.0	0.0	4.4	0.2	0.0	1.8	0.0	0.0	14.1	22.7
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.3	0.2	10.5	58.6
NIPS	0.0	0.0	0.0	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	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	0.3	4.1	0.0	7.3
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.0	0.0	0.0	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	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	0.3	4.1	0.0	7.3
TVA	26.2	15.1	3.1	0.0	7.4	1.1	2.1	5.1	0.9	0.0	0.0	18.1	79.1
Total without Up To Congestion	317.3	225.4	188.4	124.4	153.6	50.8	48.4	31.1	53.9	38.6	112.1	115.5	1,459.4
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	1,503.7	681.3	489.1	33,356.0
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	1,542.3	793.4	604.5	34,815.4

Table 9-11 Day-ahead scheduled gross export volume by interface (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	29.5	61.0	33.1	62.7	49.1	80.5	50.4	50.2	63.5	56.7	64.6	96.6	697.8
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	1.5	7.5	4.7	2.2	5.6	8.4	0.2	5.2	6.8	7.2	4.1	15.7	69.1
LGEE	118.8	135.7	109.7	52.2	25.3	74.4	89.8	78.4	55.4	47.1	87.8	90.7	965.3
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	1,757.8	1,578.7	1,248.4	18,525.9
ALTE	337.9	260.1	432.9	510.5	360.0	417.1	320.4	293.9	361.7	549.1	451.0	201.7	4,496.3
ALTW	1.2	94.0	171.8	175.5	203.6	214.1	282.4	302.2	169.0	145.3	115.6	40.4	1,915.2
AMIL	16.8	0.0	0.8	0.0	0.0	6.1	7.6	0.6	0.9	0.0	0.0	0.7	33.5
CIN	159.8	93.3	133.4	167.1	185.3	199.7	555.8	525.3	523.6	507.4	479.7	452.4	3,982.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.0	1.0	0.0	0.0	0.0	1.9
MEC	482.3	451.0	460.0	379.3	478.3	458.4	470.7	472.4	457.0	476.6	464.6	491.8	5,542.5
MECS	26.2	4.3	15.9	18.0	28.9	24.6	14.8	13.1	19.2	17.3	18.2	10.4	210.9
NIPS	257.8	139.8	293.4	295.1	334.4	323.6	7.0	0.0	0.0	0.0	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	62.1	49.5	51.1	691.9
NYISO	746.5	596.9	560.9	467.7	534.0	829.3	983.1	1,077.2	731.1	552.1	518.9	820.0	8,417.8
HUDS	119.4	89.8	45.1	9.0	14.8	10.9	15.8	22.9	22.8	22.9	51.5	70.4	495.1
LIND	0.0	0.0	0.0	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	285.7	268.9	222.9	4,478.8
NYIS	197.0	120.4	124.9	81.4	143.1	362.6	476.7	555.0	414.2	243.5	198.5	526.6	3,443.9
TVA	12.6	7.0	8.0	14.0	27.3	22.9	65.2	31.1	27.6	10.6	23.1	37.5	286.7
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	2,431.5	2,277.2	2,308.8	28,962.4
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	1,947.5	580.3	669.7	21,267.6
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	4,379.0	2,857.5	2,978.5	50,230.0

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 2020, up to congestion transactions accounted for 95.8 percent of all scheduled import MW transactions and 42.3 percent of all scheduled export MW transactions in the day-ahead energy market. The day-ahead net scheduled interchange in 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 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 show 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 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 2020 was $30.8 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 (4.9 percent of the yearly total of $30.8 million). While there was no corresponding interface pricing point available for real-time transaction scheduling, a real-time LMP was still calculated. This real-time price was 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 2020, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for day-ahead transactions.[23] The top three net exporting interface pricing points in the day-ahead energy market accounted for 73.4 percent of the total net scheduled exports: PJM/MISO with 45.1 percent, PJM/SOUTHEXP with 14.3 percent and PJM/NIPSCO with 14.0 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 25.8 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 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 92.6 percent of the total net scheduled imports: PJM/NORTHWEST with 58.7 percent, PJM/SOUTHIMP with 25.7 percent and PJM/LINDENVFT with 8.1 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 8.1 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.[24]

In the day-ahead energy market, in 2020, up to congestion transactions had net scheduled exports at four of PJM's 18 interface pricing points eligible for day-ahead transactions.[25] The top two net exporting interface pricing points eligible for up to congestion transactions accounted for 77.6 percent of the total net up to congestion scheduled exports: PJM/NIPSCO with 47.6 percent and PJM/SouthEXP with 30.0 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/

23 On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points. On October 1, 2020, PJM retired the Northwest interface pricing point. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points. These retirements reduced the number of day-ahead interface pricing points to 10.

24 In the day-ahead energy market, two PJM interface pricing points had a net interchange of zero (Southeast and Southwest).

25 On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP and DUKEXP and NIPSCO interface pricing points. On October 1, 2020, PJM retired the Northwest interface pricing point. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points. These retirements reduced the number of day-ahead interfaces to 10.

HUDSONTP and PJM/LINDENVFT) together represented 19.9 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 2020, up to congestion transactions had net scheduled imports at six 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 89.8 percent of the total net up to congestion scheduled imports: PJM/NORTHWEST with 65.1 percent, PJM/SOUTHIMP with 18.4 percent and PJM/LINDENVFT with 6.3 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 15.4 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.[26]

Table 9-12 Day-ahead scheduled net interchange volume by interface pricing point (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	77.8	24.8	(0.8)	(0.5)	11.5	27.1	9.1	27.9	27.0	47.0	25.1	23.4	299.5
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)	(2,129.0)	(1,585.9)	(1,418.4)	(14,604.1)
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)	(745.8)	(567.8)	(896.3)	(6,975.1)
HUDSONTP	(333.4)	(258.2)	(180.8)	(93.6)	(65.4)	(184.5)	(132.8)	(160.0)	(218.6)	(468.8)	(156.1)	(131.2)	(2,383.4)
LINDENVFT	80.7	61.4	42.0	41.0	25.4	112.5	190.2	206.4	180.9	308.8	53.7	66.5	1,369.3
NEPTUNE	(69.8)	(88.5)	(161.7)	(332.8)	(364.6)	(435.5)	(459.9)	(418.2)	(269.6)	(327.5)	(269.3)	(227.9)	(3,425.4)
NYIS	(33.0)	39.8	103.7	114.9	12.9	(339.0)	(530.7)	(469.7)	(376.6)	(258.2)	(196.2)	(603.6)	(2,535.7)
Southern Imports	455.9	425.6	440.7	663.0	607.5	493.5	492.9	483.2	372.0	381.4	330.9	177.1	5,323.9
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	27.6	14.2		703.7
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	229.2	254.3	267.6	542.8	465.0	461.1	488.6	471.8	334.6	353.8	316.7	177.1	4,362.5
Southern Exports	(352.6)	(392.7)	(340.5)	(223.9)	(287.6)	(637.3)	(572.8)	(424.6)	(733.5)	(390.4)	(266.3)	(260.0)	(4,882.3)
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	0.0	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	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(322.6)	(331.2)	(303.4)	(160.2)	(235.4)	(637.3)	(571.4)	(417.9)	(733.5)	(390.4)	(266.3)	(260.0)	(4,629.6)
Total	(297.1)	(549.3)	(1,143.2)	(816.0)	(454.6)	(1,500.0)	(1,460.0)	(956.8)	(962.8)	(2,836.7)	(2,064.1)	(2,374.0)	(15,414.6)

26 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): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	42.0	16.0	(0.9)	(0.5)	10.5	27.1	10.7	28.1	26.9	46.9	25.1	11.5	243.3
MISO	273.1	(61.6)	82.1	(152.2)	(108.8)	(163.0)	393.8	103.8	(14.8)	(371.3)	(7.6)	(206.7)	(233.1)
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	(194.0)	(53.0)	(76.4)	1,425.1
HUDSONTP	(215.4)	(168.5)	(139.5)	(85.4)	(50.6)	(173.6)	(116.9)	(137.1)	(195.8)	(445.9)	(105.6)	(60.7)	(1,895.1)
LINDENVFT	80.7	61.4	42.0	41.0	25.4	112.5	190.2	206.4	180.9	308.8	53.7	66.5	1,369.3
NEPTUNE	360.3	298.3	229.2	44.6	11.5	20.4	30.6	81.1	24.6	(41.8)	(0.4)	(5.0)	1,053.4
NYIS	165.1	160.1	232.3	195.5	156.0	23.6	(56.9)	89.3	25.4	(15.1)	(0.7)	(77.1)	897.5
Southern Imports	175.9	211.3	252.4	539.5	455.0	447.2	446.1	452.7	320.2	343.4	223.2	110.5	3,977.4
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	0.0		0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	175.9	211.3	252.4	539.5	455.0	447.2	446.1	452.7	320.2	343.4	223.2	110.5	3,977.4
Southern Exports	(190.3)	(181.6)	(185.1)	(92.9)	(179.6)	(451.1)	(367.3)	(252.9)	(580.2)	(268.9)	(86.7)	(19.5)	(2,856.2)
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	0.0		0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(190.3)	(181.6)	(185.1)	(92.9)	(179.6)	(451.1)	(367.3)	(252.9)	(580.2)	(268.9)	(86.7)	(19.5)	(2,856.2)
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	(443.8)	101.0	(180.6)	12,088.4
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	11,454.6	5,194.7	4,240.3	112,707.2
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	11,010.8	5,295.8	4,059.7	124,795.6

Table 9-14 Day-ahead scheduled gross import volume by interface pricing point (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	102.5	43.6	22.1	21.5	36.8	73.7	45.5	55.3	53.5	65.9	36.4	32.9	589.6
MISO	808.6	599.5	603.1	414.4	430.8	554.9	691.4	691.4	445.6	577.6	320.0	277.2	6,414.5
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	517.3	106.1	117.3	5,694.5
HUDSONTP	25.6	13.2	18.3	5.3	11.6	33.9	82.0	51.3	52.1	26.7	10.0	7.8	337.8
LINDENVFT	114.0	92.1	92.9	82.0	67.7	180.9	236.2	230.8	224.7	344.2	68.0	75.5	1,809.0
NEPTUNE	398.1	318.0	246.4	84.7	46.0	155.4	221.7	221.5	140.2	41.7	4.2	6.0	1,883.8
NYIS	197.0	187.2	268.4	215.2	180.5	95.2	65.9	167.3	130.3	104.7	23.9	28.1	1,663.8
Southern Imports	455.9	425.6	440.7	663.0	607.5	493.5	492.9	483.2	372.0	381.4	330.9	177.1	5,323.9
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	27.6	14.2		703.7
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	229.2	254.3	267.6	542.8	465.0	461.1	488.6	471.8	334.6	353.8	316.7	177.1	4,362.5
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0								0.0
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	0.0		0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	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	1,542.3	793.4	604.5	34,815.4

Table 9-15 Up to congestion scheduled gross import volume by interface pricing point (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	66.7	33.5	22.0	21.5	35.7	73.6	45.1	55.3	53.4	65.9	36.4	20.8	529.8
MISO	807.4	598.5	603.1	414.4	430.8	550.5	691.1	691.4	443.8	577.4	319.7	240.5	6,368.6
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	734.4	610.5	626.0	386.4	305.8	465.5	604.9	670.3	547.1	517.0	102.0	117.3	5,687.2
HUDSONTP	25.6	13.2	18.3	5.3	11.6	33.9	82.0	51.3	52.1	26.7	10.0	7.8	337.8
LINDENVFT	114.0	92.1	92.9	82.0	67.7	180.9	236.2	230.8	224.7	344.2	68.0	75.5	1,809.0
NEPTUNE	398.1	318.0	246.4	84.7	46.0	155.4	221.7	221.5	140.2	41.7	4.2	6.0	1,883.8
NYIS	196.7	187.2	268.4	214.4	180.5	95.2	65.0	166.7	130.1	104.4	19.8	28.1	1,656.6
Southern Imports	175.9	211.3	252.4	539.5	455.0	447.2	446.1	452.7	320.2	343.4	223.2	110.5	3,977.4
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	0.0		0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	175.9	211.3	252.4	539.5	455.0	447.2	446.1	452.7	320.2	343.4	223.2	110.5	3,977.4
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0								0.0
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	0.0		0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Interfaces	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	1,503.7	681.3	489.1	33,356.0

Table 9-16 Day-ahead scheduled gross export volume by interface pricing point (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	24.7	18.8	22.9	22.0	25.2	46.5	36.4	27.4	26.5	18.9	11.3	9.5	290.1
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	2,706.6	1,905.9	1,695.6	21,018.6
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	1,263.1	673.9	1,013.5	12,669.6
HUDSONTP	359.0	271.4	199.1	99.0	77.0	218.5	214.8	211.3	270.6	495.5	166.1	138.9	2,721.2
LINDENVFT	33.4	30.7	50.9	41.0	42.4	68.4	46.0	24.4	43.8	35.4	14.3	9.0	439.7
NEPTUNE	467.9	406.5	408.1	417.6	410.6	590.8	681.6	639.7	409.8	369.2	273.5	233.9	5,309.1
NYIS	230.0	147.4	164.8	100.3	167.6	434.2	596.6	637.0	506.9	362.9	220.1	631.7	4,199.5
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0								0.0
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	0.0		0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	352.6	392.7	340.5	223.9	287.6	637.3	572.8	424.6	733.5	390.4	266.3	260.0	4,882.3
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	0.0	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	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	322.6	331.2	303.4	160.2	235.4	637.3	571.4	417.9	733.5	390.4	266.3	260.0	4,629.6
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	4,379.0	2,857.5	2,978.5	50,230.0

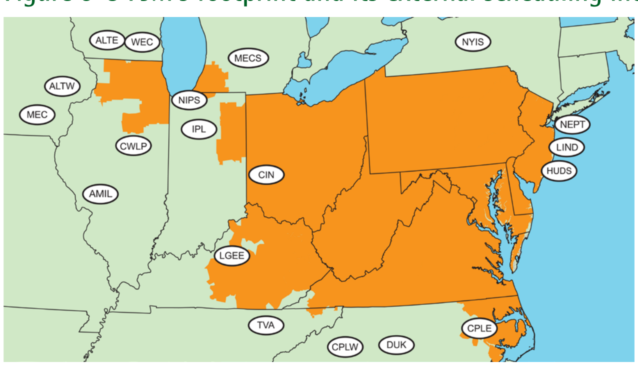
Table 9-17 Up to congestion scheduled gross export volume by interface pricing point (GWh): 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	24.7	17.5	22.9	22.0	25.2	46.5	34.4	27.2	26.5	18.9	11.3	9.3	286.5
MISO	534.3	660.1	521.1	566.6	539.6	713.5	297.2	587.6	458.6	948.8	327.3	447.2	6,601.7
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	711.0	155.0	193.7	4,262.1
HUDSONTP	241.0	181.7	157.8	90.7	62.2	207.6	199.0	188.4	247.9	472.6	115.6	68.5	2,232.9
LINDENVFT	33.4	30.7	50.9	41.0	42.4	68.4	46.0	24.4	43.8	35.4	14.3	9.0	439.7
NEPTUNE	37.8	19.7	17.2	40.2	34.5	135.0	191.0	140.4	115.6	83.5	4.5	11.0	830.4
NYIS	31.6	27.1	36.1	18.9	24.5	71.7	121.9	77.4	104.7	119.4	20.6	105.2	759.1
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0								0.0
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	0.0		0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	190.3	181.6	185.1	92.9	179.6	451.1	367.3	252.9	580.2	268.9	86.7	19.5	2,856.2
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	0.0		0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	190.3	181.6	185.1	92.9	179.6	451.1	367.3	252.9	580.2	268.9	86.7	19.5	2,856.2
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	1,947.5	580.3	669.7	21,267.6

Table 9-18 Active scheduling interfaces: 2020[27]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

Figure 9-3 PJM's footprint and its external scheduling interfaces



27 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of December 31, 2020, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Table 9-19 Active scheduled interface pricing points: 2020[28]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CPLEEXP	Active	Active	Active	Active	Active							
CPLEIMP	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	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active[1]	
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active[1]	
NEPTUNE	Active	Active	Active	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	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

[1] NCMPAIMP/EXP retired on November 3rd

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.[29]

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

28 The NIPSCO interface pricing point was valid only in the day-ahead energy market.

29 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

were submitted, there would be 100 MW of scheduled flow at the PJM/MISO interface border, but there would be no actual flows on the interface. Correspondingly, there would be no scheduled flows at the PJM/Southern interface border, but there would be 100 MW of actual flows on the interface. In 2020, there were net scheduled flows of 15 GWh through MISO that received an interface pricing point associated with the southern interface but there were no net scheduled flows across the southern interface that received the MISO interface pricing point.

In 2020, net scheduled interchange was -41,630 GWh and net actual interchange was -41,716 GWh, a difference of 86 GWh. In 2019, net scheduled interchange was -31,674 GWh and net actual interchange was -31,546 GWh, a difference of 128 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 86 GW of inadvertent interchange in 2020. To reduce this inadvertent interchange, PJM can control to an ACE less than zero, which would result in under generating. By way of the power balance equation, power would flow into PJM from its neighboring balancing authority areas. This would create additional actual imports 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.[30]

Table 9-20 shows that in 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 -11,906 GWh of net actual interchange, a difference of 10,283 GWh.

30 See PJM. "Manual 12: Balancing Operations," Rev. 41 (Nov. 19, 2020).

Table 9-20 Net scheduled and actual PJM flows by interface (GWh): 2020

	Actual	Net Scheduled	Difference (GWh)
CPLE	(1,855)	417	(2,272)
CPLW	(160)	22	(182)
DUK	1,556	1,595	(39)
LGEE	763	(779)	1,543
MISO	(38,152)	(32,813)	(5,339)
ALTE	(2,460)	(5,117)	2,657
ALTW	(2,040)	(1,901)	(139)
AMIL	(203)	(594)	391
CIN	(8,454)	(11,626)	3,173
CWLP	(518)	0	(518)
IPL	(2,600)	(1,467)	(1,133)
MEC	(7,839)	(5,590)	(2,250)
MECS	(8,086)	(4,057)	(4,029)
NIPS	(11,906)	(1,623)	(10,283)
WEC	5,955	(838)	6,792
NYISO	(10,154)	(9,988)	(166)
HUDS	(1,288)	(1,288)	0
LIND	(1,640)	(1,640)	0
NEPT	(4,421)	(4,421)	0
NYIS	(2,805)	(2,639)	(166)
TVA	6,286	(84)	6,370
Total	(41,716)	(41,630)	(86)

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.[31] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SouthIMP interface pricing point net schedule totals because SPP is mapped to the SouthIMP interface pricing point. The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

The differences between the scheduled MWh mapped to a specific interface pricing point and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. The scheduled transactions are mapped to interface pricing points based on the expected flow from the generation balancing authority and load balancing authority, whereas scheduled transactions are assigned

31 The terms balancing authority and control area are used interchangeably in this section. The NERC Tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance.

to interfaces based solely on the OASIS path that the market participants reflect the transmission path into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 9-21 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP interface pricing points were created as part of operating agreements with external balancing authorities, and reflect the same physical ties as the SouthIMP and SouthEXP interface pricing points.[32]

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 (24,369 GWh) and the total southern export actual flows (-17,779 GWh) for 6,590 GWh of net imports. The net scheduled flows from the southern region are determined by summing the total southern import scheduled flows (4,282 GWh) and the total southern export scheduled flows (-3,061 GWh) for 1,156 GWh of net imports. In 2020, the loop flows at the southern region were the difference between the southern region net scheduled flows (1,156 GW) and the southern region net actual flows (6,590 GWh) for a total of 5,434 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.

Table 9-21 PJM flows by interface pricing point (GWh): 2020

	Actual	Net Scheduled	Difference (GWh)
IMO	0	203	(203)
MISO	(38,152)	(33,002)	(5,150)
NORTHWEST	0	(1)	1
NYISO	(10,154)	(9,986)	(168)
HUDSONTP	(1,288)	(1,288)	0
LINDENVFT	(1,640)	(1,640)	0
NEPTUNE	(4,421)	(4,421)	0
NYIS	(2,805)	(2,637)	(168)
Southern Imports	24,369	4,282	20,087
CPLEIMP	0	1	(1)
DUKIMP	0	89	(89)
NCMPAIMP	0	759	(759)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	24,369	3,433	20,936
Southern Exports	(17,779)	(3,126)	(14,653)
CPLEEXP	0	(53)	53
DUKEXP	0	(12)	12
NCMPAEXP	0	(0)	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(17,779)	(3,061)	(14,718)
Total	(41,716)	(41,630)	(86)

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 205 of the 207 GWh (99.0 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 2020, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,433 GWh of net scheduled

32 On June 1, 2020, PJM retired the CPLEIMP, CPLEEXP, DUKIMP, DUKEXP interface pricing points. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points.

interchange and 24,369 GWh of net actual interchange, a difference of 20,936 GWh.

Table 9-22 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): 2020

	Actual	Net Scheduled	Difference (GWh)
MISO	(38,152)	(32,797)	(5,355)
NORTHWEST	0	(1)	1
NYISO	(10,154)	(9,988)	(166)
HUDSONTP	(1,288)	(1,288)	0
LINDENVFT	(1,640)	(1,640)	0
NEPTUNE	(4,421)	(4,421)	0
NYIS	(2,805)	(2,639)	(166)
Southern Imports	24,369	4,282	20,087
CPLEIMP	0	1	(1)
DUKIMP	0	89	(89)
NCMPAIMP	0	759	(759)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	24,369	3,433	20,936
Southern Exports	(17,779)	(3,126)	(14,653)
CPLEEXP	0	(53)	53
DUKEXP	0	(12)	12
NCMPAEXP	0	(0)	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(17,779)	(3,061)	(14,718)
Total	(41,716)	(41,630)	(86)

The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The breaking of transactions into portions can be a way to manipulate markets and the result of such behavior can be incorrect and noncompetitive pricing of transactions.

PJM attempts to ensure that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC Tag. Assigning prices in this manner is a reasonable approach to ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this method does not address loop flow issues.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game the markets.

The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loop flow would be reduced.

The MMU also recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows.

Table 9-23 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 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 (-600 GWh).

Table 9-23 Net scheduled and actual flows by interface and interface pricing point (GWh): 2020

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(2,460)	(5,117)	2,657	HUDS		(1,288)	(1,288)	0
	IMO	0	10	(10)		HUDSONTP	(1,288)	(1,288)	0
	MISO	(2,460)	(5,127)	2,668	IPL		(2,600)	(1,467)	(1,133)
	SOUTHEXP	0	(0)	0		IMO	0	17	(17)
ALTW		(2,040)	(1,901)	(139)		MISO	(2,600)	(1,481)	(1,119)
	MISO	(2,040)	(1,901)	(139)		SOUTHEXP	0	(3)	3
AMIL		(203)	(594)	391	LGEE		763	(779)	1,543
	MISO	(203)	(600)	398		SOUTHEXP	(7,787)	(861)	(6,926)
	SOUTHEXP	0	(1)	1		SOUTHIMP	8,550	82	8,468
	SOUTHIMP	0	8	(8)	LIND		(1,640)	(1,640)	0
CIN		(8,454)	(11,626)	3,173		LINDENVFT	(1,640)	(1,640)	0
	IMO	0	9	(9)	MEC		(7,839)	(5,590)	(2,250)
	MISO	(8,454)	(11,596)	3,142		MISO	(7,839)	(5,589)	(2,250)
	NORTHWEST	0	(1)	1		SOUTHEXP	0	(0)	0
	SOUTHEXP	0	(45)	45	MECS		(8,086)	(4,057)	(4,029)
	SOUTHIMP	0	6	(6)		IMO	0	169	(169)
CPLE		(1,855)	417	(2,272)		MISO	(8,086)	(4,230)	(3,857)
	CPLEEXP	0	(53)	53		SOUTHEXP	0	(2)	2
	CPLEIMP	0	1	(1)		SOUTHIMP	0	6	(6)
	DUKEXP	0	(3)	3	NEPT		(4,421)	(4,421)	0
	DUKIMP	0	66	(66)		NEPTUNE	(4,421)	(4,421)	0
	NCMPAIMP	0	385	(385)	NIPS		(11,906)	(1,623)	(10,283)
	SOUTHEXP	(5,098)	(807)	(4,291)		MISO	(11,906)	(1,623)	(10,283)
	SOUTHIMP	3,242	828	2,414	NYIS		(2,805)	(2,639)	(166)
CPLW		(160)	22	(182)		IMO	0	(2)	2
	NCMPAIMP	0	21	(21)		NYIS	(2,805)	(2,637)	(168)
	SOUTHEXP	(428)	0	(428)	TVA		6,286	(84)	6,370
	SOUTHIMP	268	1	267		SOUTHEXP	(3,606)	(936)	(2,670)
CWLP		(518)	0	(518)		SOUTHIMP	9,892	853	9,040
	MISO	(518)	0	(518)	WEC		5,955	(838)	6,792
DUK		1,556	1,595	(39)		MISO	5,955	(855)	6,809
	DUKEXP	0	(9)	9		SOUTHEXP	0	(2)	2
	DUKIMP	0	23	(23)		SOUTHIMP	0	19	(19)
	NCMPAEXP	0	(0)	0	Grand Total		(41,716)	(41,630)	(86)
	NCMPAIMP	0	353	(353)					
	SOUTHEXP	(860)	(403)	(458)					
	SOUTHIMP	2,416	1,630	786					

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 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 (169 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): 2020

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(53)	53	NCMPAIMP		0	759	(759)
	CPLE	0	(53)	53		CPLE	0	385	(385)
CPLEIMP		0	1	(1)		CPLW	0	21	(21)
	CPLE	0	1	(1)		DUK	0	353	(353)
DUKEXP		0	(12)	12	NEPTUNE		(4,421)	(4,421)	0
	CPLE	0	(3)	3		NEPT	(4,421)	(4,421)	0
	DUK	0	(9)	9	NORTHWEST		0	(1)	1
DUKIMP		0	89	(89)		CIN	0	(1)	1
	CPLE	0	66	(66)	NYIS		(2,805)	(2,637)	(168)
	DUK	0	23	(23)		NYIS	(2,805)	(2,637)	(168)
HUDSONTP		(1,288)	(1,288)	0	SOUTHEXP		(17,779)	(3,061)	(14,718)
	HUDS	(1,288)	(1,288)	0		ALTE	0	(0)	0
IMO		0	203	(203)		AMIL	0	(1)	1
	ALTE	0	10	(10)		CIN	0	(45)	45
	CIN	0	9	(9)		CPLE	(5,098)	(807)	(4,291)
	IPL	0	17	(17)		CPLW	(428)	0	(428)
	MECS	0	169	(169)		DUK	(860)	(403)	(458)
	NYIS	0	(2)	2		IPL	0	(3)	3
LINDENVFT		(1,640)	(1,640)	0		LGEE	(7,787)	(861)	(6,926)
	LIND	(1,640)	(1,640)	0		MEC	0	(0)	0
MISO		(38,152)	(33,002)	(5,150)		MECS	0	(2)	2
	ALTE	(2,460)	(5,127)	2,668		TVA	(3,606)	(936)	(2,670)
	ALTW	(2,040)	(1,901)	(139)		WEC	0	(2)	2
	AMIL	(203)	(600)	398	SOUTHIMP		24,369	3,433	20,936
	CIN	(8,454)	(11,596)	3,142		AMIL	0	8	(8)
	CWLP	(518)	0	(518)		CIN	0	6	(6)
	IPL	(2,600)	(1,481)	(1,119)		CPLE	3,242	828	2,414
	MEC	(7,839)	(5,589)	(2,250)		CPLW	268	1	267
	MECS	(8,086)	(4,230)	(3,857)		DUK	2,416	1,630	786
	NIPS	(11,906)	(1,623)	(10,283)		LGEE	8,550	82	8,468
	WEC	5,955	(855)	6,809		MECS	0	6	(6)
NCMPAEXP		0	(0)	0		TVA	9,892	853	9,040
	DUK	0	(0)	0		WEC	0	19	(19)
					Grand Total		(41,716)	(41,630)	(86)

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.[33]

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.[34]

Actual Tie Line Flow Data

An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. The available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

Dynamic Schedule and Pseudo Tie Data

Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

Pseudo-ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo ties differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo tie transactions are not required to be tagged. Pseudo tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

Area Control Error (ACE) Data

Area control error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical 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.

33 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.
34 141 FERC ¶ 61,235 (2012).

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.[35]

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

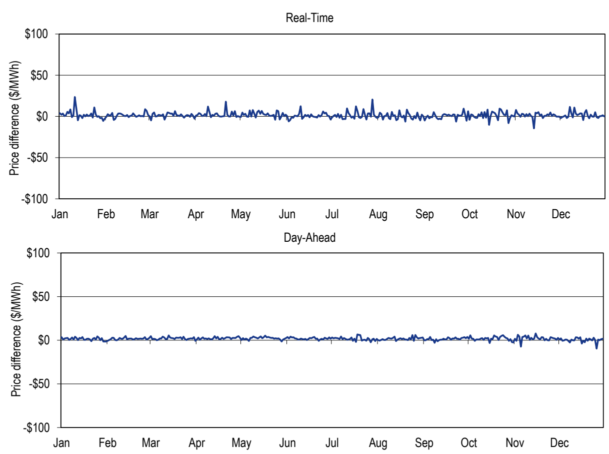
In 2020, the direction of flow was consistent with price differentials in 67.9 percent of the hours. Table 9-25 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. Figure 9-5 shows the underlying 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).

35 See "LMP Aggregate Definitions," (December 9, 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>.

Table 9-25 PJM and MISO flow based hours and price differences: 2020

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	5,965	$5.02
	Consistent Flow (PJM to MISO)	5,965	$5.02
	Inconsistent Flow (MISO to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	2,819	$6.26
	Consistent Flow (MISO to PJM)	0	$0.00
	Inconsistent Flow (PJM to MISO)	2,819	$6.26
	No Flow	0	$0.00

Figure 9-5 Price differences (MISO/PJM Interface minus PJM/MISO Interface): 2020



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In 2020, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 5,965 hours (67.9 percent of all hours), and was inconsistent with price differentials in 2,819 hours (32.1 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 2,819 hours where flows were in a direction inconsistent with price differences, 1,920 of those hours (68.1 percent) had a price difference greater than or equal to $1.00 and 738 of those hours (26.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $318.43. Of the 5,965 hours where flows were consistent with price differences, 4,739 of those hours (79.4 percent) had a price difference greater than or equal to $1.00 and 1,287 of all such hours (21.6 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: 2020

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	2,819	100.0%	5,965	100.0%
$1.00	1,920	68.1%	4,739	79.4%
$5.00	738	26.2%	1,287	21.6%
$10.00	462	16.4%	512	8.6%
$15.00	321	11.4%	317	5.3%
$20.00	229	8.1%	230	3.9%
$25.00	174	6.2%	173	2.9%
$50.00	45	1.6%	63	1.1%
$75.00	14	0.5%	31	0.5%
$100.00	7	0.2%	20	0.3%
$200.00	2	0.1%	5	0.1%
$300.00	1	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.[36]

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

36 See the *2012 State of the Market Report for PJM*, Volume2, Section 8, "Interchange Transactions," for a more detailed discussion.

with neighboring balancing authorities. A proxy bus is a single bus, located outside the NYISO footprint, which represents generation and load in a neighboring balancing authority area. The NYISO models imports from PJM as generation at the Keystone proxy bus, delivered to the NYISO reference bus with the assumption that 32 percent of the flow will enter the NYISO across the free flowing A/C ties, 32 percent will enter the NYISO across the Ramapo PARs, 21 percent will enter the NYISO across the ABC PARs and 15 percent will enter the NYISO across the J/K PARs. The NYISO models exports to PJM as being delivered to load at the Keystone proxy bus, sourced from the NYISO reference bus with the assumption that 32 percent of the flow will enter PJM across the free flowing A/C ties, 32 percent will enter PJM across the Ramapo PARs, 21 percent will enter PJM across the ABC PARs and 15 percent will enter PJM across the J/K PARs.

The PJM/NYIS interface definition using two buses was created to include the impact of the ConEd wheeling agreement. The ConEd wheeling agreement ended on May 1, 2017. The end of the wheeling agreement meant that the expected actual power flows would change and therefore the definition of the interface price needed to change. Effective May 1, 2017, PJM replaced the old PJM/NYIS interface price definition. The new PJM/NYIS interface price is based on four buses within NYISO. The four buses were chosen based on a power flow analysis of transfers between PJM and the NYISO and the resultant distribution of flows across the free flowing A/C ties.

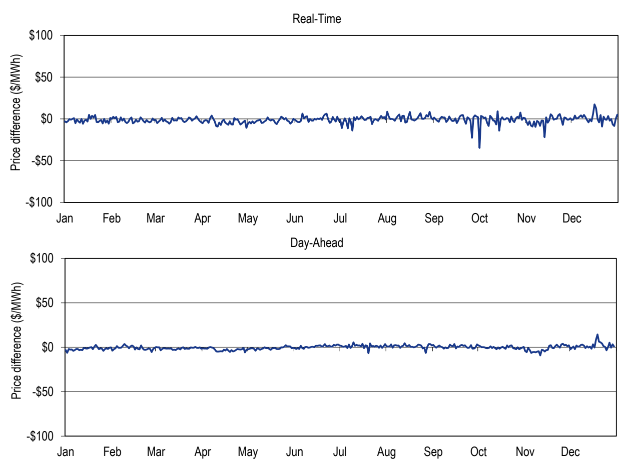
Real-Time and Day-Ahead PJM/NYISO Interface Prices

In 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 49.9 percent of the hours in 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: 2020[37]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	3,706	$5.54
	Consistent Flow (PJM to NYIS)	2,946	$5.70
	Inconsistent Flow (NYIS to PJM)	760	$4.91
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	5,078	$5.99
	Consistent Flow (NYIS to PJM)	1,440	$4.75
	Inconsistent Flow (PJM to NYIS)	3,638	$6.48
	No Flow	0	$0.00

Figure 9-6 Price differences (NY/PJM proxy - PJM/NYIS Interface): 2020



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In 2020, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 4,386 hours (49.9 percent of all hours), and was inconsistent with price differences in 4,398 hours (50.1 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

37 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

PJM/NYISO and NYISO/PJM prices. Of the 4,398 hours where flows were in a direction inconsistent with price differences, 3,634 of those hours (82.6 percent) had a price difference greater than or equal to $1.00 and 1,418 of all those hours (32.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $312.34. Of the 4,386 hours where flows were consistent with price differences, 3,591 of those hours (81.9 percent) had a price difference greater than or equal to $1.00 and 1,334 of all such hours (30.4 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $265.12.

Table 9-28 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: 2020

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	4,398	100.0%	4,386	100.0%
$1.00	3,634	82.6%	3,591	81.9%
$5.00	1,418	32.2%	1,334	30.4%
$10.00	567	12.9%	478	10.9%
$15.00	338	7.7%	242	5.5%
$20.00	227	5.2%	167	3.8%
$25.00	167	3.8%	113	2.6%
$50.00	49	1.1%	33	0.8%
$75.00	27	0.6%	13	0.3%
$100.00	15	0.3%	8	0.2%
$200.00	3	0.1%	2	0.0%
$300.00	1	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: 2020[38]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$19.38	$19.66	$18.77	$19.62
	ISO Price at PJM Border	$18.25	$21.06	$18.44	$21.40
	Difference at Border (PJM-ISO)	$1.13	($1.40)	$0.33	($1.78)
	Average Absolute Value of Interval Difference at Border	$26.23	$31.23	$2.25	$2.20
	Sign Changes per Day	36.6	45.4	3.2	2.6
Standard Deviation	PJM Price at ISO Border	$23.17	$21.32	$6.41	$6.80
	ISO Price at PJM Border	$18.44	$26.20	$7.03	$6.60
	Difference at Border (PJM-ISO)	$27.12	$31.89	$3.19	$2.86

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 70.0 percent of the hours in 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.

38 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): 2020

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	6,239	$12.42
	Consistent Flow (PJM to NYIS)	6,149	$12.35
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	90	$16.83
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	2,545	$6.38
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	2,534	$6.39
	No Flow	11	$5.08

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").[39] The PJM Out Service is covered by normal PJM OASIS business operations.[40] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

Neptune Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder does not elect to voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 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.

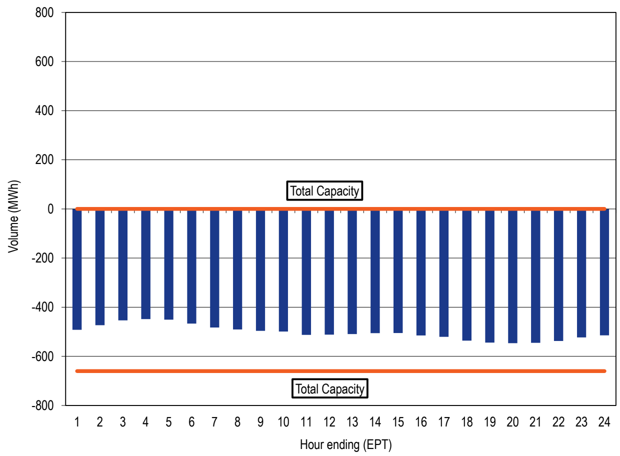
Table 9-31 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July 2007. Table 9-31 shows that in 2020, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-7 shows the hourly average flow across the Neptune Line for 2020.

Table 9-31 Percent of scheduled interchange across the Neptune Line by primary rights holder: July 2007 through December 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%	100.00%
November	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

39 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>.
40 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>.

Figure 9-7 Neptune hourly average flow: 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 61.4 percent of the hours in 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): 2020

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	5,505	$6.23
	Consistent Flow (PJM to NYIS)	5,397	$6.25
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	108	$4.94
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	3,279	$5.65
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	3,216	$5.64
	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").[41] The PJM Out Service is covered by normal PJM OASIS business operations.[42] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule 16-A of the PJM Tariff. The Linden VFT Service is also acquired on the PJM OASIS.

Linden VFT Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 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 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 2020.

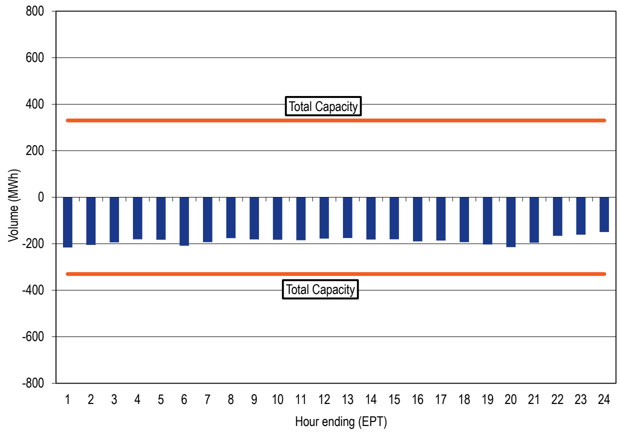
41 See OASIS "PJM Business Practices for Linden VFT Transmission Service," (June 1, 2011) <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/linden-vft-oasis-Business-practices-doc-clean.ashx>.

42 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>.

Table 9-33 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through December 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%	100.00%
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%	100.00%	100.00%	100.00%	100.00%
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 9-8 Linden hourly average flow: 2020[43]



Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) Line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (Con Ed) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC Line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC had only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of nonfirm withdrawal rights). The flows were consistent with price differentials in 58.5 percent of the hours in 2020. Table 9-34 shows the number of hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-34 PJM and NYISO flow based hours and price differences (Hudson): 2020

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	5,314	$6.29
	Consistent Flow (PJM to NYIS)	5,142	$6.15
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	172	$10.54
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	3,470	$6.17
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	3,422	$6.18
	No Flow	48	$5.33

43 The Linden VFT Line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie Line.

To move power from PJM to NYISO on the Hudson Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Hudson Line ("Out Service") and another transmission service reservation is required on the Hudson Line ("Hudson Service").[44] The PJM Out Service is covered by normal PJM OASIS business operations.[45] The Hudson Service falls under the provisions for controllable merchant facilities, Schedule 17 of the PJM Tariff. The Hudson Service is also acquired on the PJM OASIS.

Hudson Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by scheduled on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 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.

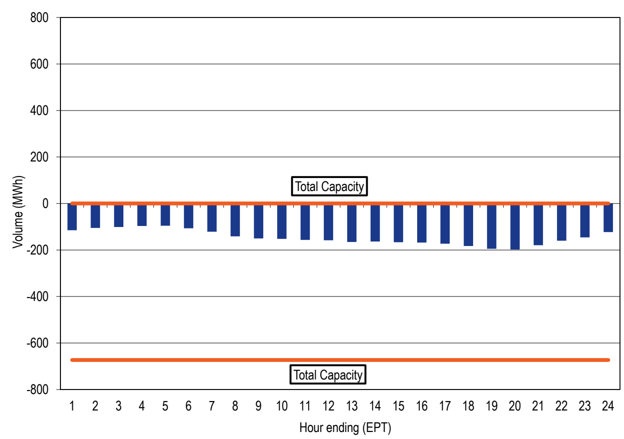
Table 9-35 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-35 shows that in 2020, the primary rights holder was responsible for less than 100 percent of the scheduled interchange across the Hudson Line in all months.[46]

Figure 9-9 shows the hourly average flow across the Hudson Line for 2020.

Table 9-35 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through December 2020[47]

	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%	52.58%
November	85.57%	99.60%	24.67%	100.00%	80.12%	50.44%	44.36%	38.60%
December	28.32%	1.68%	100.00%	NA	21.93%	29.38%	41.78%	38.82%

Figure 9-9 Hudson hourly average flow: 2020



Interchange Activity During High Load Hours

The PJM metered system peak load during 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

44 See OASIS "PJM Business Practices for Hudson Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-Business-practices.ashx>.

45 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>.

46 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.

47 The designation of "NA" means there was no flow on the Hudson Line during those months.

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 Exhange								
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 Reliablity Coordination Agreement Between PJM - Tennessee Valley Authority (TVA)
PJM-DEP = Duke Energy Progress (DEP) - PJM Joint Operating Agreement
PJM-VACAR = PJM-VACAR South Reliability Coordination Agreement
PJM-WEP = Balancing Authority Operations Coordination Agreement Between Wisconsin Electric Power Company and PJM Interconnection, LLC
Northeastern Protocol = Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol

PJM and MISO Joint Operating Agreement[48]

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.[49]

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.[50] On June 1, 2017, MISO modified their

48 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>.

49 See "PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common.aspx>.

50 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

MISO/PJM interface definition to match PJM's PJM/MISO interface definition.[51]

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.[52] 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.[53] 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 2020, PJM added 19 flowgates and deleted 17 flowgates, leaving 143 flowgates eligible for M2M coordination as of December 31, 2020. As of January 1, 2020, MISO had 186 flowgates eligible for M2M coordination. In 2020, MISO added 69 flowgates and deleted 108 flowgates, leaving 147 flowgates eligible for M2M coordination as of December 31, 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 16 years, topology and market changes have occurred, making the 2004 flows irrelevant in 2020. The RTOs and stakeholders recognize that a modification to the freeze date is necessary.[54] 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 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.

51 See "Joint and Common Market: MISO-PJM Interface Pricing Update," (November 15, 2016) <http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20161115/20161115-item-03a-interface-pricing-post-implementation.ashx>.

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 "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>.

54 See "*Freeze Date Alternatives*," (May 21, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20190521/20190521-item-01-freeze-date-update.ashx>.

Figure 9-10 PJM/MISO credits for coordinated congestion management: January 2019 through December 2020[55]

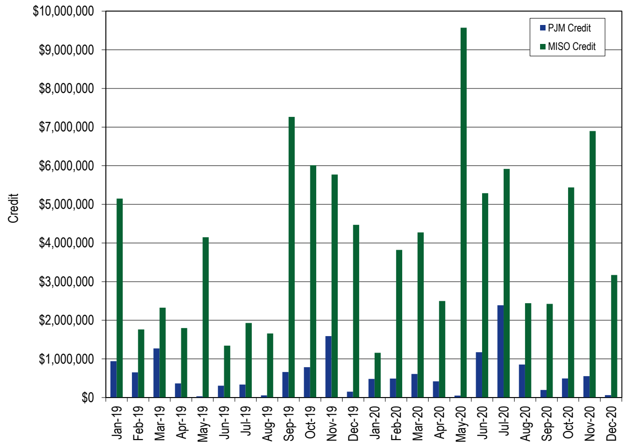
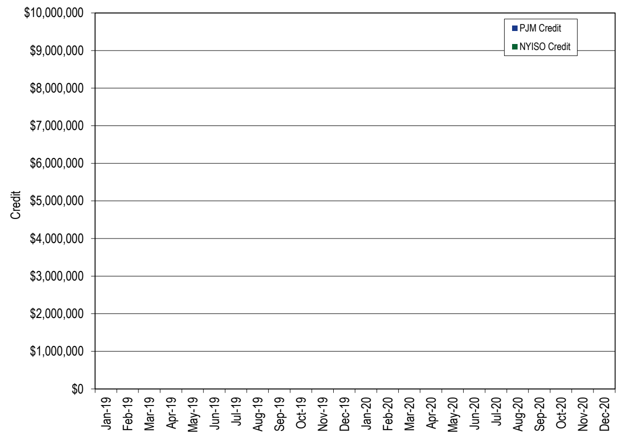


Figure 9-11 PJM/NYISO credits for coordinated congestion management (flowgates): January 2019 through December 2020[58]



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[56]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders.

On June 28, 2019, NYISO and PJM submitted revisions to the NYISO-PJM Joint Operating Agreement (JOA). The revisions would address RTO concerns identified in their joint request for limited waiver of the JOA to authorize redispatch of generation in PJM. The intent of the redispatch would be to mitigate post-contingency overloads of transmission equipment on the New York side of the East Towanda-Hillside 230 kV Transmission Line. The agreement allows for the RTOs to control for this contingency without the exchange of payments for redispatch.[57]

In 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 2020. Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

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.[59] 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

55 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

56 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

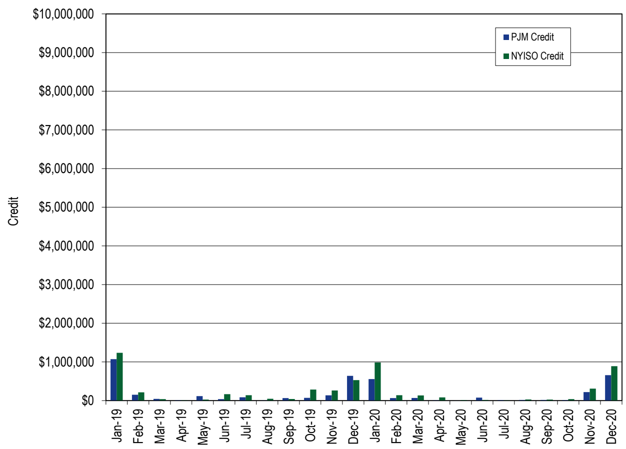
57 See NYISO Filing, FERC Docket No. ER19-2282-000 (June 28, 2019).

58 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

59 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

along the PJM/NYISO seam. Prior to May 1, 2017, only the Ramapo PARs were included in the M2M process. In 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.

Figure 9-12 PJM/NYISO credits for coordinated congestion management (PARs): January 2019 through December 2020[60]



PJM and TVA Joint Reliability Coordination Agreement (JRCA)[61]

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for the exchange of information and the implementation of reliability and efficiency protocols between TVA and PJM. The agreement also provides for the management of congestion and arrangements for both near-term and long-term system coordination. Under the JRCA, PJM and TVA honor constraints on the other's flowgates in their Available Transmission Capability (ATC) calculations. Market flows are calculated on reciprocal flowgates. When a constraint occurs on a reciprocal flowgate within TVA, PJM has the option to redispatch generation to reduce market flow, and therefore alleviate the constraint. Unlike the M2M procedure between MISO and PJM, this redispatch does not result in M2M payments. However, electing to redispatch generation within PJM can avoid potential market disruption by curtailing transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. The agreement remained in effect in 2020.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[62]

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.[63] 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.[64] 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.[65]

PJM and VACAR South Reliability Coordination Agreement[66]

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), DEP, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement which provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet

60 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

61 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority," (October 15, 2014) <http://www.pjm.com/~/media/documents/agreements/joint-reliability-coordination-agreement-miso-pjm-tva.ashx>.

62 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc.," (July 22, 2019) <http://www.pjm.com/directory/merged-tariffs/progress-joa.pdf>.

63 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

64 See *PJM Interconnection, L.L.C*, Docket No. ER19-1905-000 (May 20, 2019).

65 FERC Docket No. ER19-1905-000 (July 2, 2019).

66 See "PJM-VACAR South RC Agreement," (November 7, 2014) <http://www.pjm.com/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>.

on a yearly basis. The agreement remained in effect in 2020.

VACAR Reserve Sharing Agreement

The VACAR Reserve Sharing Agreement (VRSA) is a combination of agreements among the entities in the VACAR Subregion including Dominion.[67] VACAR is a subregion of the SERC Reliability Corporation (SERC) region. The agreement remained in effect in 2020. 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).[68] Dominion is the only party to the VRSA that is also a transmission owner and a generation owner in PJM. The VRSA is not a public agreement. PJM is not a party to the VRSA. However, as the reliability coordinator for Dominion Virginia Power, PJM is responsible for scheduling Dominion's required reserves in the SERC region as described in the PJM manuals.[69]

There are issues with the VRSA. The details of the VRSA, including any responsibilities assigned to PJM, are not public. Under PJM's Operating Reserve Demand Curve (ORDC) method of procuring reserves, expected to be implemented on May 1, 2022, it will not be possible for Dominion to meet both the VRSA and the PJM reserve rules.[70]

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[71]

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 2020.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[72]

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 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 NCMPA interface pricing points for 2020.[73] The values shown in Table 9-37 are the average LMP over only the hours in 2020 where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from -$0.35 with NCMPA 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 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 NCMPA. 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 PJM than they would have if they were to pay the SouthEXP pricing point. In 2020, market participants paid $5,667 more for exporting energy

67 VRSA entities: Dominion, Duke Energy Progress, Duke Energy Carolinas, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas.

68 *See* SERC Regional Criteria, Contingency Reserve Policy, NERC Reliability Standard BAL-002 at 10-11.

69 See PJM. "Manual 13: Emergency Operations," Rev. 77 (Jan. 1, 2021).

70 See the *2020 State of the Market Report for PJM*, Section 10: Ancillary Services, "VACAR Reserve Sharing Agreement" for more information on issues identified with the VACAR Reserve Sharing Agreement.

71 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, L.L.C.," (July 20, 2013) <http://www.pjm.com/~/media/documents/agreements/balancing-authority-operations-coordination-agreement.ashx>.

72 See "Northeastern ISO/RTO Planning Coordination Protocol," (December 8, 2004) <http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>.

73 On June 1, 2020, PJM retired the DUKE and PEC interface pricing points. On November 3, 2020, PJM retired the NCMPA interface pricing point.

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: 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	$18.61	$19.65	$18.97	$18.62	($0.35)	$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 2020.[74] The values shown in Table 9-38 are the average LMP over only the hours in 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 -$0.24 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 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 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.

Table 9-38 Day-ahead LMP comparison for DUKE, PEC and NCMPA: 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	$18.02	$34.49	$18.26	$33.45	($0.24)	$1.04

The MMU recommended 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. External entities wishing to receive the benefits of the PJM LMP market should join PJM. On November 3, 2020, PJM retired the NCMPAIMP and NCMPAEXP interface pricing points.

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

The number of PJM issued TLRs of level 3a or higher was two in 2019 and two in 2020.[75] The number of different flowgates for which PJM declared a TLR 3a or higher was one in 2019 and two in 2020. The total MWh of transactions curtailed increased by 19.4 percent from 1,499 MWh in 2019 to 1,789 MWh in 2020.

The number of MISO issued TLRs of level 3a or higher increased from 60 in 2019 to 93 in 2020. The number of different flowgates for which MISO declared a TLR 3a decreased from 25 in 2019 to 17 in 2020. The total MWh of transaction curtailments increased by 33.4 percent from 43,858 MWh in 2019 to 58,520 MWh in 2020.

The number of NYISO issued TLRs of level 3a or higher decreased from nine in 2019 to two in 2020. The number of different flowgates for which NYISO declared a TLR 3a or higher was four in 2019 and one in 2020. The total MWh of transaction curtailments decreased by 94.9 percent from 20,389 MWh in 2019 to 1,030 MWh in 2020.

74 On June 1, 2020, PJM retired the DUKE and PEC interface pricing points. On November 3, 2020, PJM retired the NCMPA interface pricing point.

75 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.

Table 9-39 PJM, MISO, and NYISO TLR procedures: 2020[76]

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-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
Oct-20	0	8	0	0	4	0	0	1,813	0
Nov-20	0	0	0	0	0	0	0	0	0
Dec-20	1	2	0	1	1	0	320	1,349	0
Total	2	93	2	2	17	1	1,789	58,520	1,030

Table 9-40 Number of TLRs by TLR level by reliability coordinator: 2020[77]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2020	MISO	39	19	0	13	22	0	93
	NYIS	2	0	0	0	0	0	2
	ONT	36	2	0	0	0	0	38
	PJM	2	0	0	0	0	0	2
	SOCO	2	2	0	0	0	0	4
	SWPP	7	8	0	20	20	0	55
	TVA	11	13	0	16	20	0	60
	VACS	2	5	0	0	0	0	7
Total		101	49	0	49	62	0	261

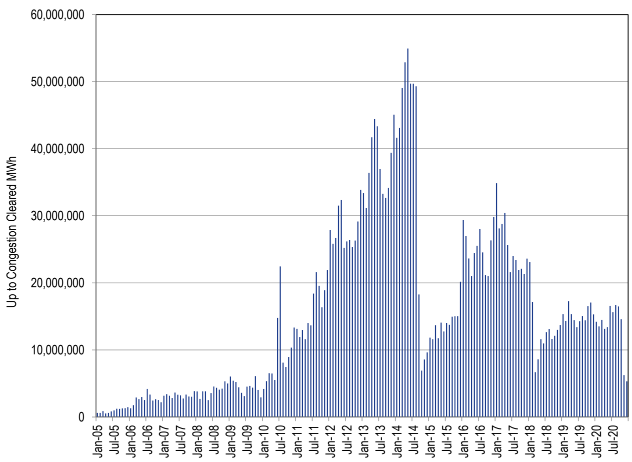
Up To Congestion

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.[78]

Up to congestion transactions affect the day-ahead dispatch and unit commitment. Despite that, up to congestion transactions were not required to pay uplift charges from their introduction in 2010 through October 31, 2020. On July 16, 2020, FERC issued an Order directing PJM to revise uplift allocation rules to allocate uplift to one side of up to congestion transactions.[79] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. Up to congestion transactions also negatively affect FTR funding.[80]

Up to congestion transaction volumes decreased following the allocation of uplift charges on November 1, 2020. The average number of up to congestion bids submitted in the day-ahead energy market decreased by 6.6 percent, from 52,046 bids per day in 2019 to 48,618 bids per day in 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 12.5 percent, from 500,819 MWh per day in 2019, to 438,170 MWh per day in 2020.

Figure 9-13 Monthly up to congestion cleared bids in MWh: January 2005 through December 2020



76 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.

77 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.

78 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

79 172 FERC ¶ 61,046 (2020).

80 See the *2020 State of the Market Report for PJM*, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

Table 9-41 Monthly volume of cleared and submitted up to congestion bids: January 2019 through December 2020

	Bid MW					Bid Volume				
Month	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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
Oct-20	3,329,528	3,582,220	1,038,616	33,641,971	41,592,335	116,339	118,061	36,445	1,185,280	1,456,125
Nov-20	1,930,357	707,420	554,083	12,050,981	15,242,840	57,036	33,287	13,729	654,986	759,038
Dec-20	1,719,227	1,017,140	131,755	10,500,435	13,368,557	59,542	57,003	8,237	576,292	701,074
Total	163,690,512	95,042,337	60,291,393	649,918,250	968,942,492	6,086,164	3,270,509	1,508,473	25,925,617	36,790,763

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-19	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	2,759,958	1,311,305	545,808	11,870,827	16,487,899	112,007	54,772	24,409	626,387	817,575
Oct-20	1,170,266	1,614,110	333,422	11,454,599	14,572,397	58,869	58,982	17,031	559,349	694,231
Nov-20	473,510	372,486	207,826	5,194,734	6,248,556	25,978	20,300	6,857	363,785	416,920
Dec-20	414,395	595,040	74,661	4,240,307	5,324,402	27,215	36,578	4,791	322,872	391,456
Total	63,136,009	36,465,003	18,025,246	225,542,944	343,169,203	2,801,359	1,735,459	648,978	13,059,196	18,244,992

In 2020, the cleared MW volume of up to congestion transactions was comprised of 16.5 percent imports, 8.9 percent exports, 4.3 percent wheeling transactions and 70.3 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.[81] 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 101.0 percent, from net profits of $15.5 million in 2014, to a net loss of $149,893 in 2020. 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 96.6 percent, from 1,898 hours in 2014 to 64 hours in 2020.

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling.

Elimination of Ontario Interface Pricing Point

The PJM/IMO interface pricing point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO interface pricing points. PJM created the PJM/IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

Prior to June 1, 2015, the PJM/IMO interface pricing point was defined as the LMP at the IESO Bruce bus. The LMP at the Bruce bus includes a congestion and

81 *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>.

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.[82] For example, a market participant can use two separate transactions to create a flow from Ontario to MISO. In this example, the market participant uses the PJM energy market as a temporary generation and load point by first submitting a wheeling transaction from Ontario, through MISO and into PJM, then by submitting a second transaction from PJM to MISO. These two transactions, combined, create an actual flow along the Ontario/MISO Interface. Through sham scheduling, the market participant receives settlements from PJM when no changes in generation occur. This activity is similar to that observed when PJM had a Southwest and Southeast interface pricing point. During that time, market participants would use the PJM spot market as a temporary load and generation point to wheel transactions through the PJM energy market. This was done to take advantage of the price differences between the interfaces without providing the market benefits of congestion relief.

A new PJM/IMO interface price method was implemented on June 1, 2015. The new method uses a dynamic weighting of the PJM/MISO interface price and the PJM/NYIS interface price, based on the performance of the Michigan-Ontario PARs. When the absolute value of the actual flows on the PARs are greater than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be equal to the PJM/MISO interface price (i.e. 100 percent weighting on the PJM/MISO Interface). When actual flows on the PARs are in the opposite direction of the scheduled flows on the PARs, the PJM/IMO interface price will be equal to the PJM/NYIS interface price (i.e. 100 percent weighting on the PJM/NYIS Interface). When the absolute value of the actual flows on the PARs are less than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be a combination to the PJM/MISO interface price and the PJM/NYIS interface price. In this case the weightings of the PJM/MISO and PJM/NYIS interface prices are determined based on the scheduled and actual flows. For example, in a given interval, the scheduled flow on the Michigan-Ontario PARs is 1,000 MW, and the actual flow is 800 MW. If in that same interval, the PJM/MISO interface price is $45.00 and the PJM/NYIS interface price $30.00, the PJM/IMO interface price would be calculated with a weighting of 80 percent of the PJM/MISO interface price ($45.00 * 0.8, or $36.00) and 20 percent of the PJM/NYIS interface price ($30.00 * 0.2, or $6.00), for a PJM/IMO interface price of $42.00.[83]

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 2020, of the 207 GWh of gross scheduled transactions between PJM and IESO, 205 GWh (99.0 percent) wheeled through MISO (Table 9-24). The MMU recommends that PJM eliminate the PJM/IMO interface pricing point, and

82 *See* "Sham Scheduling," Presented at the PJM Market Monitoring Unit Advisory Committee (MMUAC) meeting held on December 6, 2013 <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_Sham_Scheduling_20131206.pdf>.

83 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>.

assign the transactions that originate or sink in the IESO balancing authority to the PJM/MISO interface pricing point.[84]

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.[85] 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 2020. Table 9-42 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 47.2 percent of the intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $1.53 per MWh. In 4.4 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 $66.30 when the price difference was greater than $20.00, and $77.37 when the price difference was greater than -$20.00.

Table 9-42 Differences between forecast and actual PJM/NYIS interface prices: 2020

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	2.6%	$66.30
$10 to $20	3.4%	$13.88
$5 to $10	6.3%	$6.99
$0 to $5	47.2%	$1.53
$0 to -$5	35.2%	$1.28
-$5 to -$10	2.3%	$6.83
-$10 to -$20	1.2%	$14.17
< -$20	1.8%	$77.37

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 85.2 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 77.3 percent in the 135 minute ahead IT SCED results.

Table 9-43 Differences between forecast and actual PJM/NYIS interface prices: 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	3.6%	$86.35	3.6%	$86.07	1.2%	$56.68	1.1%	$45.53
$10 to $20	5.2%	$13.97	5.2%	$13.89	2.1%	$13.50	2.3%	$13.70
$5 to $10	8.8%	$7.01	8.6%	$7.02	5.2%	$6.90	5.2%	$6.89
$0 to $5	46.5%	$1.78	47.1%	$1.77	45.5%	$1.52	45.7%	$1.50
$0 to -$5	30.8%	$1.42	30.4%	$1.41	39.6%	$1.39	39.5%	$1.38
-$5 to -$10	2.3%	$6.78	2.2%	$6.84	3.1%	$6.83	3.0%	$6.84
-$10 to -$20	1.1%	$14.01	1.1%	$13.99	1.4%	$14.04	1.4%	$14.02
< -$20	1.8%	$74.83	1.7%	$82.67	2.0%	$74.57	2.1%	$81.57

84 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.
85 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

In 3.2 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price difference was $45.53 when the price difference was greater than $20.00, and $81.57 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): 2020

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	0.6%	0.0%	0.0%	0.1%	0.1%	0.7%	3.8%	2.0%	0.2%	0.5%	1.3%	3.2%	1.1%
	$10 to $20	1.1%	0.4%	0.0%	0.3%	0.9%	1.2%	4.6%	3.5%	1.3%	3.7%	3.3%	4.8%	2.3%
	$5 to $10	3.4%	1.7%	0.8%	2.1%	3.1%	4.3%	10.8%	7.2%	4.4%	10.0%	6.8%	7.4%	5.2%
	$0 to $5	42.3%	52.3%	47.6%	52.3%	43.8%	47.5%	46.7%	43.1%	49.4%	43.3%	41.5%	39.5%	45.7%
	$0 to -$5	44.4%	42.7%	47.7%	41.4%	45.2%	40.3%	27.7%	37.3%	38.7%	33.7%	40.4%	34.5%	39.5%
	-$5 to -$10	3.7%	1.3%	2.2%	1.8%	4.1%	2.5%	2.1%	2.4%	2.9%	4.1%	4.0%	4.7%	3.0%
	-$10 to -$20	2.4%	0.8%	0.8%	1.1%	1.5%	1.4%	1.2%	1.7%	1.2%	1.6%	1.1%	1.9%	1.4%
	< -$20	2.1%	0.9%	1.0%	0.9%	1.3%	2.0%	3.0%	2.7%	2.0%	3.2%	1.6%	4.0%	2.1%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	0.6%	0.1%	0.0%	0.1%	0.2%	0.6%	3.9%	2.0%	0.0%	0.4%	1.4%	3.9%	1.2%
	$10 to $20	1.3%	0.4%	0.0%	0.2%	0.8%	1.1%	4.5%	3.5%	1.5%	3.3%	3.2%	4.7%	2.1%
	$5 to $10	3.4%	1.5%	0.7%	2.3%	2.8%	4.0%	10.9%	7.0%	4.5%	10.4%	6.9%	7.4%	5.2%
	$0 to $5	42.7%	51.8%	48.0%	52.0%	43.5%	47.5%	46.0%	43.5%	49.0%	43.3%	41.0%	38.4%	45.5%
	$0 to -$5	43.8%	43.0%	47.4%	41.5%	45.6%	40.5%	28.2%	37.1%	38.8%	33.6%	40.5%	34.8%	39.6%
	-$5 to -$10	3.7%	1.5%	2.0%	1.9%	4.3%	2.6%	2.3%	2.8%	2.8%	4.1%	4.4%	4.9%	3.1%
	-$10 to -$20	2.4%	0.8%	0.9%	1.0%	1.5%	1.5%	1.2%	1.6%	1.3%	1.7%	1.2%	1.9%	1.4%
	< -$20	2.1%	0.9%	1.0%	1.0%	1.3%	2.1%	3.0%	2.6%	2.0%	3.2%	1.5%	3.8%	2.0%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	0.8%	0.4%	0.0%	0.1%	0.6%	1.1%	5.7%	4.1%	4.5%	3.7%	5.0%	16.3%	3.6%
	$10 to $20	2.7%	0.9%	0.6%	0.4%	2.0%	4.1%	11.4%	7.7%	8.7%	12.1%	5.3%	6.7%	5.2%
	$5 to $10	5.9%	3.2%	2.4%	3.0%	7.3%	8.7%	11.7%	10.1%	15.3%	15.6%	10.4%	9.4%	8.6%
	$0 to $5	47.4%	63.2%	57.6%	51.3%	48.8%	46.5%	39.3%	43.8%	47.2%	40.6%	43.5%	37.2%	47.1%
	$0 to -$5	36.7%	29.9%	36.1%	41.2%	35.4%	33.7%	26.3%	29.5%	20.4%	22.0%	30.0%	23.9%	30.4%
	-$5 to -$10	2.8%	0.9%	1.4%	2.1%	3.4%	2.6%	1.6%	1.7%	1.5%	2.1%	3.2%	3.1%	2.2%
	-$10 to -$20	1.6%	0.8%	0.8%	1.0%	1.4%	1.3%	1.2%	1.2%	0.7%	1.2%	1.0%	1.0%	1.1%
	< -$20	1.8%	0.8%	1.0%	1.0%	1.1%	2.0%	2.8%	2.1%	1.7%	2.7%	1.5%	2.5%	1.7%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	0.9%	0.5%	0.1%	0.0%	0.7%	1.0%	5.6%	4.1%	4.3%	4.0%	5.2%	16.2%	3.6%
	$10 to $20	2.4%	0.7%	0.6%	0.5%	1.9%	4.3%	11.5%	7.6%	8.7%	12.0%	5.2%	6.6%	5.2%
	$5 to $10	6.4%	3.4%	2.5%	3.1%	7.3%	8.7%	11.4%	10.6%	15.9%	15.6%	10.3%	10.0%	8.8%
	$0 to $5	46.9%	62.0%	57.3%	50.7%	48.7%	46.0%	38.7%	43.1%	46.0%	40.0%	43.1%	36.5%	46.5%
	$0 to -$5	37.1%	30.9%	35.9%	41.6%	35.3%	34.1%	27.0%	29.5%	21.0%	22.6%	30.3%	23.9%	30.8%
	-$5 to -$10	2.9%	0.9%	1.9%	2.0%	3.7%	2.5%	1.7%	1.7%	1.6%	2.1%	3.3%	3.1%	2.3%
	-$10 to -$20	1.7%	0.8%	0.8%	0.9%	1.3%	1.4%	1.3%	1.1%	0.8%	1.0%	1.1%	1.3%	1.1%
	< -$20	1.8%	0.8%	0.9%	1.1%	1.1%	2.0%	2.8%	2.3%	1.7%	2.7%	1.5%	2.4%	1.8%

Table 9-45 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): 2020

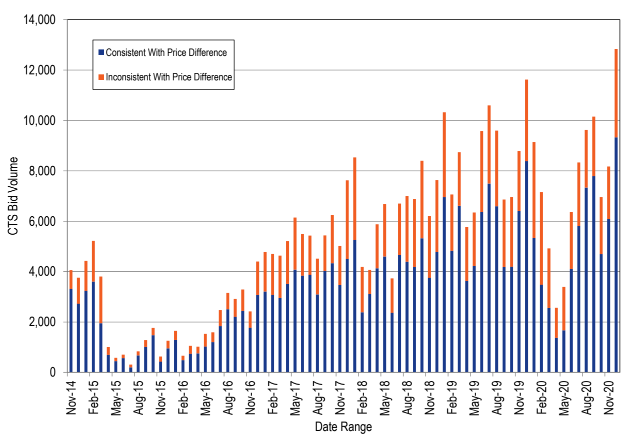
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$52.02	$23.29	$0.00	$25.08	$28.86	$34.36	$41.98	$46.10	$29.24	$26.78	$27.51	$62.32	$45.53
	$10 to $20	$14.05	$13.78	$0.00	$13.60	$13.50	$13.81	$13.48	$13.75	$13.12	$12.88	$14.48	$14.05	$13.70
	$5 to $10	$6.92	$6.57	$6.55	$6.45	$6.63	$6.84	$6.92	$6.95	$6.75	$6.93	$6.88	$7.15	$6.89
	$0 to $5	$1.40	$1.18	$1.23	$1.43	$1.51	$1.52	$1.68	$1.55	$1.51	$1.89	$1.56	$1.59	$1.50
	$0 to -$5	$1.36	$1.18	$1.28	$1.31	$1.54	$1.36	$1.22	$1.31	$1.44	$1.58	$1.46	$1.47	$1.38
	-$5 to -$10	$6.86	$6.88	$6.52	$6.90	$6.80	$7.13	$7.06	$6.72	$6.79	$6.90	$6.73	$6.89	$6.84
	-$10 to -$20	$13.86	$14.73	$15.76	$14.56	$14.04	$14.62	$13.87	$13.96	$13.68	$13.77	$13.25	$13.49	$14.02
	< -$20	$56.21	$51.33	$56.70	$53.77	$45.91	$53.45	$56.78	$47.40	$77.51	$156.12	$133.03	$102.62	$81.57
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$51.50	$22.47	$0.00	$24.44	$26.74	$32.52	$42.62	$50.81	$40.51	$23.42	$27.07	$93.81	$56.68
	$10 to $20	$13.53	$14.34	$10.56	$13.93	$13.59	$13.10	$13.57	$13.58	$13.16	$13.02	$14.33	$13.29	$13.50
	$5 to $10	$6.89	$6.28	$6.78	$6.57	$6.79	$6.79	$6.97	$6.99	$6.77	$7.02	$6.86	$6.99	$6.90
	$0 to $5	$1.38	$1.21	$1.24	$1.46	$1.53	$1.58	$1.72	$1.58	$1.53	$1.91	$1.60	$1.55	$1.52
	$0 to -$5	$1.39	$1.17	$1.32	$1.32	$1.53	$1.38	$1.23	$1.34	$1.48	$1.62	$1.46	$1.51	$1.39
	-$5 to -$10	$6.90	$6.67	$6.53	$6.79	$6.75	$7.00	$7.22	$6.69	$6.95	$6.85	$6.61	$6.96	$6.83
	-$10 to -$20	$14.15	$14.86	$14.95	$14.30	$13.83	$14.58	$14.11	$14.30	$13.66	$13.75	$13.68	$13.33	$14.04
	< -$20	$55.29	$51.28	$56.61	$51.75	$44.60	$52.69	$54.81	$48.21	$78.52	$102.45	$141.98	$105.34	$74.57
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$46.45	$31.41	$23.02	$23.81	$25.45	$36.01	$40.96	$56.63	$60.85	$38.11	$50.89	$146.24	$86.07
	$10 to $20	$13.71	$14.02	$14.64	$13.40	$13.86	$13.09	$13.79	$14.00	$13.87	$14.13	$13.76	$14.13	$13.89
	$5 to $10	$6.82	$6.38	$6.22	$6.86	$6.64	$6.90	$7.11	$7.07	$7.09	$7.28	$7.13	$7.24	$7.02
	$0 to $5	$1.61	$1.48	$1.59	$1.65	$1.95	$1.83	$1.69	$1.84	$2.16	$2.03	$1.75	$1.81	$1.77
	$0 to -$5	$1.31	$1.12	$1.24	$1.41	$1.60	$1.45	$1.27	$1.43	$1.47	$1.65	$1.50	$1.52	$1.41
	-$5 to -$10	$6.84	$6.65	$6.48	$6.83	$6.73	$6.92	$7.35	$7.10	$6.94	$6.77	$6.79	$6.80	$6.84
	-$10 to -$20	$13.88	$14.55	$13.78	$13.92	$13.77	$14.23	$14.52	$14.74	$13.39	$14.16	$14.07	$12.61	$13.99
	< -$20	$58.54	$52.76	$55.48	$51.37	$46.82	$52.52	$54.67	$48.99	$79.12	$109.48	$258.96	$102.74	$82.67
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$44.17	$29.91	$22.78	$28.32	$29.48	$35.06	$42.20	$56.71	$61.91	$37.34	$51.81	$147.91	$86.35
	$10 to $20	$13.70	$13.82	$14.09	$14.58	$13.75	$13.16	$14.02	$14.19	$14.02	$14.18	$13.96	$13.87	$13.97
	$5 to $10	$6.80	$6.46	$6.28	$6.80	$6.57	$6.90	$7.21	$7.08	$7.07	$7.23	$7.07	$7.19	$7.01
	$0 to $5	$1.62	$1.49	$1.61	$1.66	$1.96	$1.85	$1.69	$1.83	$2.18	$2.02	$1.81	$1.78	$1.78
	$0 to -$5	$1.32	$1.10	$1.23	$1.42	$1.61	$1.50	$1.26	$1.48	$1.47	$1.70	$1.48	$1.55	$1.42
	-$5 to -$10	$6.72	$6.53	$6.53	$6.79	$6.73	$6.92	$7.22	$6.95	$7.03	$6.99	$6.57	$6.64	$6.78
	-$10 to -$20	$14.09	$14.19	$13.93	$13.79	$13.78	$14.18	$14.76	$14.41	$13.51	$14.61	$13.76	$13.03	$14.01
	< -$20	$59.21	$52.72	$56.62	$49.44	$47.23	$52.26	$56.26	$47.10	$78.70	$108.54	$140.65	$111.75	$74.83

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 December 31, 2020, 388,733 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 125,888 (32.4 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 32.4 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 67.6 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 December 31, 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 +/- 1,000 MW. For example, the ramp in a given interval is currently -1,000 MW, consisting of 2,000 MW of imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. If, through the NYISO real-time market clearing process, the NYISO only approves 1,000 MW of the imports, the other 1,000 MW of import transactions from the NYISO would be curtailed. The ramp in this interval would then be -2,000 MW, consisting of the 1,000 MW of cleared imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. PJM would then be required to curtail an additional 1,000 MW of exports at its other interface to bring the limit back to within +/- 1,000. These curtailments were made on a last in first out basis as determined by the timestamp on the NERC Tag.

With the implementation of the CTS product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, does PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process would violate ramp, PJM would make additional adjustments based on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO interface from holding (or creating) ramp until NYISO has completed its economic evaluation and the transactions are approved through the NYISO market clearing process.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO proposed the implementation of coordinated interchange transactions, similar to the

PJM/NYISO approach, through the Joint and Common Market Initiative. The PJM/MISO coordinated transaction scheduling (CTS) process provides the option for market participants to submit intra-hour transactions between the MISO and PJM that include an interface spread bid on which transactions are evaluated. Similar to the PJM/NYISO approach, the evaluation is based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED). Unlike the PJM/NYISO CTS process in which the NYISO performs the evaluation, the PJM/MISO CTS process uses a joint clearing process in which both RTOs share forward looking prices. On October 3, 2017, PJM and MISO implemented the CTS process.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/MISO interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for 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 45.0 percent of all intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $1.66. In 5.1 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 $47.66 when the price difference was greater than $20.00, and $70.94 when the price difference was greater than -$20.00.

Table 9-46 Differences between forecast and actual PJM/MISO interface prices: 2020

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	2.8%	$47.66
$10 to $20	4.2%	$13.78
$5 to $10	7.8%	$7.01
$0 to $5	45.0%	$1.66
$0 to -$5	33.4%	$1.37
-$5 to -$10	2.9%	$6.89
-$10 to -$20	1.5%	$14.23
< -$20	2.3%	$70.94

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 80.6 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 75.4 percent in the 135 minute ahead IT SCED results.

Table 9-47 Differences between forecast and actual PJM/MISO interface prices: 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	2.8%	$34.92	2.7%	$34.63	1.7%	$38.41	1.5%	$38.54
$10 to $20	5.7%	$13.85	5.6%	$13.93	3.1%	$13.62	3.1%	$13.61
$5 to $10	8.7%	$7.01	8.5%	$7.05	7.6%	$6.94	7.5%	$7.00
$0 to $5	42.4%	$1.77	43.0%	$1.77	44.1%	$1.68	44.7%	$1.67
$0 to -$5	33.0%	$1.54	32.8%	$1.52	36.4%	$1.44	36.0%	$1.43
-$5 to -$10	3.5%	$6.86	3.4%	$6.90	3.2%	$6.87	3.2%	$6.85
-$10 to -$20	1.7%	$13.92	1.6%	$13.90	1.6%	$14.33	1.6%	$14.23
< -$20	2.3%	$69.38	2.3%	$74.63	2.4%	$68.51	2.4%	$73.70

In 3.9 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price differences were $38.54 when the price difference was greater than $20.00, and $73.70 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): 2020

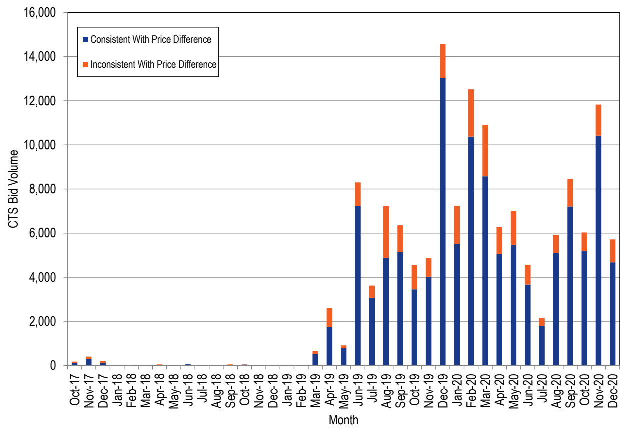
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	0.4%	0.0%	0.0%	0.5%	1.2%	1.3%	6.0%	2.8%	0.9%	1.7%	1.4%	1.6%	1.5%
	$10 to $20	1.8%	0.4%	0.6%	1.4%	2.5%	2.0%	5.3%	5.0%	2.3%	5.9%	4.1%	5.1%	3.1%
	$5 to $10	4.3%	1.9%	2.8%	5.3%	9.4%	6.9%	10.4%	8.3%	6.7%	15.4%	9.8%	8.7%	7.5%
	$0 to $5	44.2%	54.5%	47.6%	46.5%	38.3%	43.7%	46.0%	42.9%	47.2%	42.2%	40.6%	42.9%	44.7%
	$0 to -$5	44.0%	39.9%	43.1%	40.0%	37.2%	38.0%	25.7%	32.3%	35.3%	25.6%	36.0%	34.9%	36.0%
	-$5 to -$10	2.4%	1.1%	3.0%	3.2%	6.6%	3.1%	1.8%	2.8%	3.3%	3.4%	4.9%	2.9%	3.2%
	-$10 to -$20	1.1%	1.3%	1.4%	1.7%	2.5%	1.9%	1.6%	2.0%	1.9%	1.1%	1.5%	1.6%	1.6%
	< -$20	1.8%	0.9%	1.3%	1.4%	2.3%	3.1%	3.3%	4.0%	2.3%	4.7%	1.6%	2.3%	2.4%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	0.3%	0.0%	0.0%	0.4%	1.2%	1.4%	5.9%	2.8%	0.9%	1.7%	1.4%	2.2%	1.7%
	$10 to $20	1.7%	0.6%	0.7%	1.6%	2.8%	1.7%	5.6%	5.3%	2.1%	5.9%	4.1%	5.0%	3.1%
	$5 to $10	4.7%	1.6%	2.8%	4.9%	9.0%	6.8%	10.8%	8.0%	7.1%	16.0%	10.3%	8.6%	7.6%
	$0 to $5	43.8%	53.6%	48.1%	46.0%	37.8%	43.1%	44.6%	42.5%	46.3%	41.2%	39.9%	42.8%	44.1%
	$0 to -$5	44.2%	40.9%	42.8%	40.5%	37.7%	38.9%	26.5%	33.1%	36.1%	25.9%	36.6%	34.5%	36.4%
	-$5 to -$10	2.1%	1.1%	2.9%	3.7%	6.5%	3.1%	1.9%	2.3%	3.2%	3.5%	5.0%	3.2%	3.2%
	-$10 to -$20	1.4%	1.1%	1.3%	1.5%	2.7%	2.0%	1.5%	1.8%	2.0%	1.1%	1.2%	1.6%	1.6%
	< -$20	1.7%	1.0%	1.3%	1.5%	2.3%	3.1%	3.3%	4.1%	2.3%	4.8%	1.5%	2.1%	2.4%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	0.9%	0.1%	0.0%	0.3%	1.4%	2.0%	7.6%	4.9%	1.7%	2.5%	3.2%	7.2%	2.7%
	$10 to $20	3.5%	1.0%	1.2%	1.8%	3.5%	4.9%	11.4%	8.9%	5.4%	12.4%	6.2%	6.8%	5.6%
	$5 to $10	5.0%	2.8%	4.4%	5.6%	11.2%	8.4%	8.3%	7.9%	8.6%	17.0%	12.4%	10.5%	8.5%
	$0 to $5	45.9%	60.5%	51.1%	45.7%	37.6%	41.9%	39.3%	36.7%	45.6%	35.5%	38.1%	39.1%	43.0%
	$0 to -$5	39.4%	32.5%	37.3%	38.4%	34.7%	35.0%	27.0%	33.4%	30.4%	23.6%	31.6%	30.3%	32.8%
	-$5 to -$10	2.4%	1.0%	3.3%	4.8%	6.8%	2.8%	2.1%	2.6%	4.0%	3.2%	5.3%	2.9%	3.4%
	-$10 to -$20	1.3%	1.1%	1.3%	1.8%	2.5%	1.9%	1.4%	2.1%	1.8%	1.3%	1.7%	1.5%	1.6%
	< -$20	1.6%	0.9%	1.3%	1.5%	2.3%	3.1%	3.0%	3.6%	2.6%	4.4%	1.6%	1.8%	2.3%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	0.9%	0.1%	0.1%	0.3%	1.4%	2.2%	8.2%	4.8%	1.7%	2.1%	3.6%	7.4%	2.8%
	$10 to $20	3.4%	1.1%	1.3%	1.7%	3.9%	5.0%	10.6%	9.1%	5.5%	13.3%	5.9%	7.1%	5.7%
	$5 to $10	5.2%	3.0%	4.7%	5.6%	11.3%	8.3%	8.8%	8.5%	9.3%	16.5%	13.0%	9.6%	8.7%
	$0 to $5	45.7%	59.8%	50.6%	45.0%	37.8%	41.7%	38.0%	35.4%	44.3%	35.0%	37.4%	39.2%	42.4%
	$0 to -$5	39.3%	32.8%	37.8%	39.0%	33.7%	35.1%	28.0%	33.9%	30.9%	23.8%	31.3%	30.2%	33.0%
	-$5 to -$10	2.4%	1.1%	3.0%	4.9%	7.2%	2.8%	1.9%	2.5%	4.2%	3.5%	5.4%	3.2%	3.5%
	-$10 to -$20	1.3%	1.1%	1.3%	1.8%	2.7%	1.8%	1.5%	2.2%	1.7%	1.3%	1.8%	1.5%	1.7%
	< -$20	1.6%	0.9%	1.3%	1.6%	2.2%	3.1%	2.9%	3.7%	2.5%	4.4%	1.6%	1.8%	2.3%

Table 9-49 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): 2020

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$24.92	$30.34	$24.25	$32.19	$28.56	$40.75	$46.84	$39.16	$37.64	$28.30	$26.68	$38.99	$38.54
	$10 to $20	$13.55	$12.50	$13.84	$13.05	$12.91	$13.72	$14.15	$13.48	$13.64	$13.53	$13.69	$13.76	$13.61
	$5 to $10	$7.08	$6.74	$6.66	$6.76	$6.91	$6.78	$7.05	$7.35	$6.74	$7.20	$7.02	$6.97	$7.00
	$0 to $5	$1.36	$1.23	$1.52	$1.65	$1.87	$1.55	$1.72	$1.75	$1.73	$2.19	$1.85	$1.70	$1.67
	$0 to -$5	$1.26	$1.11	$1.39	$1.55	$1.69	$1.36	$1.14	$1.42	$1.44	$1.75	$1.61	$1.53	$1.43
	-$5 to -$10	$7.18	$6.87	$6.53	$6.73	$7.07	$6.88	$6.85	$7.09	$6.93	$6.60	$6.63	$6.91	$6.85
	-$10 to -$20	$14.08	$14.77	$15.01	$14.56	$14.06	$13.88	$13.95	$15.07	$14.39	$14.41	$13.11	$13.56	$14.23
	< -$20	$70.03	$54.84	$61.61	$49.47	$52.87	$62.45	$58.94	$57.91	$65.44	$112.09	$134.23	$77.39	$73.70
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$23.65	$30.28	$0.00	$33.96	$31.88	$36.01	$46.15	$39.38	$36.10	$27.28	$27.51	$40.60	$38.41
	$10 to $20	$13.60	$13.45	$13.86	$12.89	$12.67	$13.76	$14.26	$13.35	$13.56	$13.47	$13.79	$13.96	$13.62
	$5 to $10	$6.99	$6.60	$6.42	$6.86	$6.82	$7.00	$6.94	$7.23	$6.83	$7.07	$6.95	$6.79	$6.94
	$0 to $5	$1.35	$1.28	$1.52	$1.70	$1.89	$1.60	$1.71	$1.77	$1.75	$2.19	$1.88	$1.70	$1.68
	$0 to -$5	$1.28	$1.11	$1.38	$1.51	$1.65	$1.37	$1.18	$1.48	$1.47	$1.77	$1.63	$1.57	$1.44
	-$5 to -$10	$7.21	$6.92	$6.54	$6.73	$6.95	$6.93	$6.98	$7.08	$7.00	$6.72	$6.64	$6.97	$6.87
	-$10 to -$20	$13.84	$14.68	$15.18	$14.65	$13.65	$14.36	$14.42	$14.88	$14.32	$14.31	$13.68	$14.43	$14.33
	< -$20	$71.52	$52.59	$62.23	$47.79	$52.58	$63.06	$60.03	$57.03	$67.15	$79.19	$139.37	$79.47	$68.51
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$25.49	$23.79	$24.28	$37.15	$29.71	$37.13	$42.59	$35.64	$35.60	$23.65	$29.16	$32.80	$34.63
	$10 to $20	$13.97	$14.46	$13.33	$13.31	$12.65	$13.18	$13.98	$14.31	$13.96	$14.16	$13.79	$14.39	$13.93
	$5 to $10	$7.11	$6.50	$6.61	$6.78	$6.99	$7.09	$7.18	$7.36	$7.06	$7.11	$6.99	$7.14	$7.05
	$0 to $5	$1.47	$1.48	$1.67	$1.85	$2.07	$1.73	$1.65	$1.75	$1.93	$2.20	$1.93	$1.76	$1.77
	$0 to -$5	$1.26	$1.17	$1.42	$1.72	$1.73	$1.48	$1.26	$1.59	$1.63	$1.87	$1.63	$1.60	$1.52
	-$5 to -$10	$7.09	$6.75	$6.56	$6.82	$7.01	$6.77	$6.97	$7.03	$7.12	$6.87	$6.90	$6.78	$6.90
	-$10 to -$20	$13.87	$13.75	$13.94	$13.89	$13.64	$13.69	$14.63	$14.01	$14.32	$14.19	$13.15	$13.99	$13.90
	< -$20	$72.02	$54.41	$61.52	$47.71	$51.49	$61.39	$59.36	$60.37	$61.74	$81.63	$237.33	$87.09	$74.63
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$24.67	$25.62	$22.27	$36.37	$32.55	$35.43	$42.37	$36.13	$34.90	$24.40	$28.62	$33.53	$34.92
	$10 to $20	$14.10	$14.51	$13.35	$13.72	$12.78	$13.12	$14.03	$14.52	$13.71	$13.80	$13.80	$13.99	$13.85
	$5 to $10	$6.96	$6.29	$6.64	$6.81	$6.95	$7.08	$7.36	$7.28	$7.00	$7.10	$6.86	$7.08	$7.01
	$0 to $5	$1.48	$1.49	$1.68	$1.89	$2.05	$1.71	$1.63	$1.73	$1.90	$2.22	$1.92	$1.79	$1.77
	$0 to -$5	$1.29	$1.15	$1.44	$1.72	$1.77	$1.52	$1.29	$1.61	$1.63	$1.86	$1.68	$1.60	$1.54
	-$5 to -$10	$6.96	$6.74	$6.59	$6.78	$7.01	$6.91	$6.93	$6.94	$7.16	$6.76	$6.70	$6.73	$6.86
	-$10 to -$20	$13.61	$14.13	$13.75	$14.00	$13.89	$13.87	$14.60	$14.10	$13.89	$13.95	$12.87	$14.49	$13.92
	< -$20	$72.51	$54.16	$61.55	$46.61	$52.85	$61.21	$60.22	$60.34	$63.42	$81.50	$134.94	$87.83	$69.38

CTS transactions were evaluated for each interval. From October 3, 2017, through December 31, 2020, 143,308 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 25,730 (18.0 percent) of the intervals was inconsistent with the differences in real-time PJM/MISO and MISO/PJM prices. For example, if a market participant submits a CTS transaction from MISO to PJM with a spread bid of $5.00, and MISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted MISO interface price, the transaction would be approved. For 18.0 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 82.0 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 December 31, 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.

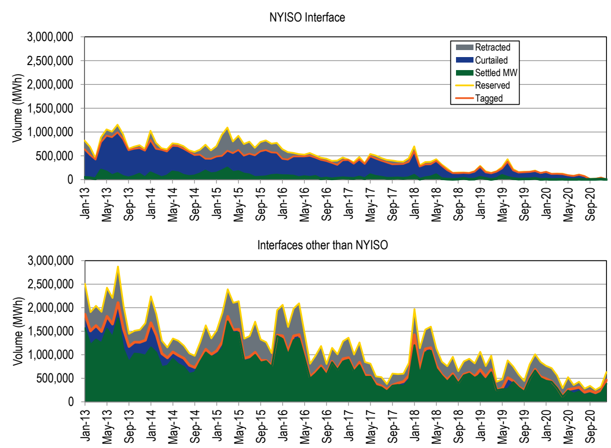
Table 9-50 Monthly uncollected congestion charges: January 2010 through December 2020

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 December 31, 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.[86]

Figure 9-16 Spot import service use: January 2013 through December 2020



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

86 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.

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.[87] 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.

87 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order No. 764.

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. 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.[88] [89] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[90]

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.[91]

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.[92] On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[93] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[94] The Commission stated that MISO had not shown that their proposal did not constitute a resumption of rate pancaking along the MISO-PJM seam. Following the December 16, 2010, Order, MISO began applying a multi-value usage rate (MUR) to monthly net actual energy withdrawals, export schedules and through schedules with the exception of transactions sinking in PJM. The MUR charge was applied to the relevant transactions in addition to the applicable transmission, ancillary service and network upgrade charges.

On June 7, 2014, the U.S. Court of Appeals for the Seventh Circuit granted a petition for review regarding the Commission's determination in the MVP Order and MVP Rehearing Order.[95] 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.[96] 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.[97]

88 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
89 Order No. 764 at P 51.
90 *See Id.* at P 12.

91 *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>.
92 See MISO. MTEP "Multi Value Project Portfolio Analysis," <https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf>.
93 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
94 133 FERC ¶ 61,221 (2010); *order on reh'g*, 137 FERC ¶ 61,074 (2011).
95 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
96 *Id.* at 780.
97 *Id.* at 779.

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[98] 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."[99]

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.[100] As shown in Table 9-4, there were 684.6 GWh of imports from MISO in 2020. At the 2020 MUR of $1.70 per MWh, PJM market participants paid $1.2 million towards the costs of MISO's multi value projects. It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-51 MISO projected multi value project usage rate: 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

98 156 FERC ¶ 61,034 (2016).
99 *Id.* at P 55.
100 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 formula rates.

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 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.

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 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 1,235 hours in 2020. In 95.0 percent of hours when the clearing price was above $0, the clearing price was the offer price of the marginal unit. In the remaining 5.0 percent of hours, the price included 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 93.5 percent of the hours in 2020.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in 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.

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the real-time energy market.

- 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.

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 2020, the average primary reserve requirement was 2,454.3 MW in the RTO Zone and 2,429.6 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 2020, there was an average hourly supply of 2,039.2 MW of tier 1 available in the RTO Zone and an average hourly supply of 957.9 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.
- **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

3 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 39 (Nov. 19, 2019).

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 112 (January 5,, 2021).

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 nonsynchronized reserve market clearing price was above $0 in 2,015 intervals (1.9 percent of intervals) in 2020 resulting in a payment to tier 1 resources of $3,319,263.

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. In PJM the required amount of synchronized reserve is defined to be no less than the largest single contingency, and 10 minute primary reserve as 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]

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM uses the tier 2 synchronized reserve market to satisfy the balance of the requirement. 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 2020, the supply of daily offered and eligible tier 2 synchronized reserve was 30,576.8 MW in the RTO Zone of which 4,919.9 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,705.4 MW in the RTO Reserve Zone and 1,684.9 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 218.3 MW in the MAD Subzone and 415.6 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 5439 which is classified as highly concentrated. The MMU calculates that the three pivotal supplier test would have been failed in 39.2 percent of intervals in 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 hours in the MAD subzone was $1.71 per MW in 2020. The weighted average price for tier 2 synchronized reserve for all cleared intervals in the RTO Synchronized Reserve Zone was $1.62 per MW in 2020.

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.

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

Market Structure

- **Supply.** In 2020, the average supply of eligible and available nonsynchronized reserve was 1,548.0 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]
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 99.8 percent of intervals where the price was above $0.01 in 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 $0.19 in 2020.

Secondary Reserve (DASR)

There is no NERC standard for secondary reserve. PJM defines secondary reserve in the day-ahead market 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.

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 2020, the average available hourly DASR was 52,303.9 MW.
- **Demand.** The DASR requirement is the sum of the PJM requirement and the Dominion requirement based on the VACAR reserve sharing agreement. For the PJM RTO between November 2019 through October 2020, the DASR daily requirement was 5.07 percent of peak load forecast. For November 2020 through October 2021, the DASR requirement was 4.78 percent of peak load forecast. The average hourly DASR MW purchased in 2020 was 4,911.5 MW, a reduction from the 5,594.9 hourly MW in 2019.
- **Concentration.** The three pivotal supplier test would have failed in zero hours in 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 2020, 39.4 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 2020.

6 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § $b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 112 (Jan. 5, 2021). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. "

7 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 112 (Jan. 5, 2021).

Market Performance

- **Price.** In 2020, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.75.

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 2020, the average hourly offered supply of regulation for nonramp hours was 720.9 performance adjusted MW (721.3 effective MW). This was a decrease of 64.6 performance adjusted MW (a decrease of 67.0 effective MW) from 2019. In 2020, the average hourly offered supply of regulation for ramp hours was 1,017.4 performance adjusted MW (1,058.9 effective MW). This was a decrease of 97.9 performance adjusted MW (a decrease of 60.8 effective MW) from 2019, when the average hourly offered supply of regulation was 1,115.3 performance adjusted MW (1,119.7 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 492.0 hourly average performance adjusted actual MW in 2020. This is an increase of 22.5 performance adjusted actual MW from 2019, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 469.5 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 702.5 hourly average performance adjusted actual MW in 2020. This is a decrease of 25.3 performance adjusted actual MW from 2019, where the average hourly regulation cleared MW for ramp hours were 727.8 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 1.45 in 2020 (1.53 in 2019). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.47 in 2020 (1.67 in 2019).

- **Market Concentration.** In 2020, the three pivotal supplier test was failed in 93.5 percent of hours. In 2020, the actual MW weighted average HHI of RegA resources was 2488 which is highly concentrated and the weighted average HHI of RegD resources was 1853 which is moderately concentrated. The weighted average HHI of all resources was 1410, 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 2020, there were 230 resources following the RegA signal and 53 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 $13.55 per MW of regulation in 2020, a decrease of $2.72 per MW, or 16.7 percent, from the weighted average clearing price of $16.27 per MW in 2019. The weighted average cost of regulation in the 2020 was $16.73 per MW of regulation, a decrease of 17.6 percent, from the weighted average cost of $20.31 per MW in 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.
- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. The current incorrect and inconsistent implementation of the MBF has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in an inefficient market signal about the value of RegD in every hour.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[9]

In 2020, total black start charges were $64.9 million, including $64.7 million in revenue requirement charges and $0.228 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 payment. 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 2020 ranged from $0.04 per MW-day in the BGE Zone (total charges were $139,118) to $2.94 per MW-day in the PENELEC Zone (total charges were $4,335,964).

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. The CRF values were later added to the black start rules. The capital recovery factor (CRF) defines the revenue requirement associated with the capital costs of black start units. The CRF is a rate, multiplied by the relevant capital investment, which defines the annual payment needed to provide a return on and of capital for the investment over a defined time period. CRFs were and are calculated using a standard financial model that incorporates the weighted average cost of capital and its components, including the rate of return on equity and the interest rate on debt and the capital structure, in addition to depreciation and taxes. For example, a five year CRF will allow the recovery of 100 percent of the investment plus a return over five years. The CRF is not a black box. The basis for the CRF was clear when the CRF values were calculated in 2007 and the basis has been explained again in the PJM stakeholder process.[10] Any market participant should be able to calculate CRF rates using the same assumptions.

As a result of the significant changes to the federal tax code in December 2017, the CRF (capital recovery factor) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A are not correct. 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. These tables should have been updated in 2018 and should be updated prior to the next capacity market auction. Correct CRFs will ensure that offer caps and offer floors in the capacity market are correct. The required changes are clear and unambiguous. An immediate filing to change the table based only on the known changes to the tax code would avoid potential uncertainty and confusion among market participants

9 OATT Schedule 1 § 1.3BB.

10 "Black Start Issues," presented at the August 6, 2020, and September 3, 2020, PJM Operating Committee Meetings, and revised on September 9, 2020. The presentations can be found at: <https://www.monitoringanalytics.com/reports/Presentations/2020.shtml>.

and would avoid any potential delay in procuring addition black start resources. PJM could file the changes under FPA Section 205.

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.

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 to ensure that the commitment to provide service matches the obligation of customers to pay 100 percent of the fixed and variable costs of the black start units over accelerated time periods.

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.[11] 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 5.68 percent from $336.3 million in 2019 to $355.4 million in 2020. Reactive capability charges increased 5.74 percent from $335.8 million in 2019 to $355.0 million in 2020. Total reactive service charges in 2020 ranged from $0 in the RECO and OVEC Zones, to $49.0 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.[12] [13]

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.[14] In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

The response of generators within PJM to NERC identified frequency events remains under evaluation. NERC uses a threshold value (L_{10}) equal to 250.8 MW/0.1 Hz and has selected four events between June 1, 2020 and December 31, 2020 as well as several events in the first two months of 2021 to evaluate. Evaluation will continue in 2021 when further recommendations

11 OATT Schedule 2.
12 See 157 FERC ¶ 61,122 (2016).
13 See 164 FERC ¶ 61,224 (2018).
14 OATT Attachment O § 4.7.2 (Primary Frequency Response).

will be discussed within PJM and the NERC Operating Committee.

Ancillary Services Costs per MWh of Load

Table 10-4 shows PJM ancillary services costs for 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.[15] The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and ReliabilityFirst Corporation charges. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary service per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and changes in total load.

Table 10-4 History of ancillary services costs per MWh of load: 1999 through 2020[16] [17]

Year	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.15	$0.23	$0.26	$0.00	$0.64
2000	$0.39	$0.26	$0.29	$0.00	$0.94
2001	$0.53	$0.71	$0.22	$0.00	$1.46
2002	$0.42	$0.86	$0.20	$0.01	$1.49
2003	$0.50	$1.05	$0.24	$0.15	$1.94
2004	$0.51	$0.93	$0.26	$0.13	$1.83
2005	$0.80	$0.72	$0.26	$0.11	$1.89
2006	$0.53	$0.74	$0.29	$0.08	$1.64
2007	$0.63	$0.72	$0.29	$0.06	$1.70
2008	$0.70	$0.38	$0.34	$0.08	$1.50
2009	$0.34	$0.29	$0.36	$0.05	$1.04
2010	$0.36	$0.35	$0.45	$0.07	$1.23
2011	$0.32	$0.36	$0.41	$0.09	$1.18
2012	$0.26	$0.41	$0.46	$0.04	$1.17
2013	$0.25	$0.41	$0.76	$0.04	$1.46
2014	$0.33	$0.42	$0.40	$0.12	$1.27
2015	$0.23	$0.42	$0.37	$0.11	$1.13
2016	$0.11	$0.41	$0.38	$0.05	$0.95
2017	$0.14	$0.47	$0.42	$0.06	$1.09
2018	$0.18	$0.46	$0.41	$0.06	$1.11
2019	$0.12	$0.46	$0.44	$0.04	$1.06
2020	$0.10	$0.46	$0.48	$0.03	$1.07

Market Procurement of Real Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services, including primary reserves and regulation. Ideally, all ancillary services would be procured taking full account of the interactions with the energy market. When a resource is used for an ancillary service instead of providing energy in real time, the cost of removing the resource, either fully or partially, from the energy market should be weighed against the benefit the ancillary service provides. The degree to which PJM markets account for these interactions depends on the timing of the product clearing and software limitations and the accuracy of unit parameters and offers.

The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services. Resources categorized as flexible tier 2 reserve, those that can provide reserves by backing down according to their ramp rate, are jointly cleared along with energy in every real-time market solution. Given the joint clearing of energy and flexible tier 2, the synchronized reserve market clearing price should always cover the opportunity cost of providing flexible tier 2. PJM should never need to pay uplift to flexible tier 2. The uplift paid to flexible tier 2 results from issues with the dispatch and pricing software timing. Inflexible tier 2 reserves, provided by resources that require longer notice to take actions to prepare for reserve deployment, are not cleared along with energy in the real-time market solution. Inflexible tier 2 reserves are cleared hourly by the Ancillary Service Optimizer (ASO). The ASO uses forward looking information about the energy market, flexible tier 2, tier 1, and regulation to estimate the costs and benefits of using a resource for inflexible tier 2 synchronized reserves.

Nonsynchronized reserves are cleared with every real-time energy market solution, but its costs are not fully known by the real-time energy market software (RT SCED) because the resources are offline. PJM uses an estimate of the cost of using a resource for nonsynchronized reserve instead of energy from a previously solved IT SCED solution. IT SCED runs every 15 minutes looking ahead at target dispatch times up to two hours in the future. The energy commitment decisions for the offline resources have already been made when the RT SCED

15 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.

16 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.

17 Reactive totals include FERC approved rates for reactive capability.

clears the nonsynchronized reserve market. RT SCED compares the IT SCED estimated cost of nonsynchronized reserve clearing to the RT SCED determined cost of synchronized reserve clearing in satisfying the primary reserve requirement. Nonsynchronized reserve clearing indirectly interacts with energy clearing through both products' substitutability with synchronized reserves.

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which is based on the RT SCED solution, but the software setting the prices is partially, but not fully clearing the market.

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.[18])
- 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.[19] FERC rejected.[20])
- 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.[21])
- 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.[22])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[23])
- 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

18 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
19 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.
20 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
21 *Id.*
22 *Id.*
23 *Id.*

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.)
- 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 the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. (Priority: Medium. First reported 2021. 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.[24] Status: Partially adopted.)
- The MMU recommends that Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. Specifically, such eligibility should be determined based on whether a generation facility's point of interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.[25] (Priority: Medium. First reported 2021. Status: Not adopted.)

Conclusion

The design of the PJM Regulation Market is significantly flawed.[26] 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.[27] 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.[28] The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.[29]

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

24 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.

25 *See* PJM Transmission Facilities (note that this requires you first log into a PJM Tools account. If you do not, then the link sends you to an Access Request page, <https://pjm.com/markets-and-operations/ops-analysis/transmission-facilities>.

26 The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders. Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

27 18 CFR § 385,211 (2017)

28 162 FERC ¶ 61,295.

29 170 FERC ¶ 61,259.

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, 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.[30] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[31] PJM maintains 10 minute reserves (primary reserve) to ensure reliability in the event of disturbances. PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. PJM does not have a Contingency Reserve Restoration Period standard.

Market Structure

Demand

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

30 See PJM "Manual 12: Balancing Operations," Rev. 41 (Nov. 19, 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."

31 See PJM "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating) Reserve, Rev. 39 (Nov. 19, 2020).

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.[32]

PJM can also increase the primary and synchronized reserve requirement in cases of hot weather or cold weather alerts or escalating emergency procedures.[33] Such additional reserves are committed as part of the hourly (ASO) and three to five minute (RT SCED) processes. In 2020, the average primary reserve requirement for the RTO Zone was 2,463.1 MW. The average primary reserve requirement in the MAD Subzone was also 2,432.3 MW. These averages include the hours when PJM raised the requirements.

The MMU identified instances when PJM increased the primary and synchronized reserve requirements (Table 10-5). The amounts of the increases are estimated against average requirement levels before and after the periods of increase.

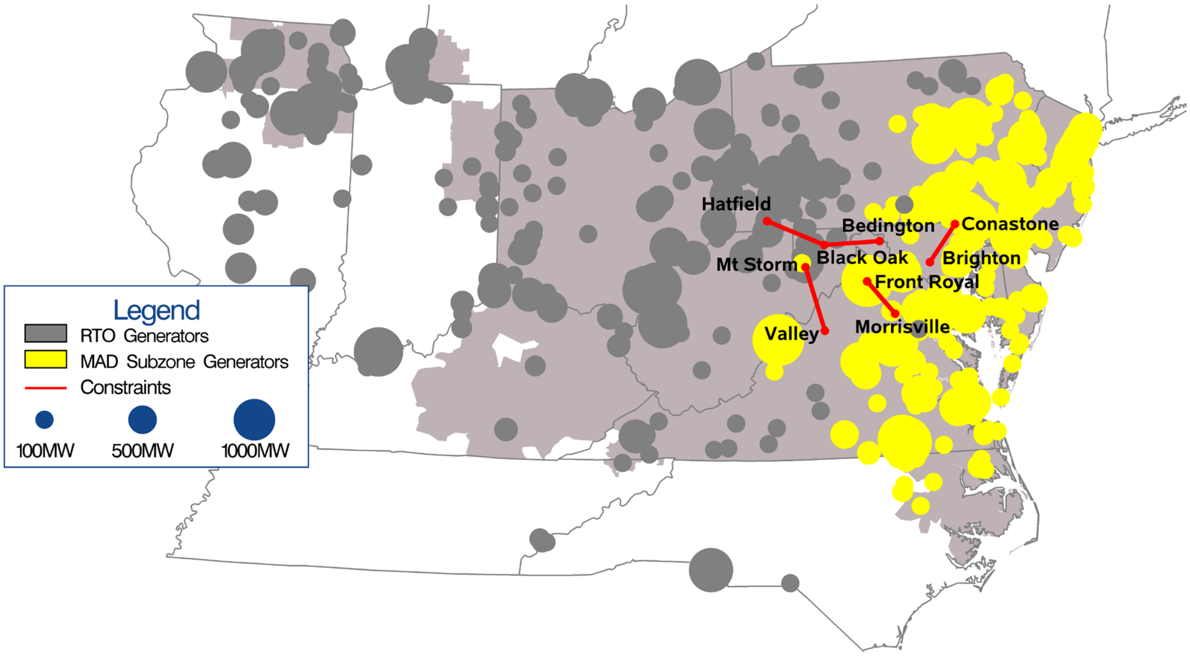
Table 10-5 Temporary adjustments to primary and synchronized reserve: 2020

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)
10-Oct-20	12-Oct-20	20	Primary Reserve (340 MW), Synchronized Reserve (285 MW)
13-Oct-20	15-Oct-20	48	Primary Reserve (1,575 MW), Synchronized Reserve (1,150 MW)
23-Oct-20	25-Oct-20	30	Primary Reserve (475 MW), Synchronized Reserve (360 MW)
30-Oct-20	4-Nov-20	38	Primary Reserve (60 MW), Synchronized Reserve (45 MW)
23-Nov-20	23-Nov-20	9	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
20-Nov-20	24-Nov-20	94	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
27-Dec-20	29-Dec-20	24	Primary Reserve (380 MW), Synchronized Reserve (250 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).[34] 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.[35] 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.

32 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 112 (Jan. 5, 2021)
33 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 112 (Jan. 5, 2021), p. 84
34 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. 112 (Jan. 5, 2021)).
35 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 112 (Jan. 5, 2021), p. 86.

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. The most frequent constraint is Brighton-Conastone, then Carson-Rodgers Road, and Hunterstown-Conastone.

The NERC standard requires a control area to carry primary reserve MW equal to or greater than the most severe single contingency (MSSC).[36] 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.[37] In 2020, the average synchronized reserve requirement was 1,684.9 MW in the MAD Subzone and 1,705.4 MW in the RTO Zone. The synchronized reserve requirement is calculated for every real-time market dispatch solution.

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 962.2 MW of tier 1 was identified by the dispatch solutions as available in 2020 (Table 10-6).[38] 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 12.7 percent of dispatch solutions in 2020. In the RTO Zone, an average of 2,047.8 MW of tier 1 was available (Table 10-7) fully satisfying the synchronized reserve requirement in 54.6 percent of real-time dispatch solutions.

36 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>.

37 "PJM Manual 13: Emergency Operations," Rev 77 (Jan. 1, 2021), p. 18.

38 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.

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.[39]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In 2020, in the RTO Zone, there were 30,576.8 MW of tier 2 synchronized reserve offered daily. Of this, 4,919.9 MW were located in the MAD Subzone and available to meet the average MAD tier 2 dispatch solution demand of 180.5 MW (Table 10-6).

In 2020, in the MAD Subzone, there was an average of 1,319.6 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 1,691.9 MW supply was available to meet the average demand of 306.2 MW (Table 10-7).

Table 10-6 provides the average dispatch solution reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone from 2019 through 2020.

Table 10-6 Average reserves used to satisfy the primary reserve requirement, MAD Subzone: 2019 through 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	1,276.6	325.9	1,249.0	2,851.5
2020	Feb	1,026.9	193.6	1,219.6	2,440.1
2020	Mar	980.7	259.0	1,231.8	2,471.4
2020	Apr	1,150.5	199.9	1,067.7	2,418.1
2020	May	911.1	200.5	1,177.5	2,289.0
2020	Jun	1,276.2	142.5	976.6	2,395.4
2020	Jul	995.4	210.5	1,216.0	2,421.9
2020	Aug	881.4	148.3	1,200.6	2,230.3
2020	Sep	1,016.9	88.5	1,123.2	2,228.6
2020	Oct	724.1	290.2	1,247.8	2,262.2
2020	Nov	566.4	257.2	1,188.8	2,012.5
2020	Dec	689.0	252.2	1,319.6	2,260.8
2020	Average	957.9	214.0	1,184.8	2,356.8

39 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2 PJM Synchronized Reserve Market Business Rules, Rev. 112 (Jan. 5, 2021).

Table 10-7 shows the average dispatch solution reserves, by type of reserve, satisfying the primary reserve requirement in the RTO Zone in 2019 through 2020.

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: 2019 through 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	2,416.4	486.8	1,364.8	4,268.0
2020	Feb	2,284.2	283.3	1,279.6	3,847.1
2020	Mar	2,155.1	458.7	1,365.6	3,979.4
2020	Apr	2,228.6	342.1	1,174.0	3,744.7
2020	May	2,128.3	297.4	1,250.6	3,676.3
2020	Jun	2,728.9	283.7	1,082.7	4,095.3
2020	Jul	2,109.4	402.2	1,363.5	3,875.1
2020	Aug	1,972.1	398.8	1,387.0	3,757.9
2020	Sep	2,053.8	299.4	1,271.0	3,624.1
2020	Oct	1,381.3	778.2	1,612.3	3,771.7
2020	Nov	1,499.7	683.9	1,509.5	3,693.1
2020	Dec	1,512.4	697.0	1,648.3	3,857.7
2020	Average	2,039.2	450.9	1,359.1	3,849.2

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 dispatch solutions determine the actual primary reserves required 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.

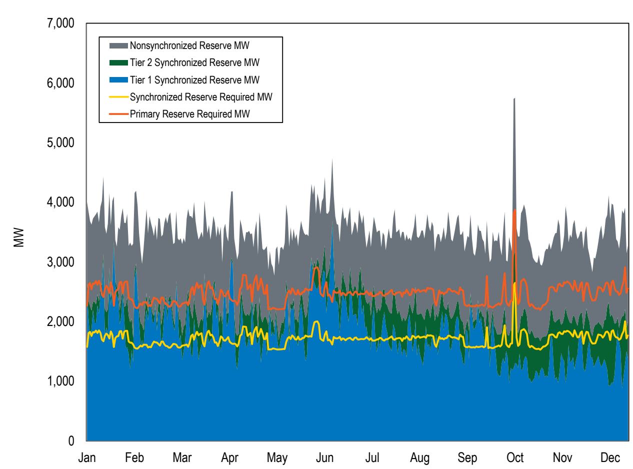
If the tier 1 synchronized reserve plus ASO committed inflexible tier 2 synchronized reserve does not meet the requirement, RT SCED will commit available flexible tier 2 synchronized reserve. If there is an excess of synchronized reserve, the RT SCED may decommit previously committed flexible synchronized reserve.

The ASO satisfied the primary reserve requirement for the RTO Zone in all hours of 2020. RT SCED for the MAD Subzone satisfied the primary reserve requirement in all but six solutions in 2020. Five of the six dispatch solutions were the result of a spinning event in which all available tier 1 was exhausted. One solution, on October 14, 2020, occurred during a temporary increase in required primary reserve of 1,575 MW. 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 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 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.

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): 2020



In 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.

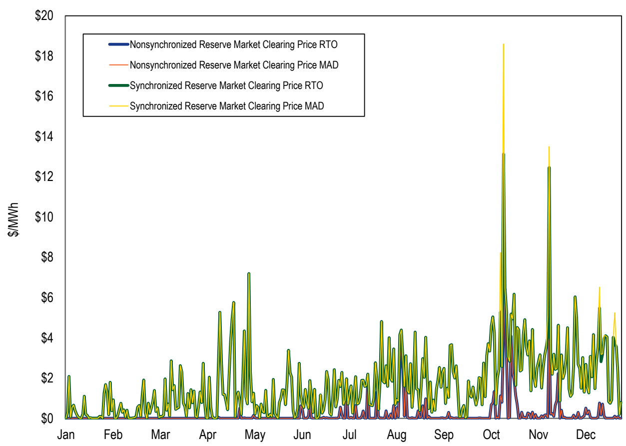
Price and Cost

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 2020. The MAD SRMCP and RTO SRMCP price diverged in only three five minute intervals in 2020. Nonsynchronized reserve prices averaged $0.09 per MW over all intervals in 2020.

Figure 10-3 Daily average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: 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 2020 was 39.3 percent. While tier 1 has zero actual incremental cost, estimated tier 1 is paid the tier 2 clearing price in any hour where nonsynchronized reserves clears at a nonzero price.

Table 10-8 Primary reserve requirement components, RTO Reserve Zone: 2020

Product	MW Share of Credited Primary Reserve Requirement	MWh	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve
Tier 1 Synchronized Reserve Response	NA	3,773	$186,176	NA	$49.34
Tier 1 Synchronized Reserve in Market Solution	2.6%	293,156	$3,319,263	$9.02	$11.32
Tier 2 Synchronized Reserve Scheduled	17.4%	1,977,144	$12,193,198	$2.57	$6.17
Non Synchronized Reserve Scheduled	80.0%	9,078,323	$8,229,669	$0.19	$0.91
Primary Reserve (total of above)	100.0%	11,352,396	$23,928,306	$0.83	$2.11

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.[40] Tier 1 resources are identified by the market solution. Tier 1 synchronized reserve has an incremental cost of zero. Tier 1 synchronized reserve is paid under two circumstances. Tier 1 reserves are paid when they respond to a synchronized reserve event. Tier 1 reserves are paid the synchronized reserve market clearing price when the nonsynchronized reserve market clearing price is above $0.

While PJM relies on tier 1 resources to respond to a synchronized reserve event, tier 1 resources are not obligated to respond during an event. Tier 1 resources are credited if they do respond but are not penalized if they do not.

Market Structure

Supply

All generating resources operating on the PJM system with the exception of those assigned to tier 2 synchronized reserve are available for tier 1 synchronized reserve and any response to a spinning event will be credited at the Synchronized Energy Premium Price.

Beginning in 2014, 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 for synchronized reserve is not the same as DGP for energy. The available tier 1 MW estimated by the market solution for each resource is based upon its economic dispatch, and 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.[41] 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 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.[42] These unit types are 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 request to be included.[43] 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 2020, including all tier 1 credited for responding to synchronized reserve events and paid when the nonsychronized reserve price exceeded $0 per MW.

Table 10-9 Supply of tier 1 synchronized reserve by unit and fuel type: 2020

Unit / Fuel Type	Percent by MW	Percent by Credits
Steam - Coal	56.9%	56.5%
Combined Cycle	31.1%	31.0%
CT - Natural Gas	4.3%	3.8%
Hydro - Run of River	3.6%	3.7%
Steam - Natural Gas	1.4%	1.3%
Wind	1.4%	1.5%
Hydro - Pumped Storage	0.5%	0.9%
Solar	0.4%	0.4%
Steam - Other	0.3%	0.4%
RICE - Natural Gas	0.0%	0.0%
Battery	0.0%	0.0%
CT - Other	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Nuclear	0.0%	0.0%
RICE - Other	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

40 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 112 (Jan. 5, 2021).

41 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>

42 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 112 (Jan. 5, 2021)

43 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 112 (Jan. 5, 2021)

In 2020, the SCED market solutions estimated that tier 1 MW from an average of 53 units could have an average of 1,765.4 MW of ramp available in a spinning event. For the 17 actual spinning events in 2020, PJM Settlements paid an average 2,472 total MW from an average of 312 distinct units. Settlements include units like wind, solar, nuclear, and demand response which are not a part of the estimated tier 1 in the SCED market solutions.

By observing spin event response recorded in PJM's SCADA data, the MMU estimates actual response as the sum of the products contributing to total ACE increase from the time the event is initiated to 10 minutes after the event is initiated. Total increase in ACE is a summation not only of tier 1 response, but also of tier 2 response, regulation A and regulation D actual response (this is sometimes a MW increase and sometimes a MW decrease), and changes to net imports/exports across PJM's boundaries (sometimes an increase and sometimes a decrease in MW).

In the RTO Reserve Zone, the average estimated tier 1 synchronized reserve was 2,039.2 MW (Table 10-7). In 53.4 percent of dispatch solutions, 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 2020, the average estimated tier 1 synchronized reserve available was 957.9 MW in the MAD Subzone (Table 10-6). In 12.1 percent of dispatch solutions 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.

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 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.

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.[44] 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

44 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 112 (Jan. 5, 2021).

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 estimate of tier 1. Many resources that are not included in PJM's estimate of tier 1 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 estimate (at market solution time) when there is no spinning event is also credited for its full 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, estimated tier 1 is credited with the lesser of its actual response or its estimated capability times the SRMCP. Tier 1 synchronized reserve not part of the estimate is credited the SRMCP times its actual response.[45] In 2020, the nonsynchronized reserve market clearing price was above $0 in 1.9 percent of intervals.

In 2020, tier 1 synchronized reserve spinning event response credits of $186,177 were paid for 17 spinning events covering 44 five minute intervals. Table 10-10 shows the number of spinning events each month, the credits paid for tier 1 response, the number of MWh credited, and the actual response in MW.

Table 10-10 Tier 1 synchronized reserve event response costs: 2020

Year	Month	Number of Spinning Events	Total Tier 1 Spinning Event Credits	Total Tier 1 Spinning Event Credited (MWh)	Total Tier 1 Spinning Response from Event Start to Event End (MW)
2020	Jan	2	$22,200	453.2	5,438.8
2020	Feb	4	$56,595	1,148.2	13,778.8
2020	Mar	1	$3,514	70.3	843.5
2020	Apr	1	$5,873	118.2	1,418.5
2020	May	1	$11,302	226.0	2,712.6
2020	Jun	0	NA	NA	NA
2020	Jul	3	$34,249	699.8	8,397.2
2020	Aug	0	NA	NA	NA
2020	Sep	1	$11,390	236.2	2,843.1
2020	Oct	2	$23,038	460.8	5,713.0
2020	Nov	1	$7,964	159.3	2,019.3
2020	Dec	1	$10,050	201.0	2,426.1

Paying Tier 1 the Tier 2 Price

Tier 1 synchronized reserve has zero marginal cost and the corresponding competitive price for tier 1 synchronized reserves is also zero. However, the PJM rules artificially create a marginal cost of tier 1 when the price of nonsynchronized reserve is greater than zero and tier 1 is paid the tier 2 price. The PJM market solutions do not include that marginal cost and therefore do not solve for the efficient level of tier 1, tier 2 and nonsynchronized reserve in those cases. When called to respond to a spinning event, tier 1 is compensated at the Synchronized Energy Premium Price (Table 10-12). However, the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the nonsynchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear, but it has had a significant impact on the cost of tier 1 synchronized reserves (Table 10-11). In 2020, the nonsynchronized reserve market clearing price was above $0.00 in 2,015 intervals. For those intervals, tier 1 synchronized reserve was paid $3,319,263 for an average of 145.5 MWh per interval.

45 See PJM "Manual 28: Operating Agreement Accounting," Rev. 84 (Dec. 17, 2020) p. 54.

Table 10-11 Price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: 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	456.9
2020	May	24	$6.20	3,105.4	$19,262	310.5
2020	Jun	116	$7.58	17,163.0	$130,140	490.4
2020	Jul	166	$11.18	22,696.6	$253,682	687.8
2020	Aug	309	$12.52	42,499.8	$531,928	708.3
2020	Sep	50	$3.94	7,277.5	$28,658	519.8
2020	Oct	944	$11.86	148,481.8	$1,760,874	1,124.9
2020	Nov	255	$13.55	32,994.0	$447,060	673.4
2020	Dec	124	$8.20	15,282.5	$125,286	527.0
2020		2015	$9.02	293,155.5	$3,319,263	611.0

The additional payments to tier 1 synchronized reserves under the shortage pricing rule are a windfall. The additional payment does not create an incentive to provide more tier 1 synchronized reserves. The additional payment is not a payment for performance; all estimated tier 1 receives the higher payment regardless of whether they provide any response during any spinning event. Tier 1 resources are not obligated to respond to synchronized reserve events. In 2020, there were five spinning events of 10 minutes or longer. In those events, 49.7 percent of the estimated tier 1 responded and 59.5 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.[46] 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 10-12.

Table 10-12 Tier 1 compensation as currently implemented by PJM

Tier 1 Compensation by Type of Interval as Currently Implemented by PJM		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = T2 SRMCP * estimated tier 1 MW	T1 credits = T2 SRMCP * min(estimated tier 1 MW, actual response MWi)

The MMU's recommended compensation rules for tier 1 MW are in Table 10-13.

Table 10-13 Tier 1 compensation as recommended by MMU

Tier 1 Compensation by Type of Hour as Recommended by MMU		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi

46 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 an synchronized reserve event. Tier 2 synchronized reserves are committed to be available in the event of a synchronized reserve event. Tier 2 resources have a must offer requirement. 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, RT SCED can dispatch additional resources. RT SCED can redispatch 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.[47]

In 2020, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 4,919.9 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 30,576.8 MW of tier 2 synchronized reserve offers (Figure 10-6).

The supply of tier 2 synchronized reserve offered in 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 2020 was from CTs running on natural gas or oil (Table 10-14). Although demand resources are limited to providing no more than 33 percent of the total synchronized reserve requirement, the amount of tier 2 synchronized reserve required in any hour is often much less than the full synchronized reserve requirement because so much of it is met with tier 1 synchronized reserve. This means that in 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

47 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 112 (Jan. 5, 2021).

clear even when the price is $0. As a result, their share of credits in the synchronized reserve market is much less than their share of cleared MW.

Table 10-14 Supply of Generation Tier 2 Synchronized Reserve by Unit Type and Fuel Type: 2020

Unit / Fuel Type	Percent by MW	Percent by Credits
CT - Natural Gas	37.0%	42.1%
DSR	27.8%	11.2%
CT - Oil	12.3%	16.7%
Combined Cycle	11.7%	21.3%
Hydro - Run of River	6.4%	3.2%
Steam - Coal	3.6%	4.2%
Hydro - Pumped Storage	0.7%	0.6%
RICE - Natural Gas	0.4%	0.4%
Steam - Natural Gas	0.1%	0.3%
Battery	0.0%	0.0%
CT - Other	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Nuclear	0.0%	0.0%
RICE - Other	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Steam - Other	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

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.[48]

In 2020, the average synchronized reserve requirement was 1,705.4 MW in the RTO Zone and 1,684.9 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 422.2 MW of tier 2 synchronized reserves in 2020. Of this, an average of 68.9 MW was scheduled hourly.

Figure 10-4 and Figure 10-5 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self scheduled) from 2018 through 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 seven intervals of shortage in 2020.

Figure 10-4 MAD hourly average tier 2 synchronized reserve scheduled MW: 2018 through 2020

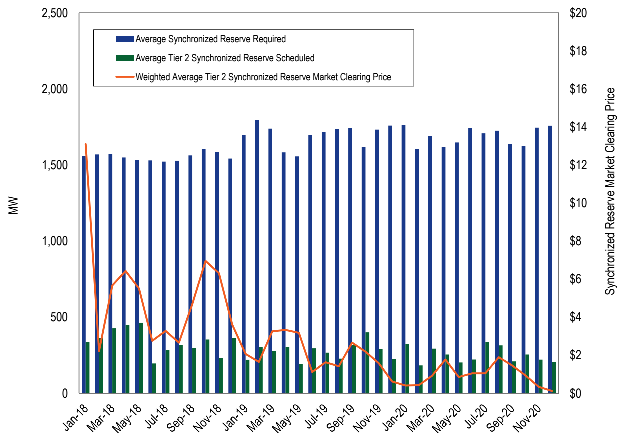
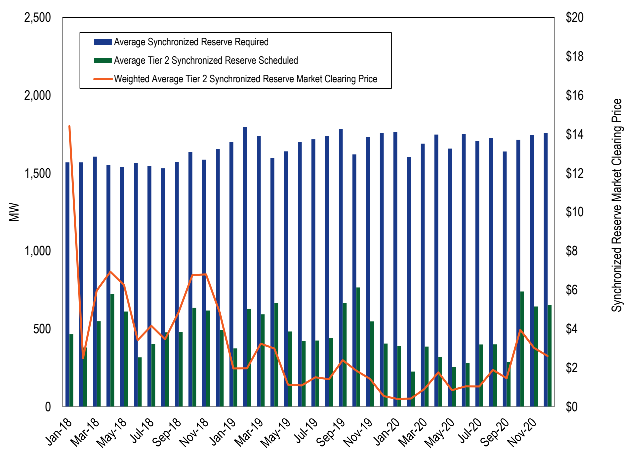


Figure 10-5 RTO hourly average tier 2 synchronized reserve scheduled MW: 2018 through 2020



48 PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 112 (Jan. 5, 2021).

Market Concentration

The average HHI for tier 2 synchronized reserve cleared intervals in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in 2020 was 5358, which is defined as highly concentrated. In 77.0 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 2020 was 5439, which is defined as highly concentrated. In 91.4 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 17.1 percent of all tier 2 synchronized reserve in 2020. In the RTO Zone, flexible synchronized reserve was 17.9 percent of all tier 2 synchronized reserve in 2020.

In 2020, 39.2 percent of intervals would have failed a three pivotal supplier test in the RT SCED five minute market solution (Table 10-15).

Table 10-15 Three pivotal supplier test results for Tier 2 RT SCED market solutions: 2020

Year	Month	RTO Zone Pivotal Supplier Intervals
2020	Jan	62.7%
2020	Feb	44.8%
2020	Mar	49.8%
2020	Apr	34.6%
2020	May	34.9%
2020	Jun	46.9%
2020	Jul	28.4%
2020	Aug	29.2%
2020	Sep	19.6%
2020	Oct	31.2%
2020	Nov	50.2%
2020	Dec	38.4%
2020	Average	39.2%

The market structure results indicate that the RTO Zone and Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Markets are not structurally competitive.

Market Behavior

Offers

Daily cost-based offers are submitted for each unit by the unit owner. For generators the offer must include when relevant a tier 1 synchronized reserve ramp rate, a tier 1 synchronized reserve maximum, self scheduled status, synchronized reserve availability, synchronized reserve offer quantity (MW), tier 2 synchronized reserve offer price, energy use for tier 2 condensing resources (MW), condense to gen cost, shutdown costs, condense startup cost, condense hourly cost, condense notification time, and spin as a condenser status. The synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus a markup of $7.50 per MW. The tier 1 synchronized reserve ramp rate must be greater than or equal to the real-time economic ramp rate. If the synchronized reserve ramp rate is greater than the economic ramp rate it must be justified by the submission of actual data from previous synchronized reserve events.[49] 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.[50]

Figure 10-6 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.[51] 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 10-6). Changes to the

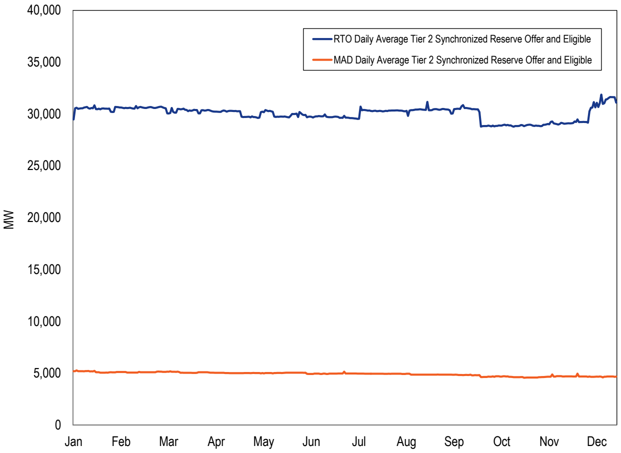
49 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 112 (Jan. 5, 2021).

50 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 112 (Jan. 5, 2021).

51 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…").

hourly offer status are only permitted when resources are physically unable to provide tier 2. Changes to hourly eligibility levels are the result of online status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints. However, resource operators can make their units unavailable for an hour or block of hours without having to provide a reason.

Figure 10-6 Tier 2 synchronized reserve hourly offer and eligible volume (MW): 2020



For 2020, 94.8 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.[52]

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).[53] The number of marginal units by schedule type is shown in Table 10-16.

Table 10-16 Schedule used for LOC of marginal units in tier 2 synchronized reserve market LOC calculation: 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	7.1%	92.9%

For 2020, the RTO cleared a tier 2 synchronized reserve market in 46.6 percent of all dispatch solutions. In all other intervals there was enough tier 1 synchronized reserve to cover the synchronized reserve requirement. For intervals when the synchronized reserve requirement could not be met with tier 1, the market cleared an average of 415.6 MW of synchronized reserve including 88.6 MW of demand response at a MW weighted average or $1.62 per hour.

The market clearing price for the MAD Subzone diverged from the RTO Zone in 21 intervals during 2020.

Supply, demand, and performance are reflected in the price of synchronized reserve (Table 10-17).

52 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.

53 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 112 (Jan. 5, 2021), p. 92.

Table 10-17 RTO Zone, average SRMCP and average scheduled, tier 1 estimated and demand response MW in RT SCED market solutions: 2019 through 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	Oct	$3.96	575.1	1,380.2	165.3
2020	Nov	$3.03	502.6	1,500.4	141.4
2020	Dec	$2.61	507.7	1,506.8	145.0
2020	Average	$1.62	327.0	2,035.2	88.6

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 2020, the price to cost (including self scheduled) ratio of the RTO Zone tier 2 synchronized reserve market averaged 44.7 percent, which was lower than the 53.2 percent price to cost ratio for 2019 (Table 10-18). The price to cost ratio of the MAD Subzone (Table 10-19) averaged 50.2 percent, which was lower than the 56.7 percent of 2019.

Table 10-18 RTO Zone tier 2 synchronized reserve MW, credits, price, and cost: 2019 through 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	260,488	$248,407	$668,973	$0.95	$3.52	27.1%
RTO Zone	2020	Feb	136,615	$136,378	$238,882	$0.99	$2.75	36.2%
RTO Zone	2020	Mar	232,757	$455,181	$374,827	$1.96	$3.57	54.8%
RTO Zone	2020	Apr	185,880	$969,352	$331,816	$5.21	$7.00	74.5%
RTO Zone	2020	May	153,053	$336,361	$378,671	$2.20	$4.67	47.0%
RTO Zone	2020	Jun	200,956	$478,017	$548,797	$2.38	$5.11	46.6%
RTO Zone	2020	Jul	306,725	$882,101	$2,532,837	$2.87	$11.13	25.7%
RTO Zone	2020	Aug	305,867	$1,081,242	$1,415,425	$3.54	$8.16	43.3%
RTO Zone	2020	Sep	194,802	$584,764	$531,167	$3.00	$5.73	52.4%
RTO Zone	2020	Oct	495,961	$3,103,868	$1,105,778	$6.26	$8.49	73.7%
RTO Zone	2020	Nov	425,670	$1,818,452	$704,908	$4.27	$5.93	72.1%
RTO Zone	2020	Dec	529,815	$1,792,351	$792,032	$3.38	$4.88	69.3%
RTO Zone	2020		1,977,144	$5,171,801	$7,021,397	$2.57	$5.74	44.7%

Table 10-19 MAD Subzone tier 2 synchronized reserve MW, credits, price, and cost: 2019 through 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
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	$6,826,660	$2.94	$6.48	45.3%
MAD Subzone	2020	Jan	158,016	$148,747	$306,243	$0.94	$2.88	32.7%
MAD Subzone	2020	Feb	85,683	$69,975	$143,493	$0.81	$2.49	32.6%
MAD Subzone	2020	Mar	118,034	$179,286	$171,076	$1.52	$2.97	51.2%
MAD Subzone	2020	Apr	105,078	$434,791	$154,653	$4.14	$5.61	73.8%
MAD Subzone	2020	May	98,793	$183,224	$225,529	$1.85	$4.14	44.8%
MAD Subzone	2020	Jun	88,359	$223,687	$266,937	$2.53	$5.55	45.6%
MAD Subzone	2020	Jul	144,737	$401,516	$1,817,050	$2.76	$15.33	18.0%
MAD Subzone	2020	Aug	100,438	$399,880	$630,380	$3.98	$10.26	38.8%
MAD Subzone	2020	Sep	48,834	$180,117	$217,558	$3.69	$8.14	45.3%
MAD Subzone	2020	Oct	167,801	$1,392,079	$255,926	$8.30	$9.82	84.5%
MAD Subzone	2020	Nov	135,825	$666,374	$123,473	$4.91	$5.82	84.4%
MAD Subzone	2020	Dec	134,913	$572,056	$239,129	$4.23	$6.01	70.3%
MAD Subzone	2020		1,386,510	$4,851,733	$4,551,445	$3.30	$6.58	50.2%

Performance

Tier 1 resource owners are paid for the actual amount of synchronized reserve they provide in response to a synchronized reserve event.[54] 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.[55] 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.[56] 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.

Tier 2 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, the response rate was 87.6 percent. In 2018, the response rate was 74.2 percent. In 2019, the response rate was 86.8 percent. In 2020, there were five spinning events 10 minutes or longer with an average response rate of 59.5 percent of scheduled tier 2 MW. Actual participant performance means that the penalty structure is not adequate to incent performance.

The penalty structure when a tier 2 resource fails to respond fully to a spinning event includes 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. There are 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.[57] The IPI uses 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 incorrectly truncates the IPI. The penalty applies only to the SRMCP credits not the LOC credits. But most credits awarded are for LOC (see Table 10-19).

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 be defined as the number of days between spinning events 10 minutes or longer. PJM had five 10 minute or longer spinning events in 2020 (February 18, July 6, July 25, September 10, and December 16). If only events 10 minutes or longer were considered, the IPI would increase to 75 days from its current level of 25 days. In that case, the penalty period for the February 18 event should not have been terminated by the nine minute event on February 10. The penalty period for the July 25 event should not have been 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 IPI the penalties may be insufficient to ensure response. A tier 2 shortfall penalty should include LOC payments as well as SRMCP and MW of shortfall.

54 See *id.* at 98.

55 See *2011 State of the Market Report for PJM*, Vol. 2, Section 9, "Ancillary Services," at 250.

56 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements Rev. 112 (Jan. 5, 2021).

57 See PJM "Manual 28: Operating Agreement Accounting,"§ 6.3 Charges for Synchronized Reserve, Rev. 84 (Dec. 17, 2020.)

Table 10-20 Comparison of tier 2 shortfall penalties under current IPI vs. MMU recommended IPI: 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
$272,618	$49,609	$111,426	$277,802

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 as reported by PJM in its Operating Committee meetings is shown in Table 10-21. The tier 1 estimate is from the most recent RT SCED market solution. The tier 1 estimate includes estimated ramp only from the units that are eligible and excludes resources that have ramp available but are not part of the estimate.

Tier 1 synchronized reserve that responds to a spinning event receives a bonus payment of $50 per MWh, based on a calculation using SCADA data, regardless of whether PJM included those reserves in the estimate.

Table 10-21 shows synchronized reserve event response compliance for tier 1 and tier 2 reserves as reported by PJM, using only response from tier 1 estimated and tier 2 cleared reserves. Actual synchronized reserve response is the total increase in MW from all resources from the moment the spinning event is called to ten minutes after. To determine the actual tier 1 response, the calculation would subtract tier 2 response, changes in assigned regulation output (net compliance level to both RegA and RegD), and changes to net power flow across PJM's interface boundary. The overall response to spinning events is adequate or more than adequate to meet NERC requirements. PJM not only corrects the ACE disturbance that led to the event but over corrects. In 16 of the 17 spinning events the ACE recovers not just to the NERC required level (which is the lesser of 0 or the value before the disturbance which caused the event) but overshoots.

Table 10-21 Synchronized reserve events 10 minutes or longer, tier 1 and tier 2 response compliance as reported by PJM, RTO Reserve Zone: 2018 through 2020

Spin Event (Day, EPT Time)	Duration (Minutes)	Tier 1 Estimate (Market Solution MW Adj by DGP)	Tier 1 DGP Estimated Response (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	DGP Estimated 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	591.2	464.6	372.5	92.1	55.6%	80.2%
Jun 30, 2018 09:46	11	2,710.1	2,086.2	71.6	56.8	14.8	77.0%	79.3%
Jul 10, 2018 15:45	12	784.3	524.9	494.6	308.8	185.8	66.9%	62.4%
Aug 12, 2018 11:06	11	1,824.5	1,390.4	274.5	229.8	44.7	76.2%	83.7%
Sep 30, 2018 11:29	11	1,430.9	976.4	231.2	216.9	14.3	68.2%	93.8%
Oct 30, 2018 06:40	11	239.7	215.9	607.7	431.5	176.2	90.1%	71.0%
2018 Average	11	1,421.4	899.3	322.4	239.1	83.3	63.3%	74.2%
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%
Sep 10, 2020 00:29	10	1,275.4	453.6	782.6	782.6	0.0	35.6%	100.0%
Dec 16, 2020 16:49	10	268.4	196.9	527.6	413.2	114.4	73.4%	78.3%
2020 Average	10	1,218.5	606.6	426.4	375.5	51.0	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. The impact of tier 1 deselection can be very significant (Table 10-22).

Table 10-22 Comparison of market solution tier 1 estimate, tier 1 response with PJM Settlements tier 1 MW credited: 2020

Start Time	Duration (Minutes)	PJM Market Solution DGP Estimated Tier 1 Estimate MW	PJM Market Solution DGP Estimated Tier 1 Response MW	PJM Settlements Tier 1 Credited Response MW
Jan 20, 2020 14:06	7.8	1,903.6	765.9	1,306.3
Jan 23, 2020 16:17	8.7	2,084.6	1,073.0	1,860.4
Feb 7, 2020 12:06	6.4	1,233.0	730.2	2,883.9
Feb 8, 2020 03:44	8.4	1,961.4	826.1	1,517.6
Feb 10, 2020 20:15	9.6	1,333.3	824.3	1,573.8
Feb 18 2020 11:16	10.0	2,216.1	1,434.8	2,528.6
Mar 8, 2020 05:17	5.6	1,541.4	660.1	843.5
Apr 13, 2020 19:53	7.9	433.0	207.2	886.5
May 3, 2020 12:23	6.6	4,154.4	1,369.6	2,260.5
Jul 6, 2020 21:22	10.4	1,464.0	526.1	1,554.5
Jul 24, 2020 01:03	9.9	1,562.7	852.8	1,762.7
Jul 25, 2020 16:39	11.7	868.4	421.6	961.5
Sep 10, 2020 00:19	9.5	1,275.4	453.6	1,417.0
Oct 10, 2020 18:52	7.7	2,134.3	1,234.3	2,187.8
Oct 12, 2020 04:29	9.3	1,625.8	670.5	1,229.2
Nov 13, 2020 11:36	5.9	1,687.9	882.4	1,682.8
Dec 16, 2020 16:38	10.0	268.4	196.9	1,213.0

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[58 59] 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 indicate 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 disturbances.

From 2010 through 2020, PJM experienced 258 synchronized reserve events, approximately 2.0 events per month. During this period, synchronized reserve events had an average duration of 11.5 minutes.[60]

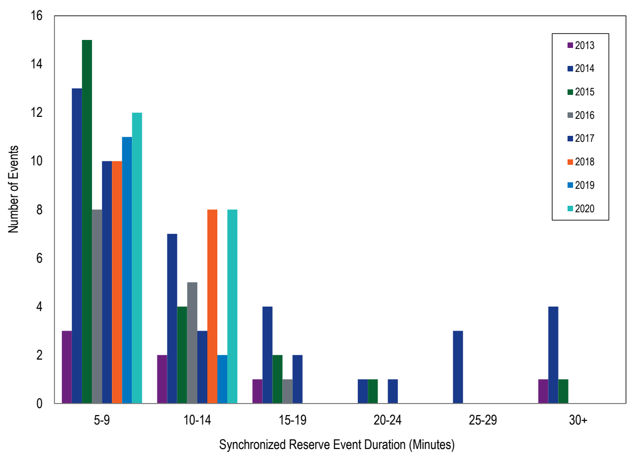
58 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, at 451–452.
59 See PJM "Manual 12: Balancing Operations," Rev. 41 (Nov. 20, 2020) § 4.1.2 Loading Reserves.
60 For full history of spinning events, see the *2019 State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.

Table 10-23 Synchronized reserve events: 2017 through 2020

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	10
SEP-04-2017 20:18	MAD	15	SEP-13-2018 09:47	RTO	7				OCT-10-2020 18:52	RTO	8
SEP-07-2017 09:16	RTO	9	SEP-14-2018 13:24	RTO	7				OCT-12-2020 04:29	RTO	9
SEP-21-2017 14:15	RTO	16	SEP-26-2018 19:08	RTO	8				NOV-13-2020 07:46	RTO	6
			SEP-30-2018 11:29	RTO	11				DEC-16-2020 16:38	MAD	10
			OCT-30-2018 10:40	RTO	11						

Figure 10-7 shows spin event durations over the past eight years.

Figure 10-7 Synchronized reserve events duration distribution curve: 2013 through 2020



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.[61]

The average scheduled nonsynchronized reserve in the RTO Zone in 2020 was 1,358.9 MW. The average scheduled nonsynchronized reserve in the MAD Subzone for primary reserve was 1,164.8 MW.

Supply

Figure 10-2 shows that most of the primary reserve requirement (orange line) in excess of the synchronized reserve requirement (yellow line) is satisfied by nonsynchronized reserve (light blue area).

There are no offers for nonsynchronized reserve. The 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.

Nonsynchronized reserve resources are scheduled economically based on estimated LOC until the Primary Reserve requirement is filled. The nonsynchronized reserve market clearing price is determined every five minutes 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 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.[62] In 2020, an average of 1,358.9 MW of nonsynchronized reserve was scheduled per hour out of 1,548.0 eligible MW as part of the primary reserve requirement in the RTO Zone.

In 2020, CTs provided 85.2 percent of scheduled nonsynchronized reserve (Table 10-24). Natural gas was the primary fuel for nonsynchronized reserve.

Table 10-24 Supply of nonsynchronized reserve by fuel and unit type: 2020

Unit / Fuel Type	Percent by MW	Percent by Credits
CT - Natural Gas	50.6%	58.9%
CT - Oil	34.6%	31.1%
Hydro - Run of River	14.6%	9.9%
Hydro - Pumped Storage	0.1%	0.1%
RICE - Other	0.0%	0.0%
Combined Cycle	0.0%	0.0%
Steam - Coal	0.0%	0.0%
RICE - Natural Gas	0.0%	0.0%
Steam - Natural Gas	0.0%	0.0%
Battery	0.0%	0.0%
CT - Other	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Nuclear	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Steam - Other	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in 2020.

61 See PJM "Manual 11: Energy and Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 112 (Jan. 5, 2021).

62 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4b.2 Non-Synchronized Reserve Market Business Rules, Rev. 112 (Jan. 5, 2021)

Table 10-25 Nonsynchronized reserve market pivotal supplier test: 2020

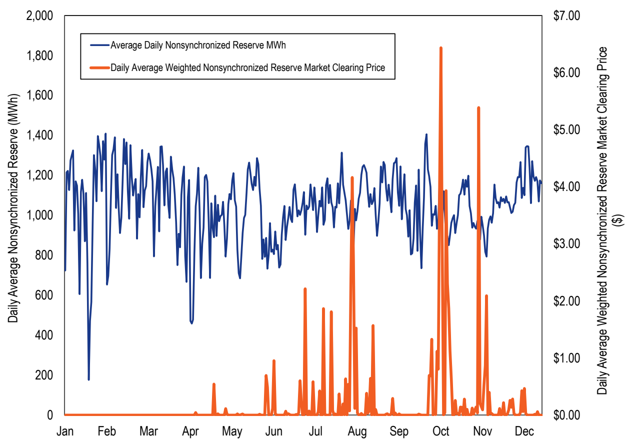
Year	Month	Number Intervals of Clearing Price > $0.01	RTO Pivotal Supplier Intervals
2020	Jan	0	NA
2020	Feb	0	NA
2020	Mar	0	NA
2020	Apr	21	100.0%
2020	May	17	100.0%
2020	Jun	105	98.1%
2020	Jul	153	100.0%
2020	Aug	286	100.0%
2020	Sep	44	100.0%
2020	Oct	877	99.8%
2020	Nov	225	100.0%
2020	Dec	111	100.0%
2020	Average	153	99.8%

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 10-8 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average scheduled MW for the RTO Zone. In 2020, the weighted average nonsynchronized market clearing price was $0.19 per MW. The average nonsynchronized reserve scheduled was 1,052.2 MW.

Figure 10-8 Daily average RTO Zone nonsynchronized reserve market clearing price and MW purchased: 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.[63]

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 2020, the average price of nonsynchronized reserve was $0.19. The average cost per MW of nonsynchronized reserve was $0.91.

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.

63 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 2.16 Minimum Capacity Emergency in Day-ahead Market, Rev. 112 (Jan. 5, 2021).

Table 10-26 RTO zone nonsynchronized reserve MW, charges, price, and cost: 2019 through 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	Oct	773,420	$1,588,183	$0.93	$2.05	45.2%
RTO Zone	2020	Nov	725,048	$809,177	$0.36	$1.12	31.9%
RTO Zone	2020	Dec	851,859	$921,357	$0.07	$1.08	6.4%
RTO Zone	2020	Total	9,078,323	$8,229,669	$0.19	$0.91	18.1%

Secondary Reserve (DASR)

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.[64]

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 2020, the average available hourly DASR was 52,303.9 MW, an 18.0 percent increase from 2019. The DASR hourly MW purchased averaged 5,133.9 MW.

PJM excludes resources that cannot reliably provide reserves in real time from participating in the DASR market. Such resources include nuclear, run of river hydro, self scheduled pumped hydro, wind, solar, and energy storage resources.[65] The intent of this proposal is to limit cleared DASR resources to those resources actually capable of

64 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 10.5 Aggregation for Economic and Emergency Demand Resources, Rev. 112 (Jan. 5, 2021).
65 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 112 (Jan. 5, 2021).

providing reserves in the real-time market. Owners of excluded resources may request an exemption from their default noneligibility.

Of the scheduled DASR MW cleared in 2020, 80.6 percent was from CTs (Table 10-27).

Table 10-27 Scheduled DASR by fuel and unit type: 2020

Unit Type	Percentage of DASR MW	Percentage of DASR Credits
CT - Natural Gas	61.7%	51.7%
CT - Oil	18.9%	18.2%
Hydro - Pumped Storage	10.3%	3.6%
Steam - Coal	5.6%	9.0%
Combined Cycle	2.8%	13.0%
Steam - Natural Gas	0.3%	3.0%
RICE - Oil	0.2%	0.7%
RICE - Other	0.1%	0.4%
RICE - Natural Gas	0.1%	0.3%
Hydro - Run of River	0.0%	0.0%
Battery	0.0%	0.0%
CT - Other	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Nuclear	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Steam - Other	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

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.[66] The DASR requirement is calculated daily and 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. Effective November 1, 2020 through October 31, 2021, the day-ahead scheduling reserve requirement is 4.78 percent of the peak load forecast. This is based on a 2.18 percent load forecast error component and a 2.60 percent forced outage rate component. The DASR requirement is applicable for all hours of the operating day.

66 See PJM "Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 77 (Jan. 1, 2021).

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."[67] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[68] 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 2020 through October 2021, the SCD values are 2.12 percent for winter and 4.72 percent for summer. PJM Dispatch may also schedule additional day-ahead scheduling reserves as deemed necessary for conservative operations.[69] 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.[70] The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand on 18 days during 2020. The 22 hours with the highest DASR market clearing prices during 2020 were all on these 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.

67 PJM. "Energy and Reserve Pricing & Interchange Volatility Final Proposal Report," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20141030/20141030-item-04-erpiv-final-proposal-report.ashx>.

68 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Requirement. Rev. 112 (Jan. 5, 2021)

69 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Reserve Requirement, Rev. 112 (Jan. 5, 2021).

70 See PJM "Manual 13: Emergency Operations," § 3.2 Conservative Operations, Rev. 77, (Jan. 1, 2021).

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: 2019 through 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	Oct	170	0.0%
2020	Nov	70	0.0%
2020	Dec	69	0.0%
2020	Average	97	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.[71] Units that do not offer have their offers set to $0.00 per MW during the day-ahead market clearing process.

Economic withholding remains an issue in the DASR market. The marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. In 2020, 39.4 percent of generation units offered DASR at a daily price above $0.00 per MW, compared to 40.0 percent in 2019. 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 2020, the DASR market cleared at a price above $0.00 per MW in 14.1 percent of all hours. The weighted average DASR price for all cleared hours was $0.25 per MW. The average cleared MW in all hours was 4,476.6 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 4,772.7 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. In 2020, PJM added AFD to the normal 5.07 percent in 430 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: 2020

Metric	Number Hours	Weighted Day-Ahead Scheduling Reserve Market Clearing Price (DASRMCP)	Average Hourly Total DASR MW
All Hours	8,784	$0.30	4,911.5
All Hours when DASRMCP > $0	1,235	$1.75	6,079.1
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.

71 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 112 (Jan. 5, 2021).

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 2020 was $1.75 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: 2019 through 2020

		Number of Hours DASRMCP>$0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
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	5,064	NA	$1,982	NA
2020	Oct	203	NA	$0.31	NA	80,004	NA	4,195	NA	$1,295	NA
2020	Nov	86	NA	$0.21	NA	89,150	NA	4,484	NA	$928	NA
2020	Dec	91	NA	$0.20	NA	100,845	NA	4,820	NA	$977	NA
2020		1235	430	$0.61	$2.55	93,687	106,187	5,150	9,843	$4,352	$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 2020.

Table 10-31 DASR market all hours of DASR market clearing price greater than $0: 2019 through 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	531,772	0	$207,765
2020	Oct	203	$0.31	80,004	851,671	0	$262,925
2020	Nov	86	$0.21	89,150	385,608	0	$79,842
2020	Dec	91	$0.20	100,845	438,634	0	$88,929
2020	Total	1,235	$0.72	103,069	7,507,959	3,979,093	$24,218,754

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 January through May and September through December of 2020 kept DASR price and cost lower than in 2019.

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.[72] 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

72 Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

with faster ramp rates. Resources must qualify to follow one or both of the RegA and RegD signals, but will be assigned by the market clearing engine to follow only one signal in a given market hour.

The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW being offered); performance ($/mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The marginal benefit factor (MBF) and performance score translate a RegD resource's capability (actual) MW into marginal effective MW and offers into $/effective MW.

The regulation market solution is intended to meet the regulation requirement with the least cost combination of RegA and RegD. When solving for the least cost combination of RegA and RegD MW to meet the regulation requirement, the regulation market will substitute RegD MW for RegA MW when RegD is cheaper. Performance adjusted RegA MW are used as the common unit of measure, called effective MW, of regulation service. All resource MW (RegA and RegD) are converted into effective MW. RegA MW are converted into effective MW by multiplying the RegA MW offered by their performance score. RegD MW are converted into effective MW by multiplying the RegD offered by their performance score and by the MBF. The regulation requirement is defined as the total effective MW required to provide a defined amount of area control error (ACE) control.

The regulation market converts performance adjusted RegD MW into effective MW using the MBF in the PJM design. The MBF is used to convert incremental additions of RegD MW into incremental effective MW. The total effective MW for a given amount of RegD MW equal the area under the MBF curve (the sum of the incremental effective MW contributions). RegA and RegD resources should be paid the same price per marginal effective MW.

The marginal rate of technical substitution (MRTS) is the marginal measure of substitutability of RegD resources for RegA resources in satisfying a defined regulation requirement at feasible combinations of RegA and RegD MW. While resources following RegA and RegD can both provide regulation service in PJM's Regulation Market, PJM's joint optimization is intended to determine and assign the optimal mix of RegA and RegD MW to meet the hourly regulation requirement. The optimal mix is a function of the relative effectiveness and cost of available RegA and RegD resources.

At any valid combination of RegA and RegD, regulation offers are converted to dollars per effective MW using the RegD offer and the MBF associated with that combination of RegA and RegD. The marginal contribution of a RegD MW to effective MW is equal to the MRTS associated with that RegA/RegD combination.

For example, a 1.0 MW RegD resource with a total offer price of $2 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.[73] Performance scores are reported on an hourly basis for each resource.

Table 10-32 and Figure 10-9 show the average performance score by resource type and the signal followed in 2020. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[74] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-9 shows, 82.2 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 33.2 percent of RegA resources had average performance scores within that range in 2020. These scores are higher than the scores for both product

73 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 40 (March 26, 2020).

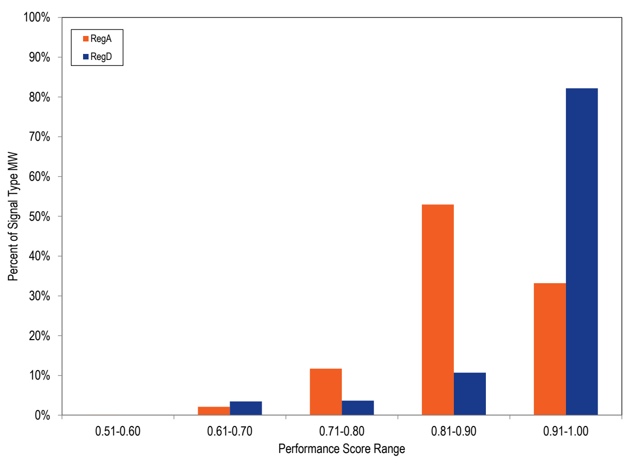
74 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

types in 2019, where 70.7 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 21.0 percent of RegA resources had average performance scores within that range.

Table 10-32 Hourly average performance score by unit type: 2020

		Performance Score Range				
		51-60	61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-	-
	CT	-	0.0%	2.1%	42.0%	55.9%
	Diesel	-	-	-	-	95.8%
	DSR	-	2.8%	4.5%	92.3%	0.4%
	Hydro	-	-	0.2%	38.1%	61.7%
	Steam	0.1%	3.0%	16.3%	59.2%	21.4%
RegD	Battery	-	3.7%	1.9%	9.1%	85.3%
	CT	-	0.0%	2.2%	97.8%	0.0%
	Diesel	-	-	0.0%	88.1%	-
	DSR	0.0%	0.0%	36.4%	38.2%	25.4%
	Hydro	-	0.0%	-	11.0%	89.0%
	Steam	-	-	-	-	-

Figure 10-9 Hourly average performance score by regulation signal type: 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 definitions[75]

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.

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,

75 See PJM. "Regulation Requirement Definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>.

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.[76]

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.[77]

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.[78] That rule continues in effect. The result of the current FERC order is that the MBF is used in market clearing to determine the relative value of an additional MW of RegD, but the MBF is not used in the settlement for RegD.

If the MBF were consistently applied, every resource would receive the same clearing price per marginal effective MW. But the MBF is not consistently applied and resources do not receive the same clearing price per marginal effective MW.

The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the mileage required of RegD resources and changed the energy neutrality component of the signal from a strict 15 minute neutrality to a conditional 30 minute neutrality. The changes in signal design increased the mileage ratio (the ratio of RegD mileage to RegA mileage). In addition, to adapt to the 30 minute neutrality requirement, some RegD resources decreased their offered capability to maintain their performance.

Figure 10-10 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio decreased from 7.17 in 2019, to 6.55 in 2020 (a decrease of 8.7 percent). The average MBF in 2019 was 1.27, and the average MBF in 2020 was 0.72. 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

76 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.

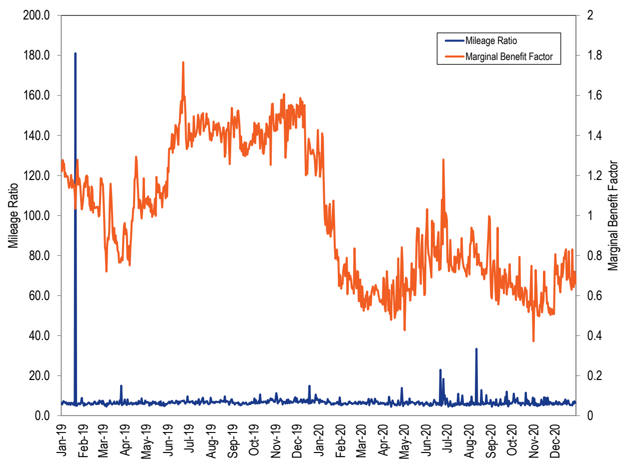
77 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

78 145 FERC ¶ 61,011 (2013).

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 10-10 Daily average MBF and mileage ratio: 2019 through 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, 2019 through 2020. Although the average regulation market clearing price in 2020 was $2.72 lower than in 2019 (See Table 10-47), RegD was still overpaid due to the lower average MBF. In 2019, RegD resources earned 35.7 percent more per performance adjusted actual MW than RegA resources. In 2020, RegD resources earned 23.2 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: 2019 through 2020

		Settlement Payments		
Year	Month	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%
	Oct	$21.82	$17.31	26.0%
	Nov	$19.45	$15.25	27.5%
	Dec	$18.18	$15.34	18.6%
Yearly		$16.01	$13.00	23.2%

The current settlement process does not result in paying RegA and RegD resources the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the MBF is not used in settlements. Instead of being paid based on the MBF, (RMCCP + RMPCP)*MBF, RegD resources are currently paid based on the mileage ratio (RMCCP + (RMPCP*mileage ratio)). Because the RMCCP component makes up the majority of the overall clearing price, when the MBF is above one, RegD resources can be underpaid on a per effective MW basis by the current payment method, unless offset by a high mileage ratio. When the MBF is less than one, RegD resources are overpaid on a per effective MW basis, unless offset by a low mileage ratio. The average MBF was greater than 1.0 in 2019 (1.27). However, RegD resources were still overpaid on average compared to payment on a per effective MW basis. In 2020, the average MBF was equal to 0.72.

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 2019 (1.72), while the average daily mileage ratio was 7.17, resulting in RegD resources being paid $12.0 million more than they would have been if the MBF were correctly implemented. In 2020, the MBF averaged 0.72, while the average daily mileage ratio was 6.55, resulting in RegD resources being paid $112.1 million more than they would have been if the MBF were correctly implemented.

Figure 10-11 Maximum, minimum, and average PJM calculated MBF by month: 2019 through 2020

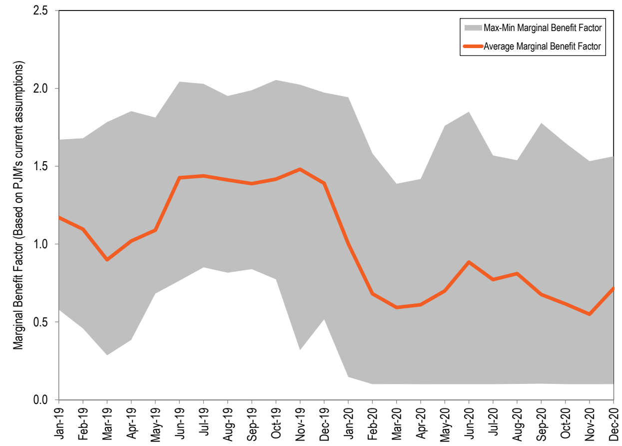


Table 10-35 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: 2019 through 2020

		RegD Settlement Payments				
Year	Month	Mileage Based RegD ($/Effective MW)	Marginal Rate of Technical Substitution Based RegD ($/Effective MW)	RegA ($/Effective MW)	Percent RegD Overpayment ($/Effective MW)	Total RegD Overpayment ($)
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%	$6,584,760
	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
	Oct	$69.18	$17.31	$17.31	299.6%	$18,415,455
	Nov	$63.11	$15.25	$15.25	313.8%	$15,834,343
	Dec	$43.39	$15.34	$15.34	182.9%	$10,642,479
Yearly		$37.30	$13.00	$13.00	186.9%	$112,115,592

Figure 10-11 shows, the monthly maximum, minimum and average MBF, for 2019 through 2020. The average daily MBF in 2020 was 0.72. The average daily MBF in 2019 was 1.27. The flat line at the bottom of the MBF range from February 2020 to December 2020 is caused by the MBF reaching the minimum threshold of 0.1, administratively set by PJM.

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.[79]

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.

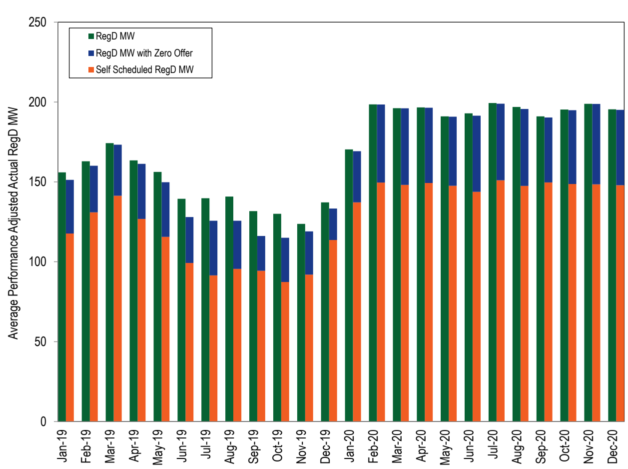
Figure 10-12 shows, by month, the proportion of cleared RegD MW with an effective price of $0.00 (units with zero offers plus self scheduled units) for 2019 through 2020. In 2020, an average of 99.7 percent of all RegD MW clearing the market had an effective offer of $0.00. In 2019, an average of 94.2 percent of all cleared RegD

79 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>.

MW had an effective cost of $0.00. In 2020, an average of 76.2 percent of all RegD offers were self scheduled, compared to an average of 74.1 percent of all RegD offers in 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 47.2 MW (32.3 percent), from 146.3 MW in 2019 to 193.5 MW in 2020. The average monthly RegD cleared with an effective cost of zero increased 54.8 MW (39.6 percent), from 138.2 MW in 2019 to 193.0 MW in 2020. Self scheduled RegD cleared MW increased 38.6 MW (35.4 percent), from 108.8 MW in 2019 to 147.4 MW in 2020. Average cleared RegD MW with a zero cost offer increased 16.2 MW (55.2 percent), from 29.4 MW in 2019 to 45.6 MW in 2020. The increase in the average monthly RegD cleared resulted in the reduction of the average monthly MBF seen in Figure 10-11.

Figure 10-12 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: 2019 through 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.

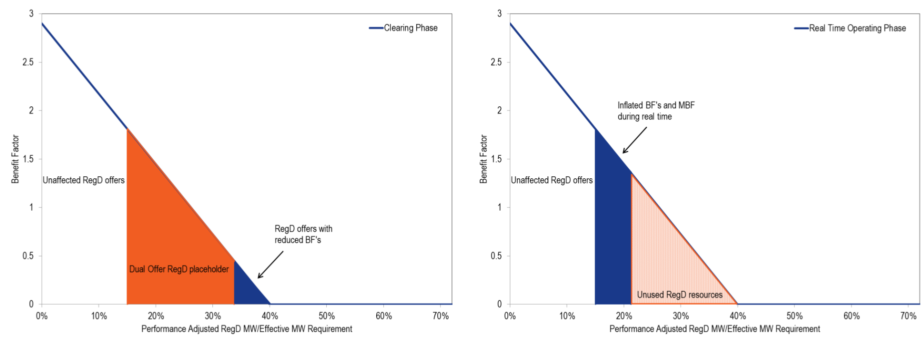
After rank ordering the resources, each dual offer resource is assigned to run as either a RegD or RegA resource based on which of the two offers has a lower effective cost. While this recognizes that the dual offer resource cannot supply both RegA MW and RegD MW at the same time, PJM does not redefine 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.

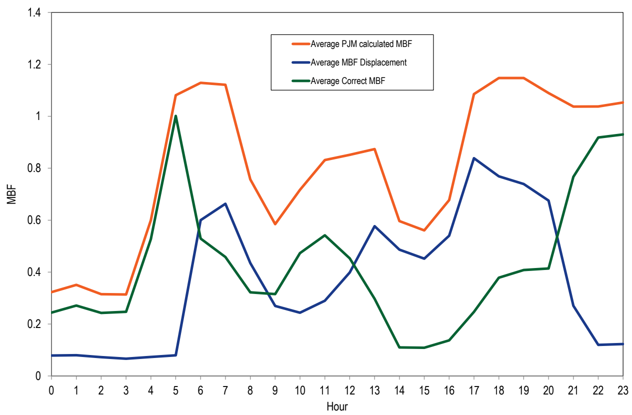
The issue is illustrated in Figure 10-13. The example shows a clearing phase and a real time operating phase. In this example, a 150 MW unit offers both RegA and RegD. The 150 MW unit's position in the RegD effective cost curve and the potential effective MW are represented as the orange area under the 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 10-13 Clearing phase BF/effective MW reduction, real-time BF/effective MW inflation, and exclusion of available RegD resources



In 2020, all but four hours had at least one unit with a dual offer. In 2020, 81.8 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 0.48 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 10-14 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 2020 if the clearing solution was solved correctly.

Figure 10-14 Effect of PJM's current dual offer clearing method on the average MBF in each hour of the day: 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.

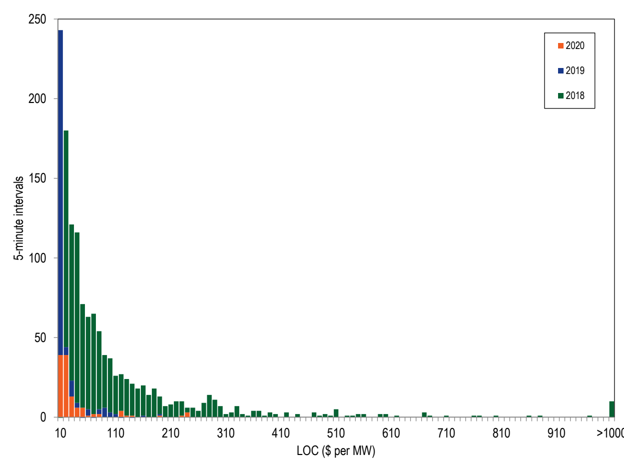
Price Spikes

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.[80] 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 10-15 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 in 2020.

Figure 10-15 LOC distribution in each five minute interval with a RegD marginal unit and an LOC greater than zero: 2018, 2019, and 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

80 See 166 FERC ¶ 61,040 (2019).

per effective MW. So long as RegA MW are available for less than $1,000 per effective MW, this resource will not clear. The only way for RegD MW to clear to the point where the MBF of the last MW is 0.001, is if the offer price of the relevant resources that clear, including estimated LOC, is $0.00. But, if the same resource(s) has a positive LOC within the hour, based on real-time changes in LMP, the zero priced offer is adjusted to reflect the positive LOC, resulting in an extremely high offer and clearing price for regulation.

While an incorrect estimate of a potential LOC can result in an extremely high price, the resulting regulation market prices are mathematically correct for the price of each effective MW. The prices in every interval reflect the marginal costs of regulation given the resources dispatched and accurately reflect the marginal offer of minimally effective resources which had unexpectedly high LOC components of their within hour offers. But, due to the current market design's failure to make use of the MBF in settlement, RegD is not paid on a dollar per effective MW basis. This disconnect between the process of setting price and the process of paying resources is the primary source of the market failure in PJM's Regulation Market and the cause of the observed price spikes in the regulation market. In the example, the 0.001 MW from the RegD resource should be paid $1,000 times 0.001 MW or $1.00. But the current rules would pay the RegD resource $1,000 times 1.0 MW or $1,000. If the market clearing and the settlements rules were consistent, the incentive for this behavior would be eliminated. The current rules provide a strong incentive for this behavior.

The prices spikes observed in PJM's Regulation Market are a symptom of a market failure in PJM's Regulation Market. The market failure in PJM's Regulation Market is caused by an inconsistent application of the MBF between market clearing and market settlement. Due to the inconsistent application of the MBF, the current market results are not consistent with a competitive market outcome. In any market, resources should be paid the marginal clearing price for their marginal contribution. In the regulation market, all resources should be paid the marginal clearing price per effective MW and all resources in the regulation market should be paid for each of their effective MW. PJM's Regulation Market does not do this. PJM's market applies the MBF in determining the relative and total value of RegD MW in the market solution for purposes of market clearing and price, but does not apply the same logic in determining the payment of RegD for purposes of settlement. As a result, market prices do not align with payment for contributions to regulation service in market settlements.

The inconsistent application of the MBF in PJM's regulation market design is generating perverse incentives and perverse market results. The price spikes are a symptom of the problem, not the problem itself.

Market Structure

Supply

Table 10-36 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in 2020.[81] 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.[82] 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 2020, the average hourly offered supply of regulation for nonramp hours was 720.9 actual MW (721.3 effective MW). This was a decrease of 64.6 actual MW (a decrease of 67.0 effective MW) from 2019, when the average hourly offered supply of regulation was 785.5 actual MW (788.3 effective MW). In 2020, the average hourly offered supply of regulation for ramp hours was 1,017.4 actual MW (1,058.9 effective MW). This was a

81 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.

82 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 112 (Jan. 5, 2021).

decrease of 97.9 actual MW (a decrease of 60.8 effective MW) from 2019, when the average hourly offered supply of regulation was 1,115.3 actual MW (1,119.7 effective MW).

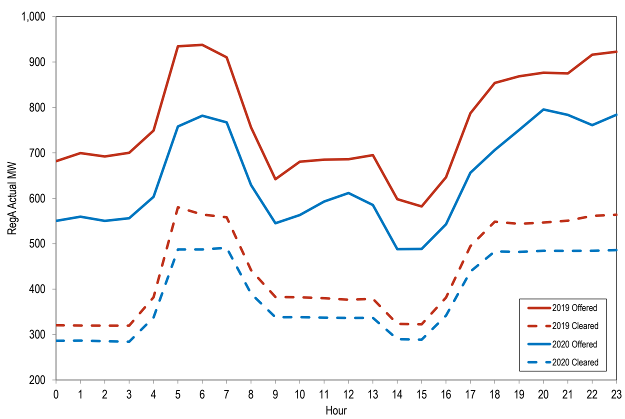
The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for ramp hours was 1.45 in 2020 (1.53 in 2019). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for nonramp hours was 1.47 in 2020 (1.67 in 2019).

Table 10-36 Hourly average actual and effective MW offered and cleared: 2020[83]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Actual Offered MW	Ramp	1,017.4	1,005.0	12.4	769.7	247.7
	Nonramp	720.9	711.7	9.2	514.5	206.4
Effective Offered MW	Ramp	1,058.9	1,044.7	14.1	668.7	390.2
	Nonramp	721.3	715.0	6.3	445.8	275.5
Actual Cleared MW	Ramp	702.8	690.5	12.4	486.9	216.0
	Nonramp	491.9	482.8	9.2	287.0	204.9
Effective Cleared MW	Ramp	800.0	785.9	14.1	424.7	375.4
	Nonramp	525.2	519.0	6.2	250.3	274.9

The average hourly offered and cleared actual MW from RegA resources are shown in Figure 10-16. The average hourly offered MW from RegA resources during ramp hours for 2020 was 769.7 actual MW, a decrease of 14.9 percent from 2019 (905.0 actual MW.) The average hourly offered MW from RegA resources during nonramp hours for 2020 was 514.5 actual MW, a decrease of 17.5 percent from 2019 (623.7 actual MW). The average hourly cleared MW from RegA resources during ramp hours for 2020 was 486.9 actual MW, a decrease of 12.7 percent from 2019 (558.0 actual MW). The average hourly cleared MW from RegA resources during nonramp hours for 2020 was 287.0 actual MW, a decrease of 9.9 percent from 2019 (318.4 actual MW).

Figure 10-16 Average hourly RegA actual MW offered and cleared: 2019 and 2020



The average hourly offered MW from RegD resources during ramp hours for 2020 was 247.7 actual MW, an increase of 17.8 percent from 2019 (210.3 actual MW). (Figure 10-17) The average hourly offered MW from RegD resources during nonramp hours for 2020 was 206.4 actual MW, an increase of 27.6 percent from 2019 (161.8 actual MW) (Figure 10-17). The average hourly cleared MW from RegD resources during ramp hours for 2020 was 216.0 actual MW, an increase of 27.1 percent from 2019 (169.9 actual MW). The average hourly cleared MW from RegD resources during nonramp hours for 2020 was 204.9 actual MW, an increase of 35.1 percent from 2019 (151.7 actual MW).

83 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 RegD actual MW offered and cleared: 2019 and 2020

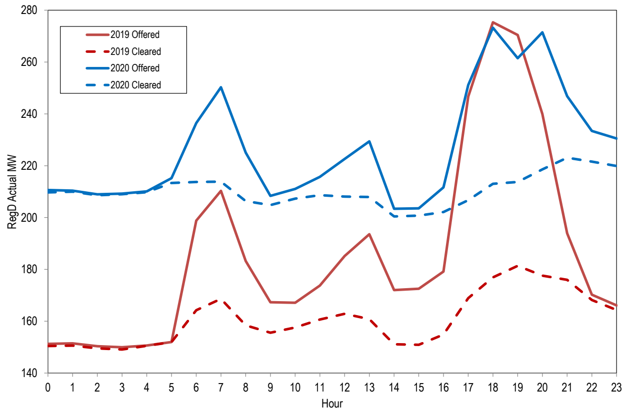


Table 10-37 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, the percent of settled regulation provided by unit type, and the clearing price, uplift, and total regulation credits. In Table 10-37 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW increased 2.0 percent from 4,533,478.5 MW in 2019 to 4,625,428.8 MW in 2020. The average proportion of regulation provided by battery units had the largest increase (10.9 percent), providing 23.7 percent of regulation in 2019 and 34.6 percent of regulation in 2020. Natural gas units had the largest decrease in average proportion of regulation provided (8.4 percent), decreasing from 47.9 percent in 2019, to 39.5 percent in 2020. The total regulation credits in 2020 were $76,831,710, down 15.1 percent from $90,505,633 in 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 2020 compared to 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 12.4 percent from $9,449,517 in 2019 to $8,277,653 in 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 2020 compared to 2019. Coal units had the largest increase in uplift payments, increasing 7.7 percentage points from 36.6 percent in 2019, to 44.4 percent in 2020, while only responsible for 7.5 percent of the provided settled regulation. Natural gas units had the largest decrease in uplift payments, decreasing 8.3 percentage points from 37.1 percent in 2019, to 28.8 percent in 2020.

The MMU has identified a potential issue in the calculation of regulation LOC and 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.

Table 10-37 PJM regulation by source: 2019 and 2020[84]

	2019						2020					
Source	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	1,074,449	23.7%	$22,390,635	$0	$22,390,636	22	1,600,435	34.6%	$25,967,275	$0	$25,967,275
Coal	21	371,954	8.2%	$6,324,731	$3,462,686	$9,787,417	19	344,862	7.5%	$5,131,262	$3,673,944	$8,805,206
Hydro	25	806,385	17.8%	$15,028,236	$2,478,514	$17,506,750	27	774,796	16.8%	$10,963,914	$2,220,425	$13,184,339
Natural Gas	173	2,170,167	47.9%	$34,925,581	$3,508,316	$38,433,897	180	1,826,396	39.5%	$25,137,267	$2,383,283	$27,520,551
DR	26	110,523	2.4%	$2,386,933	$0	$2,386,933	21	78,939	1.7%	$1,354,339	$0	$1,354,339
Total	269	4,533,478.5	100.0%	$81,056,117	$9,449,517	$90,505,633	269	4,625,428.8	100.0%	$68,554,057	$8,277,653	$76,831,710

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 by submitted year: 2014 through 2020

Year	Number of Storage Projects	Total Capacity (MW)
2014	1	10.0
2015	5	61.0
2016	0	0.0
2017	3	2.5
2018	21	690.3
2019	67	4,187.7
2020	164	9,873.3
Total	261	14,824.7

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

84 Biomass data have been added to the natural gas category for confidentiality purposes.

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 492.0 hourly average performance adjusted actual MW in 2020. This is an increase of 22.5 performance adjusted actual MW from 2019, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 469.5 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 702.5 hourly average performance adjusted actual MW in 2020. This is a decrease of 25.3 performance adjusted actual MW from 2019, where the average hourly regulation cleared MW for ramp hours were 727.8 performance adjusted actual MW.

Table 10-39 Required regulation and ratio of supply to requirement: 2019 through 2020

		Average Required Regulation (MW)		Average Required Regulation (Effective MW)		Ratio of Supply MW to MW Requirement		Ratio of Supply Effective MW to Effective MW Requirement	
Hours	Month	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	696.0	800.0	800.1	1.49	1.46	1.39	1.33
	Nov	753.3	700.9	800.1	800.1	1.47	1.43	1.37	1.30
	Dec	731.7	705.5	800.0	800.1	1.46	1.56	1.35	1.40
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	491.3	525.0	525.2	1.53	1.50	1.40	1.41
	Nov	479.6	501.8	525.0	525.5	1.65	1.50	1.50	1.41
	Dec	469.9	500.8	525.0	525.1	1.60	1.63	1.46	1.50

Market Concentration

In 2020, the effective MW weighted average HHI of RegA resources was 2488 which is highly concentrated and the weighted average HHI of RegD resources was 1853 which is highly concentrated. The weighted average HHI of all resources was 1410, 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 2020, 93.5 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market in 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 2020

	Percent of Hours Pivotal		
Month	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%	94.0%
Nov	78.2%	90.7%	91.0%
Dec	74.2%	96.1%	83.6%
Average	81.7%	90.6%	93.5%

Market Conduct

Offers

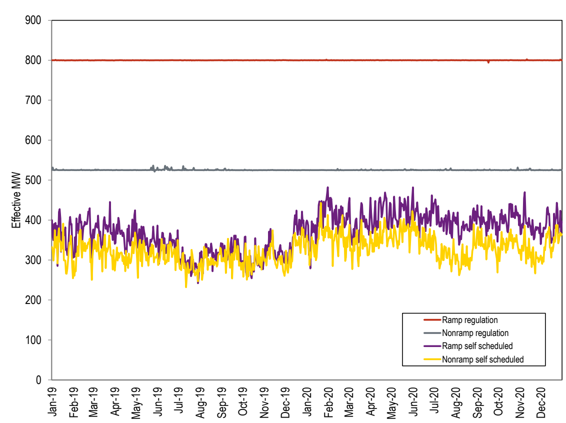
Resources seeking to regulate must qualify to follow a regulation signal by passing a test for that signal with at least a 75 percent performance score. The regulating resource must be able to supply at least 0.1 MW of regulation and not allow the sum of its regulating ramp rate and energy ramp rate to exceed its overall ramp rate.[85] 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.[86]

Offers in the PJM Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (ΔMW of regulation movement) provided. The capability component for cost-based offers is not to exceed the increased fuel costs resulting from operating the regulating unit at a lower output level than its economically optimal output level, plus a $12.00 per MW margin. The $12.00 margin embeds market power in the regulation offers 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.[87]

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.[88]

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).[89] Figure 10-18 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.[90] Self scheduled regulation comprised an average of 50.1 percent during ramp hours and 64.8 percent during nonramp hours in 2020.

Figure 10-18 Nonramp and ramp regulation levels: 2019 through 2020



85 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 112 (Jan. 5, 2021).

86 Id. at 3.2.2, at p 62.

87 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 37 (Dec. 9, 2020).

88 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 112 (Jan. 5, 2021).

89 See "PJM Manual 28: Operating Agreement Accounting," § 4.1Regulation Accounting Overview, Rev. 84 (Dec. 17, 2020).

90 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 112 (Jan. 5, 2021).

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 48.9 percent of the total effective MW in December 2020) and a growing proportion of resources that self schedule (25.0 percent of all self scheduled effective MW in October 2012 and 71.4 percent of all self scheduled effective MW in December 2020). In 2020, the average RegD percentage of total self scheduled effective MW was 71.2 percent, an increase of 5.9 percent from 2019, when the average was 65.3 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).

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 2020, 47.0 percent was purchased in the PJM market, 48.2 percent was self scheduled, and 4.8 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 2012 through 2020. Table 10-42 and Table 10-43 are based on settled (purchased) MW.

Table 10-41 RegD self scheduled regulation by month: 2018 through 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
2018	Jan	130.6	274.3	247.4	673.8	52.8%	40.7%
2018	Feb	131.1	276.6	245.5	674.0	53.4%	41.0%
2018	Mar	126.6	270.9	249.4	639.8	50.8%	42.3%
2018	Apr	124.8	266.5	232.3	639.6	53.7%	41.7%
2018	May	124.7	275.7	223.0	639.6	55.9%	43.1%
2018	Jun	136.0	298.4	241.5	696.8	56.3%	42.8%
2018	Jul	138.5	294.6	248.3	696.9	55.8%	42.3%
2018	Aug	159.6	274.3	271.6	697.0	58.8%	39.4%
2018	Sep	150.1	256.7	251.4	644.3	59.7%	39.8%
2018	Oct	148.0	266.6	256.6	639.6	57.7%	41.7%
2018	Nov	144.0	252.9	274.8	640.4	52.4%	39.5%
2018	Dec	172.0	273.0	308.5	674.0	55.7%	40.5%
2018 Average		140.5	263.8	254.2	663.0	55.2%	41.2%
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%
2020	Oct	265.7	319.2	368.3	639.8	72.1%	49.9%
2020	Nov	255.1	321.4	346.5	640.6	73.6%	50.2%
2020	Dec	262.1	329.8	366.8	674.0	71.4%	48.9%
2020 Average		264.0	325.2	371.2	662.7	71.2%	49.1%

Table 10-42 Regulation sources: spot market, self scheduled, bilateral purchases: 2019 through 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	189,151.3	46.4%	198,595.7	48.7%	19,997.5	4.9%	407,744.5
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
2020	Oct	178,179.3	46.9%	186,687.3	49.1%	15,309.5	4.0%	380,176.1
2020	Nov	180,188.6	48.9%	172,941.0	46.9%	15,668.5	4.2%	368,798.1
2020	Dec	189,587.0	47.8%	188,798.6	47.6%	18,505.0	4.7%	396,890.6
Total		2,156,968.5	47.0%	2,215,555.1	48.2%	221,642.5	4.8%	4,594,166.0

Table 10-43 Regulation sources: 2012 through 2020

Year	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2012	6,149,110.0	78.6%	1,484,446.2	19.0%	193,408.0	2.5%	7,826,964.2
2013	3,088,963.1	57.7%	2,064,156.7	38.5%	204,260.5	3.8%	5,357,380.3
2014	2,327,322.4	49.3%	2,161,996.5	45.8%	231,218.0	4.9%	4,720,536.9
2015	2,546,688.3	54.4%	1,888,040.0	40.3%	250,386.1	5.3%	4,685,114.3
2016	2,260,701.6	48.6%	2,104,775.1	45.2%	287,809.5	6.2%	4,653,286.2
2017	2,504,264.1	55.2%	1,783,045.7	39.3%	250,184.5	5.5%	4,537,494.3
2018	2,755,355.7	60.5%	1,558,388.9	34.2%	243,589.5	5.3%	4,557,334.1
2019	2,367,346.1	53.1%	1,867,285.3	41.9%	221,292.5	5.0%	4,455,923.9
2020	2,156,968.5	47.0%	2,215,555.1	48.2%	221,642.5	4.8%	4,594,166.0

In 2020, DR provided an average of 12.4 MW of regulation per hour during ramp hours (16.2 MW of regulation per hour during ramp hours in 2019), and an average of 9.2 MW of regulation per hour during nonramp hours (13.1 MW of regulation per hour during nonramp hours in 2019). Generating units supplied an average of 690.5 MW of regulation per hour during ramp hours in 2020 (711.7 MW of regulation per hour during ramp hours in 2019), and an average of 482.8 MW per hour during nonramp hours in 2020 (456.9 MW of regulation per hour during nonramp hours in 2019).

Market Performance

Price

Table 10-47 shows the regulation price and regulation cost per MW for 2009 through 2020. The weighted average RMCP for 2020 was $13.55 per MW. This is a decrease of $2.72 per MW, or 16.7 percent, from the weighted average RMCP of $16.27 per MW in 2019. This decrease in the regulation clearing price was the result of a decrease in energy prices in 2020 and the related decrease in the opportunity cost component of RMCP.

Figure 10-19 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 10-19 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 10-19 Regulation market clearing price components (Dollars per MW): 2020

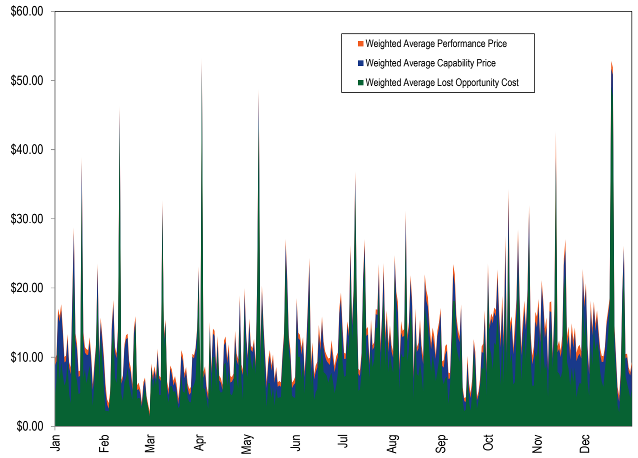


Table 10-44 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-19 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-44 Regulation market monthly component of price (Dollars per MW): 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
Oct	$16.48	$1.16	$17.64
Nov	$14.71	$1.24	$15.95
Dec	$14.99	$0.79	$15.79
Average	$12.68	$0.88	$13.55

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 2020 was $76.9 million, compared to $90.5 million in 2019.

Table 10-45 Total regulation charges: 2019 through 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	$6,112,905	$12.90	$17.11	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	$7,991,867	$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	$6,495,664	$13.70	$16.76	81.7%
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	407,744.5	$7,732,029	$16.14	$18.96	85.1%
2020	Aug	407,097.0	$7,566,611	$15.36	$18.59	82.6%
2020	Sep	366,741.7	$4,909,677	$10.88	$13.39	81.2%
2020	Oct	380,176.1	$8,168,776	$17.64	$21.49	82.1%
2020	Nov	368,798.1	$7,380,012	$15.95	$20.01	79.7%
2020	Dec	396,890.6	$7,561,054	$15.79	$19.05	82.9%
Yearly		4,594,166.0	$76,860,642	$13.55	$16.73	81.0%

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 2020, the average total cost of regulation was $16.73 per MW, 17.6 percent lower than $20.31 in 2019. In 2020, the monthly average capability component cost of regulation was $13.09, 15.4 percent lower than $15.47 in 2019. In 2020, the monthly average performance component cost of regulation was $1.83, 32.8 percent lower than $2.72 in 2019. The reduction of the average total cost in 2020 versus 2019, was primarily a result of lower LOC values due to lower prices in the energy market.

Table 10-46 Components of regulation cost: 2019 through 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	$2.38	$17.11
	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	$1.64	$16.76
	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	407,744.5	$15.74	$1.54	$1.68	$18.96
	Aug	407,097.0	$14.80	$2.01	$1.78	$18.59
	Sep	366,741.7	$10.42	$1.49	$1.47	$13.39
	Oct	380,176.1	$16.90	$2.80	$1.78	$21.49
	Nov	368,798.1	$15.21	$2.70	$2.11	$20.01
	Dec	396,890.6	$15.40	$1.72	$1.94	$19.05
Yearly		4,594,166.0	$13.09	$1.83	$1.81	$16.73

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 2020 was 81.0 percent, a 1.1 percent increase from 80.1 percent in 2019.

Table 10-47 Comparison of average price and cost for regulation: 2009 through 2020

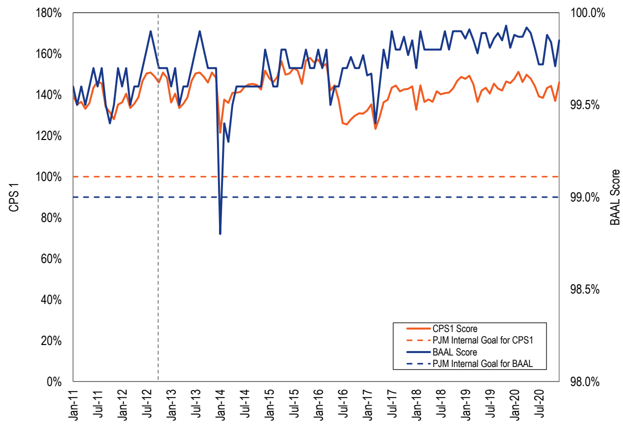
Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$23.00	$7.68	299.2%
2010	$18.00	$14.85	121.2%
2011	$16.49	$13.23	124.6%
2012	$19.02	$12.90	147.5%
2013	$30.85	$35.79	86.2%
2014	$44.49	$53.82	82.7%
2015	$31.92	$38.36	83.2%
2016	$15.73	$18.13	86.7%
2017	$16.79	$23.03	72.9%
2018	$25.32	$31.94	79.3%
2019	$16.27	$20.32	80.1%
2020	$13.55	$16.73	81.0%

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-20 for every month from 2011 through 2020 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[91] 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.

91 See *2019 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Figure 10-20 Monthly CPS1 and BAAL performance: 2011 through 2020



Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[92]

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. Under the current rules PJM has substantial flexibility in procuring black start resources and is responsible for black start resource selection.

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.[93]

In 2020, total black start charges were $64.920 million, an increase of $0.367 million (0.6 percent) from 2019. Operating reserve charges for black start service increased from $0.226 million in 2019 to $0.228 million in 2020. Table 10-48 shows total revenue requirement charges from 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. The result was a significant reduction in operating reserve charges.

Table 10-48 Black start revenue requirement charges: 2010 through 2020

Year	Revenue Requirement Charges	Operating Reserve Charges	Total
2010	$11,490,379	$0	$11,490,379
2011	$13,695,331	$0	$13,695,331
2012	$18,749,617	$8,384,651	$27,134,269
2013	$20,874,535	$86,701,561	$107,576,097
2014	$26,945,112	$32,906,733	$59,851,845
2015	$56,425,648	$5,175,644	$61,601,292
2016	$69,376,257	$279,017	$69,655,275
2017	$69,258,169	$257,174	$69,515,342
2018	$64,439,926	$332,814	$64,772,740
2019	$64,327,918	$226,014	$64,553,932
2020	$64,692,691	$227,801	$64,920,492

Black start zonal charges in 2020 ranged from $0.04 per MW-day in the BGE Zone (total charges were $138,490) to $2.94 per MW-day in the PENELEC Zone (total charges were $4,335,964). 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

92 OATT Schedule 1 § 1.3BB.

93 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).

start rates (calculated as charges per MW-day). For black start service, customers paid an average of $0.80 per MW-day of reserve capacity during 2020.

Table 10-49 Black start zonal charges: 2019 and 2020[94]

	2019					2020				
Zone	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	$2,720,591	$8,343	$2,728,934	3,465	$2.16	$2,572,240	$10,709	$2,582,949	3,656	$1.93
AEP	$17,332,510	$45,020	$17,377,529	30,402	$1.57	$17,239,814	$26,537	$17,266,351	30,052	$1.57
APS	$3,896,777	$1,102	$3,897,879	12,490	$0.85	$3,813,141	$1,159	$3,814,300	12,818	$0.81
ATSI	$5,387,731	$2,934	$5,390,665	17,146	$0.86	$5,574,883	$10,481	$5,585,364	16,786	$0.91
BGE	$362,507	$956	$363,463	8,860	$0.11	$138,490	$628	$139,118	8,957	$0.04
ComEd	$4,182,759	$22,911	$4,205,670	28,544	$0.40	$8,176,146	$22,638	$8,198,784	27,983	$0.80
DAY	$212,839	$1,176	$214,015	4,462	$0.13	$218,116	$14,120	$232,236	4,353	$0.15
DEOK	$353,139	$1,645	$354,784	6,946	$0.14	$357,187	$13,990	$371,177	6,748	$0.15
DLCO	$44,823	$0	$44,823	3,737	$0.03	$43,485	$15,810	$59,295	3,556	$0.05
Dominion	$3,555,714	$27,602	$3,583,315	28,387	$0.35	$4,905,224	$23,222	$4,928,446	26,622	$0.51
DPL	$2,220,509	$13,972	$2,234,481	5,351	$1.14	$2,147,289	$16,762	$2,164,051	5,474	$1.08
EKPC	$336,160	$1,964	$338,124	4,587	$0.20	$324,084	$1,641	$325,725	4,106	$0.22
JCPL	$6,779,387	$7,186	$6,786,572	7,991	$2.33	$2,753,548	$3,058	$2,756,606	8,091	$0.93
Met-Ed	$462,547	$49,545	$512,092	4,048	$0.35	$388,691	$28,169	$416,860	3,989	$0.29
OVEC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
PECO	$1,357,316	$3,169	$1,360,485	11,509	$0.32	$1,394,979	$1,261	$1,396,240	11,258	$0.34
PENELEC	$4,402,565	$1,284	$4,403,849	4,007	$3.01	$4,327,013	$8,952	$4,335,964	4,027	$2.94
Pepco	$2,463,774	$13,611	$2,477,384	8,573	$0.79	$1,549,645	$7,218	$1,556,864	8,269	$0.51
PPL	$1,115,469	$9,091	$1,124,560	10,270	$0.30	$3,061,185	$8,222	$3,069,407	10,604	$0.79
PSEG	$4,190,144	$4,526	$4,194,670	13,341	$0.86	$2,513,183	$2,350	$2,515,534	13,027	$0.53
RECO	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$2,950,660	$9,976	$2,960,636	10,319	$0.79	$3,194,348	$10,873	$3,205,221	10,954	$0.80
Total	$64,327,918	$226,014	$64,553,932	224,434	$0.79	$64,692,691	$227,801	$64,920,492	221,332	$0.80

Table 10-50 provides a revenue requirement estimate by zone for the 2020/2021, 2021/2022 and 2022/2023 Delivery Years.[95] 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.

94 Peak load for each zone is used to calculate the black start rate per MW day.
95 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

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 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.

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

Table 10-52 includes updated CRF values based on the new tax code. The second column is the cost recovery period and not the commitment period.

Table 10-52 Updated CRF table for black start units

Age of Black Start Unit (Years)	Black Start Cost Recovery Period (Years)	Updated 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 $21 million, the overcompensation is $12,180,000 over the 20 year recovery period. For a new black start unit with an investment of $21 million, the overcompensation is $12,285,000 over the five year recovery period.

Table 10-53 Lifetime recovery of black start units with old and updated CRF

Example	Old CRF Rate	Updated CRF Rate	Project Investment	Old CRF Lifetime Recovery	Updated CRF Lifetime Recovery	Updated 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 updated CRF rates were changed to reflect only the change in the tax rate, and for the post 2017 units, the updated 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 updated CRF

Years	Existing Annual Revenue Requirement Total	Updated Annual Revenue Requirement Total	Difference Per Year Total	Updated 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.

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.

NERC – CIP

Currently, no black start units have requested new or additional black start NERC – CIP Capital Costs.[96]

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 10-21 illustrates that the size of the oil tank does not change with the addition of the black start

96 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."

unit. Figure 10-22 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.

Figure 10-21 Oil tank MTSL not changed from addition of black start generator

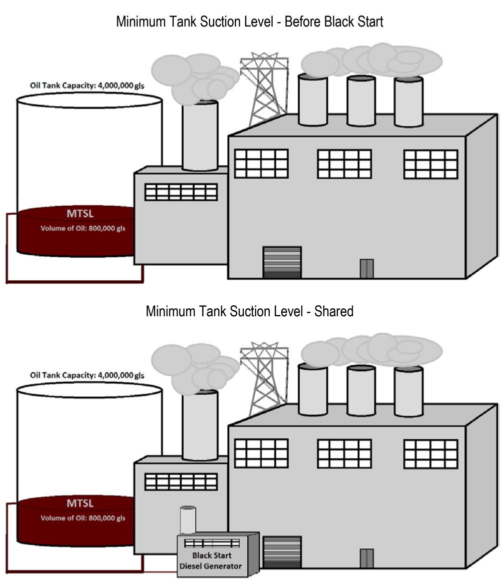
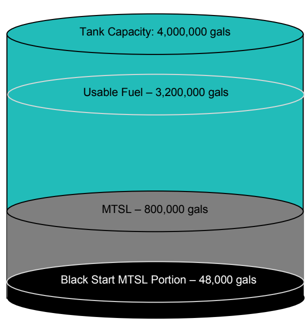


Figure 10-22 Oil tank black start MTSL portion



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.[97]

Any reactive service provided operationally that involves a MW reduction outside of its normal operating range or a startup for reactive power will be logged by PJM operators and awarded uplift or LOC credits.

Reactive Service, Reactive Supply and Voltage Control are provided by generation and other sources of reactive power (such as static VAR compensators and capacitor banks).[98] 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.[99]

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements which

97 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 93, (Aug. 31, 2020).
98 OATT Schedule 2.
99 See "PJM Manual 3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA)," para 2.2 Model Information and Data Requirements, Rev. 19 (Nov. 19, 2020).

are posted monthly on the PJM website.[100] 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.[101] [102]

In 2016, the FERC began to reexamine its policies on reactive compensation.[103] 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.[104] The continued use of fleet rates rather than unit specific rates is also an issue.

Recommended Market Approach to Reactive Costs

The best approach for recovering reactive capability costs is through markets where markets are available as they are in PJM and some other RTOs/ISOs. The best approach for recovering reactive capability costs in PJM is through the capacity market. The capacity market already incorporates reactive costs and reactive revenues. The treatment of reactive costs in the PJM market needs to be modified so that the capacity market incorporates reactive costs and revenues in a more efficient manner.

Reactive capability is an integral part of all generating units; no generating unit is built without reactive capability.[105] 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.[106] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.[107] 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 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 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.[108] The only

100 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).

101 OATT Schedule 2.

102 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.3 Reactive Supply and Voltage Control Charges, Rev. 93 (Aug. 31, 2020).

103 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).

104 See 88 FERC ¶ 61,141 (1999).

105 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.").

106 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).

107 Order No. 827, 155 FERC ¶ 61,277 (2016); *see also* 151 FERC ¶ 61,097 at P 28 (2015).

108 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.

FERC proceeding that has provided an opportunity for the MMU to raise its concerns at hearing has been Panda Stonewall LLC.[109] The initial decision issued in that case sidesteps the issues identified by the MMU.[110] 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."[111] Typically this has meant reliance on manufacturers' specified nameplate power factor.[112] More recently, the Commission has, in the Wabash Orders, required that "reactive power revenue requirement filings must include reactive power test reports."[113] 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.[114]

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 throughout their full operating range in order to obtain interconnection service.[115] 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 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.[116] This is logically consistent with the

109 See Docket No. EL17-1821.
110 167 FERC ¶ 63,010 (April 26, 2019).
111 *AEP mimeo* at 31.
112 See, e.g., *id.*
113 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29 (*Wabash Orders*).
114 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.").
115 *See supra* footnote 27.
116 See OATT Attachment DD § 5.10(a)(iv).

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.[117] This is the average annual reactive capability revenue for combustion turbines from 2005 through 2007, based on the actual costs reported to the Commission in reactive service filings.

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.[118] 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.[119]

Losses

The estimated capability costs also include estimated heating losses relative to MVAR output.[120] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[121] 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.[122] 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

117 *See* OATT Attachment DD § 5.10(a)(v).

118 See OATT Attachment DD §§ 6.4, 6.8(d).

119 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.

120 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).

121 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.

122 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).

or sales of units.[123] 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.[124]

Fleet rates create confusion about what revenue is properly attributable to each unit in the fleet. Reactive rates should be stated separately for each unit, even if multiple plants or units are considered in a single proceeding. The MMU filed with the Commission to require unit specific rates when PJM proposed limited reforms that could have corrected the oversight and compliance problems posed by fleet rates.[125] But PJM rules require fleet owners only to submit informational filings when a reactive unit is transferred or deactivated.[126] The current rules do not require a rate filing, which would place the burden of proof on the company and allow for cost review.[127]

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.[128] 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.[129] 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.[130]

The MMU recommends that fleet rates be eliminated and that compensation be based on unit specific costs and rates.

Reactive Costs

In 2020, total reactive charges were $355.4 million, a 5.7 percent increase from the $336.3 million for 2019. Reactive capability charges increased from $335.8 million in 2019 to $355.0 million in 2020 and reactive service charges decreased from $0.571 million in 2019 to $0.429 million in 2020. All $0.429 million in 2020 were paid for reactive service provided by 17 units in 147 hours.

Table 10-55 shows reactive service charges in 2019 and 2020, reactive capability charges and total charges. Reactive service charges show charges to each zone for reactive service provided and not credits to plants in each zone. Reactive capability charges show charges to each zone for reactive capability.

Table 10-55 Reactive service charges and reactive capability charges by zone: 2019 and 2020

	2019			2020		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
AECO	$0	$4,302,762	$4,302,762	$0	$4,287,746	$4,287,746
AEP	$16,330	$47,443,520	$47,459,850	$4,797	$49,023,536	$49,028,334
APS	$14,903	$15,457,310	$15,472,213	$0	$17,834,079	$17,834,079
ATSI	$697	$25,332,558	$25,333,255	$0	$24,930,943	$24,930,943
BGE	$74,264	$7,193,645	$7,267,910	$0	$6,939,736	$6,939,736
ComEd	$0	$36,552,189	$36,552,189	$0	$40,087,232	$40,087,232
DAY	$0	$2,822,626	$2,822,626	$0	$2,812,775	$2,812,775
DEOK	$0	$9,561,883	$9,561,883	$0	$9,528,512	$9,528,512
Dominion	$182,436	$38,736,292	$38,918,728	$0	$41,365,119	$41,365,119
DPL	$124,034	$9,836,843	$9,960,877	$10,538	$10,599,586	$10,610,123
DLCO	$0	$572,031	$572,031	$0	$570,034	$570,034
EKPC	$14,944	$2,185,379	$2,200,323	$46,753	$2,177,752	$2,224,505
JCPL	$0	$7,391,670	$7,391,670	$181,574	$7,474,645	$7,656,219
Met-Ed	$5,072	$5,287,973	$5,293,045	$4,631	$6,126,496	$6,131,126
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$19,713,916	$19,713,916	$0	$21,035,516	$21,035,516
PENELEC	$137,908	$13,273,303	$13,411,211	$0	$17,585,352	$17,585,352
Pepco	$0	$11,161,942	$11,161,942	$0	$10,838,558	$10,838,558
PPL	$0	$34,837,111	$34,837,111	$180,337	$35,345,889	$35,526,226
PSEG	$0	$27,616,760	$27,616,760	$0	$27,839,542	$27,839,542
RECO	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$16,465,627	$16,465,627	$0	$18,597,887	$18,597,887
Total	$570,589	$335,745,340	$336,315,929	$428,629	$355,000,934	$355,429,564

123 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
124 *Id.*
125 151 FERC ¶ 61,224 at P 29 (2015).
126 OATT Schedule 2.
127 *Id.*
128 *See* Letter Opposing Settlement, Docket No ER06-554 et al. (June 14, 2017).
129 *Id.*
130 162 FERC ¶ 61,029 (2018).

Table 10-56 shows the units which have received reactive service credits for 2020.

Table 10-56 Reactive service credits by plant: 2020

	2020	
Zone	Plant	Reactive Service Credits
AEP	AEP WOLF HILL 1 CT	$2,578
AEP	AEP WOLF HILL 2 CT	$2,219
DPL	DPL BAYVIEW 1 D	$13
DPL	DPL BAYVIEW 2 D	$16
DPL	DPL COMM CHESAPEAKE - NEW CHURCH 2 CT	$10,508
EKPC	EKPC COOPER 1 F	$28,447
EKPC	EKPC COOPER 2 F	$18,305
JCPL	JC LAKEWOOD 1 CT	$14,568
JCPL	JC LAKEWOOD 2 CT	$27,601
JCPL	JC LAKEWOOD NUG F	$28,471
JCPL	JC WOODBRIDGE 1 CC	$55,470
JCPL	JC WOODBRIDGE 2 CC	$55,464
METED	ME MOUNTAIN 1 CT	$4,631
PPL	PL HARWOOD 1-2 CT	$36,103
PPL	PL HAZELTON 2 CT	$6,090
PPL	PL HAZELTON 3 CT	$29,561
PPL	PL HAZELTON 4 CT	$108,584
Total		$428,629

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.[131] 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.[132]

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.

131 157 FERC ¶ 61,122 (2016).
132 See 164 FERC ¶ 61,224 (2018).

VACAR Reserve Sharing Agreement

The VACAR Reserve Sharing Agreement (VRSA) is a combination of agreements among the entities in the VACAR subregion including Dominion.[133] VACAR is a subregion of the SERC Reliability Corporation (SERC) region. The agreement remained in effect in 2020. 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).[134] Dominion is the only party to the VRSA that is also a transmission owner and a generation owner in PJM. The VRSA is not a public agreement. PJM is not a party to the VRSA. However, as the reliability coordinator for Dominion Virginia Power, PJM is responsible for scheduling Dominion's required reserves in the SERC region as described in the PJM manuals.[135]

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 MidAtlanic Dominion area (MAD) when the largest contingency 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.

PJM procures Day-Ahead Scheduling Reserves (DASR) for the PJM region, including Dominion, as Secondary Reserves. The DASR requirement is calculated daily and 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.[136] There is no requirement that a specific amount of DASR be located in Dominion. Equation 1 shows the DASR requirement calculation.[137]

Equation 1: DASR Requirement Formula.

$$\textbf{DASR Requirement} = (\textbf{RFC and EKPC Peak}) \times (\textbf{FOR} + \textbf{LFE}) + \textbf{DOM VACAR}$$

Issues

PJM is expected to implement its ORDC proposal on May 1, 2022. Under the ORDC, it will not be possible for Dominion to hold reserves to meet its obligations under the VRSA without double counting the reserves Dominion has in PJM or withholding such reserves from PJM. Under the ORDC proposal, it will not be possible for Dominion to meet both the VRSA and the PJM reserve rules.

Recommendations

The Market Monitor recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA.

The Market Monitor recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas.

133 VRSA entities: Dominion, Duke Energy Progress, Duke Energy Carolinas, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas.
134 *See* SERC Regional Criteria, Contingency Reserve Policy, NERC Reliability Standard BAL-002 at 10-11.
135 See PJM. "Manual 13: Emergency Operations," Rev. 77 (Jan. 1, 2021).
136 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.
137 During cold weather alerts and hot weather alerts, the DASR requirement is increased to procure additional reserves.

Congestion and Marginal Losses

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.[1] The difference is congestion.[2] As a result, congestion belongs to load and should be returned to load. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.[3]

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus can be divided into three components: the system marginal price (SMP) or energy component, the congestion component (CLMP), and the marginal loss component (MLMP). SMP, MLMP and CLMP are the simultaneous products of the least cost, security constrained dispatch of system resources to meet system load and the use of a load-weighted reference bus. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

SMP is defined as the incremental price of energy for the system, given the current dispatch, at the load-weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load-weighted reference bus. The load-weighted reference bus is not a fixed location but varies with the distribution of load at system load buses. For SMP, energy means the component of LMP not associated with a binding transmission constraint. All other locational prices that result from the least cost, security constrained market solution are higher or lower than this reference point price (SMP) as a result of binding constraints. The reference bus is a point of reference. For a given market solution, changing the reference bus does not change the LMP for any node on the system, but changes only the elements of the nodal prices that are positive or negative due to the binding constraints in that solution. CLMP is defined as the incremental price of meeting load at each bus when a transmission constraint is binding, based on the shadow price associated with the relief of a binding transmission constraint in the security constrained optimization. (There can be multiple binding transmission constraints.) CLMPs are positive or negative depending on location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system CLMPs will be zero. This means that CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion, it is just the absolute LMP difference between the two buses caused by transmission constraints. CLMP is the portion of the LMP at a bus that indicates whether the LMP at that bus is higher or lower than the marginal price of energy SMP at the selected reference bus due to binding transmission constraints. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

MLMP is defined as the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

Total losses refer to total system wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[4] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the single higher price for all the energy used, including energy from low cost and energy from high cost generation, while generators are each paid the price at their individual bus. Congestion is the difference between what load pays based on the single higher price at load buses and what generators receive based on the lower prices at the individual generator buses due to binding transmission constraints.

1 Load is generically referred to as withdrawals and generation is generically referred to as injections, unless specified otherwise.

2 The difference in losses is not part of congestion.

3 PJM billing examples can be found in *2020 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

4 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

The energy, marginal losses and congestion metrics must be interpreted carefully.

In PJM accounting, the term total congestion refers to net implicit CLMP charges plus net explicit CLMP charges plus net inadvertent CLMP charges. The net implicit CLMP charges are the implicit withdrawal CLMP charges less implicit injection CLMP credits.

As with congestion, total system energy costs are more precisely termed net system energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.[5]

While PJM accounting focuses on CLMPS, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution, it merely changes the components of the LMP.

Local congestion is the congestion paid by load at a specific bus or set of buses and is calculated on a constraint specific basis. For a given market solution, a change in the elected reference bus does not change the LMP at any bus and does not change total congestion paid by load and does not change the local congestion paid by load at a specific location. Holding aside the marginal loss component of LMP. local congestion is the sum of the total LMP charges to load at the defined set of buses minus the sum of the total LMP credits received by all generation that supplied that load, given the set of all binding transmission constraints, regardless of location.. Local congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load. Local congestion fully reflects the least cost security constrained system solution and the LMPs that result from that solution.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $54.7 million or 9.4 percent, from $583.3 million in 2019 to $528.6 million in 2020.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $51.5 million or 7.2 percent, from $714.0 million in 2019 to $662.5 million in 2020.
- **Balancing Congestion.** Negative balancing congestion costs increased by $3.2 million or 2.5 percent, from -$130.7 million in 2019 to -$133.9 million in 2020. Negative balancing explicit charges decreased by $5.7 million, from -$83.3 million in 2019 to -$77.6 million in 2020.
- **Real-Time Congestion.** Real-time congestion costs decreased by $3.0 million or 0.4 percent, from $752.3 million in 2019 to $749.3 million in 2020.
- **Monthly Congestion.** Monthly total congestion costs in 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 Three Mile Island Transformer, the Conastone - Peach Bottom Line, and the Harwood - Susquehanna Line.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in 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.

5 The total congestion and marginal losses for 2020 were calculated as of January 12, 2021, and are subject to change, based on continued PJM billing updates.

Day-ahead congestion frequency decreased by 24.1 percent from 103,140 congestion event hours in 2019 to 78,239 congestion event hours in 2020.

Real-time congestion frequency increased by 4.1 percent from 21,122 congestion event hours in 2019 to 21,984 congestion event hours in 2020.

- **Congested Facilities.** The monthly average of daily day-ahead congestion event hours decreased in November 2020 as a result of decreased UTC activity due to a FERC order issued effective November 1, 2020, directing PJM to charge uplift to up to congestion transactions.[6] Day-ahead, congestion event hours decreased on all types of facilities except interfaces. The congestion event hours on the PA Central Interface increased from 872 hours in 2019 to 1,412 hours in 2020.

  The Bagley – Graceton Line was the largest contributor to congestion costs in 2020. With $81.7 million in total congestion costs, it accounted for 15.5 percent of the total PJM congestion costs in 2020.

- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** CT Price Setting Logic caused -$0.4 million of day-ahead congestion in 2020 and -$1.7 million of balancing congestion in 2020. None of the closed loop interfaces was binding in 2020 or 2019.

- **Zonal Congestion.** AEP had the largest zonal congestion costs among all control zones in 2020. AEP had $92.7 million in zonal congestion costs, comprised of $112.3 million in zonal day-ahead congestion costs and -$19.6 million in zonal balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $163.5 million or 25.5 percent, from $642.0 million in 2019 to $478.5 million in 2020. The loss MWh in PJM decreased by 891.3 GWh or 5.9 percent, from 15,208.5 GWh in 2019 to 14,317.2 GWh in 2020. The loss component of real-time LMP in 2020 was $0.01, compared to $0.02 in 2019.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 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 $170.3 million or 24.4 percent, from $696.5 million in 2019 to $526.3 million in 2020.

- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $6.8 million or 12.4 percent, from -$54.5 million in 2019 to -$47.7 million in 2020.

- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2020 by $45.8 million or 22.5 percent, from $203.7 million in 2019, to $157.9 million in 2020.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs increased by $116.2 million or 26.7 percent, from -$435.2 million in 2019 to -$319.0 million in 2020.

- **Day-Ahead System Energy Costs.** Day-ahead system energy costs increased by $127.2 million or 24.1 percent, from -$528.6 million in 2019 to -$401.4 million in 2020.

- **Balancing System Energy Costs.** Balancing system energy costs decreased by $15.0 million or 15.8 percent, from $94.9 million in 2019 to $79.9 million in 2020.

- **Monthly Total System Energy Costs.** Monthly total system energy costs in 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 2020 was lower than congestion in 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 2020.

6 172 FERC ¶ 61,046 (2020).

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all congestion revenues. The congestion offset for the first seven months of the 2020/2021 planning period was 55.8 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first seven months of the 2020/2021 planning period, using the rules effective for each planning period, was 74.9 percent. Load has been underpaid by $2.2 billion from the 2011/2012 planning period through the first seven 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 closed loop interfaces 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 constrained 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 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

7 The constrained side means the higher priced side with a positive CLMP created by the constraint.

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 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 change in 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 did not change. This means that the change in 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 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 share 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 2017 through 2020. Table 11-1 also shows the actual total balancing implicit CLMP charges for 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 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 $8.6 million (17.9 percent) in 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): 2017 through 2020

Balancing Implicit CLMP Charges ($ Million)										
	Old Method			New Method			Actual			
	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	Change Between New and Old
2017	$22.1	$47.1	($25.0)	$14.2	$45.8	($31.7)	$22.1	$47.1	($25.0)	($6.7)
2018	$18.9	$62.8	($43.9)	$0.1	$59.7	($59.6)	$11.5	$62.0	($50.5)	($15.6)
2019	$17.9	$53.8	($35.8)	$3.7	$51.1	($47.4)	$3.7	$51.1	($47.4)	($11.5)
2020	($4.2)	$43.6	($47.8)	($15.1)	$41.3	($56.3)	($14.7)	$41.6	($56.3)	($8.6)

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 (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, 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 paid by load in the transmission constrained area and the total revenue received by generation to meet the load in the transmission constrained area, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-3 shows the PJM real-time, load-weighted, average LMP components for 2008 through 2020.[11]

The real-time, load-weighted, average LMP decreased $5.55 or 20.3 percent from $27.32 in 2019 to $21.77 in 2020. The real-time, load-weighted, average congestion component was $0.02 in 2019 and $0.02 in 2020. Using a load-weighted reference bus, the real-time, load-weighted, average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero at the time that LMPs are set based on state estimator data. Metering updates during the settlement process change the load weights after the fact, but the reference bus price (SMP) is not updated with these changes over time. As a result, the average congestion and loss component used in real-time settlement is not zero, although this component is not fully accurate. The real-time, load-weighted, average loss component in 2020 was $0.01 compared to $0.02 in 2019. The real-time, load-weighted, average system energy component decreased by $5.55 or 20.3 percent from $27.28 in 2019 to $21.73 in 2020.

9 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

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 Real-time, load-weighted, average LMP components (Dollars per MWh): 2008 through 2020[12]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$71.13	$71.02	$0.06	$0.05
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02
2012	$35.23	$35.18	$0.04	$0.01
2013	$38.66	$38.64	$0.01	$0.02
2014	$53.14	$53.13	($0.02)	$0.02
2015	$36.16	$36.11	$0.04	$0.02
2016	$29.23	$29.18	$0.04	$0.01
2017	$30.99	$30.96	$0.02	$0.01
2018	$38.24	$38.19	$0.04	$0.02
2019	$27.32	$27.28	$0.02	$0.02
2020	$21.77	$21.73	$0.02	$0.01

Table 11-4 shows the PJM day-ahead, load-weighted, average LMP components for 2008 through 2020.[13] The day-ahead, load-weighted, average LMP decreased $5.83, or 21.4 percent, from $27.23 in 2019 to $21.40 in 2020. The day-ahead, load-weighted, average congestion component decreased $0.01 from $0.08 in 2019 to $0.07 in 2020. The day-ahead, load-weighted, average loss component was -$0.01 in 2019 and -$0.00 in 2020. The day-ahead, load-weighted, average energy component decreased $5.83, or 21.5 percent, from $27.17 in 2019 to $21.34 in 2020. Using a load-weighted reference bus, the day-ahead, load-weighted, average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero based on day-ahead firm load weights. Total billing however, includes price sensitive demand and virtual load congestion related charges, which makes the total load weights in accounting different than the load weights used to determine the SMP at the load-weighted reference bus. The resulting load-weighted average price from settlement for congestion and marginal losses components of price in day ahead is therefore not zero, although this component is not fully accurate.

Table 11-4 Day-ahead, load-weighted, average LMP components (Dollars per MWh): 2008 through 2020

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$70.25	$70.56	($0.08)	($0.22)
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)
2012	$34.55	$34.46	$0.11	($0.01)
2013	$38.93	$38.79	$0.13	$0.00
2014	$53.62	$53.38	$0.26	($0.02)
2015	$36.73	$36.51	$0.24	($0.01)
2016	$29.68	$29.55	$0.14	($0.01)
2017	$30.85	$30.81	$0.05	($0.02)
2018	$37.97	$37.83	$0.16	($0.01)
2019	$27.23	$27.17	$0.08	($0.01)
2020	$21.40	$21.34	$0.07	($0.00)

Table 11-5 shows the PJM real-time, load-weighted, average LMP by constrained and unconstrained hours.

Table 11-5 Real-time, load-weighted, average LMP by constrained and unconstrained hours (Dollars per MWh): 2019 and 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	$22.19	$22.78
Nov	$28.54	$19.94	$20.86	$26.31
Dec	$24.37	$16.20	$27.28	$21.27
Avg	$28.33	$21.07	$22.29	$17.59

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-6 for 2019 and 2020. In 2020, BGE had the highest real-time congestion component of all control zones, $3.30, and AECO had the lowest real-time congestion component, -$2.36.

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 11-6 Zonal and PJM real-time, load-weighted, average LMP components (Dollars per MWh): 2019 and 2020

	2019				2020			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$25.07	$27.28	($2.39)	$0.17	$19.72	$22.04	($2.36)	$0.05
AEP	$28.21	$27.24	$1.00	($0.03)	$22.14	$21.60	$0.45	$0.09
APS	$27.83	$27.28	$0.52	$0.03	$22.40	$21.64	$0.82	($0.06)
ATSI	$28.06	$27.16	$0.50	$0.41	$22.55	$21.67	$0.58	$0.30
BGE	$30.82	$27.49	$2.47	$0.86	$25.78	$21.89	$3.30	$0.59
ComEd	$24.72	$27.12	($1.54)	($0.86)	$20.18	$21.70	($1.08)	($0.44)
DAY	$29.52	$27.38	$1.12	$1.02	$23.23	$21.76	$0.49	$0.98
DEOK	$28.49	$27.33	$1.17	($0.00)	$22.37	$21.72	$0.51	$0.14
DLCO	$27.69	$27.18	$0.56	($0.05)	$22.79	$21.75	$1.18	($0.15)
Dominion	$29.08	$27.39	$1.42	$0.28	$23.05	$21.77	$1.23	$0.05
DPL	$27.71	$27.54	($0.39)	$0.56	$22.90	$21.94	$0.65	$0.30
EKPC	$28.18	$27.69	$0.65	($0.16)	$22.14	$21.79	$0.31	$0.04
JCPL	$25.40	$27.49	($2.18)	$0.09	$20.05	$22.13	($2.12)	$0.04
Met-Ed	$26.34	$27.26	($0.74)	($0.18)	$21.16	$21.74	($0.40)	($0.18)
OVEC	$26.23	$26.39	$0.52	($0.68)	$20.75	$20.78	$0.32	($0.34)
PECO	$24.75	$27.25	($2.33)	($0.17)	$19.29	$21.78	($2.25)	($0.23)
PENELEC	$26.17	$27.03	($0.76)	($0.10)	$20.84	$21.50	($0.52)	($0.14)
Pepco	$29.68	$27.46	$1.69	$0.53	$23.59	$21.85	$1.47	$0.28
PPL	$24.85	$27.25	($1.97)	($0.42)	$19.42	$21.65	($1.85)	($0.39)
PSEG	$25.28	$27.14	($1.84)	($0.02)	$19.69	$21.77	($2.03)	($0.04)
RECO	$25.72	$27.39	($1.64)	($0.03)	$20.74	$22.16	($1.45)	$0.03
PJM	$27.32	$27.28	$0.02	$0.02	$21.77	$21.73	$0.02	$0.01

The day-ahead components of LMP for each control zone are presented in Table 11-7 for 2019 and 2020. In 2020, BGE had the highest day-ahead congestion component of all control zones, $3.31, and AECO had the lowest day-ahead congestion component, -$2.40.

Table 11-7 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): 2019 and 2020

	2019				2020			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$24.92	$27.21	($2.36)	$0.07	$19.18	$21.60	($2.40)	($0.02)
AEP	$28.02	$27.21	$0.84	($0.03)	$21.89	$21.25	$0.57	$0.07
APS	$27.84	$27.16	$0.67	$0.01	$21.96	$21.29	$0.71	($0.04)
ATSI	$28.14	$27.04	$0.68	$0.43	$21.91	$21.25	$0.43	$0.23
BGE	$30.93	$27.33	$2.89	$0.71	$25.36	$21.48	$3.31	$0.57
ComEd	$24.62	$26.95	($1.61)	($0.71)	$20.01	$21.24	($0.86)	($0.38)
DAY	$29.27	$27.22	$1.08	$0.98	$23.19	$21.38	$0.81	$1.00
DEOK	$28.64	$27.24	$1.36	$0.04	$22.50	$21.36	$0.94	$0.19
DLCO	$27.72	$27.03	$0.75	($0.07)	$22.27	$21.37	$1.02	($0.12)
Dominion	$29.33	$27.32	$1.82	$0.19	$22.89	$21.37	$1.48	$0.04
DPL	$27.44	$27.51	($0.47)	$0.40	$21.47	$21.63	($0.45)	$0.29
EKPC	$27.97	$27.69	$0.57	($0.29)	$22.17	$21.62	$0.62	($0.08)
JCPL	$25.04	$27.28	($2.27)	$0.03	$19.23	$21.64	($2.38)	($0.03)
Met-Ed	$25.78	$27.15	($1.07)	($0.30)	$20.23	$21.38	($0.89)	($0.25)
OVEC	$28.03	$27.64	$0.99	($0.60)	$21.12	$20.78	$0.68	($0.35)
PECO	$24.38	$27.12	($2.46)	($0.28)	$18.75	$21.34	($2.29)	($0.30)
PENELEC	$26.89	$27.36	($0.50)	$0.03	$21.13	$21.49	($0.36)	($0.01)
Pepco	$29.99	$27.39	$2.13	$0.48	$23.55	$21.56	$1.66	$0.33
PPL	$24.39	$27.15	($2.23)	($0.52)	$18.82	$21.24	($1.94)	($0.48)
PSEG	$25.13	$27.08	($1.90)	($0.05)	$19.18	$21.36	($2.11)	($0.08)
RECO	$25.93	$27.36	($1.41)	($0.02)	$20.22	$21.87	($1.66)	$0.01
PJM	$27.23	$27.17	$0.08	($0.01)	$21.40	$21.34	$0.07	($0.00)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-8 for 2019 and 2020.[14]

Table 11-8 Hub real-time, average LMP components (Dollars per MWh): 2019 and 2020

	2019				2020			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$25.71	$25.98	$0.42	($0.70)	$20.38	$20.63	$0.19	($0.44)
AEP-DAY Hub	$26.80	$25.98	$0.88	($0.06)	$21.17	$20.63	$0.47	$0.07
ATSI Gen Hub	$26.43	$25.98	$0.50	($0.06)	$20.91	$20.63	$0.33	($0.04)
Chicago Gen Hub	$23.27	$25.98	($1.58)	($1.13)	$18.72	$20.63	($1.23)	($0.67)
Chicago Hub	$23.65	$25.98	($1.58)	($0.76)	$19.12	$20.63	($1.12)	($0.38)
Dominion Hub	$27.17	$25.98	$1.14	$0.06	$21.39	$20.62	$0.89	($0.13)
Eastern Hub	$25.09	$25.98	($1.28)	$0.39	$20.40	$20.63	($0.42)	$0.20
N Illinois Hub	$23.49	$25.98	($1.59)	($0.90)	$19.02	$20.63	($1.11)	($0.49)
New Jersey Hub	$23.94	$25.98	($2.00)	($0.04)	$18.63	$20.63	($1.93)	($0.07)
Ohio Hub	$26.92	$25.98	$0.96	($0.02)	$21.22	$20.63	$0.47	$0.13
West Interface Hub	$26.45	$25.98	$0.67	($0.19)	$20.93	$20.63	$0.48	($0.18)
Western Hub	$26.38	$25.98	$0.49	($0.09)	$20.92	$20.63	$0.41	($0.11)

The day-ahead components of LMP for each hub are presented in Table 11-9 for 2019 and 2020.

Table 11-9 Hub day-ahead, average LMP components (Dollars per MWh): 2019 and 2020

	2019				2020			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$25.80	$25.99	$0.48	($0.67)	$20.24	$20.29	$0.35	($0.40)
AEP-DAY Hub	$26.77	$25.99	$0.83	($0.04)	$20.96	$20.29	$0.59	$0.08
ATSI Gen Hub	$26.71	$25.99	$0.70	$0.03	$20.63	$20.29	$0.38	($0.04)
Chicago Gen Hub	$23.33	$25.99	($1.66)	($0.99)	$18.62	$20.29	($1.07)	($0.60)
Chicago Hub	$23.71	$25.99	($1.66)	($0.61)	$19.06	$20.29	($0.92)	($0.31)
Dominion Hub	$27.43	$25.99	$1.48	($0.03)	$21.13	$20.29	$1.01	($0.17)
Eastern Hub	$25.08	$25.99	($1.20)	$0.29	$19.49	$20.29	($0.99)	$0.18
N Illinois Hub	$23.54	$25.99	($1.66)	($0.78)	$18.93	$20.29	($0.92)	($0.44)
New Jersey Hub	$23.87	$25.99	($2.05)	($0.07)	$18.14	$20.29	($2.06)	($0.10)
Ohio Hub	$26.83	$25.99	$0.85	($0.01)	$20.97	$20.29	$0.57	$0.10
West Interface Hub	$26.75	$25.99	$0.93	($0.17)	$20.74	$20.29	$0.62	($0.17)
Western Hub	$26.69	$25.99	$0.76	($0.06)	$20.95	$20.29	$0.66	($0.01)

Congestion

Congestion Accounting

In PJM accounting, total congestion costs equal net implicit CLMP charges, plus net explicit CLMP charges, plus net inadvertent CLMP charges. Implicit CLMP charges equal implicit withdrawal charges less implicit injection credits. Explicit CLMP charges are the net CLMP charges associated with the injection credits and withdrawal charges for point to point energy transactions. Inadvertent CLMP charges are 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.

While PJM accounting focuses on CLMPS, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference

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.

bus does not change the LMPs or the difference between LMPs for a given market solution, it merely changes the components of the LMP.

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 Load CLMP Charges.** Day-ahead implicit withdrawal charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit withdrawal charges are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Implicit Generation CLMP Credits.** Day-ahead implicit injection credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions.[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 Load CLMP Charges.** Balancing implicit withdrawal charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit withdrawal charges are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Balancing Implicit Generation CLMP Credits.** Balancing implicit injection credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit injection credits are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Explicit CLMP Charges.** Explicit CLMP charges are the net CLMP costs associated with point to point energy transactions. Day-ahead explicit CLMP charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing explicit CLMP charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit CLMP charges are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent CLMP Charges.** Inadvertent CLMP charges are charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent CLMP charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[17]

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.

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.

17 PJM Operating Agreement Schedule 1 §3.7.

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).

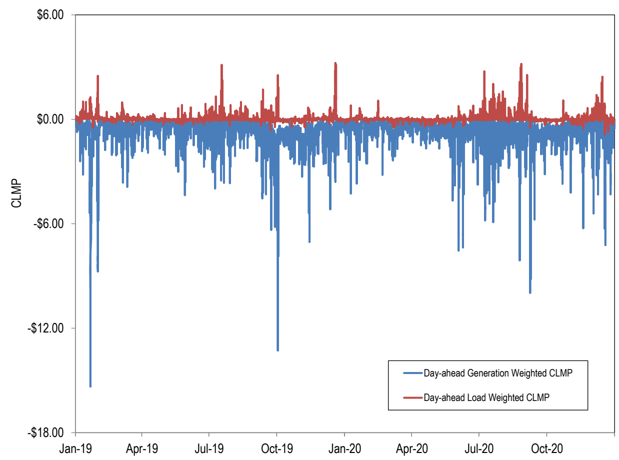
The accounting definitions can be misleading. Load pays congestion. Congestion is the difference between what load pays for energy and what generation is paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

The CLMP is calculated with respect to the LMP at the system reference bus, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor from the constraint to the pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[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 reported differences are the result of accounting issues. A positive CLMP at a load bus indicates that the load at that bus has a total energy price higher than the average LMP, due to transmission constraints. A negative CLMP at a load bus indicates that the load at that bus has a total energy price lower than the average LMP, due to transmission constraints. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses. Due to transmission constraints, the average generation weighted CLMP for generation resources is lower than the LMP at the load-weighted reference bus price. Calculated relative to the load reference bus which has a CLMP of zero, this means that the average of the generation bus CLMPs is negative. This means that total generation CLMP credits are negative.

Figure 11-1 shows the weighted average CLMPs of generation and load in the day-ahead market. Figure 11-1 shows that in 2019 and 2020, day-ahead generation weighted CLMPs were generally negative and day-ahead, load weighted CLMPs were generally positive, indicating that load was charged a higher weighted average LMP for energy as a result of transmission constraints than the weighted average LMP generation was paid to provide that energy. This means that total CLMP load payments are higher than total CLMP generation credits. The difference in load payments and generation credits (load charges minus generation credits) is congestion (Table 11-13 and Table 11-14). This result is a product of the least cost, security constrained dispatch and the use of a load-weighted reference bus that is used for the determination of the components of LMP. More generally, in a least cost, security constrained market solution the weighted average LMP at load buses is higher than the weighted average price at generation buses.

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load-weighted CLMPs: 2019 and 2020



Total Congestion

Total congestion costs in PJM in 2020 were $528.6 million, comprised of implicit withdrawal charges of $178.5 million, implicit injection credits of -$360.1 million and explicit charges of -$10.0 million. Total congestion costs in 2020 were lower than total congestion costs in any year from 2008 through 2019. Total congestion is the difference between what load pays for energy and what generation is paid for energy due to binding transmission constraints.

Table 11-11 shows total congestion for 2008 through 2020. Total congestion costs in Table 11-11 include

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>.

congestion associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[19 20]

Table 11-11 Total congestion costs (Dollars (Millions)): 2008 through 2020

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,300	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,770	4.1%
2011	$999	(29.8%)	$35,890	2.8%
2012	$529	(47.0%)	$29,180	1.8%
2013	$677	28.0%	$33,860	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%
2016	$1,024	(26.1%)	$39,050	2.6%
2017	$698	(31.9%)	$40,170	1.7%
2018	$1,310	87.8%	$49,790	2.6%
2019	$583	(55.5%)	$39,200	1.5%
2020	$529	(9.4%)	$33,640	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.

Table 11-12 shows total congestion by day-ahead and balancing component for 2008 through 2020.

Table 11-12 Total CLMP credits and charges by accounting category by market (Dollars (Millions)): 2008 through 2020

	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	$1,260.3	($1,133.1)	$203.0	$2,596.5	($225.9)	$79.2	($239.5)	($544.6)	$0.0	$2,051.8
2009	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$0.0	$719.0
2010	$376.4	($1,239.8)	$96.9	$1,713.1	($37.5)	$72.8	($179.5)	($289.8)	($0.0)	$1,423.3
2011	$400.5	($777.6)	$66.9	$1,245.0	$53.5	$109.5	($190.0)	($246.0)	$0.0	$999.0
2012	$122.7	($525.3)	$131.9	$779.9	($7.6)	$57.9	($185.4)	($250.9)	$0.0	$529.0
2013	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9
2014	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2
2015	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3
2016	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	($0.0)	$1,023.7
2017	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6
2018	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$0.0	$1,309.9
2019	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$0.0	$583.3
2020	$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.6	($77.6)	($133.9)	$0.0	$528.6

19 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.

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>.

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 2020 and 2019. Table 11-13 shows that in 2020 DECs paid $16.1 million in CLMP charges in the day-ahead market, were paid $26.2 million in CLMP credits in the balancing energy market, resulting in a net payment of $10.1 million in total CLMP credits. In 2020, INCs paid $17.0 million in CLMP charges in the day-ahead market, were paid $34.6 million in CLMP credits in the balancing energy market resulting in a net payment of $17.6 million in total CLMP credits. In 2020, up to congestion (UTCs) paid $60.8 million in CLMP charges in the day-ahead market, were paid $77.5 million in CLMP credits in the balancing market resulting in a total payment of $16.7 million in total CLMP credits.

Table 11-13 Total CLMP credits and charges by transaction type by market (Dollars (Millions)): 2020

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$16.1	$0.0	$0.0	$16.1	($26.2)	$0.0	$0.0	($26.2)	$0.0	($10.1)
Demand	$34.5	$0.0	$0.0	$34.5	$22.2	$0.0	$0.0	$22.2	$0.0	$56.7
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	$3.1	$3.1	$0.0	$0.0	($0.5)	($0.5)	$0.0	$2.6
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	($34.7)	$0.0	$0.7	($34.0)	($9.0)	$0.0	$0.8	($8.2)	$0.0	($42.2)
Generation	$0.0	($564.7)	$0.0	$564.7	$0.0	$10.5	$0.0	($10.5)	$0.0	$554.2
Import	$0.0	($0.2)	$0.0	$0.2	$0.0	($1.8)	($0.0)	$1.8	$0.0	$2.0
INC	$0.0	($17.0)	$0.0	$17.0	$0.0	$34.6	$0.0	($34.6)	$0.0	($17.6)
Internal Bilateral	$177.3	$180.2	$2.9	$0.0	($1.5)	($1.5)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$60.8	$60.8	$0.0	$0.0	($77.5)	($77.5)	$0.0	($16.7)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.4)	($0.1)	$0.0	($0.1)
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.0	$0.0	($0.3)	$0.0	($0.3)
Total	$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.6	($77.6)	($133.9)	$0.0	$528.6

Table 11-14 Total CLMP credits and charges by transaction type by market (Dollars (Millions)): 2019

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$14.8	$0.0	$0.0	$14.8	($17.3)	$0.0	$0.0	($17.3)	$0.0	($2.4)
Demand	$49.0	$0.0	$0.0	$49.0	$23.9	$0.0	$0.0	$23.9	$0.0	$72.9
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$1.7	$1.7	$0.0	$0.0	($0.6)	($0.6)	$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	($32.8)	$0.0	($0.4)	($33.2)	($1.9)	$0.0	($0.6)	($2.5)	$0.0	($35.7)
Generation	$0.0	($613.5)	$0.0	$613.5	$0.0	$26.5	$0.0	($26.5)	$0.0	$587.0
Import	$0.0	$1.7	$0.0	($1.7)	$0.0	($2.7)	($0.2)	$2.5	$0.0	$0.8
INC	$0.0	($15.5)	$0.0	$15.5	$0.0	$28.2	$0.0	($28.2)	$0.0	($12.7)
Internal Bilateral	$214.9	$215.0	$0.1	($0.0)	($0.9)	($0.9)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$54.2	$54.2	$0.0	$0.0	($81.6)	($81.6)	$0.0	($27.4)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.3)	($0.2)	$0.0	($0.2)
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	$0.0	($0.1)	$0.0	($0.1)
Total	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$0.0	$583.3

Table 11-15 shows the change in total CLMP credits and charges incurred by transaction type from 2019 to 2020. Total negative CLMP credits incurred by generation decreased by $32.8 million, and total CLMP charges incurred by demand decreased by $16.2 million. The total CLMP credits to up to congestion transactions (UTCs) decreased from $27.4 million in 2019 to $16.7 million in 2020. Total day-ahead CLMP charges to UTCs increased by $6.6 million from $54.2 million in 2019 to $60.8 million in 2020. Over the same period balancing CLMP credits to UTCs decreased by $4.1 million, from $81.6 million in 2019 to $77.5 million in 2020.

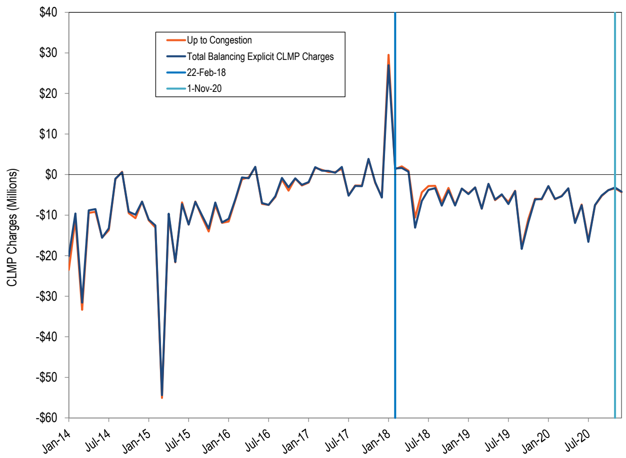
Table 11-15 Change in total PCLMP credits and charges by transaction type by market (Dollars (Millions)): 2019 to 2020

	Change in CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$1.3	$0.0	$0.0	$1.3	($8.9)	$0.0	$0.0	($8.9)	$0.0	($7.6)
Demand	($14.5)	$0.0	$0.0	($14.5)	($1.6)	$0.0	$0.0	($1.6)	$0.0	($16.2)
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$1.4	$1.4	$0.0	$0.0	$0.1	$0.1	$0.0	$1.5
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	($1.9)	$0.0	$1.1	($0.8)	($7.1)	$0.0	$1.4	($5.7)	$0.0	($6.5)
Generation	$0.0	$48.8	$0.0	($48.8)	$0.0	($16.0)	$0.0	$16.0	$0.0	($32.8)
Import	$0.0	($1.9)	$0.0	$1.9	$0.0	$0.9	$0.2	($0.7)	$0.0	$1.2
INC	$0.0	($1.5)	$0.0	$1.5	$0.0	$6.4	$0.0	($6.4)	$0.0	($4.9)
Internal Bilateral	($37.5)	($34.7)	$2.8	$0.0	($0.6)	($0.6)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$6.6	$6.6	$0.0	$0.0	$4.1	$4.1	$0.0	$10.6
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.1)	$0.1	$0.0	$0.1
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.0	$0.0	($0.2)	$0.0	($0.2)
Total	($52.7)	$10.6	$11.8	($51.5)	($18.4)	($9.5)	$5.7	($3.2)	$0.0	($54.7)

UTCs and Negative Balancing Explicit CLMP Charges

Figure 11-2 shows the change in up to congestion balancing explicit CLMP charges from 2014 through 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 2020, 99.9 percent (-$77.5 million out of -$77.6 million) of negative balancing explicit CLMP charges was incurred by UTCs and 0.6 percent (-$0.1 out of -$77.6 million) was incurred by Explicit Congestion Only, Export, Import and Wheel In transactions (Table 11-13). The vertical line on the left 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] The vertical line at November 1, 2020, shows the date on which the FERC order required PJM to allocate uplift to up to congestion transactions.[22]

Figure 11-2 Monthly balancing explicit CLMP charges incurred by UTC: 2014 through 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.[23] 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.[24]

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 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

21 For additional information about the FERC order, see the *2020 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

22 172 FERC ¶ 61,046 (2020).

23 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.

24 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

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.[25]

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 and Load Aggregate Congestion

Zonal, and load aggregate, congestion is calculated on a constraint specific basis for a specific location or set of load pricing nodes (an aggregate). Local congestion is the difference between what load pays for energy and what generation is paid for energy due to individual binding transmission constraints. Local congestion includes all energy charges or credits incurred to serve a specific load, load aggregate or zone. Local congestion calculations account for the total difference between what the specified load pays and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

25 153 FERC ¶ 61,180.

Local congestion is calculated on a constraint specific basis. This constraint based congestion is the total congestion payments by load at the buses within a defined area minus total CLMP credits received by generation that supplied that load, given the transmission constraints. Constraint based congestion reflects the underlying characteristics of the entire power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of decremental bids and incremental offers and the geographic and temporal distribution of load.

On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation.

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load CLMP charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation CLMP credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

Constraint specific CLMPs are determined relative to a reference bus, where there is no congestion and no losses. For purposes of 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, 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 2020. AEP had the largest zonal congestion costs among all control zones in 2020. AEP had $92.7 million in zonal congestion costs, comprised of $112.3 million in zonal day-ahead congestion costs and -$19.6 million in zonal balancing congestion costs. The Bagley – Graceton Line, the East Elkhart - Mottville Tap Line, the Conastone – Graceton Line, the Three Mile Island Transformer, and the Conastone - Peach Bottom Line contributed $29.8 million, or 32.2 percent of the AEP zonal congestion costs.[26]

Table 11-18 shows the congestion costs by zone for 2019.

26 For additional information about the top 20 constraints that affected each zone, see the *2020 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

Table 11-17 Day-ahead and balancing congestion by zone (Dollars (Millions)): 2020

	CLMP Credits and Charges (Millions)								
	Day-Ahead				Balancing				
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs
AECO	$1.7	($3.9)	$0.7	$6.4	($0.1)	$0.5	($0.9)	($1.5)	$4.9
AEP	$23.7	($76.1)	$12.4	$112.3	($0.9)	$6.8	($11.9)	($19.6)	$92.7
APS	$17.6	($23.1)	$3.2	$43.9	($0.4)	$2.8	($4.6)	($7.8)	$36.2
ATSI	$10.7	($37.0)	$5.0	$52.8	($0.5)	$3.6	($6.3)	($10.4)	$42.4
BGE	$9.0	($13.9)	$1.9	$24.7	($0.2)	$1.7	($2.9)	($4.7)	$20.0
ComEd	$0.9	($68.0)	$12.1	$81.0	($0.6)	$5.4	($8.3)	($14.4)	$66.7
DAY	$1.3	($10.1)	$1.4	$12.8	($0.1)	$0.9	($1.6)	($2.7)	$10.1
DEOK	$2.7	($14.1)	$2.0	$18.8	($0.2)	$1.4	($2.5)	($4.2)	$14.6
DLCO	$0.7	($6.9)	$0.7	$8.3	($0.1)	$0.8	($1.3)	($2.2)	$6.1
Dominion	$40.3	($42.1)	$7.3	$89.6	($8.1)	$3.5	($10.4)	($21.9)	$67.7
DPL	$25.6	($2.7)	$2.8	$31.1	($0.5)	$1.0	($1.8)	($3.4)	$27.7
EKPC	$1.2	($7.3)	$1.1	$9.6	($0.1)	$0.7	($1.2)	($2.0)	$7.7
EXT	$3.8	($12.1)	$2.4	$18.3	($0.3)	$2.2	($3.5)	($6.0)	$12.4
JCPL	$3.8	($9.7)	$1.3	$14.8	($0.2)	$1.1	($2.2)	($3.4)	$11.4
Met-Ed	$9.9	($5.5)	$1.1	$16.5	($0.8)	$1.0	($1.8)	($3.5)	$13.0
OVEC	$0.1	($0.5)	$0.6	$1.2	($0.0)	$0.1	($0.1)	($0.1)	$1.1
PECO	$4.7	($17.1)	$2.0	$23.9	($0.4)	$1.8	($3.6)	($5.8)	$18.1
PENELEC	$9.2	($5.9)	$1.3	$16.4	($0.3)	$0.9	($1.7)	($2.9)	$13.5
Pepco	$7.1	($11.7)	$1.6	$20.4	($0.2)	$1.5	($2.6)	($4.3)	$16.1
PPL	$10.6	($16.0)	$3.6	$30.1	($0.4)	$1.9	($3.8)	($6.1)	$24.0
PSEG	$8.2	($17.5)	$2.7	$28.4	($0.4)	$2.1	($4.1)	($6.6)	$21.7
RECO	$0.3	($0.6)	$0.2	$1.1	($0.0)	$0.1	($0.2)	($0.3)	$0.8
Total	$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.6	($77.6)	($133.9)	$528.6

Table 11-18 Day-ahead and balancing congestion by zone (Dollars (Millions)): 2019

	CLMP Credits and Charges (Millions)								
	Day-Ahead				Balancing				
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs
AECO	$3.6	($4.2)	$0.9	$8.7	$0.1	$0.6	($1.1)	($1.6)	$7.2
AEP	$45.4	($62.5)	$10.1	$118.0	$1.0	$8.0	($13.3)	($20.4)	$97.7
APS	$21.7	($24.0)	$2.3	$47.9	$0.4	$3.1	($5.0)	($7.8)	$40.2
ATSI	$17.8	($30.8)	$3.5	$52.1	$0.5	$3.9	($6.7)	($10.1)	$42.0
BGE	$10.4	($13.3)	$1.2	$25.0	$0.1	$2.1	($3.4)	($5.4)	$19.5
ComEd	$20.6	($61.7)	$13.5	$95.8	($1.4)	$5.1	($7.9)	($14.3)	$81.4
DAY	$5.0	($7.8)	$1.1	$13.9	$0.1	$1.1	($1.9)	($2.8)	$11.1
DEOK	$8.8	($11.4)	$1.8	$22.0	$0.2	$1.7	($3.0)	($4.5)	$17.5
DLCO	$2.9	($4.9)	$0.5	$8.2	$0.1	$0.8	($1.4)	($2.1)	$6.1
Dominion	$28.6	($49.9)	$4.1	$82.6	$1.0	$6.7	($10.6)	($16.4)	$66.2
DPL	$17.8	($10.2)	$2.9	$30.9	($0.0)	$1.2	($2.2)	($3.4)	$27.4
EKPC	$4.1	($5.8)	$0.8	$10.7	$0.1	$0.9	($1.4)	($2.2)	$8.5
EXT	$4.0	($10.3)	$1.7	$16.0	$0.3	$1.8	($2.9)	($4.4)	$11.6
JCPL	$4.7	($13.1)	$1.1	$18.9	$0.2	$1.4	($2.3)	($3.6)	$15.3
Met-Ed	$5.2	($9.9)	$0.7	$15.8	($0.2)	$1.1	($2.0)	($3.3)	$12.5
OVEC	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.1	($0.1)	($0.2)	($0.1)
PECO	$4.9	($22.0)	$1.6	$28.5	$0.4	$2.6	($4.1)	($6.4)	$22.2
PENELEC	$9.8	($8.9)	$1.0	$19.7	($0.1)	$1.3	($2.0)	($3.4)	$16.2
Pepco	$9.7	($11.9)	$1.1	$22.7	$0.3	$1.9	($3.1)	($4.7)	$17.9
PPL	$11.0	($23.7)	$3.2	$37.9	$0.2	$2.4	($4.1)	($6.3)	$31.6
PSEG	$9.8	($25.2)	$2.2	$37.2	$0.3	$2.9	($4.5)	($7.1)	$30.1
RECO	$0.3	($0.9)	$0.3	$1.5	$0.0	$0.1	($0.2)	($0.2)	$1.2
Total	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$583.3

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 2020, the total congestion costs associated with the special cases were $6.9 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 2019 and 2020.

Table 11-19 Day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): 2020

	Congestion Costs (Millions)																
	Day-Ahead							Balancing									
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	Grand Total	Special Cases Total	Percent of Special Cases
AECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$6.4	$6.4	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($1.5)	($1.5)	$4.9	($0.0)	(0.4%)
AEP	$0.0	($0.1)	$0.0	$0.5	$0.4	$111.4	$112.3	($0.0)	($0.2)	$0.0	($0.1)	($0.2)	($19.1)	($19.6)	$92.7	$0.4	0.4%
APS	$0.0	($0.0)	$0.0	$0.2	$0.2	$43.6	$43.9	($0.0)	($0.1)	$0.0	($0.0)	($0.1)	($7.6)	($7.8)	$36.2	$0.2	0.5%
ATSI	$0.0	($0.0)	$0.0	$0.0	$0.2	$52.6	$52.8	($0.0)	($0.1)	$0.0	($0.0)	($0.1)	($10.1)	($10.4)	$42.4	($0.1)	(0.2%)
BGE	$0.0	($0.0)	$0.0	$0.0	$0.1	$24.6	$24.7	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($4.6)	($4.7)	$20.0	($0.1)	(0.3%)
ComEd	$1.1	($0.0)	$0.0	$2.7	$0.3	$77.0	$81.0	($0.0)	($0.3)	$0.0	($0.0)	($0.1)	($14.0)	($14.4)	$66.7	$3.7	5.5%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.1	$12.7	$12.8	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($2.6)	($2.7)	$10.1	($0.0)	(0.2%)
DEOK	$0.0	($0.0)	$0.0	$0.0	$0.1	$18.7	$18.8	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($4.1)	($4.2)	$14.6	($0.0)	(0.2%)
DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$8.3	$8.3	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($2.2)	($2.2)	$6.1	($0.0)	(0.3%)
Dominion	$0.0	($0.0)	$0.0	$1.5	$0.3	$87.9	$89.6	($0.0)	($0.2)	$0.0	($0.3)	($0.1)	($21.3)	($21.9)	$67.7	$1.1	1.6%
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$31.0	$31.1	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($3.3)	($3.4)	$27.7	($0.0)	(0.1%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$9.6	$9.6	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($1.9)	($2.0)	$7.7	($0.0)	(0.2%)
EXT	$1.0	($0.0)	$0.0	$0.1	$0.1	$17.1	$18.3	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($5.8)	($6.0)	$12.4	$1.0	8.5%
JCPL	$0.0	($0.0)	$0.0	$0.0	$0.1	$14.8	$14.8	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($3.3)	($3.4)	$11.4	($0.0)	(0.4%)
Met-Ed	$0.0	($0.0)	$0.0	$0.5	$0.0	$16.1	$16.5	($0.0)	($0.0)	$0.0	($0.4)	($0.0)	($3.1)	($3.5)	$13.0	$0.0	0.3%
OVEC	$0.0	($0.0)	$0.0	$0.6	$0.0	$0.6	$1.2	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.1)	($0.1)	$1.1	$0.6	55.5%
PECO	$0.0	($0.0)	$0.0	$0.0	$0.1	$23.8	$23.9	($0.0)	($0.1)	$0.0	($0.0)	($0.1)	($5.7)	($5.8)	$18.1	($0.1)	(0.4%)
PENELEC	$0.0	($0.0)	$0.0	$0.3	$0.1	$16.0	$16.4	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($2.8)	($2.9)	$13.5	$0.3	2.1%
Pepco	$0.0	($0.0)	$0.0	$0.0	$0.1	$20.3	$20.4	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($4.2)	($4.3)	$16.1	($0.0)	(0.3%)
PPL	$0.0	($0.0)	$0.0	$0.2	$0.1	$29.8	$30.1	($0.0)	($0.1)	$0.0	($0.0)	($0.1)	($6.0)	($6.1)	$24.0	$0.1	0.6%
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.1	$28.3	$28.4	($0.0)	($0.1)	$0.0	($0.0)	($0.1)	($6.5)	($6.6)	$21.7	($0.1)	(0.4%)
RECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$1.1	$1.1	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.2)	($0.3)	$0.8	($0.0)	(0.3%)
Total	$2.1	($0.4)	$0.0	$6.7	$2.3	$651.8	$662.5	($0.0)	($1.7)	$0.0	($1.0)	($1.1)	($130.1)	($133.9)	$528.6	$6.9	1.3%

Table 11-20 Day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): 2019

	Congestion Costs (Millions)																	
	Day-Ahead							Balancing										
"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	Grand Total	Special Cases Total	Percent of Special Cases
AECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$8.8	$8.7	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($1.5)	($1.6)	$7.2	($0.1)	(1.3%)
AEP	$0.0	($0.3)	$0.0	$2.0	$0.0	$116.2	$118.0	($0.0)	($0.9)	$0.0	($0.0)	($0.1)	($19.4)	($20.4)	$97.7	$0.8	0.8%
APS	$0.0	($0.1)	$0.0	$0.0	$0.0	$48.0	$47.9	($0.0)	($0.3)	$0.0	($0.0)	($0.0)	($7.4)	($7.8)	$40.2	($0.5)	(1.2%)
ATSI	$0.0	($0.2)	$0.0	$0.0	$0.0	$52.2	$52.1	($0.0)	($0.4)	$0.0	($0.0)	($0.1)	($9.6)	($10.1)	$42.0	($0.6)	(1.5%)
BGE	$0.0	($0.1)	$0.0	$0.2	$0.0	$24.9	$25.0	($0.0)	($0.2)	$0.0	($0.0)	($0.0)	($5.2)	($5.4)	$19.5	($0.1)	(0.7%)
ComEd	$0.2	($0.3)	$0.0	$1.9	$0.0	$93.9	$95.8	($0.0)	($0.9)	$0.0	$0.0	($0.1)	($13.4)	($14.3)	$81.4	$0.9	1.1%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$13.9	$13.9	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($2.7)	($2.8)	$11.1	($0.2)	(1.5%)
DEOK	$0.0	($0.1)	$0.0	$0.0	$0.0	$22.0	$22.0	($0.0)	($0.2)	$0.0	($0.0)	($0.0)	($4.3)	($4.5)	$17.5	($0.3)	(1.5%)
DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$8.2	$8.2	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($2.0)	($2.1)	$6.1	($0.1)	(2.1%)
Dominion	$0.0	($0.2)	$0.0	$0.1	$0.0	$82.6	$82.6	($0.0)	($0.7)	$0.0	($0.0)	($0.1)	($15.5)	($16.4)	$66.2	($0.9)	(1.3%)
DPL	$0.0	($0.0)	$0.0	$0.1	$0.0	$30.8	$30.9	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($3.3)	($3.4)	$27.4	($0.1)	(0.3%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$10.7	$10.7	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($2.1)	($2.2)	$8.5	($0.1)	(1.6%)
EXT	$0.1	($0.0)	$0.0	$0.2	$0.0	$15.7	$16.0	($0.0)	($0.2)	$0.0	($0.0)	($0.0)	($4.2)	($4.4)	$11.6	$0.0	0.2%
JCPL	$0.0	($0.1)	$0.0	$0.0	$0.0	$18.9	$18.9	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($3.4)	($3.6)	$15.3	($0.2)	(1.4%)
Met-Ed	$0.0	($0.0)	$0.0	$1.4	$0.0	$14.4	$15.8	$0.0	($0.1)	$0.0	($0.1)	($0.0)	($3.1)	($3.3)	$12.5	$1.2	9.5%
OVEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.2)	($0.2)	($0.1)	$0.0	(25.0%)
PECO	$0.0	($0.1)	$0.0	$0.0	$0.0	$28.5	$28.5	$0.0	($0.3)	$0.0	($0.0)	($0.0)	($6.0)	($6.4)	$22.2	($0.3)	(1.6%)
PENELEC	$0.0	($0.0)	$0.0	$0.2	$0.0	$19.5	$19.7	$0.0	($0.1)	$0.0	($0.1)	($0.0)	($3.2)	($3.4)	$16.2	($0.0)	(0.3%)
Pepco	$0.0	($0.1)	$0.0	$0.0	$0.0	$22.7	$22.7	($0.0)	($0.2)	$0.0	($0.0)	($0.0)	($4.5)	($4.7)	$17.9	($0.3)	(1.6%)
PPL	$0.0	($0.1)	$0.0	$0.2	$0.0	$37.9	$37.9	($0.0)	($0.3)	$0.0	$0.0	($0.0)	($6.0)	($6.3)	$31.6	($0.2)	(0.8%)
PSEG	$0.0	($0.1)	$0.0	$0.0	$0.0	$37.2	$37.2	$0.0	($0.3)	$0.0	($0.0)	($0.0)	($6.7)	($7.1)	$30.1	($0.4)	(1.3%)
RECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$1.5	$1.5	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.2)	($0.2)	$1.2	($0.0)	(1.1%)
Total	$0.4	($1.9)	$0.0	$6.4	$0.2	$708.8	$714.0	($0.0)	($5.8)	$0.0	($0.2)	($0.8)	($123.9)	($130.7)	$583.3	($1.6)	(0.3%)

Monthly Congestion

Table 11-21 shows day-ahead, balancing and inadvertent congestion costs by month for 2019 and 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. The total congestion cost in 2020 decreased in October and November compared to the same months in 2019 as day-ahead negative implicit injection credits incurred by generation decreased.

Table 11-21 Monthly congestion costs by market (Dollars (Millions)): 2019 and 2020

	Congestion Costs (Millions)							
	2019				2020			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	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	$52.5	($9.3)	$0.0	$43.2
Nov	$67.0	($16.2)	($0.0)	$50.8	$41.3	($7.8)	$0.0	$33.5
Dec	$63.0	($8.6)	$0.0	$54.5	$66.2	($10.5)	$0.0	$55.8
Total	$714.0	($130.7)	$0.0	$583.3	$662.5	($133.9)	$0.0	$528.6

Figure 11-3 shows PJM monthly total congestion cost for 2008 through 2020.

Figure 11-3 Monthly total congestion cost (Dollars (Millions)): 2008 through 2020

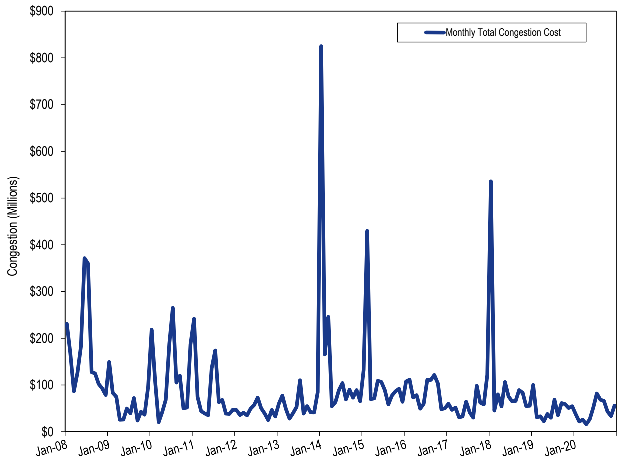


Table 11-22 shows monthly total CLMP credits and charges for each virtual transaction type in 2019 and 2019. Virtual transaction CLMP charges, when positive, are the total CLMP charges to the virtual transactions and when negative, are the total CLMP credits to the virtual transactions. The negative totals in Table 11-22 show that virtuals were paid, in net, CLMP credits in 2020 and 2019. In 2020, 37.7 percent of the total credits to virtuals went to UTCs, compared to 64.4 percent in 2019. The decrease in CLMP credits to UTCs was a result of the FERC requirement that UTCs pay uplift effective November 1, 2020, the elimination of NIPSCO interface pricing point on June 1, 2020, and the elimination of NORTHWEST interface pricing point on October 1, 2020.

Table 11-22 Monthly CLMP charges by virtual transaction type and by market (Dollars (Millions)): 2019 and 2020

		CLMP Credits and Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
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)
	Oct	$1.0	($2.0)	($1.0)	$1.6	($3.2)	($1.6)	$2.8	($3.8)	($1.1)	($3.7)
	Nov	($1.1)	$1.4	$0.3	$3.0	($5.4)	($2.5)	$2.7	($3.4)	($0.7)	($2.9)
	Dec	$3.0	($6.2)	($3.2)	($1.0)	($1.3)	($2.4)	$2.5	($4.3)	($1.8)	($7.4)
	Total	$16.1	($26.2)	($10.1)	$17.0	($34.6)	($17.6)	$60.8	($77.5)	($16.7)	($44.4)

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 2020, there were 78,239 day-ahead, congestion event hours compared to 103,140 day-ahead congestion event hours in 2019. Of the day-ahead congestion event hours in 2020, only 10,625 (13.6 percent) were also constrained in the real-time energy market (Table 11-25). In 2020, there were 21,984 real-time, congestion event hours compared to 21,122 real-time, congestion event hours in 2019. Of the real-time congestion event hours in 2020, 10,743 (48.9 percent) were also constrained in the day-ahead energy market (Table 11-26).

The top five constraints by congestion costs contributed $174.4 million, or 33.0 percent, of the total PJM congestion costs in 2020. The top five constraints were the Bagley – Graceton Line, the Conastone - Graceton Line, the Three Mile Island Transformer, the Conastone - Peach Bottom Line, and the Harwood – Susquehanna Line.

Several of the top constraints by congestion costs are located in the BGE Zone in 2019 and 2020 (Figure 11-4). The PA Central Interface remains a top constraint by congestion costs, along with the Bagley – Graceton Line, in 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.[27]

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on all types of facilities except interfaces. Interfaces increased from 1,523 day-ahead, congestion event hours in 2019 to 1,762 day-ahead congestion event hours in 2020. Of 1,762 congestion event hours, 80.1 percent were on the PA Central Interface.

Real-time, congestion event hours increased on all types of facilities except flowgates in 2020. Interfaces increased from 714 real-time, congestion event hours in 2019 to 1,343 real-time congestion event hours in 2020. Of 1,343 congestion event hours, 92.1 percent was incurred on the PA Central Interface.

Day-ahead congestion costs decreased on all types of facilities except lines in 2020 compared to 2019. Day-ahead negative implicit injection credits decreased on all types of facilities except lines and transformers in 2020 compared to 2019.

Negative balancing congestion costs decreased on all types of facilities except lines in 2020 compared to 2019 (Table 11-24). Table 11-23 provides congestion event hour subtotals and congestion cost subtotals comparing 2020 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[28 29]

27 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>.

28 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.

29 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Table 11-23 Congestion summary (By facility type): 2020

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($30.6)	($87.6)	$16.9	$73.8	($0.8)	$6.2	($40.3)	($47.3)	$26.5	6,715	4,795
Interface	$3.2	($16.0)	$1.1	$20.3	$0.2	$2.6	($1.9)	($4.3)	$16.0	1,762	1,343
Line	$195.2	($224.3)	$38.9	$458.4	($14.0)	$22.6	($26.7)	($63.4)	$395.0	56,500	12,753
Transformer	$16.9	($60.3)	$9.1	$86.2	($2.2)	$6.8	($5.1)	($14.1)	$72.1	11,134	2,259
Other	$8.7	($11.4)	$1.3	$21.4	$2.1	$3.3	($2.5)	($3.7)	$17.7	2,128	834
Unclassified	($0.1)	($2.1)	$0.3	$2.3	$0.1	$0.1	($1.0)	($1.1)	$1.3	NA	NA
Total	$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.6	($77.6)	($133.9)	$528.6	78,239	21,984

Table 11-24 Congestion summary (By facility type): 2019

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($25.3)	($101.1)	$8.5	$84.4	$4.0	$8.6	($55.3)	($59.9)	$24.5	11,396	6,219
Interface	$9.2	($42.4)	$0.8	$52.4	$1.4	$7.3	$0.8	($5.0)	$47.4	1,523	714
Line	$203.9	($182.3)	$36.3	$422.5	$3.0	$22.5	($21.0)	($40.5)	$382.1	65,750	10,958
Transformer	$31.3	($58.7)	$7.8	$97.8	($5.5)	$8.7	($4.2)	($18.4)	$79.4	19,411	1,416
Other	$26.8	($27.6)	$2.2	$56.6	$0.6	$3.9	($2.8)	($6.1)	$50.5	5,060	1,815
Unclassified	$0.1	($0.1)	$0.0	$0.2	$0.1	$0.2	($0.8)	($0.8)	($0.6)	NA	NA
Total	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$583.3	103,140	21,122

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 2020, there were 78,239 congestion event hours in the day-ahead energy market. Of those day-ahead congestion event hours, only 10,625 (13.6 percent) were also constrained in the real-time energy market. In 2019, of the 103,140 day-ahead congestion event hours, only 9,549 (9.3 percent) were binding in the real-time energy market.[30]

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 2020, of the 21,984 congestion event hours in the real-time energy market, 10,743 (48.9 percent) were also constrained in the day-ahead energy market. In 2019, of the 21,122 real-time congestion event hours, 9,812 (46.5 percent) were also in the day-ahead energy market.

Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in 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.

30 Constraints are mapped to transmission facilities. In the day-ahead energy market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the day-ahead energy market. Similarly in the real-time market a facility may account for more than one constraint-hour within a given hour.

Table 11-25 Congestion event hours (day-ahead against real-time): 2019 and 2020

	Congestion Event Hours					
	2019			2020		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Interface	1,523	500	32.8%	1,762	1,018	57.8%
Transformer	19,411	773	4.0%	11,134	1,312	11.8%
Flowgate	11,396	1,664	14.6%	6,715	1,441	21.5%
Line	65,750	5,493	8.4%	56,500	6,587	11.7%
Other	5,060	1,119	22.1%	2,128	267	12.5%
Total	103,140	9,549	9.3%	78,239	10,625	13.6%

Table 11-26 Congestion event hours (real-time against day-ahead): 2019 and 2020

	Congestion Event Hours					
	2019			2020		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Interface	714	514	72.0%	1,343	1,063	79.2%
Transformer	1,416	781	55.2%	2,259	1,337	59.2%
Flowgate	6,219	1,681	27.0%	4,795	1,446	30.2%
Line	10,958	5,696	52.0%	12,753	6,629	52.0%
Other	1,815	1,140	62.8%	834	268	32.1%
Total	21,122	9,812	46.5%	21,984	10,743	48.9%

Table 11-27 shows congestion costs by facility voltage class for 2020. Congestion costs in 2020 decreased for all facilities except 230 kV, 161 kV, 138 kV and 115 kV facilities compared to 2019.

Table 11-27 Congestion summary (By facility voltage): 2020

	CLMP Credits and Charges (Millions)									Event Hours	
	Day-Ahead				Balancing						
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
765	($0.0)	($0.2)	$0.3	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	61	0
500	$32.1	($63.0)	$5.0	$100.0	$0.3	$10.6	($5.9)	($16.2)	$83.8	5,432	2,792
345	($10.4)	($44.4)	$12.0	$46.0	($0.1)	$2.0	($10.4)	($12.5)	$33.5	7,887	840
230	$141.5	($107.2)	$12.5	$261.2	$1.1	$12.4	($6.9)	($18.3)	$242.9	19,473	7,037
161	($14.0)	($40.9)	$5.8	$32.7	$0.6	$5.3	($15.8)	($20.6)	$12.1	2,770	2,049
138	($17.7)	($157.1)	$26.5	$165.8	($6.9)	$9.1	($35.3)	($51.2)	$114.6	23,780	6,138
115	$50.2	$12.0	$2.4	$40.6	($9.6)	$2.1	($1.8)	($13.6)	$27.0	8,408	2,842
69	$11.7	$1.2	$2.8	$13.3	($0.2)	($0.1)	($0.4)	($0.5)	$12.8	10,334	286
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	16	0
Unclassified	($0.1)	($2.1)	$0.3	$2.3	$0.1	$0.1	($1.0)	($1.1)	$1.3	NA	NA
Total	$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.6	($77.6)	($133.9)	$528.6	78,239	21,984

Table 11-28 Congestion summary (By facility voltage): 2019

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Congestion Costs	Day-Ahead	Real-Time
765	($0.0)	($1.9)	$1.3	$3.2	($0.1)	$0.2	($0.2)	($0.5)	$2.6	249	46
500	$134.1	($57.0)	$1.6	$192.7	$4.1	$9.7	($0.8)	($6.4)	$186.4	7,527	4,618
345	($4.5)	($80.4)	$14.2	$90.2	$0.8	$4.1	($17.3)	($20.6)	$69.6	11,801	1,438
230	$63.1	($110.1)	$6.2	$179.3	($0.8)	$13.6	($5.8)	($20.2)	$159.2	16,176	4,495
212	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	117	0
161	($2.2)	($9.9)	($0.2)	$7.5	$0.1	$0.5	($2.9)	($3.4)	$4.2	1,620	598
138	$24.3	($123.4)	$27.3	$175.1	$0.2	$12.8	($54.0)	($66.6)	$108.5	33,362	7,539
115	$14.5	($19.2)	$0.8	$34.5	($0.8)	$6.5	($1.0)	($8.3)	$26.2	8,944	1,520
69	$15.8	($10.5)	$4.4	$30.7	$0.1	$3.5	($0.5)	($3.9)	$26.8	21,095	868
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	($0.1)	$0.0	$0.2	$0.1	$0.2	($0.8)	($0.8)	($0.6)	NA	NA
Total	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$583.3	103,140	21,122

Constraint Frequency

Table 11-29 lists the constraints for 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 2019 to 2020. In Table 11-29, constraints are presented in descending order of total day-ahead event hours and real-time event hours for 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 2019 to 2020.

Table 11-29 Top 25 constraints with frequent occurrence: 2019 and 2020

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2019	2020	Change	2019	2020	Change	2019	2020	Change	2019	2020	Change
1	Bagley - Graceton	Line	826	3,868	3,042	126	1,945	1,819	9.4%	44%	35%	1%	22%	21%
2	Easton - Emuni	Line	4,833	2,859	(1,974)	9	9	0	55%	33%	(23%)	0%	0%	(0%)
3	Lenox - North Meshoppen	Line	569	1,349	780	757	1,308	551	6%	15%	9%	9%	15%	6%
4	PA Central	Interface	872	1,412	540	665	1,237	572	10%	16%	6%	8%	14%	6%
5	DoeX530	Transformer	1,853	2,330	477	0	0	0	21%	27%	5%	0%	0%	0%
6	Sub 85 - Sub 18	Flowgate	0	1,167	1,167	0	850	850	0%	13%	13%	0%	10%	10%
7	Mountain	Transformer	1,390	1,874	484	0	0	0	16%	21%	5%	0%	0%	0%
8	Graceton - Safe Harbor	Line	1,631	1,145	(486)	563	712	149	19%	13%	(6%)	6%	8%	2%
9	Three Mile Island	Transformer	252	1,180	928	39	626	587	3%	13%	11%	0%	7%	7%
10	Monroe - Vineland	Line	4,560	1,665	(2,895)	108	90	(18)	52%	19%	(33%)	1%	1%	(0%)
11	Sayreville - Sayreville	Line	317	1,706	1,389	0	0	0	4%	19%	16%	0%	0%	0%
12	White Stone - Harmony Village	Line	7	1,233	1,226	1	286	285	0%	14%	14%	0%	3%	3%
13	Logtown - North Delphos	Line	617	955	338	13	462	449	7%	11%	4%	0%	5%	5%
14	Harwood - Susquehanna	Line	252	1,015	763	35	334	299	3%	12%	9%	0%	4%	3%
15	Cedar Grove Sub - Roseland	Line	246	1,136	890	16	84	68	3%	13%	10%	0%	1%	1%
16	New Carisle - Pletcher	Line	24	1,098	1,074	0	110	110	0%	13%	12%	0%	1%	1%
17	Conastone - Peach Bottom	Line	4,999	1,178	(3,821)	3,250	23	(3,227)	57%	13%	(44%)	37%	0%	(37%)
18	Berwick - Koonsville	Line	3,025	1,196	(1,829)	33	3	(30)	35%	14%	(21%)	0%	0%	(0%)
19	Paradise - BR Tap	Flowgate	104	703	599	105	482	377	1%	8%	7%	1%	5%	4%
20	Quad Cities	Transformer	891	1,177	286	0	0	0	10%	13%	3%	0%	0%	0%
21	Nottingham	Other	809	870	61	468	306	(162)	9%	10%	1%	5%	3%	(2%)
22	East Moline	Flowgate	9	518	509	19	480	461	0%	6%	6%	0%	5%	5%
23	East Lima - Haviland	Line	111	732	621	1	244	243	1%	8%	7%	0%	3%	3%
24	Grant - Greentown	Line	762	967	205	3	0	(3)	9%	11%	2%	0%	0%	(0%)
25	Gardners - Texas Eastern	Line	1,787	897	(890)	131	63	(68)	20%	10%	(10%)	1%	1%	(1%)

Table 11-30 Top 25 constraints with largest year to year change in occurrence: 2019 and 2020

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2019	2020	Change	2019	2020	Change	2019	2020	Change	2019	2020	Change
1	Conastone - Peach Bottom	Line	4,999	1,178	(3,821)	3,250	23	(3,227)	57%	13%	(44%)	37%	0%	(37%)
2	Bagley - Graceton	Line	826	3,868	3,042	126	1,945	1,819	9%	44%	35%	1%	22%	21%
3	Monroe - Vineland	Line	4,560	1,665	(2,895)	108	90	(18)	52%	19%	(33%)	1%	1%	(0%)
4	Marblehead	Flowgate	1,760	25	(1,735)	1,103	28	(1,075)	20%	0%	(20%)	13%	0%	(12%)
5	Face Rock	Other	2,552	665	(1,887)	484	44	(440)	29%	8%	(22%)	6%	1%	(5%)
6	Sub 85 - Sub 18	Flowgate	0	1,167	1,167	0	850	850	0%	13%	13%	0%	10%	10%
7	Easton - Emuni	Line	4,833	2,859	(1,974)	9	9	0	55%	33%	(23%)	0%	0%	(0%)
8	Roxana - Praxair	Flowgate	1,274	0	(1,274)	603	0	(603)	15%	0%	(15%)	7%	0%	(7%)
9	Berwick - Koonsville	Line	3,025	1,196	(1,829)	33	3	(30)	35%	14%	(21%)	0%	0%	(0%)
10	Three Mile Island	Transformer	252	1,180	928	39	626	587	3%	13%	11%	0%	7%	7%
11	White Stone - Harmony Village	Line	7	1,233	1,226	1	286	285	0%	14%	14%	0%	3%	3%
12	Marquis - Dept of Energy	Line	1,494	0	(1,494)	0	0	0	17%	0%	(17%)	0%	0%	0%
13	Sayreville - Sayreville	Line	317	1,706	1,389	0	0	0	4%	19%	16%	0%	0%	0%
14	Lenox - North Meshoppen	Line	569	1,349	780	757	1,308	551	6%	15%	9%	9%	15%	6%
15	New Carisle - Pletcher	Line	24	1,098	1,074	0	110	110	0%	13%	12%	0%	1%	1%
16	PA Central	Interface	872	1,412	540	665	1,237	572	10%	16%	6%	8%	14%	6%
17	New Carlisle - Olive	Line	1,080	1	(1,079)	0	0	0	12%	0%	(12%)	0%	0%	0%
18	Harwood - Susquehanna	Line	252	1,015	763	35	334	299	3%	12%	9%	0%	4%	3%
19	East Towanda - Hillside	Line	1,161	436	(725)	781	487	(294)	13%	5%	(8%)	9%	6%	(3%)
20	Bosserman - New Carlisle	Line	1,009	0	(1,009)	4	0	(4)	12%	0%	(12%)	0%	0%	(0%)
21	Paradise - BR Tap	Flowgate	104	703	599	105	482	377	1%	8%	7%	1%	5%	4%
22	East Moline	Flowgate	9	518	509	19	480	461	0%	6%	6%	0%	5%	5%
23	Gardners - Texas Eastern	Line	1,787	897	(890)	131	63	(68)	20%	10%	(10%)	1%	1%	(1%)
24	Cedar Grove Sub - Roseland	Line	246	1,136	890	16	84	68	3%	13%	10%	0%	1%	1%
25	Munster	Flowgate	709	0	(709)	171	0	(171)	8%	0%	(8%)	2%	0%	(2%)

Constraint Costs

Table 11-31 and Table 11-32 show the top constraints affecting congestion costs by facility for 2020 and 2019. The Bagley – Graceton Line was the largest contributor to congestion costs in 2020, with $81.7 million in total congestion costs and 15.5 percent of the total PJM congestion costs in 2020.

Table 11-31 Top 25 constraints affecting congestion costs (By facility): 2020[31]

				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	$75.0	($4.5)	$3.1	$82.6	$1.5	$4.5	$2.0	($0.9)	$81.7	15.5%
2	Conastone - Graceton	Line	BGE	$8.4	($19.6)	$0.4	$28.4	$0.2	($0.7)	($0.1)	$0.8	$29.2	5.5%
3	Three Mile Island	Transformer	500	$13.4	($10.0)	$1.6	$25.0	$0.8	$1.1	($0.6)	($0.9)	$24.1	4.6%
4	Conastone - Peach Bottom	Line	500	$18.8	($1.1)	$0.5	$20.5	($0.0)	($0.1)	$0.0	$0.1	$20.6	3.9%
5	Harwood - Susquehanna	Line	PPL	$1.4	($17.8)	$0.6	$19.8	($0.2)	$0.4	($0.3)	($0.9)	$18.9	3.6%
6	Pleasant View - Ashburn	Line	Dominion	$13.4	($4.6)	($0.2)	$17.9	$0.4	$0.8	($0.3)	($0.6)	$17.2	3.3%
7	Graceton - Safe Harbor	Line	BGE	$17.2	$2.2	$1.1	$16.0	$0.6	$0.9	($0.2)	($0.5)	$15.5	2.9%
8	Yukon	Transformer	500	($6.4)	($27.8)	$1.4	$22.7	($0.8)	$5.4	($2.7)	($8.8)	$13.9	2.6%
9	Cumberland - Juniata	Line	PPL	($0.3)	($13.5)	$0.9	$14.1	$0.1	($0.4)	($1.5)	($1.0)	$13.2	2.5%
10	PA Central	Interface	500	$1.1	($13.4)	$0.8	$15.3	$0.3	$1.9	($1.3)	($2.9)	$12.4	2.3%
11	Smithton - Yukon	Line	APS	($4.8)	($14.3)	$1.3	$10.7	$0.2	$0.4	($0.3)	($0.5)	$10.3	1.9%
12	Coolspring - Milford	Line	DPL	$1.5	($8.4)	$0.3	$10.2	($1.5)	($0.2)	($0.3)	($1.6)	$8.6	1.6%
13	East Lima - Haviland	Line	AEP	($14.5)	($21.7)	$0.7	$7.9	($0.2)	($0.5)	($0.0)	$0.2	$8.1	1.5%
14	Nelson - Vienna	Line	DPL	$4.7	($4.0)	$0.2	$8.9	($1.3)	($0.6)	($0.3)	($1.0)	$7.9	1.5%
15	Braidwood - East Frankfort	Line	ComEd	($0.2)	($7.8)	$0.4	$8.0	($0.0)	$0.0	($0.3)	($0.3)	$7.7	1.5%
16	Mohomet - ChampTP	Flowgate	MISO	($1.4)	($6.6)	$2.1	$7.3	$0.1	($1.4)	($2.1)	($0.6)	$6.7	1.3%
17	Juniata	Transformer	500	$2.8	($3.9)	$0.1	$6.8	($0.2)	($0.1)	($0.1)	($0.1)	$6.7	1.3%
18	Pruntytown	Other	APS	($1.5)	($7.8)	($0.5)	$5.8	$0.0	($0.0)	$0.3	$0.3	$6.1	1.2%
19	Nottingham	Other	PECO	$6.4	$1.7	$0.9	$5.6	$0.0	$0.0	$0.0	$0.0	$5.6	1.1%
20	Plymouth Meeting - Whitpain	Line	PECO	($0.4)	($5.2)	$0.1	$4.9	$0.3	$0.0	$0.1	$0.5	$5.3	1.0%
21	Logtown - North Delphos	Line	AEP	($15.3)	($25.2)	$2.1	$11.9	$0.0	$3.5	($3.3)	($6.8)	$5.2	1.0%
22	Paradise - BR Tap	Flowgate	MISO	($3.9)	($9.8)	($0.5)	$5.3	$0.0	$0.0	($0.3)	($0.3)	$5.0	1.0%
23	Loretto - Vienna	Line	DPL	$5.5	$1.4	$0.4	$4.6	($0.1)	($0.2)	($0.1)	$0.0	$4.6	0.9%
24	Seward - Towanda	Line	PENELEC	$17.3	$12.7	($0.0)	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	0.9%
25	Gardners - Texas Eastern	Line	Met-Ed	$3.6	($0.8)	$0.4	$4.7	($0.3)	($0.1)	($0.0)	($0.2)	$4.5	0.8%
	Top 25 Total			$141.8	($209.6)	$18.2	$369.6	$0.1	$14.6	($11.6)	($26.1)	$343.4	65.0%
	All Other Constraints			$51.5	($192.2)	$49.3	$292.9	($14.8)	$27.0	($65.9)	($107.7)	$185.2	35.0%
	Total			$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.6	($77.6)	($133.9)	$528.6	100.0%

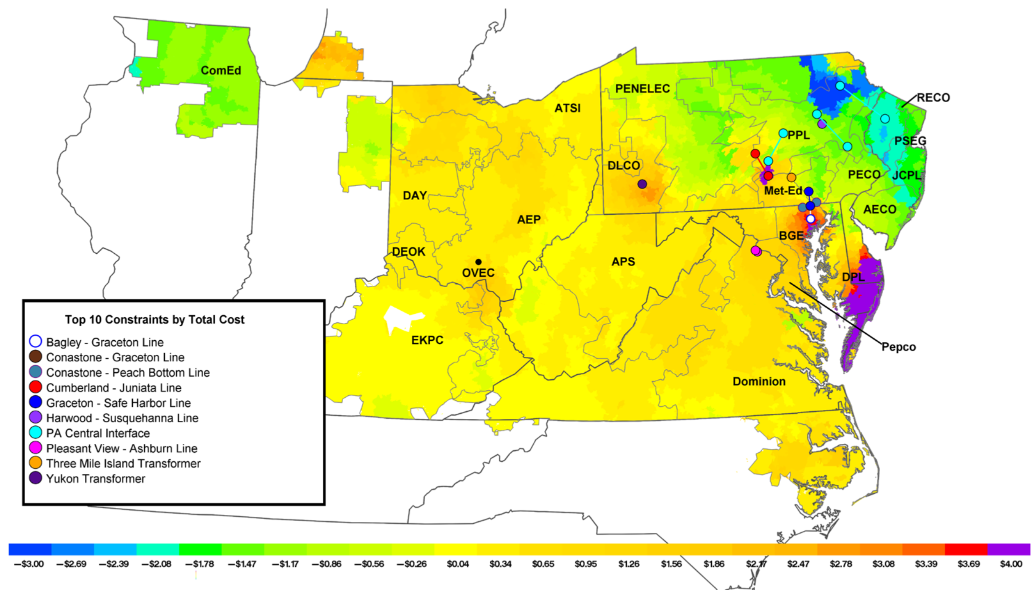
31 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11-32 Top 25 constraints affecting congestion costs (By facility): 2019[32]

				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	Conastone - Peach Bottom	Line	500	$108.1	($2.5)	($0.1)	$110.5	$3.6	$6.0	$2.8	$0.4	$111.0	19.0%
2	Conastone	Other	500	$16.4	($0.6)	$0.4	$17.3	($0.9)	($3.0)	($0.8)	$1.3	$18.6	3.2%
3	Tanners Creek - Miami Fort	Flowgate	MISO	($6.8)	($24.2)	$0.3	$17.6	$0.0	$0.0	$0.0	$0.0	$17.6	3.0%
4	Coolspring - Milford	Line	DPL	($0.6)	($16.2)	$0.2	$15.9	($0.1)	($0.6)	($0.7)	($0.2)	$15.7	2.7%
5	Graceton - Safe Harbor	Line	BGE	$15.4	$0.3	$0.1	$15.2	$0.5	$1.2	$0.4	($0.3)	$14.9	2.6%
6	AP South	Interface	500	$9.1	($5.7)	($0.2)	$14.6	$0.2	$0.3	$0.1	($0.1)	$14.5	2.5%
7	Wescosville	Transformer	PPL	$9.3	($7.5)	($0.0)	$16.7	($0.1)	$2.0	($0.5)	($2.6)	$14.1	2.4%
8	Siegfried	Transformer	PPL	$6.8	($13.7)	$0.4	$20.9	($1.6)	$5.2	($0.1)	($6.8)	$14.1	2.4%
9	Face Rock	Other	PPL	$0.5	($13.4)	$0.8	$14.6	$1.2	$2.6	$0.1	($1.3)	$13.4	2.3%
10	Roxana - Praxair	Flowgate	MISO	($1.2)	($4.1)	$2.9	$5.7	$3.3	$4.2	($17.6)	($18.5)	($12.8)	(2.2%)
11	East	Interface	500	($6.0)	($20.4)	$0.1	$14.6	$0.9	$4.0	$0.9	($2.2)	$12.4	2.1%
12	Bagley - Graceton	Line	BGE	$8.0	($2.3)	$0.2	$10.5	$0.3	$0.5	$0.3	$0.1	$10.5	1.8%
13	Conastone - Northwest	Line	BGE	$7.0	($3.0)	$0.4	$10.4	$0.0	($0.0)	($0.3)	($0.3)	$10.2	1.7%
14	Cedar Creek - Red Lion	Line	DPL	$1.6	($7.9)	$0.9	$10.5	($0.8)	($0.6)	($0.7)	($1.0)	$9.5	1.6%
15	Nottingham	Other	PECO	$12.3	$2.7	($0.1)	$9.5	$0.0	$0.0	$0.0	$0.0	$9.5	1.6%
16	Palisades - Argenta	Flowgate	MISO	($0.4)	($9.8)	$0.5	$9.9	$0.0	($0.1)	($0.9)	($0.8)	$9.1	1.6%
17	PA Central	Interface	500	$1.2	($9.7)	$0.6	$11.5	$0.3	$2.9	($0.1)	($2.7)	$8.8	1.5%
18	Pleasant View - Ashburn	Line	Dominion	$6.9	($1.8)	$0.3	$9.0	$0.8	$1.2	($0.1)	($0.6)	$8.4	1.4%
19	CPL - DOM	Interface	500	$3.5	($4.2)	$0.1	$7.8	$0.0	$0.0	$0.0	$0.0	$7.8	1.3%
20	Tanners Creek - Miami Fort	Line	AEP	($0.0)	($0.1)	$0.0	$0.1	($0.1)	$1.4	($4.9)	($6.3)	($6.3)	(1.1%)
21	Gardners - Texas Eastern	Line	Met-Ed	($0.5)	($8.1)	$0.2	$7.9	($1.0)	$0.2	($0.4)	($1.6)	$6.3	1.1%
22	Greentown	Flowgate	MISO	($0.2)	($1.7)	($0.1)	$1.5	($0.6)	$0.9	($6.2)	($7.7)	($6.1)	(1.1%)
23	Smithton - Yukon	Line	APS	($3.6)	($9.2)	$0.4	$6.1	$0.9	$0.2	($0.7)	($0.1)	$6.0	1.0%
24	Harwood - Susquehanna	Line	PPL	$0.3	($5.5)	$0.2	$6.1	$0.0	($0.0)	($0.1)	($0.1)	$6.0	1.0%
25	East Towanda - Hillside	Line	PENELEC	($1.5)	($7.3)	($0.1)	$5.7	$0.1	$0.2	($0.0)	($0.1)	$5.5	1.0%
	Top 25 Total			$185.6	($175.9)	$8.5	$370.1	$7.0	$28.7	($29.6)	($51.4)	$318.7	54.6%
	All Other Constraints			$60.4	($236.4)	$47.2	$343.9	($3.3)	$22.3	($53.7)	($79.3)	$264.6	45.4%
	Total			$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$583.3	100.0%

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 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 total congestion costs: 2020



32 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 11-5 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 2020.

Figure 11-5 Location of top 10 constraints by balancing congestion costs: 2020

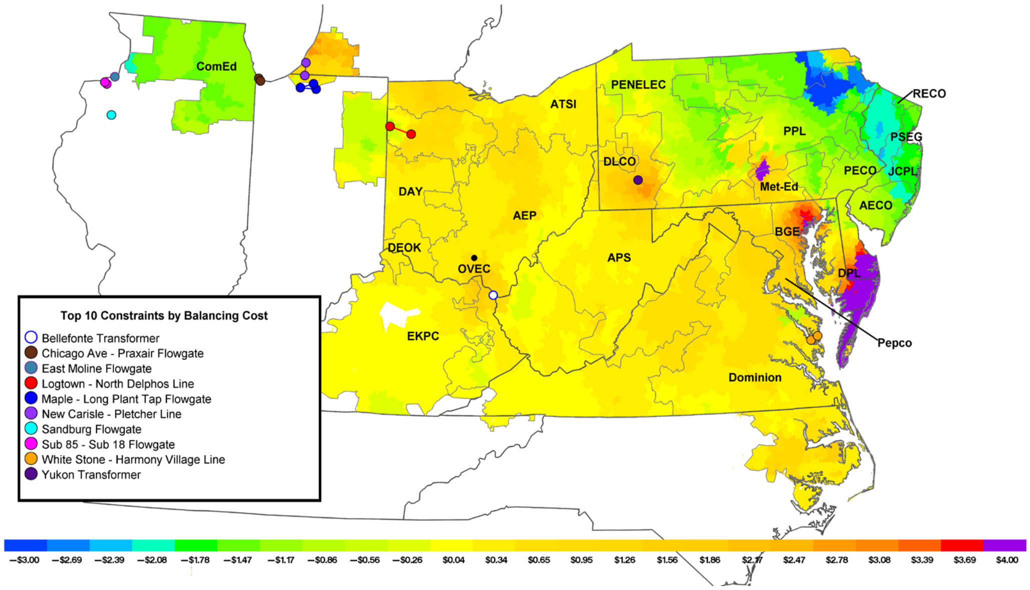
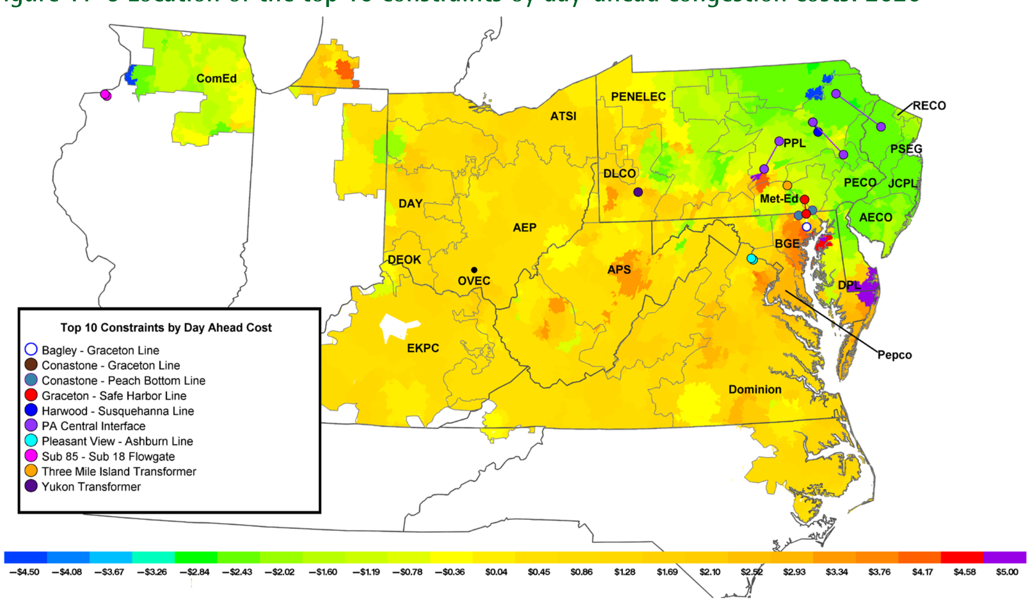


Figure 11-6 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead, load-weighted, average CLMP in 2020.

Figure 11-6 Location of the top 10 constraints by day-ahead congestion costs: 2020



Congestion Event Summary: Impact of Changes in UTC Volumes

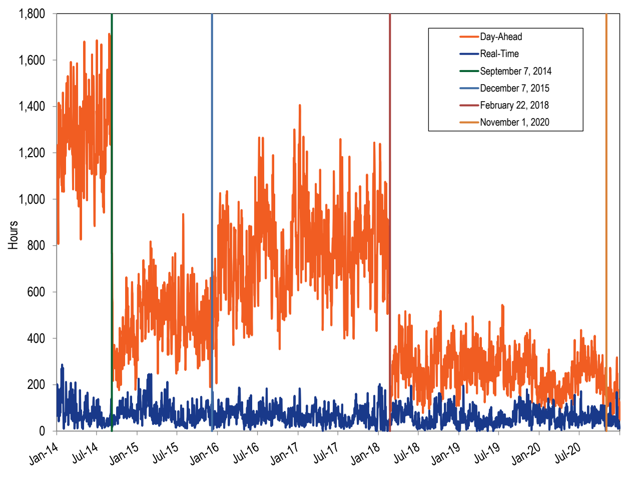
UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.[33]

In 2020, the average hourly cleared UTC MW decreased by 12.4 percent, compared to 2019. Day-ahead congestion event hours decreased by 24.1 percent from 103,140 congestion event hours in 2019 to 78,239 congestion event hours in 2020 (Table 11-25).

Day-ahead daily average congestion event hours decreased 33.1 percent from 226 congestion event hours for the period January 1, 2020, through October 31, 2020, to 151 congestion event hours for the period November 1, 2020 through December 31, 2020. The daily average cleared UTC MW decreased by 61.2 percent from 487,023 MW for the period January 1, 2020, through October 31, 2020, to 189,019 MW for the period November 1, 2020 through December 31, 2020.

Figure 11-7 shows the daily day-ahead and real-time congestion event hours for 2014 through 2020.

Figure 11-7 Daily congestion event hours: 2014 through 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.[34] 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.[35] 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

33 A series of FERC orders has affected UTC activity which has in turn affected congestion events in the day-ahead market. See Appendix F: Congestion and Marginal Losses

34 PJM Operating Agreement Schedule 1 §3.7.
35 *Id.*

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.[36]

- **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 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

36 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 83 (Dec. 3, 2019).

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.[37]

Total Marginal Loss Cost

The total marginal loss cost in PJM for 2020 was $478.5 million, which was comprised of implicit withdrawal loss charges of -$25.9 million, implicit injection loss credits of -$518.2 million, explicit loss charges of -$13.7 million and inadvertent loss charges of $0.0 million (Table 11-34). The total marginal loss cost in 2020 was lower than the total marginal loss cost in any year from 2008 through 2019.

Monthly marginal loss costs in 2020 ranged from $22.5 million in April to $67.0 million in July. Total marginal loss surplus decreased in 2020 by $45.8 million or 22.5 percent from $203.7 million in 2019 to $157.9 million in 2020.

Table 11-33 shows the total marginal loss component costs and the total PJM billing for 2008 through 2020.

Table 11-33 Total loss component costs (Dollars (Millions)): 2008 through 2020[38]

	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,497	NA	$34,300	7.3%
2009	$1,268	(49.2%)	$26,550	4.8%
2010	$1,635	29.0%	$34,770	4.7%
2011	$1,380	(15.6%)	$35,890	3.8%
2012	$982	(28.8%)	$29,180	3.4%
2013	$1,035	5.5%	$33,860	3.1%
2014	$1,466	41.6%	$50,030	2.9%
2015	$969	(33.9%)	$42,630	2.3%
2016	$697	(28.1%)	$39,050	1.8%
2017	$691	(0.8%)	$40,170	1.7%
2018	$960	39.0%	$49,790	1.9%
2019	$642	(33.1%)	$39,200	1.6%
2020	$479	(25.5%)	$33,640	1.4%

Table 11-34 shows PJM total marginal loss costs by accounting category for 2008 through 2020. Table 11-35 shows PJM total marginal loss costs by accounting category by market for 2008 through 2020.

Table 11-34 Total marginal loss costs by accounting category (Dollars (Millions)): 2008 through 2020

	Marginal Loss Costs (Millions)				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	($237.2)	($2,641.5)	$92.4	$0.0	$2,496.7
2009	($78.5)	($1,314.3)	$32.0	($0.0)	$1,267.7
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5
2012	($11.1)	($1,036.8)	($44.0)	$0.0	$981.7
2013	($4.1)	($1,083.3)	($43.9)	($0.0)	$1,035.3
2014	($59.2)	($1,581.3)	($56.0)	$0.0	$1,466.1
2015	($31.7)	($1,021.0)	($20.5)	$0.0	$968.7
2016	($55.0)	($782.1)	($30.6)	($0.0)	$696.5
2017	($40.9)	($766.9)	($35.1)	$0.0	$690.8
2018	($42.2)	($1,014.3)	($11.9)	$0.0	$960.1
2019	($44.7)	($703.4)	($16.6)	($0.0)	$642.0
2020	($25.9)	($518.2)	($13.7)	$0.0	$478.5

37 PJM Operating Agreement Schedule 1 §3.7.
38 The loss costs include net inadvertent charges.

Table 11-35 Total marginal loss costs by accounting category by market (Dollars (Millions)): 2008 through 2020

	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
2008	($158.1)	($2,582.2)	$134.3	$2,558.4	($79.1)	($59.4)	($42.0)	($61.7)	$0.0	$2,496.7
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.2	($2.7)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.8)	($0.0)	$1,634.8
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.4	$40.2	($52.2)	($51.0)	$0.0	$1,379.5
2012	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7
2013	($37.1)	($1,112.4)	$62.4	$1,137.8	$33.0	$29.1	($106.4)	($102.5)	($0.0)	$1,035.3
2014	($113.9)	($1,618.8)	$66.6	$1,571.4	$54.7	$37.5	($122.5)	($105.3)	$0.0	$1,466.1
2015	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7
2016	($61.7)	($781.6)	$53.4	$773.2	$6.8	($0.5)	($84.0)	($76.7)	($0.0)	$696.5
2017	($52.2)	($767.2)	$54.9	$769.9	$11.3	$0.3	($90.0)	($79.1)	$0.0	$690.8
2018	($48.3)	($1,003.8)	$41.7	$997.2	$6.1	($10.5)	($53.7)	($37.0)	$0.0	$960.1
2019	($47.1)	($700.3)	$43.3	$696.5	$2.4	($3.1)	($60.0)	($54.5)	($0.0)	$642.0
2020	($27.6)	($517.4)	$36.5	$526.3	$1.7	($0.8)	($50.3)	($47.7)	$0.0	$478.5

Table 11-36 and Table 11-37 show the total loss costs for each transaction type in 2020 and 2019. In 2020, generation paid loss costs of $501.9 million, 104.9 percent of total loss costs. In 2019, generation paid loss costs of $677.6 million, 105.5 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 2020, DECs were paid $1.8 million in loss credits in the day-ahead market, paid $3.9 million in loss charges in the balancing energy market and paid $2.1 million in total loss payments. In 2020, INCs paid $7.7 million in loss charges in the day-ahead market, were paid $9.0 million in loss credits in the balancing energy market and were paid $1.3 million in total loss credits. In 2020, up to congestion paid $36.5 million in loss charges in the day-ahead market, were paid $50.6 million in loss credits in the balancing energy market and received $14.1 million in total loss credits.

Table 11-36 Total loss costs by transaction type by market (Dollars (Millions)): 2020

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($1.8)	$0.0	$0.0	($1.8)	$3.9	$0.0	$0.0	$3.9	$0.0	$2.1
Demand	$0.7	$0.0	$0.0	$0.7	$4.2	$0.0	$0.0	$4.2	$0.0	$4.9
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)
Explicit Congestion and Loss Only	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.4)
Export	($11.6)	$0.0	$0.0	($11.6)	($5.3)	$0.0	$0.4	($4.9)	$0.0	($16.5)
Generation	$0.0	($494.5)	$0.0	$494.5	$0.0	($7.4)	$0.0	$7.4	$0.0	$501.9
Import	$0.0	($0.7)	$0.0	$0.7	$0.0	($1.3)	($0.0)	$1.3	$0.0	$2.0
INC	$0.0	($7.7)	$0.0	$7.7	$0.0	$9.0	$0.0	($9.0)	$0.0	($1.3)
Internal Bilateral	($14.9)	($14.5)	$0.4	($0.0)	($1.2)	($1.1)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$36.5	$36.5	$0.0	$0.0	($50.6)	($50.6)	$0.0	($14.1)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)
Total	($27.6)	($517.4)	$36.5	$526.3	$1.7	($0.8)	($50.3)	($47.7)	$0.0	$478.5

Table 11-37 Total loss costs by transaction type by market (Dollars (Millions)): 2019

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	"Grand Total"
DEC	($4.5)	$0.0	$0.0	($4.5)	$6.1	$0.0	$0.0	$6.1	$0.0	$1.6
Demand	($5.8)	$0.0	$0.0	($5.8)	$6.0	$0.0	$0.0	$6.0	$0.0	$0.1
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	($0.5)	($0.5)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.5)
Export	($17.0)	$0.0	($0.0)	($17.0)	($8.6)	$0.0	$0.4	($8.3)	$0.0	($25.3)
Generation	$0.0	($668.5)	$0.0	$668.5	$0.0	($9.1)	$0.0	$9.1	$0.0	$677.6
Import	$0.0	($1.7)	$0.0	$1.7	$0.0	($5.7)	($0.1)	$5.6	$0.0	$7.3
INC	$0.0	($10.5)	$0.0	$10.5	$0.0	$12.7	$0.0	($12.7)	$0.0	($2.2)
Internal Bilateral	($19.7)	($19.5)	$0.2	$0.0	($1.0)	($1.0)	$0.0	($0.0)	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$43.7	$43.7	$0.0	$0.0	($60.1)	($60.1)	$0.0	($16.4)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	$0.0	($0.2)
Total	($47.1)	($700.3)	$43.3	$696.5	$2.4	($3.1)	($60.0)	($54.5)	$0.0	$642.0

Monthly Marginal Loss Costs

Table 11-38 shows a monthly summary of marginal loss costs by market type for 2019 and 2020.

Table 11-38 Monthly marginal loss costs by market (Millions): 2019 and 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	$37.0	($3.0)	$0.0	$34.0
Nov	$58.2	($6.0)	($0.0)	$52.2	$37.8	($1.4)	$0.0	$36.4
Dec	$53.1	($4.9)	($0.0)	$48.1	$59.9	($1.1)	$0.0	$58.8
Total	$696.5	($54.5)	($0.0)	$642.0	$526.3	($47.7)	$0.0	$478.5

Figure 11-8 shows PJM monthly marginal loss costs for 2008 through 2020.

Figure 11-8 Monthly marginal loss costs (Dollars (Millions)): 2008 through 2020

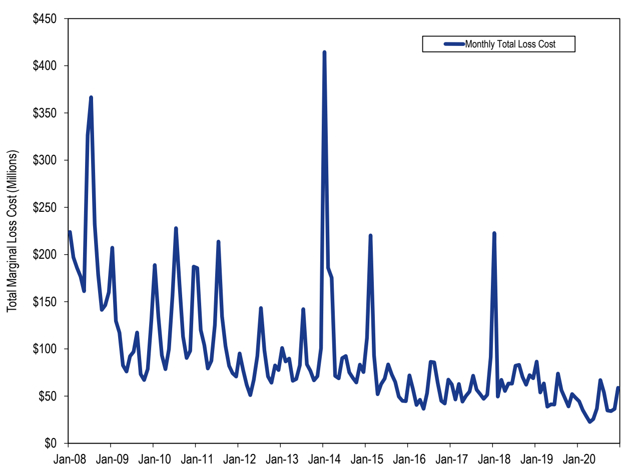


Table 11-39 shows the monthly total loss costs for each virtual transaction type in 2019 and 2020.

Table 11-39 Monthly loss charges by virtual transaction type and by market (Dollars (Millions)): 2019 and 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)
	Oct	$0.0	$0.1	$0.2	$0.7	($0.8)	($0.1)	$2.5	($3.0)	($0.6)	($0.5)
	Nov	($0.5)	$0.6	$0.1	$0.7	($0.8)	($0.0)	$1.6	($2.1)	($0.4)	($0.4)
	Dec	$0.3	$0.1	$0.4	$0.7	($0.9)	($0.3)	$1.9	($2.4)	($0.5)	($0.4)
	Total	($1.8)	$3.9	$2.1	$7.7	($9.0)	($1.3)	$36.5	($50.6)	($14.1)	($13.3)

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 2008 through 2020. The total marginal loss surplus decreased $45.8 million in 2020 from 2019.

Table 11-40 Marginal loss surplus (Dollars (Millions)): 2008 through 2020[39]

	Marginal Loss Surplus (Millions)					
			Net Residual Market Adjustment			
	System Energy Costs	Marginal Loss Costs	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total
2008	($1,193.2)	$2,496.7	$0.0	$0.0	$0.0	$1,303.5
2009	($628.8)	$1,267.7	($0.0)	($0.4)	($0.1)	$639.4
2010	($797.9)	$1,634.8	$0.0	($0.7)	($0.0)	$837.7
2011	($793.8)	$1,379.5	$0.1	$0.7	($0.0)	$585.2
2012	($593.0)	$981.7	$0.1	($1.0)	$0.1	$389.6
2013	($687.6)	$1,035.3	$0.0	$2.0	($0.0)	$345.7
2014	($977.7)	$1,466.1	$0.0	($0.0)	($0.0)	$488.4
2015	($627.4)	$968.7	($0.0)	$6.3	$0.1	$335.0
2016	($466.3)	$696.5	($0.0)	$5.1	($0.1)	$225.2
2017	($475.2)	$690.8	($0.0)	$3.2	($0.2)	$212.6
2018	($636.7)	$960.1	$0.0	$1.1	($0.1)	$322.4
2019	($435.2)	$642.0	($0.0)	$3.2	($0.1)	$203.7
2020	($319.0)	$478.5	($0.0)	$1.7	($0.1)	$157.9

System Energy Costs

Energy Accounting

The system energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The system energy cost is based on the day-ahead and real-time energy components of LMP. Total system energy costs, analogous to total congestion costs or total loss costs, are equal to the withdrawal energy charges minus injection energy credits, 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 2020 was -$319.0 million, which was comprised of implicit withdrawal energy charges of $23,400.9 million, implicit injection energy credits of $23,722.4 million, explicit energy charges of $0.0 million and inadvertent energy charges of $2.5 million. The monthly system energy costs for 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 2008 through 2020.

Table 11-41 Total system energy costs (Dollars (Millions)): 2008 through 2020[40]

	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($1,193)	NA	$34,300	(3.5%)
2009	($629)	(47.3%)	$26,550	(2.4%)
2010	($798)	26.9%	$34,770	(2.3%)
2011	($794)	(0.5%)	$35,890	(2.2%)
2012	($593)	(25.3%)	$29,180	(2.0%)
2013	($688)	15.9%	$33,860	(2.0%)
2014	($978)	42.2%	$50,030	(2.0%)
2015	($627)	(35.8%)	$42,630	(1.5%)
2016	($466)	(25.7%)	$39,050	(1.2%)
2017	($475)	1.9%	$40,170	(1.2%)
2018	($637)	34.0%	$49,790	(1.3%)
2019	($435)	(31.6%)	$39,200	(1.1%)
2020	($319)	(26.7%)	$33,640	(0.9%)

39 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.

40 The system energy costs include net inadvertent charges.

System energy costs for 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.

Table 11-42 Total system energy costs by accounting category (Dollars (Millions)): 2008 through 2020

	System Energy Costs (Millions)				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	$105,665.6	$106,860.0	$0.0	$1.2	($1,193.2)
2009	$42,535.2	$43,165.7	$0.0	$1.7	($628.8)
2010	$53,101.5	$53,886.9	$0.0	($12.6)	($797.9)
2011	$47,658.9	$48,481.0	$0.0	$28.3	($793.8)
2012	$37,471.3	$38,073.5	$0.0	$9.1	($593.0)
2013	$42,774.3	$43,454.6	$0.0	($7.4)	($687.6)
2014	$60,258.5	$61,232.0	$0.0	($4.2)	($977.7)
2015	$40,601.8	$41,231.9	$0.0	$2.7	($627.4)
2016	$34,053.6	$34,510.1	$0.0	($9.8)	($466.3)
2017	$35,152.1	$35,634.4	$0.0	$7.1	($475.2)
2018	$43,805.9	$44,447.2	$0.0	$4.6	($636.7)
2019	$30,647.4	$31,081.1	$0.0	($1.5)	($435.2)
2020	$23,400.9	$23,722.4	$0.0	$2.5	($319.0)

Table 11-43 Total system energy costs by market category (Dollars (Millions)): 2008 through 2020

	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	$81,789.8	$83,120.0	$0.0	($1,330.1)	$23,875.8	$23,740.0	$0.0	$135.7	$1.2	($1,193.2)
2009	$42,683.8	$43,351.2	$0.0	($667.4)	($148.5)	($185.5)	$0.0	$36.9	$1.7	($628.8)
2010	$53,164.9	$53,979.1	$0.0	($814.1)	($63.4)	($92.2)	$0.0	$28.8	($12.6)	($797.9)
2011	$48,144.9	$48,880.0	$0.0	($735.2)	($485.9)	($399.1)	$0.0	($86.9)	$28.3	($793.8)
2012	$37,641.2	$38,251.1	$0.0	($609.9)	($169.9)	($177.6)	$0.0	$7.7	$9.1	($593.0)
2013	$42,795.2	$43,628.9	$0.0	($833.7)	($20.9)	($174.4)	$0.0	$153.5	($7.4)	($687.6)
2014	$60,325.2	$61,668.9	$0.0	($1,343.7)	($66.7)	($436.9)	$0.0	$370.2	($4.2)	($977.7)
2015	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	$2.7	($627.4)
2016	$34,245.1	$34,885.7	$0.0	($640.6)	($191.5)	($375.6)	$0.0	$184.0	($9.8)	($466.3)
2017	$35,490.1	$36,138.6	$0.0	($648.5)	($338.0)	($504.2)	$0.0	$166.2	$7.1	($475.2)
2018	$43,948.7	$44,659.7	$0.0	($711.0)	($142.9)	($212.6)	$0.0	$69.7	$4.6	($636.7)
2019	$31,034.3	$31,562.9	$0.0	($528.6)	($386.9)	($481.8)	$0.0	$94.9	($1.5)	($435.2)
2020	$23,581.5	$23,983.0	$0.0	($401.4)	($180.6)	($260.5)	$0.0	$79.9	$2.5	($319.0)

Table 11-44 and Table 11-45 show the total system energy costs for each transaction type in 2020 and 2019. In 2020, generation was paid $17,020.6 million and demand paid $15,872.1 million in net energy payment. In 2019, generation was paid $22,210.6 million and demand paid $21,012.3 million in net energy payment.

Table 11-44 Total system energy costs by transaction type by market (Dollars (Millions)): 2020

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$851.8	$0.0	$0.0	$851.8	($871.8)	$0.0	$0.0	($871.8)	($20.0)
Demand	$15,632.8	$0.0	$0.0	$15,632.8	$239.3	$0.0	$0.0	$239.3	$15,872.1
Demand Response	($0.3)	$0.0	$0.0	($0.3)	$0.3	$0.0	$0.0	$0.3	$0.0
Export	$598.0	$0.0	$0.0	$598.0	$359.2	$0.0	$0.0	$359.2	$957.2
Generation	$0.0	$17,008.7	$0.0	($17,008.7)	$0.0	$12.0	$0.0	($12.0)	($17,020.6)
Import	$0.0	$29.6	$0.0	($29.6)	$0.0	$84.9	$0.0	($84.9)	($114.5)
INC	$0.0	$445.5	$0.0	($445.5)	$0.0	($449.8)	$0.0	$449.8	$4.3
Internal Bilateral	$6,499.2	$6,499.2	$0.0	($0.0)	$65.6	$65.6	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$26.9	$0.0	($26.9)	($26.9)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$26.9	$0.0	$0.0	$26.9	$26.9
Total	$23,581.5	$23,983.0	$0.0	($401.4)	($180.6)	($260.5)	$0.0	$79.9	($321.5)

Table 11-45 Total system energy costs by transaction type by market (Dollars (Millions)): 2019

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$917.1	$0.0	$0.0	$917.1	($932.0)	$0.0	$0.0	($932.0)	($14.8)
Demand	$20,912.4	$0.0	$0.0	$20,912.4	$99.9	$0.0	$0.0	$99.9	$21,012.3
Demand Response	($0.8)	$0.0	$0.0	($0.8)	$0.7	$0.0	$0.0	$0.7	($0.0)
Export	$661.1	$0.0	$0.0	$661.1	$401.1	$0.0	$0.0	$401.1	$1,062.2
Generation	$0.0	$22,247.3	$0.0	($22,247.3)	$0.0	($36.6)	$0.0	$36.6	($22,210.6)
Import	$0.0	$86.1	$0.0	($86.1)	$0.0	$195.2	$0.0	($195.2)	($281.4)
INC	$0.0	$685.1	$0.0	($685.1)	$0.0	($683.7)	$0.0	$683.7	($1.4)
Internal Bilateral	$8,544.4	$8,544.4	$0.0	$0.0	$26.4	$26.4	$0.0	($0.0)	$0.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$17.0	$0.0	($17.0)	($17.0)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$17.0	$0.0	$0.0	$17.0	$17.0
Total	$31,034.3	$31,562.9	$0.0	($528.6)	($386.9)	($481.8)	$0.0	$94.9	($433.7)

Monthly System Energy Costs

Table 11-46 shows a monthly summary of system energy costs by market type for 2019 and 2020. Total balancing system energy costs in 2020 decreased from 2019. Monthly total system energy costs in 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)): 2019 through 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)	($35.2)
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)	($29.4)	$7.3	$0.3	($21.9)
Nov	($45.9)	$10.3	($0.8)	($36.4)	($27.3)	$2.3	$0.1	($24.9)
Dec	($41.5)	$9.1	($0.3)	($32.7)	($41.2)	$2.7	$0.2	($38.3)
Total	($528.6)	$94.9	($1.5)	($435.2)	($401.4)	$79.9	$2.5	($319.0)

Figure 11-9 shows PJM monthly system energy costs for 2008 through 2020.

Figure 11-9 Monthly system energy costs (Millions): 2008 through 2020

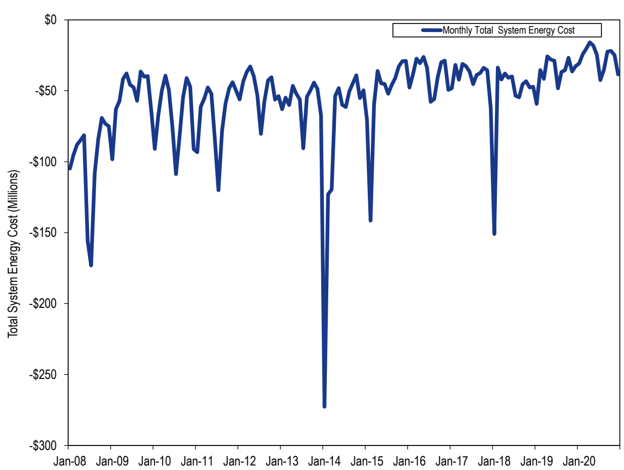


Table 11-47 shows the monthly total system energy costs for each virtual transaction type in 2020 and year of 2019. In 2020, DECs paid $851.8 million in energy charges in the day-ahead market, were paid $871.8 million in energy credits in the balancing energy market and were paid $20.0 million in total energy credits. In 2020, INCs were paid $445.5 million in energy credits in the day-ahead market, paid $449.8 million in energy charges in the balancing market and paid $4.3 million in total energy charges. In 2019, DECs paid $917.1 million in energy charges in the day-ahead market, were paid $932.0 million in energy credits in the balancing energy market and were paid $14.8 million in total energy credits. In 2019, INCs were paid $685.1 million in energy credits in the day-ahead market, paid $683.7 million in energy charges in the balancing energy market and were paid $1.4 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 energy charges by virtual transaction type and by market (Dollars (Millions)): 2019 and 2020

		Energy Charges (Millions)						
		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand 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
	Oct	$78.9	($81.4)	($2.5)	($39.2)	$40.9	$1.7	($0.8)
	Nov	$72.4	($74.8)	($2.4)	($38.4)	$38.8	$0.4	($2.1)
	Dec	$92.6	($95.1)	($2.5)	($40.5)	$41.4	$0.9	($1.6)
	Total	$851.8	($871.8)	($20.0)	($445.5)	$449.8	$4.3	($15.7)

Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of December 31, 2020, PJM had a total installed capacity of 198,129.0 MW, of which 50,230.8 MW (25.4 percent) are coal fired steam units, 50,602.0 MW (25.5 percent) are combined cycle units and 33,452.6 MW (16.9 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 198,129.0 MW of installed capacity, 72,244.4 MW (36.5 percent) are from units older than 40 years, of which 37,578.4 MW (52.0 percent) are coal fired steam units, 532.0 MW (0.7 percent) are combined cycle units and 16,184.6 MW (22.4 percent) are nuclear units.

Generation Retirements[2]

- There are 44,181.3 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 32,084.1 MW (72.6 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 2020, 3,255.0 MW of generation retired. The largest generator that retired in 2020 was the 786.0 MW Possum Point 5 oil fired steam unit located in the Dominion Zone. Of the 3,255.0 MW of generation that retired, 786.0 MW (24.1 percent) were located in the Dominion Zone.
- As of December 31, 2020, there are 4,163.9 MW of generation that have requested retirement after December 31, 2020, of which 1,794.5 MW (43.1 percent) are located in the ComEd Zone. Of the generation requesting retirement in the ComEd Zone, 1,786.5 MW (99.6 percent) are nuclear units.

Generation Queue[3]

- There were 126,818.9 MW in generation queues, in the status of active, under construction or suspended, at the end of 2019. In 2020, the AF2 and AG1 queue windows closed, and the AG2 queue window opened. 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 December 31, 2020, there were 173,581.3 MW in generation queues, in the status of active, under construction or suspended, an increase of 46,762.4 MW (36.9 percent) from the end of 2019.[4]
- As of December 31, 2020, 5,821 projects, representing 657,391.2 MW, have entered the queue process since its inception in 1998. Of those, 953 projects, representing 73,137.3 MW, went into service. Of the projects that entered the queue process, 2,983 projects, representing 410,672.5 MW (62.5 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 December 31, 2020, 173,581.3 MW were in generation request queues in the status of active, under construction or suspended. Based on historical completion rates, 37,214.3 MW of new generation in the queue are expected to go into service.
- The number of queue entries has increased during the past several years, primarily renewable projects. Of the 3,169 projects entered from January 2015 through December 2020, 2,380 projects (75.1 percent) were renewable. Of the 969 projects entered in 2020, 768 projects (79.3 percent) were renewable. Renewable projects make up 78.6 percent of all projects in the queue and those projects account for 74.8 percent of the nameplate MW currently active, suspended or under construction in the queue as of December 31, 2020.

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 December 31, 2020) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
3 See PJM. Planning. "New Services Queue," (Accessed on December 31, 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.

But of the 129,844.9 MW of renewable projects in the queue, only 6,487.5 MW (5.0 percent) of capacity resources are expected to go into service, based on both historical completion rates and average derate factors for wind and solar.

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 December 31, 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.

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

PJM MISO Targeted Market Efficiency Process (TMEP)

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

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[6] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 715.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890[7]) to 163 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.[8]

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project. Under the current approach, end of life projects are excluded from competition.[9]

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews internal and external proposals to

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 December 31, 2020) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

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

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

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

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.[10] In 2020, the PJM Board approved $235.2 million in upgrades. As of December 31, 2020, the PJM Board has approved $37.8 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 December 31, 2020, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[11]
- There were 11,827 transmission outage requests submitted in the first seven months of 2020/2021 planning period. Of the requested outages, 75.9 percent of the requested outages were planned for less than or equal to five days and 9.2 percent of requested outages were planned for greater than 30 days. Of the requested outages, 43.9 percent were late according to the rules in PJM's Manual 3.

Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[12] (Priority: 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

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

11 See PJM. "PJM Manual 03: Transmission Operations," Rev. 58 (November 19, 2020).

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

and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)

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

Market Efficiency Process

- The MMU recommends that 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.)

Comparative Cost Framework

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

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)
- 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. First reported Q3, 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution-based DFAX is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution-based DFAX method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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.[13] (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

13 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 and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The MMU recognizes that the Commission has recently issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and 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.

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

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

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

If it is retained, there are significant issues with PJM's 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.[14] As of December 31, 2020, PJM had an installed capacity of 198,129.0 MW, of which 50,230.8 MW (25.4 percent) are coal fired steam units, 60,602.0 MW (25.5 percent) are combined cycle units and 33,452.6 MW (16.9 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, external units and uses nameplate values for solar and wind resources.

The AEP Zone has the most installed capacity of any PJM zone. Of the 198,129.0 MW of PJM installed capacity, 31,500.1 MW (15.9 percent) are in the AEP Zone, of which 13,463.0 MW (42.7 percent) are coal fired steam units, 6,990.0 MW (22.2 percent) are combined cycle units and 2,071.0 MW (6.6 percent) are nuclear units.

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

Table 12-1 Existing capacity: December 31, 2020 (By zone and unit type (MW))[15]

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	64.1	0.0	0.0	458.9	0.0	0.0	0.0	7.5	0.0	2,017.5
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	244.7	0.0	0.0	13,463.0	738.0	0.0	50.0	3,300.9	0.0	31,500.1
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	4,831.0	0.0	30,187.0
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	9,138.0	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	39.0	106.4	2,114.0	0.0	0.0	3,852.6	35.0	1,586.0	368.4	587.0	0.0	29,098.7
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	371.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,010.5
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	213.5	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	14,600.3
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	50,602.0	24,655.7	3,962.4	43.8	32.0	5,052.0	3,040.6	33,452.6	161.7	218.5	362.4	3,484.1	0.0	0.0	50,230.8	8,414.6	2,136.0	1,010.5	10,918.4	0.0	198,129.0

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most installed capacity of any PJM state. Of the 198,129.0 MW of installed capacity, 48,185.9 MW (24.3 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 capacity: December 31, 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	4,831.0	0.0	30,187.0
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	841.5	0.0	0.0	0.0	0.0	0.0	0.0	208.0	0.0	1,547.5
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	660.4	0.0	0.0	458.9	3.0	0.0	179.1	7.5	0.0	15,398.8
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	151.1	0.0	0.0	9,689.0	47.0	0.0	0.0	1,147.7	0.0	25,372.2
PA	49.9	17,616.5	1,491.9	1,512.0	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	48,185.9
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	8,973.0	4,172.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	33.0	112.4	1,382.5	0.0	0.0	2,847.6	495.0	1,586.0	368.4	12.0	0.0	27,696.0
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	50,602.0	24,655.7	3,962.4	43.8	32.0	5,052.0	3,040.6	33,452.6	161.7	218.5	362.4	3,484.1	0.0	0.0	50,230.8	8,414.6	2,136.0	1,010.5	10,918.4	0.0	198,129.0

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of December 31, 2020. Of the 198,129.0 MW of installed capacity, 72,244.4 MW (36.5 percent) are from units older than 40 years, of which 37,578.4 MW (52.0 percent) are coal fired steam units, 532.0 MW (0.7 percent) are combined cycle units and 16,184.6 MW (22.4 percent) are nuclear units.

Table 12-3 Capacity (MW) by unit type and age (years): December 31, 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	16,727.9	604.5	43.8	32.0	0.0	297.2	0.0	149.7	20.0	301.0	3,484.1	0.0	0.0	3,475.0	82.0	0.0	97.4	10,918.4	0.0	81,555.6
20 to 40	0.0	5,098.3	7,458.1	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	9,177.4	600.0	0.0	843.1	0.0	0.0	44,329.0
40 to 60	0.0	532.0	469.7	3,002.4	0.0	0.0	2,049.0	340.0	16,184.6	0.0	173.5	0.0	0.0	0.0	0.0	34,725.6	5,971.1	2,136.0	70.0	0.0	0.0	65,653.9
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	50,602.0	24,655.7	3,962.4	43.8	32.0	5,052.0	3,040.6	33,452.6	161.7	218.5	362.4	3,484.1	0.0	0.0	50,230.8	8,414.6	2,136.0	1,010.5	10,918.4	0.0	198,129.0

15 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.

Figure 12-1 Capacity (MW) by age (years): December 31, 2020

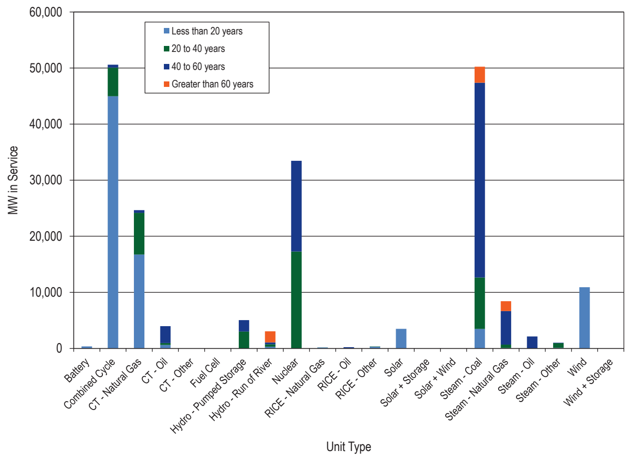


Figure 12-2 is a map of units, less than 20 MW in size, that came online between January 1, 2011 and December 31, 2020. A mapping to these unit names is in Table 12-4.

Figure 12-2 Map of unit additions (less than 20 MW): 2011 through 2020

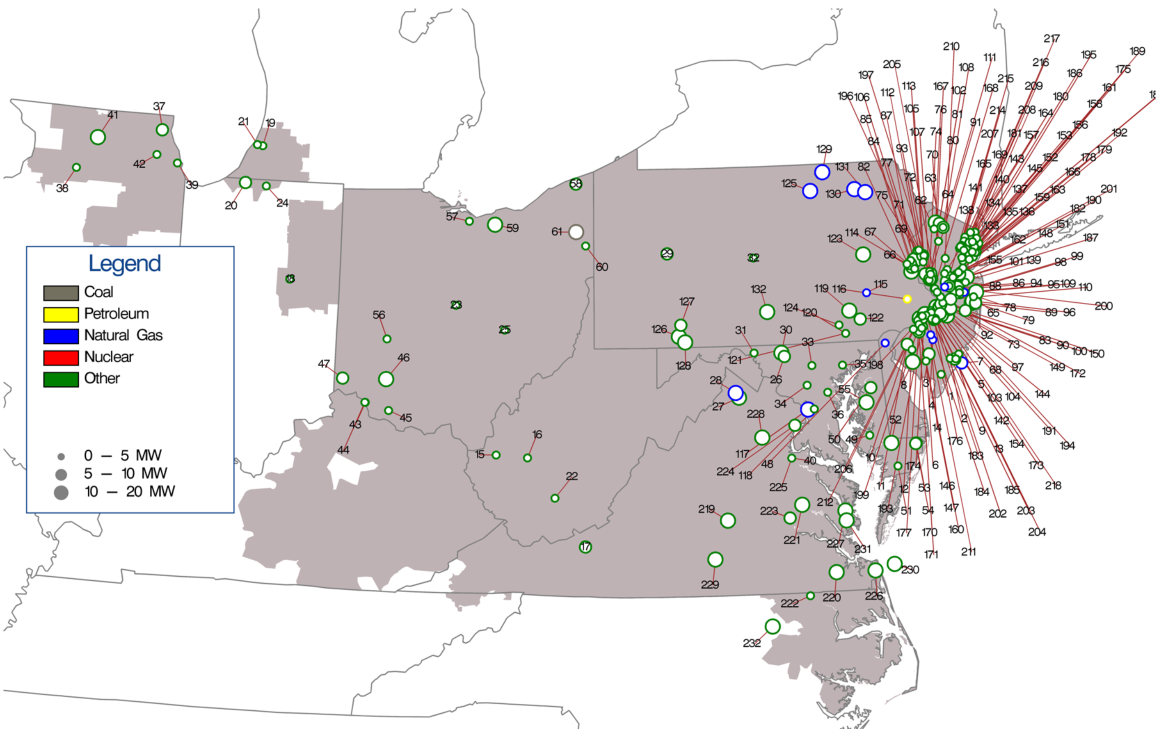


Table 12-4 Unit identification for map of unit additions (less than 20 MW): 2011 through 2020

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CAPE MAY COUNTY 1 LF	56	FE DOVETAIL 1 CT	111	JC WANTAGE 2 SP	166	PS HOBOKEN SOLAR 2 SP	221	VP HOLLYFIELD 1 SP
2	ACE CATES ROAD 2 SP	57	FE ERIE COUNTY 1 LF	112	JC WARREN 1 SP	167	PS HOPEWELL 1 SP	222	VP MURPHY 1 SP
3	ACE CEDAR BRANCH 1 SP	58	FE GENEVA 1 LF	113	JC WASHBURN AVE 4 SP	168	PS HOPEWELL 2 BT	223	VP NORTHEAST 2 LF
4	ACE EGG HARBOR-KELLOGG 1 FC	59	FE LORAIN 1 LF	114	ME GLENDON 1 LF	169	PS JACKSON SOLAR 1 SP	224	VP OCCOQUAN 1 LF
5	ACE GALLOWAY LANDFILL 2 SP	60	FE MAHONING 1 LF	115	ME READING HOSPITAL 1 CT	170	PS KINSLEY BEAVER 2 SP	225	VP OCCOQUAN 2 LF
6	ACE MAYS LANDING 1 SP	61	FE WARREN-EVERGREEN 1 CT	116	PE MORRIS ROAD 1 D	171	PS KINSLEY DEPTFORD 1 SP	226	VP OCEANA 1 SP
7	ACE MIDTOWN THERMAL 2 CT	62	JC AUGUSTA 1 SP	117	PEP CAPITAL POWER PLANT 1 CT	172	PS KUSER SOLAR 1 SP	227	VP PULLER 1 SP
8	ACE OAK FAIRTON 1 SP	63	JC BEAVER RUN 3 SP	118	PEP ROLLINS AVENUE 3 SP	173	PS LANDFILL 5 SP	228	VP REMINGTON 1 SP
9	ACE PEAR STREET 1 SP	64	JC BERNARDS TOWNSHIP 1 SP	119	PL DART CONTAINER 1-2 LF	174	PS LAWNSIDE 14 BT	229	VP TWITTYS CREEK 1 SP
10	ACE PILESGROVE 1 SP	65	JC BRICKYARD 4 SP	120	PL HOLTWOOD 11	175	PS LEONIA SOLAR 1 SP	230	VP VIRGINIA OFFSHORE 1 WF
11	ACE PILESGROVE 2 SP	66	JC COPPER HILL 4 SP	121	PL HOLTWOOD 13	176	PS LUMBERTON STACY HAINES 5 SP	231	VP WAN - GLOUCESTER 1 SP
12	ACE PITTSGROVE 1 SP	67	JC CYPHERS ROAD 5 SP	122	PL KEYSTONE 1 SP	177	PS MANTUA CREEK 7 BT	232	VP WHITAKERS 1 SP
13	ACE SEASHORE 1 SP	68	JC DIXSOLAR 5 SP	123	PL PA SOLAR 1 SP	178	PS MARION SOLAR 1 SP		
14	ACE TANSBORO ROAD 1 FC	69	JC DOMIN LANE 1 SP	124	PL TURKEY HILL 1 WF	179	PS MATRIX PA SOLAR 2 SP		
15	AEP BALLS GAP 1 BT	70	JC DURBAN AVENUE 1 SP	125	PN ALPACA GLORY BARN 1 D	180	PS MAYWOOD SOLAR 1 SP		
16	AEP CHARLESTON 1 LF	71	JC E FLEMINGTON 5 SP	126	PN GARRETT 1 BT	181	PS METRO HQ 2 SP		
17	AEP CLOYDS MT 1 LF	72	JC EAST AMWELL 7 SP	127	PN LAUREL HIGHLANDS 2 LF	182	PS MIDDLESEX 1 SP		
18	AEP DEERCREEK 1 SP	73	JC EGYPT 3 SP	128	PN MEYERSDALE 2 BT	183	PS MILL CREEK 1 SP		
19	AEP EAST WATERVLIET 1 SP	74	JC FISCHER 8 SP	129	PN MILAN ENERGY 1 D	184	PS MOORESTOWN 1 SP		
20	AEP OLIVE 1 SP	75	JC FOUL RIFT ROAD 1 SP	130	PN NORTH MESHOPPEN 1 CT	185	PS MT LAUREL 1 SP		
21	AEP ORCHARD HILLS 1 LF	76	JC FRANKFORD 4 SP	131	PN OXBOW CREEK ENERGY CENTER 1 D	186	PS NEW MILFORD SOLAR 1 SP		
22	AEP RALEIGH COUNTY 1 LF	77	JC FRANKLIN 7 SP	132	PN WHITETAIL 1 SP	187	PS NEW ROAD 1 SP		
23	AEP TRENT 1 BT	78	JC FREEMALL 1 FC	133	PS ALDENE SOLAR 1 SP	188	PS NEWARK SOLAR 1 SP		
24	AEP TWINBRANCH 1 SP	79	JC FRENCHES 2 SP	134	PS ATHENIA SOLAR 1 SP	189	PS NEWARK SOLAR 3 SP		
25	AEP ZANESVILLE 2 LF	80	JC FRENCHTOWN 1 SP	135	PS BAYONNE 1 SP	190	PS NIXON LANE 2 SP		
26	AP BAKER POINT 1 SP	81	JC FRENCHTOWN 2 SP	136	PS BAYONNE SOLAR 2 SP	191	PS NORTH AMERICAN 4 SP		
27	AP DOUBLE TOLLGATE SP	82	JC FRENCHTOWN 3 SP	137	PS BELLEVILLE SOLAR 1 SP	192	PS NORTH AVE SOLAR 1 SP		
28	AP HP HOOD 1 CT	83	JC HANOVER 2 SP	138	PS BENNETTS SOLAR 1 SP	193	PS OWENS CORNING 1 SP		
29	AP MAHONING CREEK 1 H	84	JC HARMONY 1 SP	139	PS BLACK ROCK 1 SP	194	PS PARKLANDS 1 SP		
30	AP MT ST MARYS PV PARK 2 SP	85	JC HIGH STREET 6 SP	140	PS BRIDGEWATER SOLAR 2 SP	195	PS PATERSON PLANK ROAD 1 SP		
31	AP PINESBURG 1 SP	86	JC HOFFMAN STATION ROAD 2 SP	141	PS CALDWELL PUMP 2 BT	196	PS PENNINGTON 3 BT		
32	AP STATE COLLEGE 1 BT	87	JC HOLLAND 4 SP	142	PS CAMPUS DRIVE 2 SP	197	PS PENNINGTON 4 SP		
33	BC ALPHA RIDGE 1 LF	88	JC HOLMDEL 9 SP	143	PS CEDAR GROVE SOLAR 1 SP	198	PS PENNSAUKEN 1 LF		
34	BC BRIGHTON DAM 1 H	89	JC HOWELL 1 SP	144	PS CEDAR LANE FLORENCE 6 SP	199	PS PENNSAUKEN 3 SP		
35	BC KINGSVILLE 1 SP	90	JC JACOBSTOWN 1 SP	145	PS COOK ROAD SOLAR 2 SP	200	PS PRINCETON HOSPITAL 1 CT		
36	BC MILLERSVILLE 1 LF	91	JC JUNCTION ROAD 6 SP	146	PS COOPER HOSPITAL 1 BT	201	PS RARITAN CENTER 3 SP		
37	COM COUNTRYSIDE 1 LF	92	JC LAKEHURST 3 SP	147	PS COOPER HOSPITAL 15 SP	202	PS REEVES EAST 3 SP		
38	COM DIXON LEE 5 LF	93	JC LEBANON 1 SP	148	PS CRANBURY 2 SP	203	PS REEVES SOUTH 1 SP		
39	COM GRAND RIDGE 6 BT	94	JC MANALAPAN 1 SP	149	PS CROSSWIC 1 SP	204	PS REEVES WEST 4 SP		
40	COM MORRIS 1 LF	95	JC MILLHURST 3 SP	150	PS CROSSWIC 2 SP	205	PS RIDER UNIVERSITY 3 SP		
41	COM ORCHARD 1 LF	96	JC MUDDY FORGE 3 SP	151	PS DEVILSBROOK 1 SP	206	PS RIVER ROAD 2 SP		
42	COM SOLBERG 1 BT	97	JC NORTH HANOVER 4 SP	152	PS DOREMUS SOLAR 1 SP	207	PS ROSELAND SOLAR 1 SP		
43	DEOK BECKJORD 1 BT	98	JC NORTH PARK 1 SP	153	PS E RUTHERFORD SOLAR 1 SP	208	PS SADDLE BROOK SOLAR 1 SP		
44	DEOK BECKJORD 2 BT	99	JC NORTH PARK 2 SP	154	PS EASTAMPTON 1 SP	209	PS SPRINGFIELD SOLAR 1 SP		
45	DEOK BROWN COUNTY 1 LF	100	JC NORTH RUN 11 SP	155	PS EDISON 1 SP	210	PS SUNNYMEADE SOLAR 1 SP		
46	DEOK CLINTON 1 BT	101	JC OLD BRIDGE 1 SP	156	PS ESSEX 105 CT	211	PS TAYLORS LANE 1 SP		
47	DEOK WILLEY 1 BT	102	JC PAUCH 3 SP	157	PS FAIRLAWN SOLAR 1 SP	212	PS THOROFARE SOLAR 2 SP		
48	DPL BLOOM ENERGY 1 FC	103	JC PEMBERTON 1 SP	158	PS FOODBANK 1 SP	213	PS TURNPIKE 1 SP		
49	DPL BUCKTOWN 1 SP	104	JC PEMBERTON 2 SP	159	PS FORTY NINTH SOLAR 1 SP	214	PS W CALDWELL SOLAR 1 SP		
50	DPL CHURCH HILL 1 SP	105	JC QUAKERTOWN 9 SP	160	PS GLOUCESTER SOLAR 1 SP	215	PS W CALDWELL SOLAR 2 SP		
51	DPL COSTEN 1 SP	106	JC RICHLINE 3 SP	161	PS HACKENSACK 1 SP	216	PS WALDWICK SOLAR 1 SP		
52	DPL HEBRON 1 SP	107	JC RINGOES 1 SP	162	PS HIGHLAND PARK 3 BT	217	PS WEST ORANGE SOLAR 1 SP		
53	DPL WORCESTER NORTH 1 SP	108	JC SUSSEX 1 LF	163	PS HIGHLAND PARK 4 SP	218	PS WEST PEMBERTON 1 SP		
54	DPL WORCESTER SOUTH 2 SP	109	JC TINTON FALLS 3 SP	164	PS HILLSDALE SOLAR 1 SP	219	VP BUCKINGHAM 1 SP		
55	DPL WYE MILLS 1 SP	110	JC UPPER FREEHOLD 1 SP	165	PS HINCHMANS SOLAR 1 SP	220	VP GARDNER FARMS 1 SP		

Figure 12-3 is a map of units, 20 MW or greater in size, that came online between January 1, 2011 and December 31, 2020. A mapping to these unit names is in Table 12-5.

Figure 12-3 Map of unit additions (20 MW or greater): 2011 through 2020

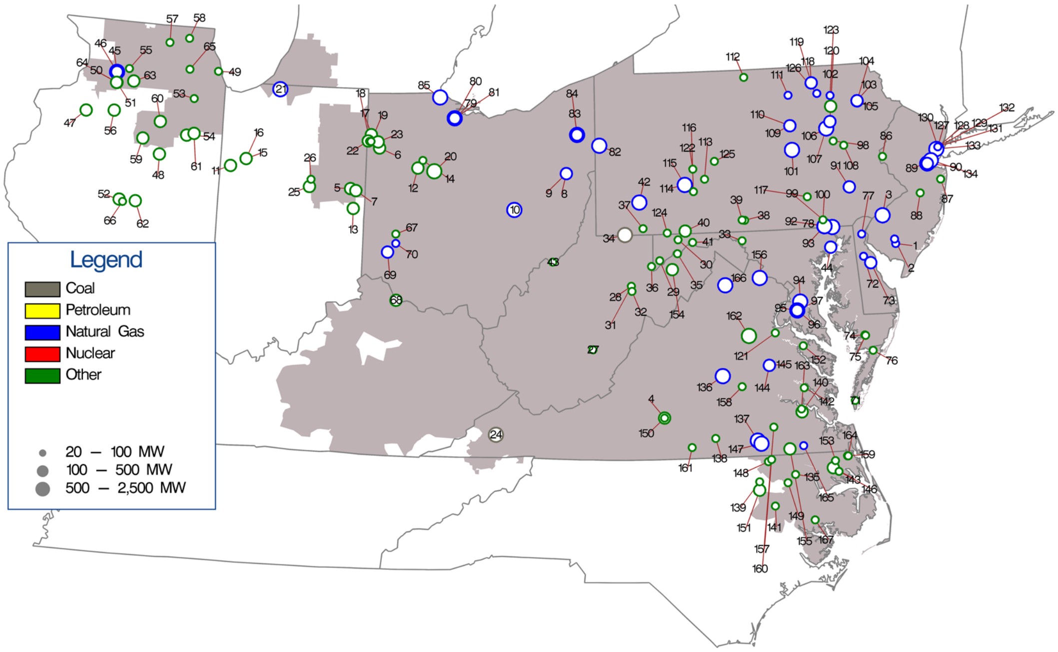


Table 12-5 Unit identification for map of unit additions (20 MW or greater): 2011 through 2020

ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	51	COM GREEN RIVER 2 WF	101	PL HUMMEL STATION 1 CC	151	VP MOCCASIN CREEK 1 SP
2	ACE VINELAND 11 CT	52	COM HILLTOPPER 1 WF	102	PL HUNLOCK CC	152	VP MONTROSS 1 SP
3	ACE WEST DEPTFORD CROWN POINT 1 CC	53	COM JOLIET 1 BT	103	PL LACKAWANNA COUNTY 1 CC	153	VP MORGAN CORNER 1 SP
4	AEP ALTAVISTA 1 SP	54	COM KELLY CREEK 1 WF	104	PL LACKAWANNA COUNTY 2 CC	154	VP NEW CREEK 1 WF
5	AEP BITTER RIDGE 1 WF	55	COM LEE DEKALB 3 BT	105	PL LACKAWANNA COUNTY 3 CC	155	VP NEWSOMS 1 SP
6	AEP BLUE CREEK 3 WF	56	COM LONE TREE 3 WF	106	PL MOXIE FREEDOM 11 CC	156	VP PANDA STONEWALL 1 CC
7	AEP BLUFF POINT 2 WF	57	COM MARENGO 1 BT	107	PL MOXIE FREEDOM 21 CC	157	VP PECAN 1 SP
8	AEP CARROLL COUNTY 1 CC	58	COM MCHENRY 1 BT	108	PL PA SOLAR 2 SP	158	VP POWHATAN 2 SP
9	AEP CARROLL COUNTY 2 CC	59	COM MINONK 1 WF	109	PL PATRIOT 1 F	159	VP RANCHLAND 2 SP
10	AEP DRESDEN 1 CC	60	COM OTTER CREEK 1 WF	110	PL PATRIOT 2 F	160	VP SAPONY 1 SP
11	AEP FOWLER RIDGE 4 WF	61	COM PILOT HILL 1 WF	111	PN BEAVER DAM 1 D	161	VP SOUTH BOSTON 1 F
12	AEP HARDIN 2 SP	62	COM RADFORDS RUN 1 WF	112	PN BIG LEVEL 1 WF	162	VP SPOTSYLVANIA 1 SP
13	AEP HEADWATERS 1 WF	63	COM SHADY OAKS 1 WF	113	PN CHESTNUT FLATS 1 WF	163	VP SPRING GROVE 1 SP
14	AEP HOG CREEK 1 WF	64	COM WALNUT RIDGE 1 WF	114	PN FAIRVIEW 1 CC	164	VP SUMMIT FARMS 1 SP
15	AEP MEADOW LAKE 5 WF	65	COM WEST CHICAGO 3 BT	115	PN FAIRVIEW 2 CC	165	VP UNION CAMP 9-10 F
16	AEP MEADOW LAKE 6 WF	66	COM WHITNEY HILL 2 WF	116	PN HIGHLAND NORTH 2 WF	166	VP WARREN COUNTY FRONT ROYAL CC
17	AEP PAULDING 3 WF	67	DAY TAIT 8 BT	117	PN LAUREL HILLS 1 WF	167	VP WILKINSON ENERGY CENTER 1 SP
18	AEP PAULDING 41 WF	68	DEOK MELDAHL DAM 1 H	118	PN LIBERTY ASYLUM 10 F		
19	AEP PAULDING 42 WF	69	DEOK MIDDLETOWN ENERGY 1 CC	119	PN LIBERTY ASYLUM 20 F		
20	AEP SCIOTO RIDGE 1 WF	70	DEOK YANKEE 1 F	120	PN MEHOOPANY 1 WF		
21	AEP ST JOSEPH ENERGY CENTER 1 CC	71	DPL CHERRYDALE 1 SP	121	PN MEHOOPANY 2 WF		
22	AEP TIMBER2 1 WF	72	DPL DEMEC - CLAYTON 2 CT	122	PN PATTON 1 WF		
23	AEP TRISHE 1 WF	73	DPL GARRISON EC 1 CC	123	PN PGCOGEN 2 CT		
24	AEP VIRGINIA CITY 1 F	74	DPL GREAT BAY KINGS CREEK 1 SP	124	PN RINGER HILL 1 WF		
25	AEP WILDCAT 1A WF	75	DPL GREAT BAY KINGS CREEK 2 SP	125	PN SANDY RIDGE 1 WF		
26	AEP WILDCAT 1B WF	76	DPL OAK HALL 1 SP	126	PN SUGAR RUN 2 CT		
27	AP BEECH RIDGE 2 WF	77	DPL RED LION 1 FC	127	PS KEARNY 131 CT		
28	AP BEECH RIDGE 3 BT	78	DPL WILDCAT POINT 1 CC	128	PS KEARNY 132 CT		
29	AP FAIR WIND 2 WF	79	FE FREMONT 1 SCCT	129	PS KEARNY 133 CT		
30	AP FOURMILE RIDGE 1 WF	80	FE FREMONT 2 SCCT	130	PS KEARNY 134 CT		
31	AP LAUREL MOUNTAIN 1 BT	81	FE FREMONT ENERGY CENTER 3 CC	131	PS KEARNY 141 CT		
32	AP LAUREL MOUNTAIN 1 WF	82	FE HICKORY RUN 1 CC	132	PS KEARNY 142 CT		
33	AP MARLOWE 1 SP	83	FE LORDSTOWN ENERGY CENTER 1 CC	133	PS NEWARK ENERGY CENTER 10 CC		
34	AP NORTH LONGVIEW 1 F	84	FE LORDSTOWN ENERGY CENTER 2 CC	134	PS SEWAREN 7 CC		
35	AP PINNACLE 1 WF	85	FE OREGON ENERGY CENTER 1 CC	135	VP AULANDER HOLLOMAN 1 SP		
36	AP ROTH ROCK 1 WF	86	JC EDGE ROAD 5 BT	136	VP BEAR GARDEN		
37	AP SOUTH CHESTNUT 1 WF	87	JC HAMILTON ROAD 5 SP	137	VP BRUNSWICK 1CC		
38	AP ST THOMAS 1 SP	88	JC PLUMSTED ENERGY 6 BT	138	VP BUTCHER CREEK 1 SP		
39	AP ST THOMAS 2 SP	89	JC WOODBRIDGE 1 CC	139	VP CHESTNUT 1 SP		
40	AP TWIN RIDGES 1 WF	90	JC WOODBRIDGE 2 CC	140	VP COLONIAL TRAIL WEST 1 SP		
41	AP WARRIOR RUN 2 BT	91	ME BIRDSBORO 1 CC	141	VP CONETOE 2 SP		
42	AP WESTMORELAND 1 CC	92	PE DELTA 1-4 CC	142	VP CORRECTIONAL 1 SP		
43	AP WILLOW ISLAND 1 H	93	PE DELTA 5-7 CC	143	VP DESERT 1 WF		
44	BC PERRYMAN 6 CT	94	PEP KEYS ENERGY CENTER 1 CC	144	VP DOSWELL 2 CT		
45	COM 942 NELSON 1 CC	95	PEP ST CHARLES - KELSON RIDGE 1 CC	145	VP DOSWELL 3 CT		
46	COM 942 NELSON 2 CC	96	PEP ST CHARLES-KELSON RIDGE 1 CC	146	VP ELIZABETH CITY 1 SP		
47	COM BISHOP HILL SP in PJM WF	97	PEP ST CHARLES-KELSON RIDGE 2 CC	147	VP GREENSVILLE 1 CC		
48	COM BRIGHT STALK 1 WF	98	PL HAZEL 1 FW	148	VP GUTENBERG - OCONECHE 1 SP		
49	COM GRAND RIDGE 7 BT	99	PL HOLTWOOD 18	149	VP KELFORD 1 SP		
50	COM GREEN RIVER 1 WF	100	PL HOLTWOOD 19	150	VP MECHANICSVILLE 2 SP		

Generation Retirements[16 17]

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.[18] The definition of economic is that unit net revenues are greater than or equal to the unit's avoidable or going forward costs.

16 See PJM. Planning. "Generator Deactivations," (Accessed on December 31, 2020) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

17 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.

18 See OATT Section V and Attachment M–Appendix § IV.

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.[19]

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.[20] 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.[21] 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.[22]

Generation Retirements 2011 through 2024

Table 12-6 shows that as of December 31, 2020, there are 44,181.3 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 32,084.1 MW (72.6 percent) are coal fired steam units. Retirements are primarily a result of the inability of coal and other units to compete with efficient combined cycle units burning low cost gas.

Table 12-6 Summary of unit retirements by unit type (MW): 2011 through 2024

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Retirements 2011	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	0.0	543.0	522.5	0.0	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,907.9	0.0	548.0	16.0	0.0	0.0	6,961.9
Retirements 2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	7.0	0.0	0.0	0.0	2,589.9	82.0	166.0	8.0	0.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	0.0	0.0	2,239.0	158.0	0.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	856.2	2.0	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	0.0	9,262.7
Retirements 2016	0.0	0.0	0.0	65.0	6.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	0.0	0.0	243.0	74.0	0.0	0.0	0.0	0.0	400.4
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	2,038.0	34.0	0.0	0.0	0.0	0.0	2,112.8
Retirements 2018	1.0	425.0	0.0	38.0	1.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	0.0	0.0	3,186.5	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	786.0	60.0	0.0	0.0	3,255.0
Planned Retirements (January 2021 and later)	2.0	118.0	80.0	28.0	0.0	0.0	0.0	0.0	1,786.5	0.0	13.0	8.0	0.0	0.0	0.0	2,026.4	102.0	0.0	0.0	0.0	0.0	4,163.9
Total	43.0	543.0	2,364.3	1,852.9	22.0	0.0	0.5	0.0	3,206.0	0.0	57.1	72.5	0.0	0.0	0.0	32,084.1	2,065.5	1,658.0	202.0	10.4	0.0	44,181.3

19 See PJM. "*Explaining Power Plant Retirements in PJM*," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.
20 See OATT § 230.3.3.
21 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).
22 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2024, while Table 12-8 shows these retirements by state. Of the 44,181.3 MW of units that has been, or are planned to be, retired between 2011 and 2024, 32,084.1 MW (72.6 percent) are coal fired steam units. These coal fired steam units have an average age of 52.7 years and an average size of 188.7 MW. Over half of the retiring coal fired steam units, 55.8 percent, are located in Ohio or Pennsylvania.

Table 12-7 Retirements by unit type: 2011 through 2024

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	3	14.3	6.4	43.0	0.1%
Combined Cycle	4	135.8	29.1	543.0	1.2%
Combustion Turbine	116	26.7	34.8	4,239.2	9.6%
Natural Gas	60	39.4	40.9	2,364.3	5.4%
Oil	50	37.1	44.3	1,852.9	4.2%
Other	6	3.7	19.2	22.0	0.0%
Fuel Cell	0	0.0	0.0	0.0	0.0%
Hydro	1	0.5	113.8	0.5	0.0%
Pumped Storage	1	0.5	113.8	0.5	0.0%
Run of River	0	0.0	0.0	0.0	0.0%
Nuclear	4	801.5	49.1	3,206.0	7.3%
RICE	29	4.6	28.7	129.6	0.3%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	11	5.2	46.1	57.1	0.1%
Other	18	4.0	11.2	72.5	0.2%
Solar	0	0	0	0	0.0%
Solar + Storage	0	0	0	0	0.0%
Solar + Wind	0	0	0	0	0.0%
Steam	201	152.2	46.1	36,009.6	81.5%
Coal	170	188.7	52.7	32,084.1	72.6%
Natural Gas	18	114.8	60.8	2,065.5	4.7%
Oil	6	276.3	45.6	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	359	123.1	45.8	44,181.3	100.0%

Table 12-8 Retirements (MW) by unit type and state: 2011 through 2024

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0	0.0	0.0	0.0	788.0
DE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.0	136.0	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	1,786.5	0.0	0.0	20.4	0.0	0.0	0.0	1,624.0	0.0	0.0	0.0	0.0	0.0	3,726.9
IN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0	0.0	0.0	0.0	0.0	0.0	982.0
KY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	0.0	0.0	0.0	0.0	995.0
MD	0.0	0.0	347.5	104.0	1.6	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	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	324.5	0.0	0.0	0.0	0.0	0.0	355.5
NJ	0.0	225.0	1,590.0	1,040.2	6.4	0.0	0.5	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	6,137.6
OH	42.0	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	13,179.4	0.0	0.0	0.0	0.0	0.0	13,545.1
PA	1.0	51.0	50.8	72.0	14.0	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	6,338.4
VA	0.0	267.0	80.0	79.7	0.0	0.0	0.0	0.0	0.0	0.0	2.9	8.4	0.0	0.0	0.0	3,917.9	543.0	786.0	83.0	0.0	0.0	5,767.9
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	2,691.0	0.0	0.0	0.0	0.0	0.0	2,691.0
Total	43.0	543.0	2,364.3	1,852.9	22.0	0.0	0.5	0.0	3,206.0	0.0	57.1	72.5	0.0	0.0	0.0	32,084.1	2,065.5	1,658.0	202.0	10.4	0.0	44,181.3

Figure 12-4 is a map of unit retirements between 2011 and 2024, with a mapping to unit names in Table 12-9.

Figure 12-4 Map of unit retirements: 2011 through 2024

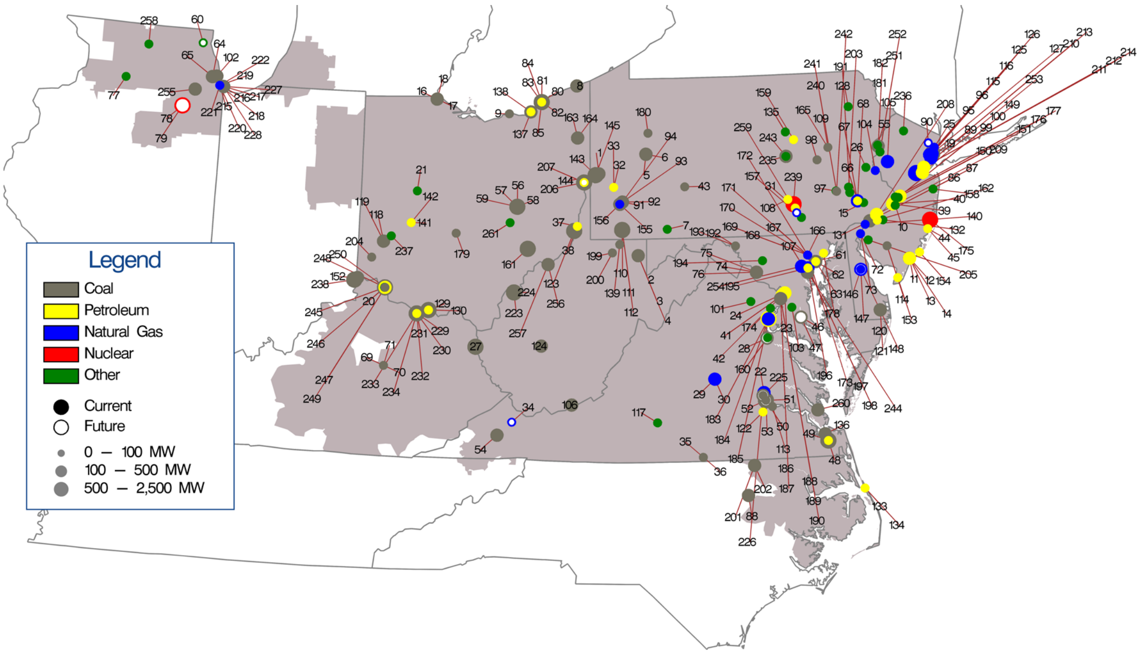


Table 12-9 Unit identification for map of unit retirements: 2011 through 2024

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AES Beaver Valley	56	Conesville 3	111	Hatfield's Ferry 2	166	Notch Cliff GT1	221	Southeast Chicago GT10
2	Albright 1	57	Conesville 4	112	Hatfield's Ferry 3	167	Notch Cliff GT2	222	Southeast Chicago GT9
3	Albright 2	58	Conesville 5	113	Hopewell James River Cogeneration	168	Notch Cliff GT3	223	Sporn 1-4
4	Albright 3	59	Conesville 6	114	Howard Down 10	169	Notch Cliff GT4	224	Sporn 5
5	Armstrong 1	60	Countryside Landfill	115	Hudson 1	170	Notch Cliff GT5	225	Spruance NUG1 (Rich 1-2)
6	Armstrong 2	61	Crane 1	116	Hudson 2	171	Notch Cliff GT6	226	Spruance NUG2 (Rich 3-4)
7	Arnold (Green Mtn. Wind Farm	62	Crane 2	117	Hurt NUG	172	Notch Cliff GT7	227	State Line 3
8	Ashtabula 5	63	Crane GT1	118	Hutchings 1-3, 5-6	173	Notch Cliff GT8	228	State Line 4
9	Avon Lake 7	64	Crawford 7	119	Hutchings 4	174	Occoquan 1 LF	229	Stuart 1
10	BC Landfill	65	Crawford 8	120	Indian River 1	175	Oyster Creek	230	Stuart 2
11	BL England 1	66	Cromby 1	121	Indian River 3	176	Pennsbury Generator Landfill 1	231	Stuart 3
12	BL England 2	67	Cromby 2	122	Ingenco Petersburg	177	Pennsbury Generator Landfill 2	232	Stuart 4
13	BL England 3	68	Cromby D	123	Kammer 1-3	178	Perryman 2	233	Stuart Diesels 1-4
14	BL England Diesel Units 1-4	69	Dale 1-2	124	Kanawha River 1-2	179	Picway 5	234	Stuart Diesels 1-4
15	Barbados AES Battery	70	Dale 3	125	Kearny 10	180	Piney Creek NUG	235	Sunbury 1-4
16	Bay Shore 2	71	Dale 4	126	Kearny 11	181	Portland 1	236	Sussex County LF
17	Bay Shore 3	72	Deepwater 1	127	Kearny 9	182	Portland 2	237	Tait Battery
18	Bay Shore 4	73	Deepwater 6	128	Keystone Recovery (Units 1 - 7)	183	Possum Point 3	238	Tanners Creek 1-4
19	Bayonne Cogen Plant (CC)	74	Dickerson Unit 1	129	Killen 2	184	Possum Point 4	239	Three Mile Island Unit 1
20	Beckjord Battery Unit 2	75	Dickerson Unit 2	130	Killen CT	185	Possum Point 5	240	Titus 1
21	Bellefontaine Landfill Generating Station	76	Dickerson Unit 3	131	Kimberly Clark Generator	186	Potomac River 1	241	Titus 2
22	Bellemeade	77	Dixon Lee Landfill Generator	132	Kinsley Landfill	187	Potomac River 2	242	Titus 3
23	Benning 15	78	Dresden 2	133	Kitty Hawk GT 1	188	Potomac River 3	243	Viking Energy NUG
24	Benning 16	79	Dresden 3	134	Kitty Hawk GT 2	189	Potomac River 4	244	Wagner 2
25	Bergen 3	80	Eastlake 1	135	Koppers Co. IPP	190	Potomac River 5	245	Walter C Beckjord 1
26	Bethlehem Renewable Energy Generator (Landfill)	81	Eastlake 2	136	Lake Kingman	191	Pottstown LF (Moser)	246	Walter C Beckjord 2
27	Big Sandy 2	82	Eastlake 3	137	Lake Shore 18	192	R Paul Smith 3	247	Walter C Beckjord 3
28	Birchwood Plant	83	Eastlake 4	138	Lake Shore EMD	193	R Paul Smith 4	248	Walter C Beckjord 4
29	Bremo 3	84	Eastlake 5	139	MEA NUG (WVU)	194	Reichs Ford Road Landfill Generator	249	Walter C Beckjord 5-6
30	Bremo 4	85	Eastlake 6	140	MH50 Markus Hook Co-gen	195	Riverside 4	250	Walter C Beckjord GT 1-4
31	Brunner Island Diesels	86	Eddystone 1	141	Mad River CTs A	196	Riverside 6	251	Warren County Landfill
32	Brunot Island 1B	87	Eddystone 2	142	Mad River CTs B	197	Riverside 7	252	Warren County NUG
33	Brunot Island 1C	88	Edgecomb NUG (Rocky 1-2)	143	Mansfield 1	198	Riverside 8	253	Werner 1-4
34	Buchanan 1-2	89	Edison 1-3	144	Mansfield 2	199	Riversville 5	254	Westport 5
35	Buggs Island 1 (Mecklenberg)	90	Elmwood Park Power	145	Mansfield 3	200	Riversville 6	255	Will County 3
36	Buggs Island 2 (Mecklenberg)	91	Elrama 1	146	McKee 1	201	Roanoke Valley 1	256	Willow Island 1
37	Burger 3	92	Elrama 2	147	McKee 2	202	Roanoke Valley 2	257	Willow Island 2
38	Burger EMD	93	Elrama 3	148	McKee 3	203	Rolling Hills Landfill Generator	258	Winnebago Landfill
39	Burlington 8,11	94	Elrama 4	149	Mercer 1	204	SMART Paper	259	York Generation Facility
40	Burlington 9	95	Essex 10-11	150	Mercer 2	205	Salem County LF	260	Yorktown 1-2
41	Buzzard Point East Banks 1,2,4-8	96	Essex 12	151	Mercer 3	206	Sammis 1-4	261	Zanesville Landfill
42	Buzzard Point West Banks 1-9	97	Evergreen Power United Corstack	152	Miami Fort 6	207	Sammis Diesel		
43	Cambria CoGen	98	FRACKVILLE WHEELABRATOR 1	153	Middle 1-3	208	Schuylkill 1		
44	Cedar 1	99	Fairless Hills Landfill A	154	Missouri Ave B,C,D	209	Schuylkill Diesel		
45	Cedar 2	100	Fairless Hills Landfill B	155	Mitchell 2	210	Sewaren 1		
46	Chalk Point Unit 1	101	Fauquier County Landfill	156	Mitchell 3	211	Sewaren 2		
47	Chalk Point Unit 2	102	Fisk Street 19	157	Modern Power Landfill NUG	212	Sewaren 3		
48	Chesapeake 1-4	103	GUDE Landfill	158	Monmouth NUG landfill	213	Sewaren 4		
49	Chesapeake 7-10	104	Gilbert 1-4	159	Montour ATG	214	Sewaren 6		
50	Chesterfield 3	105	Glen Gardner 1-8	160	Morris Landfill Generator	215	Southeast Chicago CT11		
51	Chesterfield 4	106	Glen Lyn 5-6	161	Muskingum River 1-5	216	Southeast Chicago CT12		
52	Chesterfield 5	107	Gould Street Generation Station	162	National Park 1	217	Southeast Chicago CT5		
53	Chesterfield 6	108	Harrisburg 4 CT	163	Niles 1	218	Southeast Chicago CT6		
54	Clinch River 3	109	Harwood 1-2	164	Niles 2	219	Southeast Chicago CT7		
55	Columbia Dam Hydro	110	Hatfield's Ferry 1	165	Northeastern Power NEPCO	220	Southeast Chicago CT8		

Current Year Generation Retirements

Table 12-10 shows that in 2020, 3,255.0 MW of generation retired. The largest generator that retired in 2020 was the 786.0 MW Possum Point 5 oil fired steam unit located in the Dominion Zone. Of the 3,255.0 MW of generation that retired, 786.0 MW (24.1 percent) were located in the Dominion Zone.

Table 12-10 Unit deactivations: 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
Dominion Resources, Inc.	Possum Point 5	786.0	Steam-Oil	Dominion	45.6	30-Dec-20

Planned Generation Retirements

Table 12-11 shows that, as of December 31, 2020, there are 4,163.9 MW of generation that have requested retirement after December 31, 2020, of which 1,794.5 MW (43.1 percent) are located in the ComEd Zone. Of the generation requesting retirement in the ComEd Zone, 1,786.5 MW (99.6 percent) are nuclear units.

Table 12-11 Planned retirement of units: December 31, 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
Biogas Energy Solutions, LLC	Countryside Landfill	8.0	RICE-Other	ComEd	27-Jan-21
Galt Power Inc.	Beckjord Battery Unit 2	2.0	Battery	DEOK	03-Feb-21
General Electric Company	Birchwood Plant	237.9	Steam-Coal	Dominion	01-Mar-21
Riverstone Holdings LLC	Elmwood Park Power	67.0	Combined Cycle	PSEG	12-Mar-21
Riverstone Holdings LLC	Harwood 1-2	28.0	CT-Oil	PPL	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
Riverstone Holdings LLC	York Generation Facility	51.0	Combined Cycle	Met-Ed	31-May-22
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, L.P.	Buchanan 1-2	80.0	CT-Natural Gas	AEP	01-Jun-23

Generation Queue[23]

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.[24] 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 and Queue AG2 opened on October 1, 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.[25] 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.[26]

The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result.[27] The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition from new generation investments are not created. The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.

Process Timelines

In the study phase of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-12 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.

23 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
24 See OATT Parts IV & VI.
25 See PJM. "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 13 (August 23, 2018).
26 PJM does not track the duration of suspensions or PJM termination of projects.
27 See *PJM Interconnection, L.L.C.*, Docket No. ER12-1177 (Feb. 29, 2012).

Table 12-12 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

Process improvements have allowed PJM to continue to meet the deadlines for feasibility and system impact studies despite the increase in interconnection requests. The increase in the number of projects submitted in the queue combined with the rules for evaluating projects have contributed to a significant backlog in performing timely facility studies. The facility study includes the conceptual design, stability analyses and determines the network upgrades, and the costs associated with those upgrades. Modifications to proposed facilities and restudies resulting from the withdrawal of projects from the queue also affect the time to complete a facility study. In 2020, PJM scheduled interconnection process workshops designed to review current processes, receive input and recommendations from stakeholders and to develop improvements to the process, including ways to resolve the current interconnection study backlog.

Planned Generation Additions

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets. On December 31, 2020, 173,581.3 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.[28]

There were 126,818.9 MW in generation queues, in the status of active, under construction or suspended, at the end of 2019. In 2020, the AF2 and AG1 queue windows closed and the AG2 window opened. 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 December 31, 2020, there were 173,581.3 MW in generation queues, in the status of active, under construction or suspended, an increase of 46,762.4 MW (36.9 percent). Table 12-13 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2019, and December 31, 2020, for ongoing projects, i.e. projects with the status active, under construction or suspended.[29]

Table 12-13 Queue comparison by expected completion year (MW): December 31, 2019 and December 31, 2020[30]

			Year Change	
Year	As of 12/31/2019	As of 12/31/2020	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	0.0	(1.3)	(100.0%)
2016	19.4	19.4	0.0	0.0%
2017	1,136.0	1,017.8	(118.2)	(10.4%)
2018	3,206.3	2,174.7	(1,031.6)	(32.2%)
2019	10,495.9	7,994.2	(2,501.7)	(23.8%)
2020	15,042.4	12,127.0	(2,915.3)	(19.4%)
2021	27,839.0	31,979.3	4,140.3	14.9%
2022	31,643.0	43,952.1	12,309.1	38.9%
2023	10,167.5	44,153.3	33,985.8	334.3%
2024	6,887.3	20,569.2	13,681.9	198.7%
2025	3,676.9	4,012.9	336.0	9.1%
2026	1,325.2	2,645.2	1,320.0	99.6%
2027	800.1	2,100.1	1,300.0	162.5%
2028	0.0	0.0	0.0	0.0%
2029	800.1	800.1	0.0	0.0%
Total	113,076.4	173,581.3	60,504.9	53.5%

28 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>.

29 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

30 Wind and solar capacity in Table 12-11 through Table 12-15 have not been adjusted to reflect derating.

Table 12-14 shows the project status changes in more detail and how scheduled queue MW have changed between December 31, 2019, and December 31, 2020. For example, 67,494.8 MW entered the queue in 2020. Of those 67,494.8 MW, 6,989.9 MW have been withdrawn. Of the total 118,297.3 MW marked as active on December 31, 2019, 16,281.7 MW were withdrawn, 4,203.1 MW were suspended, 3,470.6 MW started construction, and 989.6 MW went into service by December 31, 2020. Analysis of projects that were suspended on December 31, 2019 show that 3,147.2 MW came out of suspension and are now active as of December 31, 2020.

Table 12-14 Change in project status (MW): December 31, 2019 to December 31, 2020

		Status at 12/31/2020				
Status at 12/31/2019	Total at 12/31/2019	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2020)	0.0	60,496.2	0.0	1.5	7.3	6,989.9
Active	118,294.9	93,349.9	989.6	3,470.6	4,203.1	16,281.7
In Service	68,964.2	0.0	68,964.2	0.0	0.0	0.0
Under Construction	9,082.2	0.0	2,983.5	6,098.7	0.0	0.0
Suspended	7,781.3	3,147.2	200.0	0.0	2,806.9	1,627.2
Withdrawn	385,773.8	0.0	0.0	0.0	0.0	385,773.8
Total	589,896.4	156,993.3	73,137.3	9,570.8	7,017.3	410,672.5

On December 31, 2020, 173,581.3 MW were in generation request queues in the status of active, suspended or under construction. Table 12-15 shows each status by unit type. Of the 156,993.3 MW in the status of Active on December 31, 2020, 12,495.5 MW (8.0 percent) were combined cycle projects. Of the 9,570.8 MW in the status of under construction, 6,598.6 MW (68.9 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 156,993.3 MW in the status of Active on December 31, 2020, 18,018.6 MW (11.5 percent) were renewable hybrid projects. Of the 9,570.8 MW in the status of under construction, 2.6 MW (.03 percent) were renewable hybrid projects.

Table 12-15 Current project status (MW) by unit type: December 31, 2020

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	14,810.3	12,495.5	4,442.3	18.0	0.0	0.0	700.0	125.9	145.5	20.0	0.0	0.0	75,817.2	17,819.6	199.0	40.0	11.0	0.0	0.0	30,349.0	0.0	156,993.3
Suspended	14.5	4,001.0	705.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,353.0	100.0	0.0	0.0	0.0	0.0	0.0	737.6	106.3	7,017.3
Under Construction	0.0	6,598.6	336.5	13.0	0.0	3.0	0.0	22.7	44.0	1.3	4.0	0.0	1,859.1	2.6	0.0	36.0	0.0	0.0	0.0	650.0	0.0	9,570.8
Total	14,824.7	23,095.1	5,483.8	31.0	0.0	3.0	700.0	148.6	189.5	21.3	4.0	0.0	79,029.2	17,922.2	199.0	76.0	11.0	0.0	0.0	31,736.6	106.3	173,581.3

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 December 31, 2020, of the 173,581.3 MW in the generation request queues in the status of active, suspended or under construction, 79,029.2 MW (45.5 percent) were solar projects, 31,736.6 MW (18.3 percent) were wind projects, 28,611.2 MW (16.5 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 18,227.5 MW (10.5 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 76.0 MW (.04 percent) were coal fired steam projects.

As of December 31, 2020, there are 2,026.4 MW of coal fired steam units and 300.0 MW of natural gas units slated for deactivation between January 1, 2021, and December 31, 2024 (See Table 12-11). The ongoing replacement of coal fired steam units by natural gas units will continue to significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Table 12-16 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 December 31, 2020, there are 173,581.3 MW in queues that are not yet in service or withdrawn, of which 4.0 percent are suspended, 5.5 percent are under construction and 90.4 percent have not begun construction.

Table 12-16 Queue totals by status (MW): December 31, 2020[31]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	9,094.0	0.0	0.0	17,252.0	26,346.0
B Expired 31-Jan-99	0.0	4,645.5	0.0	0.0	14,956.7	19,602.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,558.3	4,089.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,358.0	8,208.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,189.6	0.0	0.0	17,961.8	19,151.4
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	42.0	0.0	0.0	846.0	888.0
K Expired 31-Jul-03	0.0	93.1	0.0	0.0	485.3	578.4
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	4,210.4
N Expired 31-Jan-05	0.0	2,398.8	0.0	0.0	8,129.3	10,528.0
O Expired 31-Jul-05	0.0	1,890.2	0.0	0.0	5,466.8	7,357.0
P Expired 31-Jan-06	0.0	3,290.3	0.0	0.0	5,320.5	8,610.8
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	11,385.7	14,533.6
R Expired 31-Jan-07	0.0	1,892.5	0.0	0.0	20,708.9	22,601.4
S Expired 31-Jul-07	70.0	3,543.5	0.0	0.0	12,396.5	16,010.0
T Expired 31-Jan-08	0.0	4,196.5	0.0	0.0	23,313.3	27,509.8
U1 Expired 30-Apr-08	0.0	218.9	0.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	0.0	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	1,460.8	0.0	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	0.0	89.2	20.0	0.0	7,665.9	7,775.1
X4 Expired 31-Jan-12	0.0	2,948.9	0.0	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	0.0	1,795.5	0.0	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	38.0	3,074.5	0.0	975.3	4,037.0	8,124.8
Z2 Expired 30-Apr-14	0.0	3,063.0	0.0	10.0	3,027.8	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	946.2	1,230.6	1,590.0	1,099.0	11,200.5	16,066.3
AB1 Expired 31-Oct-15	5,005.2	1,259.0	208.7	3,104.3	10,868.7	20,445.9
AB2 Expired 31-Mar-16	3,363.9	762.4	2,232.2	285.0	8,564.4	15,207.9
AC1 Expired 30-Sep-16	6,350.9	825.8	2,623.6	838.6	9,433.6	20,072.3
AC2 Expired 30-Apr-17	3,581.5	313.0	152.2	30.5	8,524.5	12,601.6
AD1 Expired 30-Sep-17	5,678.4	123.9	104.6	245.0	5,160.7	11,312.6
AD2 Expired 31-Mar-18	6,782.7	267.4	316.4	49.0	12,963.9	20,379.3
AE1 Expired 30-Sep-18	16,688.6	11.6	40.0	27.6	17,142.6	33,910.5
AE2 Expired 31-Mar-19	22,572.9	29.0	18.8	73.8	11,198.9	33,893.3
AF1 Expired 30-Sep-19	22,713.8	2.4	47.0	0.0	6,234.7	28,997.9
AF2 Expired 31-Mar-20	22,556.5	0.0	1.5	7.3	5,683.2	28,248.5
AG1 Expired 30-Sep-20	36,512.8	0.0	0.0	0.0	1,668.7	38,181.4
AG2 Through 31-Mar-21	2,927.4	0.0	0.0	0.0	185.0	3,112.4
Total	156,993.3	73,137.3	9,570.8	7,017.3	410,672.5	657,391.2

31 Projects listed as partially in service are counted as in service for the purposes of this analysis.

Table 12-17 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of December 31, 2020, 173,581.3 MW were in generation request queues for construction through 2029. Table 12-17 also shows the planned retirements for each zone.

Table 12-17 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): December 31, 2020[32]

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind
EMAAC	AECO	793.0	7.6	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	724.5	0.0	0.0
	DPL	520.2	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,052.2	130.0	0.0
	JCPL	670.2	35.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	229.6	199.8	0.0
	PECO	20.0	67.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	4.0	0.0	45.8	0.0	0.0
	PSEG	967.0	182.6	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	74.4	22.6	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
	EMAAC Total	2,970.4	743.2	905.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	4.0	0.0	3,126.4	352.4	0.0
SWMAAC	BGE	322.5	0.0	144.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	30.0	0.0	0.0
	Pepco	2.0	0.0	57.3	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.9	562.5	0.0
	SWMAAC Total	324.5	0.0	201.9	18.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	128.9	562.5	0.0
WMAAC	Met-Ed	405.2	75.0	13.5	7.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	986.3	182.1	0.0
	PENELEC	530.8	248.0	588.5	0.0	0.0	3.0	0.0	0.0	0.0	20.0	0.0	0.0	3,754.4	886.2	0.0
	PPL	390.0	106.6	0.0	0.0	0.0	0.0	700.0	0.0	100.0	0.0	0.0	0.0	2,027.1	270.0	0.0
	WMAAC Total	1,326.0	429.6	602.0	7.5	0.0	3.0	700.0	0.0	100.0	20.0	0.0	0.0	6,767.8	1,338.2	0.0
Non-MAAC	AEP	2,788.8	6,015.0	599.6	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	22,852.0	7,033.2	0.0
	APS	422.8	4,659.7	112.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,578.5	1,285.3	0.0
	ATSI	490.3	3,635.0	533.7	5.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,921.5	579.9	0.0
	ComEd	2,126.8	3,712.6	1,125.2	0.0	0.0	0.0	0.0	22.7	0.0	0.0	0.0	0.0	7,806.9	1,441.8	199.0
	DAY	175.0	1,150.0	43.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,454.1	40.0	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	0.0	649.9	0.0	0.0
	DLCO	55.0	0.0	222.9	0.0	0.0	0.0	0.0	74.9	0.0	0.0	0.0	0.0	58.9	37.5	0.0
	Dominion	3,996.8	2,750.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23,649.4	3,254.6	0.0
	EKPC	76.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,915.0	1,997.0	0.0
	OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.0	0.0	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-MAAC Total	10,203.8	21,922.3	3,774.9	5.5	0.0	0.0	0.0	148.6	0.0	0.0	0.0	0.0	69,006.1	15,669.2	199.0
	Total	14,824.7	23,095.1	5,483.8	31.0	0.0	3.0	700.0	148.6	189.5	21.3	4.0	0.0	79,029.2	17,922.2	199.0

LDA	Zone	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	AECO	0.0	0.0	0.0	0.0	3,441.6	0.0	5,196.7	0.0
	DPL	0.0	0.0	0.0	0.0	1,877.1	0.0	5,030.4	102.0
	JCPL	0.0	0.0	0.0	0.0	4,269.2	0.0	5,403.8	0.0
	PECO	0.0	0.0	0.0	0.0	0.0	0.0	180.8	0.0
	PSEG	0.0	5.0	0.0	0.0	1,300.0	0.0	3,226.6	67.0
	RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	0.0	5.0	0.0	0.0	10,887.9	0.0	19,038.3	169.0
SWMAAC	BGE	0.0	0.0	0.0	0.0	0.0	0.0	557.9	0.0
	Pepco	0.0	6.0	0.0	0.0	0.0	0.0	730.7	667.0
	SWMAAC Total	0.0	6.0	0.0	0.0	0.0	0.0	1,288.6	667.0
WMAAC	Met-Ed	0.0	0.0	0.0	0.0	0.0	0.0	1,669.6	51.0
	PENELEC	0.0	0.0	0.0	0.0	210.2	0.0	6,241.0	0.0
	PPL	0.0	0.0	0.0	0.0	514.9	90.0	4,198.6	28.0
	WMAAC Total	0.0	0.0	0.0	0.0	725.1	90.0	12,109.2	79.0
Non-MAAC	AEP	76.0	0.0	0.0	0.0	4,831.9	0.0	44,247.4	80.0
	APS	0.0	0.0	0.0	0.0	620.0	16.3	10,694.5	0.0
	ATSI	0.0	0.0	0.0	0.0	816.1	0.0	9,981.9	13.0
	ComEd	0.0	0.0	0.0	0.0	8,438.5	0.0	24,873.5	1,794.5
	DAY	0.0	0.0	0.0	0.0	0.0	0.0	4,862.6	0.0
	DEOK	0.0	0.0	0.0	0.0	0.0	0.0	722.1	2.0
	DLCO	0.0	0.0	0.0	0.0	0.0	0.0	449.2	0.0
	Dominion	0.0	0.0	0.0	0.0	5,417.2	0.0	40,206.0	1,359.4
	EKPC	0.0	0.0	0.0	0.0	0.0	0.0	4,988.0	0.0
	OVEC	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
	Non-MAAC Total	76.0	0.0	0.0	0.0	20,123.6	16.3	141,145.2	3,248.9
	Total	76.0	11.0	0.0	0.0	31,736.6	106.3	173,581.3	4,163.9

Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of nameplate capacity until actual generation data are available. Beginning with Queue U, PJM derated wind resources to 13 percent of nameplate capacity until there was operational data to support a different conclusion. 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

32 This data includes only projects with a status of active, under construction, or suspended.

solar resources are dependent on the solar installation type and have an average derate of 46.7 percent. Using the average derate factors, based on the derating of 31,736.6 MW of wind resources to 5,141.3 MW and 79,029.2 MW of solar resources to 36,907.0 MW, the 173,581.3 MW currently under construction, suspended or active in the queue would be reduced to 104,863.5 MW.[33]

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.[34] 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 12-18 and Table 12-19.

Table 12-18 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 2,983 projects withdrawn as of December 31, 2020, 1,488 (49.9 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted. Of the 2,983 projects withdrawn, 577 (19.3 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-18 Last milestone at time of withdrawal: 1997 through 2020

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	514	17.2%	155	944
Feasibility Study	974	32.7%	273	1,633
System Impact Study	621	20.8%	716	3,248
Facilities Study	297	10.0%	1,126	4,107
Construction Service Agreement (CSA) or beyond	577	19.3%	1,348	5,642
Total	2,983	100.0%		

Average Time in Queue

Table 12-19 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 1,074 days, or 2.9 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 625 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-19 Project queue times by status (days): December 31, 2020[35]

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	539	506	3	5,036
In-Service	1,074	784	0	5,306
Suspended	1,676	768	332	4,388
Under Construction	1,530	1,002	275	4,544
Withdrawn	625	729	0	5,642

33 Adjustments to totals for derates are applied to the solar and wind fuel types only. Additional derates may apply to hybrid units.
34 See PJM. "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 48 (Oct. 1, 2020).
35 The queue data shows that some projects were withdrawn and a withdrawal date was not identified. These projects were removed for the purposes of this analysis.

Table 12-20 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 1,885 projects in the queue as of December 31, 2020, 338 (17.9 percent) had a completed feasibility study and 359 (19.0 percent) had a completed construction service agreement.

Table 12-20 Project queue times by milestone (days): December 31, 2020

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	553	29.3%	108	272
Feasibility Study	338	17.9%	384	1,666
System Impact Study	588	31.2%	784	2,253
Facilities Study	47	2.5%	1,421	4,476
Construction Service Agreement (CSA) or beyond	359	19.0%	1,253	5,036
Total	1,885	100.0%		

Table 12-21 shows the time spent in the queue by fuel type, and year the project entered the queue, for projects that are in service. The time from when a project enters the queue to the time the project goes in service has generally been decreasing. For example, for a battery project entering the queue in 2015, there was an average of 1,082 days from the time it entered the queue until it went in service, compared to only 293 days when entering the queue in 2018, but the time increased to 504 days in 2019.

Table 12-21 Average time in queue (days) by fuel type and year submitted (In Service Projects): December 31, 2020[36]

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	1,419	1,106	838	746	702	309		
CT - Natural Gas	1,131	804	953	1,021	734	901	1,192	657	564	206	
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		466		
Solar	1,701	1,313	969	1,014	1,003	1,341	918	658	643	499	
Solar + Storage									553		
Solar + Wind											
Steam - Coal	745		513	1,010	583	853	677	647			
Steam - Natural Gas				1,182		421	751				
Steam - Oil											
Steam - Other	256	838	643								
WInd	2,748	2,711	1,750	1,589	1,494	1,463	1,362	1,200	561		
Wind + Storage											

Completion Rates

The probability of a project going into service increases as each step of the planning process is completed.

Table 12-22 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, 16.2 percent of the queued MW have gone into service. The completion rate for battery projects increases to 36.1 percent when battery projects complete the facility study agreement and further increases to 43.1 percent when battery projects complete the construction service agreement. Of all battery projects to enter the queue, only 1.3 percent of the queued MW have gone into service.

36 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.

Table 12-22 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: 1997 through 2020

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	16.2%	36.1%	43.1%	1.3%
CC	32.5%	50.8%	80.7%	13.8%
CT - Natural Gas	69.9%	82.3%	85.9%	44.3%
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%	21.0%
Nuclear	35.2%	42.1%	51.3%	28.6%
RICE - Natural Gas	31.9%	42.9%	47.6%	26.4%
RICE - Oil	30.6%	55.9%	55.9%	23.8%
RICE - Other	89.0%	91.4%	92.0%	78.1%
Solar	15.1%	35.0%	43.6%	2.3%
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	91.1%	91.1%	91.1%	90.0%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	30.4%	39.9%	47.8%	27.4%
Wind	0.2%	100.0%	100.0%	0.0%
Wind + Storage	0.0%	0.0%	0.0%	0.0%

On December 31, 2020, 173,581.3 MW were in generation request queues in the status of active, under construction or suspended. Of the total 173,581.3 MW in the queue, 134,141.7 MW (77.3 percent) have reached at least the SIS milestone and 39,439.6 MW (22.7 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), 37,214.3 MW of new generation in the queue are expected to go into service.

Table 12-23 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 December 31, 2020. Of all battery projects that entered the queue in 2016, only 1.3 percent have reached the status of in service as of December 31, 2020.

Table 12-23 Percent of all projects (MW energy) to go in service by unit type and year submitted to the queue: December 31, 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%	35.6%	43.7%	3.7%	2.2%	1.8%	1.2%	0.0%	NA
CT - Natural Gas	100.0%	98.3%	89.7%	23.5%	32.0%	0.2%	8.2%	16.5%	3.6%	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%	71.6%	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%	100.0%	NA	NA
Solar	10.7%	7.1%	16.9%	24.4%	30.7%	14.4%	4.4%	0.4%	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%	100.0%	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	6.5%	3.4%	2.5%	5.8%	20.7%	12.5%	12.3%	2.6%	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 12-24 shows the number of projects that entered the queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including solar, hydro, biomass, renewable hybrid and wind) and traditional units (all other fuels). The number of queue entries has increased during the past several years, primarily by renewable projects. Of the 3,169 projects entered from January 2015 through December 2020, 2,380 projects (75.1 percent) were renewable. Of the 969 projects entered in 2020, 768 projects (79.3 percent) were renewable.

Table 12-24 Number of projects entered in the queue: December 31, 2020[37]

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	Total
1997	2	0	11	13
1998	0	0	18	18
1999	1	5	84	90
2000	2	3	78	83
2001	4	6	81	91
2002	3	15	33	51
2003	1	34	18	53
2004	4	17	33	54
2005	3	75	55	133
2006	9	67	81	157
2007	9	65	145	219
2008	3	102	111	216
2009	10	107	56	173
2010	5	370	66	441
2011	6	264	85	355
2012	2	59	98	159
2013	1	54	99	154
2014	0	100	92	192
2015	0	134	175	309
2016	2	298	99	399
2017	2	293	60	355
2018	1	343	96	440
2019	0	544	153	697
2020	2	768	199	969
Total	72	3,723	2,026	5,821

As of December 31, 2020, renewable projects make up 78.6 percent of all projects in the queue and those projects account for 74.8 percent of the nameplate MW currently active, suspended or under construction in the queue as of December 31, 2020 (Table 12-25).

Table 12-25 Queue details by fuel group: December 31, 2020[38]

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	6	0.3%	189.5	0.1%
Renewable	1,482	78.6%	129,844.9	74.8%
Traditional	397	21.1%	43,546.9	25.1%
Total	1,885	100.0%	173,581.3	100.0%

Historical completion rates for renewable projects may not be an accurate predictor of completion rates for current renewable projects. The outcomes for current projects will provide additional information and improve the ability to assess the likely future generation mix based on the type of projects in the queue.

While renewables currently make up the majority of both projects and nameplate MW in the queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by renewables (Table 12-22). Table 12-26 shows the total MW of all projects in the queue as of December 31, 2020, in the status of active, suspended and under construction, by unit type. Table 12-26 also shows the total MW for each fuel type adjusted based on current historical completion rates and for the average solar and wind derates. Of the 23,095 MW of combined cycle projects in the queue, 15,849.4 MW (68.6 percent) are expected to go in service based on historical completion rates as of December 31, 2020. Of the 129,844.9 MW of renewable projects in the queue, only 16,541 MW (12.7 percent) are expected to go in service based on historical completion rates. Of the 129,844.9 MW of renewable projects in the queue, only 6,487.5 MW (5.0 percent) of capacity resources are expected to go into service, based on both historical completion rates and average derate factors for wind and solar.

37 This table has been updated to reflect the reclassification of battery queue projects from the renewable fuel group to the traditional fuel group.

38 This table has been updated to reflect the reclassification of battery queue projects from the renewable fuel group to the traditional fuel group.

Table 12-26 Queue totals for projects (active, suspended and under construction) by unit type adjusted based on current historical completion rates and average solar and wind derates (MW): December 31, 2020[39]

Unit Type	MW in Queue	Completion Rate Adjusted MW in Queue	Completion Rate and Derate Adjusted MW in Queue
Battery	14,824.7	801.5	801.5
CC	23,095.1	15,849.4	15,849.4
CT - Natural Gas	5,483.8	3,895.2	3,895.2
CT - Oil	31.0	17.8	17.8
CT - Other	0.0	0.0	0.0
Fuel Cell	3.0	0.9	0.9
Hydro - Pumped Storage	700.0	700.0	700.0
Hydro - Run of River	148.6	58.2	58.2
Nuclear	189.5	64.2	64.2
RICE - Natural Gas	21.3	7.0	7.0
RICE - Oil	4.0	2.2	2.2
RICE - Other	0.0	0.0	0.0
Solar	79,029.2	9,609.6	4,487.7
Solar + Storage	17,922.2	287.2	287.2
Solar + Wind	199.0	0.0	0.0
Steam - Coal	76.0	25.9	25.9
Steam - Natural Gas	11.0	9.9	9.9
Steam - Oil	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0
Wind	31,736.6	5,885.3	953.4
Wind + Storage	106.3	0.0	0.0
Total	173,581.3	37,214.3	27,160.5

Queue Analysis by Unit Type and Project Classification

Table 12-27 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through December 31, 2020. As of December 31, 2020, 5,821 projects, representing 657,391.2 MW, have entered the queue process since its inception. Of those, 953 projects, representing 73,137.3 MW, went into service. Of the projects that entered the queue process, 2,983 projects, representing 410,672.5 MW (62.5 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 4,701 projects have been classified as new generation and 1,120 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 4,645 projects (79.8 percent) of all 5,821 generation queue projects to enter the queue since January 1, 1997.

Table 12-27 Status of all generation queue projects: 1997 through 2020

		Number of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	22	62	49	10	25	3	0	10	2	10	0	55	162	1	0	8	5	0	4	94	0	522
	Upgrade	7	99	106	15	5	0	3	19	42	9	1	16	25	0	0	55	10	0	8	11	0	431
Under Construction	New Generation	0	6	2	0	0	0	0	2	0	1	0	0	24	2	0	0	0	0	0	3	0	40
	Upgrade	0	10	16	8	0	1	0	0	1	0	1	0	12	0	0	1	0	0	0	1	0	51
Suspended	New Generation	5	4	1	0	0	0	0	0	0	0	0	0	27	1	0	0	0	0	0	6	1	45
	Upgrade	0	3	1	0	0	0	0	0	0	0	0	0	4	0	0	0	0	0	0	0	1	9
Withdrawn	New Generation	170	428	26	9	81	26	2	41	9	27	12	16	1,258	54	0	55	1	0	34	444	0	2,693
	Upgrade	31	95	15	13	13	2	0	5	13	0	2	3	49	1	0	15	0	0	2	31	0	290
Active	New Generation	169	14	9	1	0	0	2	4	0	1	0	0	916	194	1	0	1	0	0	89	0	1,401
	Upgrade	87	20	29	2	0	0	0	1	5	0	0	0	157	16	0	3	2	0	0	16	1	339
Total Projects	New Generation	366	514	87	20	106	29	4	57	11	39	12	71	2,387	252	1	63	7	0	38	636	1	4,701
	Upgrade	125	227	167	38	18	3	3	25	61	9	4	19	247	17	0	74	12	0	10	59	2	1,120

39 Adjustments to totals for derates are applied to the solar and wind fuel types only. Additional derates may apply to hybrid units.

Table 12-28 shows the totals in Table 12-27 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 12-28 Status of all generation queue projects as a percent of total projects by classification: 1997 through 2020

		Percent of Projects											
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other
In Service	New Generation	6.0%	12.1%	56.3%	50.0%	23.6%	10.3%	0.0%	17.5%	18.2%	25.6%	0.0%	77.5%
	Upgrade	5.6%	43.6%	63.5%	39.5%	27.8%	0.0%	100.0%	76.0%	68.9%	100.0%	25.0%	84.2%
Under Construction	New Generation	0.0%	1.2%	2.3%	0.0%	0.0%	0.0%	0.0%	3.5%	0.0%	2.6%	0.0%	0.0%
	Upgrade	0.0%	4.4%	9.6%	21.1%	0.0%	33.3%	0.0%	0.0%	1.6%	0.0%	25.0%	0.0%
Suspended	New Generation	1.4%	0.8%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	1.3%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	46.4%	83.3%	29.9%	45.0%	76.4%	89.7%	50.0%	71.9%	81.8%	69.2%	100.0%	22.5%
	Upgrade	24.8%	41.9%	9.0%	34.2%	72.2%	66.7%	0.0%	20.0%	21.3%	0.0%	50.0%	15.8%
Active	New Generation	46.2%	2.7%	10.3%	5.0%	0.0%	0.0%	50.0%	7.0%	0.0%	2.6%	0.0%	0.0%
	Upgrade	69.6%	8.8%	17.4%	5.3%	0.0%	0.0%	0.0%	4.0%	8.2%	0.0%	0.0%	0.0%

		Percent of Projects									
Project Status	Project Classification	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	6.8%	0.4%	0.0%	12.7%	71.4%	0.0%	10.5%	14.8%	0.0%	11.1%
	Upgrade	10.1%	0.0%	0.0%	74.3%	83.3%	0.0%	80.0%	18.6%	0.0%	38.5%
Under Construction	New Generation	1.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.0%	0.9%
	Upgrade	4.9%	0.0%	0.0%	1.4%	0.0%	0.0%	0.0%	1.7%	0.0%	4.6%
Suspended	New Generation	1.1%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	100.0%	1.0%
	Upgrade	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	0.8%
Withdrawn	New Generation	52.7%	21.4%	0.0%	87.3%	14.3%	0.0%	89.5%	69.8%	0.0%	57.3%
	Upgrade	19.8%	5.9%	0.0%	20.3%	0.0%	0.0%	20.0%	52.5%	0.0%	25.9%
Active	New Generation	38.4%	77.0%	100.0%	0.0%	14.3%	0.0%	0.0%	14.0%	0.0%	29.8%
	Upgrade	63.6%	94.1%	0.0%	4.1%	16.7%	0.0%	0.0%	27.1%	50.0%	30.3%

Table 12-29 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 December 31, 2020, (as shown in Table 12-27) constitute 77,087.8 MW. The 428 new generation combined cycle projects that have been withdrawn in the same time period constitute 213,253.2 MW.

Table 12-29 Status of all generation (MW) in the generation queue: 1997 through 2020

			Project MW											
Project Status	Project Classification	Project Status	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
In Service	New Generation	In Service	223.4	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
	Upgrade		44.4	6,538.8	2,722.5	127.8	12.3	0.0	390.0	387.6	2,310.8	17.3	23.3	50.7
Under Construction	New Generation	Under Construction	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
	Upgrade		0.0	1,151.7	91.5	13.0	0.0	3.0	0.0	0.0	44.0	0.0	4.0	0.0
Suspended	New Generation	Suspended	14.5	3,470.0	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade		0.0	531.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	Withdrawn	3,981.0	213,253.2	3,750.1	1,721.0	1,244.2	5.5	500.0	2,007.2	8,161.0	459.9	63.9	88.6
	Upgrade		811.3	11,540.4	619.5	589.0	72.5	0.9	0.0	105.1	966.0	0.0	13.0	10.0
Active	New Generation	Active	12,098.2	10,515.5	2,727.5	14.0	0.0	0.0	700.0	74.9	0.0	20.0	0.0	0.0
	Upgrade		2,712.0	1,980.0	1,714.8	4.0	0.0	0.0	0.0	51.0	145.5	0.0	0.0	0.0
Total Projects	New Generation	Total Projects	16,317.1	266,388.6	14,064.1	2,411.5	1,395.6	7.4	1,200.0	2,476.3	9,800.0	637.6	63.9	528.7
	Upgrade		3,567.7	21,741.9	5,178.3	733.8	84.8	3.9	390.0	543.7	3,466.3	17.3	40.3	60.7

			Project MW							
Project Status	Project Classification	Project Status	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind
In Service	New Generation	In Service	2,250.7	1.1	0.0	1,343.0	723.0	0.0	60.9	9,964.6
	Upgrade		41.3	0.0	0.0	965.5	225.5	0.0	667.8	238.7
Under Construction	New Generation	Under Construction	1,600.9	2.6	0.0	0.0	0.0	0.0	0.0	650.0
	Upgrade		258.2	0.0	0.0	36.0	0.0	0.0	0.0	0.0
Suspended	New Generation	Suspended	1,305.4	100.0	0.0	0.0	0.0	0.0	0.0	737.6
	Upgrade		47.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	Withdrawn	38,194.4	6,847.0	0.0	33,511.6	27.0	0.0	1,050.9	77,087.8
	Upgrade		1,451.5	3.7	0.0	885.0	0.0	0.0	37.1	1,613.4
Active	New Generation	Active	69,986.2	17,372.5	199.0	0.0	5.0	0.0	0.0	28,749.8
	Upgrade		5,831.0	447.2	0.0	40.0	6.0	0.0	0.0	1,599.2
Total Projects	New Generation	Total Projects	113,337.5	24,323.1	199.0	34,854.6	755.0	0.0	1,111.8	117,189.7
	Upgrade		7,629.7	450.9	0.0	1,926.5	231.5	0.0	704.9	3,451.3

Table 12-30 shows the MW totals in Table 12-29 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, 69.8 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and December 31, 2020.

Table 12-30 Status of all generation queue projects as percent of total MW in project classification: 1997 through 2020

	Percent of Total Projects by Classification												
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other
In Service	New Generation	1.4%	12.7%	47.4%	28.1%	10.8%	26.2%	0.0%	15.0%	16.7%	24.5%	0.0%	83.2%
	Upgrade	1.2%	30.1%	52.6%	17.4%	14.5%	0.0%	100.0%	71.3%	66.7%	100.0%	57.8%	83.5%
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%
	Upgrade	0.0%	5.3%	1.8%	1.8%	0.0%	76.0%	0.0%	0.0%	1.3%	0.0%	9.9%	0.0%
Suspended	New Generation	0.1%	1.3%	4.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	2.4%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	24.4%	80.1%	26.7%	71.4%	89.2%	73.8%	41.7%	81.1%	83.3%	72.1%	100.0%	16.8%
	Upgrade	22.7%	53.1%	12.0%	80.3%	85.5%	24.0%	0.0%	19.3%	27.9%	0.0%	32.3%	16.5%
Active	New Generation	74.1%	3.9%	19.4%	0.6%	0.0%	0.0%	58.3%	3.0%	0.0%	3.1%	0.0%	0.0%
	Upgrade	76.0%	9.1%	33.1%	0.5%	0.0%	0.0%	0.0%	9.4%	4.2%	0.0%	0.0%	0.0%

Project Status	Project Classification	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	2.0%	0.0%	0.0%	3.9%	95.8%	0.0%	5.5%	8.5%	0.0%	9.6%
	Upgrade	0.5%	0.0%	0.0%	50.1%	97.4%	0.0%	94.7%	6.9%	0.0%	29.4%
Under Construction	New Generation	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	0.0%	1.3%
	Upgrade	3.4%	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	3.2%
Suspended	New Generation	1.2%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	100.0%	1.1%
	Upgrade	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	1.2%
Withdrawn	New Generation	33.7%	28.1%	0.0%	96.1%	3.6%	0.0%	94.5%	65.8%	0.0%	64.6%
	Upgrade	19.0%	0.8%	0.0%	45.9%	0.0%	0.0%	5.3%	46.7%	0.0%	37.3%
Active	New Generation	61.8%	71.4%	100.0%	0.0%	0.7%	0.0%	0.0%	24.5%	0.0%	23.5%
	Upgrade	76.4%	99.2%	0.0%	2.1%	2.6%	0.0%	0.0%	46.3%	0.0%	28.9%

Table 12-31 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 78.6 percent of all new projects entering the generation queue have been combined cycle (15.8 percent), wind (18.2 percent) or solar projects (44.6 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 December 31, 2020, 25,079.3 MW have entered the queue.

Table 12-31 Queue project MW by unit type and queue entry year: 1997 through 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	16.3	35,819.4
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	13,656.7	424.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,740.2
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	27,116.6	9,921.1	0.0	11.0	0.0	0.0	0.0	11,585.4	0.0	59,996.9
2020	10,986.6	0.0	552.6	4.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	37,356.7	9,766.6	199.0	0.0	11.0	0.0	0.0	6,786.2	0.0	65,842.8
Total	19,884.8	288,130.5	19,242.4	3,145.3	1,480.3	11.3	1,590.0	3,020.0	13,266.3	654.9	104.2	589.4	120,967.2	24,774.0	199.0	36,781.1	986.5	0.0	1,816.7	120,641.0	106.3	657,391.2

Combined Cycle Project Analysis

Table 12-32 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2020, by zone. Of the 57 combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 13 projects (22.8 percent) are located in APS.

Table 12-32 Status of all combined cycle queue projects by zone (number of projects): 1997 through 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	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	11	4	4	7	14	0	99
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	1	0	0	1	1	0	10
Suspended	New Generation	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
	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	44	13	8	14	0	1	2	17	17	3	26	25	0	43	40	34	42	55	2	428
	Upgrade	7	7	8	3	0	4	0	1	0	11	4	0	7	7	0	3	5	5	8	15	0	95
Active	New Generation	0	3	2	0	0	4	1	0	0	2	0	0	0	0	0	0	1	0	0	1	0	14
	Upgrade	1	2	6	1	0	3	0	0	0	2	0	0	0	0	0	1	2	0	2	0	0	20
Total Projects	New Generation	24	30	51	19	10	20	1	2	2	26	19	3	33	29	0	48	43	38	52	62	2	514
	Upgrade	11	25	23	9	0	11	0	1	0	28	10	0	14	11	0	16	11	9	18	30	0	227

Table 12-33 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2020, by zone. Of the 23,095.1 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 6,015.0 MW (26.0 percent) are located in the AEP Zone.

Table 12-33 Status of all combined cycle queue projects by zone (MW): 1997 through 2020

		Project MW										
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL
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
	Upgrade	229.0	384.0	790.0	306.0	0.0	633.6	0.0	0.0	0.0	963.0	102.0
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
	Upgrade	0.0	916.0	20.0	38.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	1,575.0	1,895.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.0
Withdrawn	New Generation	8,542.4	12,509.5	20,807.1	8,641.0	3,122.1	10,142.0	0.0	134.5	665.0	11,261.0	5,436.4
	Upgrade	149.4	711.0	824.0	86.0	0.0	1,735.0	0.0	36.0	0.0	780.4	668.0
Active	New Generation	0.0	2,200.0	1,811.0	0.0	0.0	2,400.0	1,150.0	0.0	0.0	2,660.0	0.0
	Upgrade	7.6	320.0	693.7	550.0	0.0	111.7	0.0	0.0	0.0	90.0	0.0
Total Projects	New Generation	9,192.4	20,833.5	26,163.1	14,287.0	3,262.1	14,342.9	1,150.0	154.5	665.0	19,749.6	5,755.6
	Upgrade	386.0	2,331.0	2,372.7	980.0	0.0	2,480.3	0.0	36.0	0.0	1,833.4	1,221.0

Project Status	Project Classification	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	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	0.0	110.0	83.9	0.0	1,008.5	142.3	228.6	712.0	845.9	0.0	6,538.8
Under Construction	New Generation	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	0.0	75.0	0.0	0.0	0.0	0.0	51.6	51.1	0.0	1,151.7
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,470.0
	Upgrade	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	991.8	13,562.6	13,001.0	0.0	23,340.0	15,951.0	21,308.2	18,917.7	24,913.1	6.9	213,253.2
	Upgrade	0.0	378.0	1,742.0	0.0	240.0	1,040.6	229.1	703.0	2,217.9	0.0	11,540.4
Active	New Generation	0.0	0.0	0.0	0.0	0.0	163.0	0.0	0.0	131.5	0.0	10,515.5
	Upgrade	0.0	0.0	0.0	0.0	67.0	85.0	0.0	55.0	0.0	0.0	1,980.0
Total Projects	New Generation	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	266,388.6
	Upgrade	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	21,741.9

Combustion Turbine - Natural Gas Project Analysis

Table 12-34 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2020, by zone. Of the 58 combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 14 projects (24.1 percent) are located in the ComEd Zone.

Table 12-34 Status of all combustion turbine - natural gas generation queue projects by zone (number of projects): 1997 through 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	5	0	6	0	3	0	0	0	0	3	7	0	3	1	0	2	4	2	4	9	0	49
	Upgrade	4	9	7	2	0	12	5	0	0	28	7	0	4	1	0	4	2	3	4	14	0	106
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	3	0	0	0	0	0	0	1	4	0	0	5	0	0	0	0	16
Suspended	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	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	4	0	1	0	0	0	1	5	0	1	5	0	26
	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	2	0	0	0	0	0	0	2	0	0	0	0	9
	Upgrade	1	2	2	5	0	9	2	0	1	0	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	3	11	2	5	15	0	87
	Upgrade	7	12	12	10	0	26	9	0	2	31	7	0	5	6	0	4	10	8	4	14	0	167

Table 12-35 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2020, by zone. Of the 5,483.8 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,138.0 MW (20.8 percent) are located in the Dominion Zone.

Table 12-35 Status of all combustion turbine - natural gas queue projects by zone (MW): 1997 through 2020

		Project MW																					
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	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	208.0	187.7	40.0	0.0	371.0	60.0	0.0	0.0	925.7	86.0	0.0	200.0	34.1	0.0	42.0	25.0	32.0	252.3	215.0	0.0	2,722.5
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	47.0	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	91.5
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	675.0	0.0	675.0
	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	1,069.8	0.0	73.0	0.0	0.0	0.0	0.5	326.8	0.0	19.9	1,140.1	0.0	3,750.1
	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	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	481.0	0.0	0.0	0.0	0.0	2,727.5
	Upgrade	0.0	70.1	70.0	528.7	0.0	848.2	43.5	0.0	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	93.5	57.3	0.0	0.0	0.0	1,714.8
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	559.5	1,169.7	5.0	170.8	2,741.0	0.0	14,064.1
	Upgrade	209.2	284.1	303.7	598.7	0.0	1,289.2	207.5	0.0	3.5	982.7	86.0	0.0	200.0	47.6	0.0	42.0	367.5	89.3	252.3	215.0	0.0	5,178.3

Wind Project Analysis

Table 12-36 shows the status of all wind generation projects, by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2020, by zone. Of the 115 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 41 projects (35.7 percent) are located in the ComEd Zone.

Table 12-36 Status of all wind generation queue projects by zone (number of projects): 1997 through 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	26	0	0	0	3	0	0	0	0	0	0	23	0	8	0	0	94
	Upgrade	0	0	1	0	0	5	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	11
Under Construction	New Generation	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
	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	8	0	0	8	0	0	0	3	0	0	0	0	0	0	6	0	2	0	0	31
Active	New Generation	6	23	5	3	0	31	0	0	0	7	5	0	5	0	0	0	1	0	2	1	0	89
	Upgrade	0	1	0	0	0	10	0	0	0	0	3	0	1	0	0	0	1	0	0	0	0	16
Total Projects	New Generation	25	150	67	11	0	164	15	0	0	32	16	1	7	0	0	0	88	0	58	2	0	636
	Upgrade	2	3	10	0	0	23	0	0	0	3	3	0	1	0	0	0	12	0	2	0	0	59

Table 12-37 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2020, by zone. Of the 31,736.6 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 8,438.5 MW (26.6 percent) are located in the ComEd Zone.

Table 12-37 Status of all wind generation queue projects by zone (MW): 1997 through 2020

		Project MW																						
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	7.5	3,094.6	1,114.6	0.0	0.0	4,133.9	0.0	0.0	0.0	322.5	0.0	0.0	0.0	0.0	0.0	0.0	1,065.0	0.0	226.5	0.0	0.0	9,964.6
	Upgrade	0.0	0.0	5.0	0.0	0.0	213.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.5	0.0	0.0	0.0	0.0	238.7
Under Construction	New Generation	0.0	450.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	650.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	119.4	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	1,613.4
Active	New Generation	3,441.6	4,093.2	420.0	816.1	0.0	7,943.5	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	1,300.0	0.0	28,749.8
	Upgrade	0.0	16.6	0.0	0.0	0.0	495.0	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	1,599.2
Total Projects	New Generation	8,092.7	30,041.6	5,206.8	2,111.7	0.0	37,110.5	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	1,320.0	0.0	117,189.7
	Upgrade	5.0	386.6	124.4	0.0	0.0	1,463.8	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	3,451.3

Solar Project Analysis

Table 12-38 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2020, by zone. Of the 1,140 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 306 projects (26.8 percent) are located in the Dominion Zone.

Table 12-38 Status of all solar generation queue projects by zone (number of projects): 1997 through 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	9	4	8	0	1	1	1	0	0	28	11	0	50	0	0	1	1	1	2	44	0	162
	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	14	2	0	1	0	0	0	0	0	0	3	0	24
	Upgrade	0	2	0	0	0	0	0	2	0	6	0	0	0	0	0	0	0	0	0	2	0	12
Suspended	New Generation	0	4	11	0	0	0	1	0	0	8	0	0	0	1	0	0	2	0	0	0	0	27
	Upgrade	0	0	0	0	0	0	0	0	0	1	0	0	1	2	0	0	0	0	0	0	0	4
Withdrawn	New Generation	180	110	83	20	14	38	19	15	1	212	134	11	191	21	1	9	47	20	44	88	0	1,258
	Upgrade	3	4	1	1	0	6	0	0	0	16	1	0	9	0	0	0	3	2	0	3	0	49
Active	New Generation	19	162	68	38	2	50	29	5	4	230	44	32	19	30	1	3	104	9	61	6	0	916
	Upgrade	1	34	19	9	0	5	8	1	1	47	6	1	3	3	0	0	10	1	6	2	0	157
Total Projects	New Generation	208	282	171	58	17	89	50	21	5	492	191	43	261	52	2	13	154	30	107	141	0	2,387
	Upgrade	5	40	20	10	0	11	8	3	1	74	15	1	22	5	0	0	13	3	9	7	0	247

Table 12-39 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2020, by zone. Of the 79,029.2 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 23,649.4 MW (29.9 percent) are located in the Dominion Zone.

Table 12-39 Status of all solar generation queue projects by zone (MW): 1997 through 2020

		Project MW																					
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	62.0	14.7	112.3	0.0	1.1	9.0	2.5	0.0	0.0	1,279.2	130.4	0.0	373.4	0.0	0.0	3.3	13.5	2.5	15.0	231.9	0.0	2,250.7
	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	1,178.4	170.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	17.5	0.0	1,600.9
	Upgrade	0.0	150.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	29.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	258.2
Suspended	New Generation	0.0	180.0	248.1	0.0	0.0	0.0	400.0	0.0	0.0	415.0	0.0	0.0	0.0	35.0	0.0	0.0	27.3	0.0	0.0	0.0	0.0	1,305.4
	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	7.6	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	47.6
Withdrawn	New Generation	2,004.0	7,382.5	2,019.0	1,322.3	112.3	2,498.8	1,093.9	489.4	20.0	12,506.6	1,966.4	661.9	1,594.8	648.5	78.0	78.4	2,093.8	258.0	831.6	534.2	0.0	38,194.4
	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	724.5	20,296.9	3,002.5	3,296.8	30.0	7,621.9	2,718.6	439.9	50.6	20,412.4	1,810.2	2,875.0	191.0	861.3	120.0	45.8	3,470.6	98.9	1,866.2	53.1	0.0	69,986.2
	Upgrade	0.0	2,145.1	317.9	624.7	0.0	185.0	335.5	10.0	8.3	1,614.2	72.0	40.0	11.0	50.0	0.0	0.0	256.5	0.0	160.9	0.0	0.0	5,831.0
Total Projects	New Generation	2,790.5	27,954.1	5,391.9	4,619.1	143.4	10,129.7	4,215.0	1,054.3	70.6	35,791.6	4,076.9	3,536.9	2,179.1	1,544.8	198.0	127.5	5,605.2	359.5	2,712.8	836.7	0.0	113,337.5
	Upgrade	170.0	2,421.1	317.9	632.7	0.0	295.0	335.5	85.0	8.3	2,649.4	72.0	40.0	56.7	90.0	0.0	0.0	276.5	3.6	170.9	5.1	0.0	7,629.7

Renewable Hybrid Project Analysis

Table 12-40 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 December 31, 2020, by zone.[40] Of the 217 renewable hybrid projects currently active, suspended or under construction in the PJM generation queue, 52 projects (24.0 percent) are located in the Dominion Zone.

Table 12-40 Status of all renewable hybrid generation queue projects by zone (number of projects): 1997 through 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	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	1	0	0	0	0	1	0	0	2
	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	3	4	0	5	0	0	0	15	0	6	0	0	0	0	0	0	0	8	0	54
	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	31	20	11	0	8	1	0	2	45	2	16	6	11	0	0	19	2	20	1	0	195
	Upgrade	0	3	1	0	0	2	0	0	0	7	0	2	0	0	0	0	0	0	2	0	0	17
Total Projects	New Generation	4	40	23	15	0	13	1	0	2	60	2	22	6	12	0	0	19	2	21	12	0	254
	Upgrade	0	3	2	0	0	2	0	0	0	7	0	2	0	1	0	0	0	0	2	0	0	19

Table 12-41 shows the status of all renewable hybrid projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2020, by zone. Of the 18,227.5 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation queue, 7,033.2 MW (38.6 percent) are located in the AEP Zone.

Table 12-41 Status of all renewable hybrid generation queue projects by zone (MW): 1997 through 2020

		Project MW																					
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	100.0	0.0	0.0	0.0	0.0	90.0	0.0	0.0	190.0
	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	280.0	209.9	0.0	629.9	0.0	0.0	0.0	1,505.0	0.0	907.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.9	0.0	6,847.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7
Active	New Generation	0.0	6,890.0	1,285.3	579.9	0.0	1,620.8	40.0	0.0	37.5	3,160.6	130.0	1,897.0	199.8	82.1	0.0	0.0	886.2	562.5	180.0	20.0	0.0	17,571.5
	Upgrade	0.0	143.2	0.0	0.0	0.0	20.0	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	447.2
Total Projects	New Generation	14.5	10,160.8	1,565.3	789.8	0.0	2,250.7	40.0	0.0	37.5	4,665.6	130.0	2,804.0	199.8	182.1	0.0	0.0	886.2	562.5	270.0	53.5	0.0	24,612.1
	Upgrade	0.0	143.2	16.3	0.0	0.0	20.0	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	467.2

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."[41] Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation or transmission of the parent company and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a nonincumbent transmission developer which is a competitor of the transmission owner. The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest.

Table 12-42 shows the relationship between the project developer and transmission owner for all project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2020, by transmission owner

40 PJM does not currently have a definition of a hybrid resource.
41 See OATT § 1 (Transmission Owner).

and unit type. A project where the developer is affiliated with the transmission owner is classified as related. A project where the developer is not affiliated with the transmission owner is classified as unrelated. For example, 36.0 MW of combined cycle generation projects that have entered the PJM generation queue in the DEOK Zone were projects developed by Duke Energy or subsidiaries of Duke Energy, the transmission owner for the DEOK Zone. 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 the DEOK Zone by developers not affiliated with Duke Energy. These project MW are classified as unrelated.

Of the 657,391.2 MW that have entered the queue during the time period of January 1, 1997, through December 31, 2020, 68,459.1 MW (6.9 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 38,924.5 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2020, 14,287.3 MW (36.7 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-42 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: December 31, 2020

				MW by Unit Type																					
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
AEP	AEP	Related	49	16.0	678.0	0.0	0.0	0.0	0.0	34.0	2.4	214.0	0.0	0.0	0.0	247.7	0.0	0.0	3,918.0	90.0	0.0	0.0	0.0	0.0	5,200.1
		Unrelated	732	3,824.0	22,486.5	1,803.1	7.5	127.3	0.0	0.0	453.6	0.0	12.0	0.0	75.4	30,127.5	10,304.0	0.0	10,399.0	0.0	0.0	452.0	30,428.2	0.0	110,500.0
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	88	289.9	1,150.0	273.5	0.0	1.9	0.0	0.0	0.0	0.0	0.0	0.0	10.0	4,529.0	40.0	0.0	0.0	0.0	0.0	0.0	2,128.0	0.0	8,422.3
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	37	75.0	665.0	222.9	40.0	19.2	0.0	0.0	186.2	1,879.0	0.0	0.0	0.0	78.9	37.5	0.0	2,810.0	0.0	0.0	0.0	0.0	0.0	6,013.7
Dominion	Dominion	Related	136	350.0	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	2,775.9	17.0	0.0	301.0	0.0	0.0	4.0	2,786.0	0.0	23,062.1
		Unrelated	779	4,013.0	9,244.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4	35,665.1	4,742.6	0.0	20.0	0.0	0.0	316.3	8,056.1	0.0	64,675.6
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	75	96.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,576.9	2,904.0	0.0	0.0	0.0	0.0	0.0	150.3	0.0	6,970.5
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	346	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	2,952.2	14.5	0.0	15.0	5.5	0.0	10.0	8,097.7	0.0	22,093.5
	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	64	560.6	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	7,322.9
	ComEd	Related	17	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	460	2,673.3	16,823.2	1,529.2	42.0	65.2	0.0	0.0	22.7	0.0	35.0	0.0	67.7	10,415.7	2,071.7	199.0	1,926.0	91.0	0.0	90.0	38,574.3	0.0	74,626.0
	DPL	Related	8	1.0	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	1,724.4
		Unrelated	333	687.7	5,611.6	1,226.0	600.9	42.6	0.0	0.0	0.0	0.0	0.0	0.0	84.6	4,141.6	130.0	0.0	653.0	15.0	0.0	65.0	4,845.9	0.0	18,103.8
	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	86	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	127.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21,142.5
	Pepco	Related	1	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
		Unrelated	108	21.0	23,325.9	94.3	34.0	9.0	0.0	0.0	0.0	1,640.0	32.0	0.0	3.5	363.1	562.5	0.0	0.0	6.0	0.0	0.0	0.0	0.0	26,091.3
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	483	818.7	27,082.8	1,479.7	0.0	84.4	0.0	0.0	623.3	0.0	140.0	53.8	25.4	5,709.7	1,565.3	0.0	4,092.0	0.0	0.0	184.4	5,331.2	16.3	47,206.9
	ATSI	Related	6	0.0	1,678.0	0.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,694.0
		Unrelated	156	546.4	13,589.0	598.7	10.5	166.4	0.0	0.0	0.0	0.0	59.7	0.0	6.9	5,251.8	789.8	0.0	0.0	16.5	0.0	0.0	2,111.7	0.0	23,147.4
	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	422	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	2,223.8	199.8	0.0	0.0	0.0	0.0	30.0	5,773.2	0.0	26,182.7
	Met-Ed	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	163	619.9	17,458.9	57.6	1,204.4	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2	1,634.8	185.8	0.0	0.0	0.0	0.0	84.0	0.0	0.0	21,421.7
	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	434	940.2	18,747.9	1,532.2	0.0	214.4	3.0	16.0	46.3	0.0	341.8	8.0	14.8	5,881.7	886.2	0.0	561.0	590.0	0.0	525.0	6,916.1	0.0	37,224.3
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	348	719.8	23,928.3	423.1	8.0	234.5	0.0	1,200.0	142.6	488.0	19.9	2.4	44.7	2,758.9	270.0	0.0	6,896.6	0.0	0.0	31.0	4,122.5	90.0	41,380.4
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	235	979.5	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	661.4	49.9	0.0	0.0	25.0	0.0	0.0	1,320.0	0.0	24,637.3
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	436	477.8	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	3,513.3	20.7	0.0	9,288.5	235.0	0.0	4.0	2,786.0	0.0	68,459.1
		Unrelated	5385	19,407.1	247,184.1	14,969.6	2,955.8	1,480.3	11.3	1,216.0	2,623.6	7,380.0	654.9	104.2	520.9	117,453.9	24,753.3	199.0	27,492.6	751.5	0.0	1,812.7	117,855.0	106.3	588,932.1

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-43 shows the relationship between the project developer and transmission owner for all combined cycle project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 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 in the EKPC Zone during the time period of January 1, 1997, through December 31, 2020, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-43 Relationship between project developer and transmission owner for all combined cycle project MW in the queue: December 31, 2020

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
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	2,660.0	2,044.1	0.0	0.0	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	3,673.5	0.0	0.0	16,615.0	20,355.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	1,788.6	0.0	0.0	21,537.3	23,325.9
FirstEnergy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0
		Unrelated	2,504.7	1,720.0	535.0	1,620.0	20,703.1	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	131.5	806.4	0.0	0.0	17,834.0	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	12,405.5	31,013.3	6,547.5	4,001.0	193,216.7	247,184.1

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-44 shows the relationship between the project developer and transmission owner for all CT – natural gas project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2020, by transmission owner and project status. Of the 9,725.5 CT – natural gas project MW that have achieved in service or under construction status during this time period, 2,145.0 (22.1 percent) have been developed by Transmission Owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building CT – natural gas projects in their own service territory. Of the 2,956.0 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2020, 1,818.1 MW (61.5 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-44 Relationship between project developer and transmission owner for all CT – natural gas project MW in the queue: December 31, 2020

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	599.6	208.0	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	1,138.0	824.0	0.0	0.0	83.7	2,045.7
		Unrelated	0.0	1,182.7	0.0	0.0	1,043.1	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	371.0	87.0	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	0.0	596.0	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	528.7	40.0	5.0	0.0	25.0	598.7
	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	0.0	228.9	0.0	675.0	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	1,138.0	2,145.0	0.0	0.0	989.8	4,272.8
		Unrelated	3,304.3	7,244.0	336.5	705.0	3,379.8	14,969.6

Wind Project Developer and Transmission Owner Relationships

Table 12-45 shows the relationship between the project developer and transmission owner for all wind project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2020, by transmission owner and project status. Of the 10,853.3 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 in the Dominion Zone during the time period of January 1, 1997, through December 31, 2020, 2,786.0 MW (25.7 percent) have been submitted by Dominion or one of their affiliated companies.

Table 12-45 Relationship between project developer and transmission owner for all wind project MW in the queue: December 31, 2020

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	4,109.9	3,094.6	450.0	272.0	22,501.8	30,428.2
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	12.0	0.0	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	8,438.5	4,347.1	0.0	0.0	25,788.7	38,574.3
	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	420.0	1,119.6	200.0	0.0	3,591.6	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	1,300.0	0.0	0.0	0.0	20.0	1,320.0
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	12.0	0.0	0.0	134.0	2,786.0
		Unrelated	27,709.0	10,191.3	650.0	737.6	78,567.2	117,855.0

Solar Project Developer and Transmission Owner Relationships

Table 12-46 shows the relationship between the project developer and transmission owner for all solar project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2020, by transmission owner and project status. Of the 4,151.1 solar project MW that have achieved in service or under construction status during this time period, 1,183.1 MW (28.5 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building solar projects in their own service territory. Of the 841.8 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2020, 180.4 MW (21.4 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-46 Relationship between project developer and transmission owner for all solar project MW in the queue: December 31, 2020

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	68.0	14.7	0.0	10.0	155.0	247.7
		Unrelated	22,374.0	0.0	230.0	170.0	7,353.5	30,127.5
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5
		Unrelated	3,054.1	2.5	0.0	400.0	1,072.4	4,529.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	58.9	0.0	0.0	0.0	20.0	78.9
Dominion	Dominion	Related	1,451.5	726.4	286.1	60.0	251.9	2,775.9
		Unrelated	20,575.1	569.8	921.7	355.0	13,243.5	35,665.1
Duke	DEOK	Related	50.0	0.0	0.0	0.0	56.4	106.4
		Unrelated	399.9	0.0	200.0	0.0	433.0	1,032.9
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,915.0	0.0	0.0	0.0	661.9	3,576.9
Exelon	AECO	Related	0.0	0.0	0.0	0.0	8.3	8.3
		Unrelated	724.5	62.0	0.0	0.0	2,165.8	2,952.2
	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	7,806.9	0.0	0.0	0.0	2,608.8	10,415.7
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4
		Unrelated	1,882.2	123.0	170.0	0.0	1,966.4	4,141.6
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	45.8	3.3	0.0	0.0	78.4	127.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	98.9	2.5	0.0	0.0	261.6	363.1
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,320.4	112.3	10.0	248.1	2,019.0	5,709.7
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,921.5	0.0	0.0	0.0	1,330.3	5,251.8
	JCPL	Related	0.0	0.0	0.0	0.0	12.0	12.0
		Unrelated	202.0	387.7	20.0	7.6	1,606.6	2,223.8
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	911.3	0.0	0.0	75.0	648.5	1,634.8
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,727.1	13.5	0.0	27.3	2,113.8	5,881.7
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	1,902.4	25.0	0.0	0.0	831.6	2,758.9
PSEG	PSEG	Related	0.0	134.3	5.2	0.0	40.9	180.4
		Unrelated	53.1	97.6	16.1	0.0	494.6	661.4
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	1,694.3	891.8	291.3	70.0	566.0	3,513.3
		Unrelated	74,123.0	1,400.3	1,567.8	1,283.0	39,079.9	117,453.9

Renewable Hybrid Project Developer and Transmission Owner Relationships

Table 12-47 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 December 31, 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 in the PSEG Zone during the time period of January 1, 1997, through December 31, 2020, 3.7 MW (6.9 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-47 Relationship between project developer and transmission owner for all hybrid project MW in the queue: December 31, 2020

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	7,033.2	0.0	0.0	0.0	3,270.8	10,304.0
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	40.0	0.0	0.0	0.0	0.0	40.0
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	3,237.6	0.0	0.0	0.0	1,505.0	4,742.6
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	1,997.0	0.0	0.0	0.0	907.0	2,904.0
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	1,640.8	0.0	0.0	0.0	629.9	2,270.7
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	130.0	0.0	0.0	0.0	0.0	130.0
	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	562.5	0.0	0.0	0.0	0.0	562.5
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,285.3	0.0	0.0	16.3	280.0	1,581.6
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	579.9	0.0	0.0	0.0	209.9	789.8
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	199.8	0.0	0.0	0.0	0.0	199.8
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	82.1	0.0	0.0	100.0	3.7	185.8
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	886.2	0.0	0.0	0.0	0.0	886.2
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	270.0	0.0	0.0	90.0	0.0	360.0
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	18,001.6	0.0	0.0	206.3	6,850.7	25,058.6

Regional Transmission Expansion Plan (RTEP)[42]

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 analyses.[43] 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.

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.

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

42 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).

43 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>.

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.[44]

The Benefit/Cost Evaluation

For an RTEP project to be recommended to the PJM Board of Managers for approval as a market efficiency project, the relative benefits and costs of the economic based enhancement or expansion must meet a benefit/cost ratio threshold of at least 1.25:1.

The total benefit of a project is calculated as the sum of the net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. 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

44 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.

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 allocate operational revenues and costs it is impossible to develop forecasted benefits and/or costs of a SATA project.

The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. The MMU recommends that the market efficiency process be eliminated.

The Transource Project

The Transource Project (Project 9A) is an example of a PJM approved market efficiency project that 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.[45] 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 by ignoring areas where energy costs are increased. MISO, on the other hand, measures benefits as changes in projected system wide production cost caused by the project. The use of different approaches to measuring benefits is an issue when studying potential benefits of projects in a joint effort, and when using the defined benefits to allocate the costs of IMEP projects to each RTO. PJM's approach will over allocate the costs of IMEP projects to PJM members.

PJM and MISO conducted a two year interregional market efficiency project study in 2018/2019 and included the

45 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>.

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, the Bosserman to Trail Creek 138 kV Project.[46] The approved project has an in service cost of $24.7 million, and counting only PJM positive zonal benefits, a total present value of projected benefits of $69.2 million. Ignoring PJM zones with negative benefits (increased costs to load) the project has a calculated PJM benefit/cost ratio of 2.63. MISO, using both positive and negative zonal effects, calculated the projected benefits of the project to be $8.4 million. Based on the proportion of the calculated benefits, PJM is to be allocated 89.1 percent ($23.4 million) of the project costs and MISO is to be allocated 10.9 percent ($2.9 million) of the interregional costs. The PJM board approved the recommended project in December 2019. The MISO board approved the recommended project in September 2020.

Using a rational measure of benefits and costs, the Bosserman to Trail Creek 138 kV Project should not have been approved. Including the projected positive and negative benefits of the project to all PJM zones, the projected total benefits of the project drops from $69.2 million to -$68.1 million dollars. PJM analysis shows benefits to only one zone of $69.2 million, with the negative effect on all other zones of -$137.3 million. The resulting benefit/cost ratio would be -2.59. Even including the net MISO benefit of $8.4 million, the total projected benefit of the project would still be a -$59.7 million dollars. Allocating the costs of the project based on the proportion of total regional benefit (-$68.1 million to PJM and $8.4 million to MISO) would have allocated 100 percent of the cost to MISO, resulting in a benefit/cost ratio of 0.32 to MISO, and a rejection of the project by MISO.

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.

PJM MISO Targeted Market Efficiency Process (TMEP)

PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects. The TMEP process operates on a 12 month study schedule. To qualify as a TMEP project, the project must have an estimated in service date by the third summer peak season from the year the project was approved, have an estimated cost of less than $20 million and must have estimated benefits, based on the projected congestion cost relief over a four year period, that exceed the expected installed capacity cost of the proposed project.[47] [48]

The benefit of a proposed TMEP project is calculated as the value of eliminating congestion on the affected constraint over a four year period. PJM and MISO calculate the estimated value of eliminating congestion by calculating the average congestion for the two prior years prior and multiplying by four.

The allocation of costs to each RTO for an approved TMEP project will be in proportion to the benefits received by that RTO.[49] The proportion of benefits is calculated using the average shadow price of the constraint times the dfax to affected downstream buses times MW of load at the buses, which is effectively the proportion of congestion paid by the RTO. Within an RTO, the RTO's share of the cost of the approved project is allocated to each transmission control area in proportion to the benefits received by each transmission control area.

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

46 Analysis showed that no projects met the B/C criteria on two of the identified flowgates.

47 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>.

48 On November 2, 2017, PJM submitted a compliance filing including additional revisions to the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process. See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, et al. (November 2, 2017).

49 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).

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 and recommended five TMEP projects. The five projects address $59.0 million in historical congestion, with a calculated 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.[50]

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. 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 and recommended two TMEP projects. The two projects address $25.0 million in historical congestion, with a calculated TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average benefit/cost ratio. PJM and MISO presented the two recommended projects to their boards in December 2018, and both boards approved the projects.[51]

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.

The PJM and MISO TMEP process for measuring the projected benefits of a TMEP transmission projects is flawed. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through the ARRs and FTRs. The benefit of a TMEP transmission upgrade should be the expected difference in the total cost of energy before and after the upgrade to all affected load. This measurement would include the change in expected LMP of all affected load before and after the upgrade, times the MW of load, plus the change in congestion dollars returned to the affected load before and after the upgrade. Congestion revenue returned to load is not a cost to the load, it is a credit against the overpayment of load payments relative to generation credits caused by the transmission constraint. Ignoring the return of congestion from ARRs/FTRs overstates the potential benefits of eliminating congestion through the TMEP upgrades, and ignores the value of smaller upgrades that may not eliminate a constraint, but may reduce the average cost of energy for load.

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."[52] Attachment M-3 of the PJM OATT defines the process that Transmission Owners (TO) must follow in adding Supplemental Projects in their local plan.

The M-3 Process requires TOs to present the criteria, assumptions and models that they will use to plan and identify Supplemental Projects on a yearly basis. The criteria identified for Supplemental Projects are very broad and include: equipment material condition, performance and risk, operational flexibility and efficiency, infrastructure resilience, customer service or other, as well as asset management.

While the identification of the criteria violations and solutions are reviewed, and stakeholders have the opportunity to comment, the solution that is submitted in the Local Plan is the Transmission Owner's decision. PJM conducts a do no harm analysis to ensure the Supplemental Projects do not negatively affect the reliability of the system. Supplemental Projects are ultimately included in PJM's Regional Transmission Expansion Plan and are allocated 100 percent to the

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

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

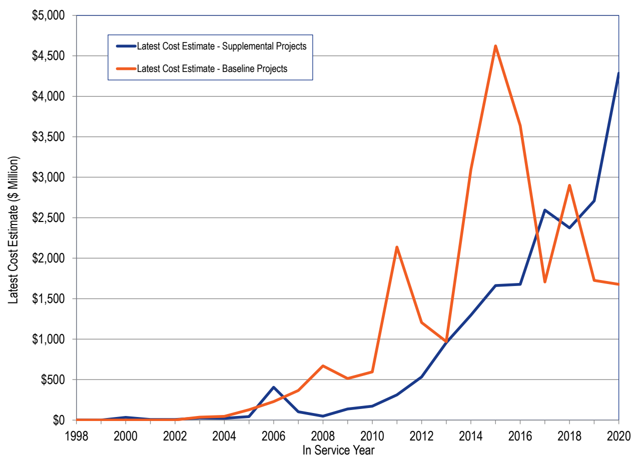
52 See PJM. Planning. "Transmission Construction Status," (Accessed on December 31, 2020) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

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.[53] 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 12-5 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 12-5, Table 12-48 and Table 12-49 because PJM did not track or report such projects. There has been a significant increase in supplemental projects coincident with the implementation of Order No. 890 starting in 2008 and the competitive planning process introduced by FERC Order No. 1000 starting in 2011.

Figure 12-5 Cost estimate of baseline and supplemental projects by expected in service year: 1998 through 2020



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

Table 12-48 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 715.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 163 for years 2008 through 2020 (post Order 890).

Table 12-48 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	157	4	30	6	14	2	16	1	33	8	5	3	14	0	1	15	0	15	27	0	354
2020	5	151	8	41	9	12	7	15	2	28	2	6	12	30	0	0	58	1	15	22	0	424
2021	2	233	2	36	2	6	5	13	0	27	2	6	13	65	5	5	37	0	27	25	0	511
2022	5	204	3	30	2	5	2	3	1	16	5	0	12	26	0	4	32	3	24	23	0	400
2023	6	90	0	8	0	1	14	7	0	10	4	2	1	11	0	3	36	0	16	25	0	234
2024	4	54	0	6	0	4	0	2	0	3	4	1	2	21	0	0	11	1	13	11	0	137
2025	3	37	0	6	3	0	0	0	0	12	3	0	0	7	0	0	10	0	6	0	0	87
2026	4	19	0	1	7	1	0	1	0	0	0	0	0	0	0	0	0	0	14	0	0	47
2027	0	9	0	0	1	0	0	2	2	0	0	0	0	0	0	0	1	0	26	0	0	41
2028	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	2	0	0	3
2029	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	6
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1
2031	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	94	1,315	105	240	49	221	30	108	56	275	160	37	56	182	5	34	215	15	267	328	0	3,792

Table 12-49 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 2,119.8 percent, from $65.0 million for years 1998 through 2007 (pre Order No. 890) to $1,442.9 million for years 2008 through 2020 (post Order No. 890).

Table 12-49 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	$1,158.43	$11.97	$190.40	$150.25	$90.19	$0.30	$98.59	$0.30	$90.14	$33.55	$23.67	$0.90	$62.30	$0.00	$2.00	$75.80	$0.00	$298.00	$356.41	$0.00	$2,707.50
2020	$59.58	$1,053.24	$1.48	$133.20	$65.81	$78.09	$18.16	$88.35	$24.50	$257.18	$39.50	$26.20	$43.90	$35.80	$0.00	$0.00	$171.00	$102.70	$186.09	$1,900.68	$0.00	$4,285.46
2021	$28.50	$1,915.88	$0.90	$391.85	$29.70	$179.20	$26.90	$159.10	$0.00	$71.97	$6.70	$29.77	$22.60	$247.70	$4.40	$30.90	$106.36	$0.00	$291.33	$527.72	$0.00	$4,071.48
2022	$180.56	$1,757.78	$5.50	$211.96	$244.30	$51.50	$10.00	$24.66	$45.00	$217.70	$67.90	$0.00	$47.10	$73.16	$0.00	$0.00	$67.50	$737.50	$336.25	$1,014.87	$0.00	$5,093.24
2023	$88.30	$931.00	$0.00	$116.20	$0.00	$1.00	$54.15	$54.79	$0.00	$56.80	$21.00	$20.40	$6.80	$56.30	$0.00	$201.80	$166.10	$0.00	$253.44	$783.50	$0.00	$2,811.58
2024	$38.74	$685.41	$0.00	$64.10	$0.00	$199.70	$0.00	$17.64	$0.00	$42.42	$69.42	$15.20	$30.50	$184.20	$0.00	$0.00	$17.70	$0.50	$237.10	$212.70	$0.00	$1,815.33
2025	$30.39	$373.30	$0.00	$541.70	$144.10	$0.00	$0.00	$0.00	$0.00	$148.87	$22.21	$0.00	$0.00	$42.70	$0.00	$0.00	$49.70	$0.00	$127.00	$0.00	$0.00	$1,479.97
2026	$64.00	$201.10	$0.00	$80.00	$336.00	$67.00	$0.00	$4.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$387.05	$0.00	$0.00	$1,139.85
2027	$0.00	$134.00	$0.00	$0.00	$118.00	$0.00	$0.00	$32.57	$160.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$200.00	$0.00	$582.41	$0.00	$0.00	$1,226.98
2028	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$30.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$51.00	$0.00	$0.00	$81.40
2029	$0.00	$0.00	$0.00	$0.00	$231.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$96.60	$0.00	$0.00	$327.60
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	$91.90	$0.00	$0.00	$91.90
2031	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2032	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2033	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2034	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2036	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2037	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2038	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2039	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2040	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$809.74	$11,146.83	$154.00	$2,233.31	$1,410.69	$1,798.02	$109.51	$682.18	$513.55	$1,702.66	$580.01	$130.51	$171.55	$727.91	$4.40	$644.60	$877.99	$1,061.40	$3,660.04	$9,128.49	$0.00	$37,547.39

The MMU recommends, to increase the role of competition, that the exemption of supplemental from the Order No. 1000 competitive process be terminated.

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. Under the current process, end of life transmission projects are not subject to the RTEP open window process and have become a form of supplemental project that is exempt from competition under the existing rules.[54]

The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP

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

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.[55] 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.[56] 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.[57] Some supplemental projects are in this category.
- Substation Equipment. Due to identification of the limiting element(s) as substation equipment, such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[58] 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.

Comparative Cost Framework

The MMU recommended that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative cost framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. On March 20, 2020, the Commission approved PJM's filing to amend the PJM Operating Agreement to incorporate this requirement.[59]

The 2020 RTEP Window 1 was the first open window that received cost capping proposals to be evaluated under the comparative cost framework. The analysis performed under the new process was insufficient and did not follow the process defined in the PJM manual.[60] The existing proposal templates do not provide enough information to adequately perform a financial analysis. The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life.

Storage As A Transmission Asset (SATA)

The PJM Planning Committee is currently considering whether storage devices should be included in the RTEP process as transmission assets.[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

55 See OA Schedule 6 § 1.5.8(m).
56 169 FERC ¶ 61,054 (2019).
57 See OA Schedule 6 § 1.5.8(n).
58 See OA Schedule 6 § 1.5.8(p).

59 170 FERC ¶ 61,243 (2020).
60 See PJM. "PJM Manual 14F: Competitive Planning Process," Rev. 5 (April 10, 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>.

margin. This relationship has always been a relatively unexamined area in the design of competitive wholesale power markets. For example, there is little if any explicit consideration of the impact of transmission planning on competitive generation investment in RTO/ISO market rules. Improvement is needed in these areas. Introducing confusion about what assets are classified as generation and what assets are classified as transmission frustrates potential reform and undermines the competitive markets.

On July 22, 2020, through the supplemental planning process, American Electric Power Service Corporation (AEP) filed, on behalf of Kentucky Power Company (Kentucky Power), a Petition for Declaratory Order seeking confirmation that its Middle Creek energy storage project is eligible for cost-of-service recovery through AEP's formula rates.[62] AEP's Middle Creek energy storage project was a proposed battery storage device that would discharge energy to serve retail load at the Middle Creek substation in the event of a transmission outage. On December 21, 2020, the Commission ruled that the Middle Creek energy storage project did not perform a transmission function, and was ineligible to recover its costs through formula rates.[63]

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.[64]

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 2020, the PJM Board approved a net change of $235.2 million in transmission upgrades. As of December 30, 2020, the PJM Board had approved $37.8 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. On December 14, 2020, the PJM Board of Managers authorized a net decrease of $535.2 million in transmission upgrades and additions. This decrease was primarily due to the cancellation of network transmission projects due to new generation projects being withdrawn from the queue.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions.

If a QTU that was cleared in a Base Residual Auction (BRA) or Incremental Auction (IA) is not completed by the start of the Delivery Year, the submitting party is required to provide replacement capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of December 31, 2020, no QTUs have cleared a BRA or IA.

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

62 See AEP, Docket No. EL20-58 (July 22, 2020).
63 173 FERC ¶ 61,264 (2020).
64 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

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."[65] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[66]

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.[67] 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 MMU recommends a comprehensive review of the ways in which the solution-based DFAX is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution-based DFAX method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed.

65 153 FERC ¶ 61,245 at P 35 (2015).
66 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
67 170 FERC ¶ 61,122 (2020).

As an example, the use of the arbitrary 0.01 distribution factor cutoff can result in large and inappropriate shifts in cost allocation. If the intent of the use of the 0.01 cutoff is to help eliminate small, arbitrary cost allocations to geographically distant areas, this could be achieved by adding a threshold for a minimum usage impact on the line. The MMU recommends 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. 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.[68]

68 See the *2018 State of the Market Report for PJM*, Volume 2, Section 11: Congestion and Marginal Losses.

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.[69] 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.[70]

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.[71]

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.[72] PJM requires transmission owners to provide thermal ratings under normal operating conditions, long term emergency operating conditions, short term emergency operating conditions and the extreme load dump conditions. But there is no requirement that the ratings differ for these operating conditions. PJM typically uses normal line ratings for precontingency (base case) constraints and long term emergency line ratings (four hours) for contingency constraints. PJM requires transmission owners to provide temperature based line ratings separately for night and day times. The temperature ranges from 32 degree Fahrenheit or below to 95 degree Fahrenheit or above in nine degree increments. But there is no requirement that the ratings differ for these operating condition temperatures. In PJM, transmission owners are responsible for developing their own methods to compute line ratings subject to a range of NERC guidelines and requirements. PJM does not review or verify the accuracy of transmission owners' methods to compute line ratings. In PJM, transmission owners have substantial discretion in the approach to line ratings.[73]

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

69 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>.

70 See the *2019 State of the Market Report for PJM*, Volume 2, Section 3: Energy Market.

71 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).

72 See "PJM Manual 3: Transmission Operations," Rev. 58 (November 19, 2020) § 2.1.1, at p 28.

73 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.

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 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.[74] 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.[75] 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.[76] 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.[77] The specific timeline is shown in Table 12-51.[78]

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 seven months of the 2020/2021 planning period, regardless of when they were initially submitted.[79] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through December 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.[80] Table 12-50 shows that 75.9 percent of requested outages were planned for less than or equal to five days and 9.2 percent of requested outages were planned for greater than 30 days in the first seven months of the 2020/2021 planning period. Table 12-50 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 12-50 Transmission facility outage request summary by planned duration: June 2019 through December 2020

	2019/2020 (12 months)		2020/2021 (7 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	16,609	77.8%	8,977	75.9%
>5 & <=30	3,078	14.4%	1,764	14.9%
>30	1,674	7.8%	1,086	9.2%
Total	21,361	100.0%	11,827	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request

74 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>.

75 See the *2018 State of the Market Report for PJM*, Volume 2, Section 2: Recommendations.

76 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).

77 See PJM, "Manual 3: Transmission Operations," Rev. 57 (May 29, 2020).

78 See PJM, "Manual 3: Transmission Operations," Rev. 57 (May 29, 2020).

79 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.

80 *Id.* at 70.

based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-51.[81]

The purpose of the rules defined in Table 12-51 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.[82]

Table 12-51 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 12-52 shows a summary of requests by received status. In the first seven months of the 2020/2021 planning period, 43.9 percent of outage requests received were late. In the 2019/2020 planning period, 44.4 percent of outage requests received were late.

Table 12-52 Transmission facility outage request summary by received status: June 2019 through December 2020

	2019/2020 (12 months)				2020/2021 (7 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,570	7,039	16,609	42.4%	5,216	3,761	8,977	41.9%
>5 & <=30	1,641	1,437	3,078	46.7%	958	806	1,764	45.7%
>30	662	1,012	1,674	60.5%	461	625	1,086	57.6%
Total	11,873	9,488	21,361	44.4%	6,635	5,192	11,827	43.9%

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.[83]

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.[84] Table 12-53 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first seven months of the 2020/2021 planning period, 13.0 percent were for emergency outages. Of all outage requests scheduled to occur in the 2019/2020 planning period, 12.2 percent were for emergency outages.

81 See PJM, "Manual 3: Transmission Operations," Rev. 58 (Nov. 29, 2020).
82 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).
83 See PJM, "Manual 3: Transmission Operations," Rev. 58 (Nov. 19, 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).
84 PJM, "Manual 3: Transmission Operations," Rev. 58 (Nov. 19, 2020).

Table 12-53 Transmission facility outage request summary by emergency: June 2019 through December 2020

	2019/2020 (12 months)				2020/2021 (7 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,952	14,657	16,609	11.8%	1,106	7,871	8,977	12.3%
>5 & <=30	402	2,676	3,078	13.1%	275	1,489	1,764	15.6%
>30	262	1,412	1,674	15.7%	162	924	1,086	14.9%
Total	2,616	18,745	21,361	12.2%	1,543	10,284	11,827	13.0%

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."[85]

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 12-54 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first seven months of the 2020/2021 planning period, 6.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 2.5 percent (19 out of 763) were denied by PJM in the first seven months of the 2020/2021 planning period and 20.4 percent (156 out of 763) were cancelled (Table 12-56). 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, 2.1 percent (29 out of 1,399) were denied by PJM in the 2019/2020 planning period and 21.7 percent (304 out of 1,399) were cancelled (Table 12-56).

Table 12-54 Transmission facility outage request summary by congestion: June 2019 through December 2020

	2019/2020 (12 months)				2020/2021 (7 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	976	15,633	16,609	5.9%	562	8,415	8,977	6.3%
>5 & <=30	267	2,811	3,078	8.7%	143	1,621	1,764	8.1%
>30	156	1,518	1,674	9.3%	58	1,028	1,086	5.3%
Total	1,399	19,962	21,361	6.5%	763	11,064	11,827	6.5%

Table 12-55 shows the outage requests summary by received status, congestion status and emergency status. In the first seven months of the 2020/2021 planning period, 31.0 percent of requests were submitted late and were nonemergency while 1.1 percent of requests (131 out of 11,827) 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 (238 out of 21,361) were late, nonemergency, and expected to cause congestion.

Table 12-55 Transmission facility outage request summary by received status, emergency and congestion: June 2019 through December 2020

		2019/2020 (12 months)				2020/2021 (7 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	68	2,517	2,585	12.1%	52	1,469	1,521	12.9%
	Non Emergency	238	6,665	6,903	32.3%	131	3,540	3,671	31.0%
On Time	Emergency	4	27	31	0.1%	0	22	22	0.2%
	Non Emergency	1,089	10,753	11,842	55.4%	580	6,033	6,613	55.9%
Total		1,399	19,962	21,361	100.0%	763	11,064	11,827	100.0%

85 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 14 (Jan. 27, 2021).

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.[86] Table 12-56 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 12-56. Table 12-56 shows that of all the outage requests that were expected to cause congestion, 2.5 percent (19 out of 763) were denied by PJM in the first seven months of the 2020/2021 planning period, 68.0 percent were complete and 20.4 percent (156 out of 765) were cancelled. Of all the outage requests that were expected to cause congestion, 2.1 percent (29 out of 1,399) were denied by PJM in the 2019/2020 planning period, 70.0 percent were complete and 21.7 percent (304 out of 1,399) were cancelled.

Table 12-56 Transmission facility outage requests status summary: June 2019 through December 2020

		2019/2020 (12 months)						2020/2021 (7 months)					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	6	61	0	1	68	89.7%	3	48	0	1	52	92.3%
	Non Emergency	37	185	7	8	238	77.7%	26	93	4	7	131	71.0%
On Time	Emergency	1	3	0	0	4	75.0%	0	0	0	0	0	0.0%
	Non Emergency	260	730	77	20	1,089	67.0%	127	378	60	11	580	65.2%
Total		304	979	84	29	1,399	70.0%	156	519	64	19	763	68.0%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[87] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-56 shows that in the 2019/2020 planning period, 238 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 12-57 is a summary of all the outage requests planned for the 2019/2020 planning period and the first seven 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 seven months of the 2020/2021 planning period, 30.8 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 12.1 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2019/2020 planning period, 31.6 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 11.3 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-57 Rescheduled and cancelled transmission outage request summary: June 2019 through December 2020

	2019/2020 (12 months)					2020/2021 (7 months)				
Planned Duration (Days)	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	16,609	3,862	23.3%	2,150	12.9%	8,977	2,038	22.7%	1,269	14.1%
>5 & <=30	3,078	1,812	58.9%	185	6.0%	1,764	970	55.0%	107	6.1%
>30	1,674	1,083	64.7%	81	4.8%	1,086	632	58.2%	50	4.6%
Total	21,361	6,757	31.6%	2,416	11.3%	11,827	3,640	30.8%	1,426	12.1%

86 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).
87 OA Schedule 1 § 1.9.2.

If a requested outage is determined to be late and TO reschedules the outage, the outage will be revaluated by PJM again as On Time or Late.

A transmission outage ticket with duration of five days or less with an On Time status can retain its On Time status if the outage is rescheduled within the original scheduled month.[88] 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.[89] 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.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-51) 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 12-58 shows equipment outages by the equipment instead of by outage request.

Table 12-58 shows that there were 8,180 transmission equipment planned outages in the first seven months of the 2020/2021 planning period, of which 1,053 were longer than 30 days, and of which 88 or 1.1 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-58 Transmission equipment outage summary: June 2019 through December 2020

		2019/2020 (12 months)		2020/2021 (7 months)	
Planned Duration (Days)	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
> 30	No	1,472	11.2%	965	11.8%
	Yes	229	1.7%	88	1.1%
<= 30		11,429	87.0%	7,127	87.1%
Total		13,130	100.0%	8,180	100.0%

Table 12-59 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 seven months of the 2020/2021 planning period, within effective duration greater than a month and shorter than two months, there were 21 outages with a combined duration longer than 30 days.

Table 12-59 Transmission equipment outages by effective duration: June 2019 through December 2020

	2019/2020 (12 months)		2020/2021 (7 months)	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	3	1.3%	3	3.4%
>31 & <=62	27	11.8%	21	23.9%
>62 & <=93	21	9.2%	21	23.9%
>93	178	77.7%	43	48.9%
Total	229	100.0%	88	100.0%

88 PJM, "Manual 3: Transmission Operations," Rev. 58 (Nov. 19, 2020).
89 *Id.*

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.[90]

In the first seven months of the 2020/2021 planning period, 51 outage requests were included in the annual FTR market outage list and 11,776 outage requests were not included.[91] In the 2019/2020 planning period, 243 outage requests were included in the annual FTR market outage list and 21,118 outage requests were not included. Table 12-60, Table 12-61, Table 12-62 and Table 12-63 show the summary information on the modeled outage requests and Table 12-64 and Table 12-65 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-60 shows that 2.0 percent of the outage requests modeled in the Annual FTR Market for the first seven months of the 2020/2021 planning period had a planned duration of less than two weeks and that 25.5 percent of the outage requests (13 out of 51) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 7.0 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 15.6 percent of the outage requests (38 out of 243) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-60 Annual FTR market modeled transmission facility outage requests by received status: June 2019 through December 2020

	2019/2020 (12 months)				2020/2021 (7 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	13	4	17	7.0%	1	0	1	2.0%
>=2 weeks & <2 months	77	7	84	34.6%	9	1	10	19.6%
>=2 months	115	27	142	58.4%	28	12	40	78.4%
Total	205	38	243	100.0%	38	13	51	100.0%

90 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.

91 PJM's treatment of transmission outages in the FTR models is discussed in the *2020 State of the Market Report for PJM*: Section 13: FTRs and ARRs: Supply and Demand.

Table 12-61 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 seven 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 12-61 Annual FTR market modeled transmission facility outage requests by emergency and received status: June 2019 through December 2020

		2019/2020 (12 months)				2020/2021 (7 months)			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	13	13	100.0%	0	1	1	100.0%
	>=2 weeks & <2 months	0	77	77	100.0%	0	9	9	100.0%
	>=2 months	0	115	115	100.0%	0	28	28	100.0%
	Total	0	205	205	100.0%	0	38	38	100.0%
Late	<2 weeks	0	4	4	100.0%	0	0	0	0.0%
	>=2 weeks & <2 months	0	7	7	100.0%	0	1	1	100.0%
	>=2 months	2	25	27	92.6%	1	11	12	91.7%
	Total	2	36	38	94.7%	1	12	13	92.3%

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 12-62 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 seven 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, 13.2 percent (5 out of 38) were expected to cause congestion.

Table 12-62 Annual FTR market modeled transmission facility outage requests by congestion and received status: June 2019 through December 2020

		2019/2020 (12 months)				2020/2021 (7 months)			
Received Status	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	6	7	13	46.2%	1	0	1	100.0%
	>=2 weeks & <2 months	23	54	77	29.9%	1	8	9	11.1%
	>=2 months	21	94	115	18.3%	2	26	28	7.1%
	Total	50	155	205	24.4%	4	34	38	10.5%
Late	<2 weeks	2	2	4	50.0%	0	0	0	0.0%
	>=2 weeks & <2 months	2	5	7	28.6%	0	1	1	0.0%
	>=2 months	1	26	27	3.7%	0	12	12	0.0%
	Total	5	33	38	13.2%	0	13	13	0.0%

Table 12-63 shows that 50.0 percent of outage requests modeled in the annual FTR market for the first seven 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 31.0 percent for the 2019/2020 planning period. Table 12-63 also shows that 17.5 percent of outages requests modeled in the Annual FTR Market for the first seven months of the 2020/2021 planning period and with a duration of two months or longer were cancelled, compared to 21.8 percent for the 2019/2020 planning period.

Table 12-63 Annual FTR market modeled transmission facility outage requests by processed status: June 2019 through December 2020

		2019/2020 (12 months)		2020/2021 (7 months)	
Planned Duration	Processed Status	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%	1	100.0%
	Total	17	100.0%	1	100.0%
>=2 weeks & <2 months	In Progress	14	16.7%	1	10.0%
	Cancelled	26	31.0%	5	50.0%
	Active	0	0.0%	0	0.0%
	Completed	44	52.4%	4	40.0%
	Total	84	100.0%	10	100.0%
>=2 months	In Progress	23	16.2%	6	15.0%
	Cancelled	31	21.8%	7	17.5%
	Active	4	2.8%	13	32.5%
	Completed	84	59.2%	14	35.0%
	Total	142	100.0%	40	100.0%
Total Cancelled		60	24.7%	12	23.5%
Grand Total		243		51	

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first seven months of the 2020/2021 planning period, 51 outage requests were modeled and 11,776 outage requests were not modeled in the Annual FTR Market. In the 2019/2020 planning period, 243 outage requests were modeled and 21,118 outage requests were not modeled in the Annual FTR Market.

Table 12-64 shows that 8.0 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted or rescheduled after the Annual FTR Auction bidding opening date for the first seven months of the 2020/2021 planning period compared to 14.1 percent in the 2019/2020 planning period.

Table 12-64 Transmission facility outage requests not modeled in Annual FTR Auction: June 2019 through December 2020

	2019/2020 (12 months)						2020/2021 (7 months)					
	On Time			Late			On Time			Late		
Planned Duration	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	1,697	8,706	83.7%	238	7,665	97.0%	1,840	3,823	67.5%	188	4,043	95.6%
>=2 weeks & <2 months	626	412	39.7%	151	825	84.5%	612	98	13.8%	126	453	78.2%
>=2 months	195	32	14.1%	222	349	61.1%	206	18	8.0%	187	182	49.3%
Total	2,518	9,150	78.4%	611	8,839	93.5%	2,658	3,939	59.7%	501	4,678	90.3%

Table 12-65 shows that 63.2 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the first seven months of the 2020/2021 planning period. It also shows that 85.7 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 2019/2020 planning period.

Table 12-65 Late transmission facility outage requests: June 2019 through December 2020

	2019/2020 (12 months)			2020/2021 (7 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	6,597	7,665	86.1%	3,473	4,043	85.9%
>=2 weeks & <2 months	707	825	85.7%	371	453	81.9%
>=2 months	299	349	85.7%	115	182	63.2%
Total	7,603	8,839	86.0%	3,959	4,678	84.6%

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on time, but are rescheduled so that they are late. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long duration outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent those transmission outages from being submitted late. The MMU recommends that PJM 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.[92] Table 12-66 and Table 12-67 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-68 and Table 12-69 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-66 shows that on average, 31.0 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 seven 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.

Table 12-66 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2019 through December 2020

	2019/2020				2020/2021			
Month	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%	596	176	772	22.8%
Nov	431	163	594	27.4%	486	185	671	27.6%
Dec	311	146	457	31.9%	324	130	454	28.6%
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%	329	126	455	31.0%

Table 12-67 shows that on average, 17.8 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first

92 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).

seven 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 12-67 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2019 through December 2020

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent 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%
	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%
2020/2021	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%
	Oct	67	4	17	161	2	208	313	772	20.9%
	Nov	52	1	42	151	0	160	265	671	22.5%
	Dec	31	1	7	97	0	75	243	454	21.4%
	Avg	39	4	14	88	0	122	187	455	17.8%

Table 12-68 shows that on average, 9.5 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the first seven months of the 2020/2021 planning period, compared to 9.1 percent in the 2019/2020 planning period. On average, 66.2 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the first seven months of the 2020/2021 planning period, compared to 66.1 percent in the 2019/2020 planning period.

Table 12-68 Transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction: June 2019 through December 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%	801	102	11.3%	332	791	70.4%
Jul	391	64	14.1%	268	729	73.1%	431	89	17.1%	271	605	69.1%
Aug	357	44	11.0%	300	640	68.1%	439	73	14.3%	262	617	70.2%
Sep	894	124	12.2%	318	661	67.5%	1,074	74	6.4%	274	639	70.0%
Oct	1,111	119	9.7%	388	929	70.5%	1,200	62	4.9%	367	612	62.5%
Nov	1,000	63	5.9%	457	659	59.1%	975	60	5.8%	358	576	61.7%
Dec	738	62	7.8%	328	636	66.0%	755	51	6.3%	392	585	59.9%
Jan	581	36	5.8%	292	572	66.2%						
Feb	645	51	7.3%	280	603	68.3%						
Mar	1,319	97	6.9%	333	702	67.8%						
Apr	1,503	177	10.5%	448	693	60.7%						
May	1,268	86	6.4%	484	702	59.2%						
Avg	873	84	9.1%	354	685	66.1%	811	73	9.5%	322	632	66.2%

Table 12-69 shows that on average, 71.1 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 seven months of the 2020/2021 planning period, compared to 71.8 percent in the 2019/2020 planning period.

Table 12-69 Late transmission facility outage requests: June 2019 through December 2020

	2019/2020			2020/2021		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	528	694	76.1%	574	791	72.6%
Jul	489	729	67.1%	436	605	72.1%
Aug	500	640	78.1%	447	617	72.4%
Sep	455	661	68.8%	436	639	68.2%
Oct	616	929	66.3%	419	612	68.5%
Nov	472	659	71.6%	392	576	68.1%
Dec	469	636	73.7%	440	585	75.2%
Jan	441	572	77.1%			
Feb	475	603	78.8%			
Mar	461	702	65.7%			
Apr	480	693	69.3%			
May	518	702	73.8%			
Avg	492	685	71.8%	449	632	71.1%

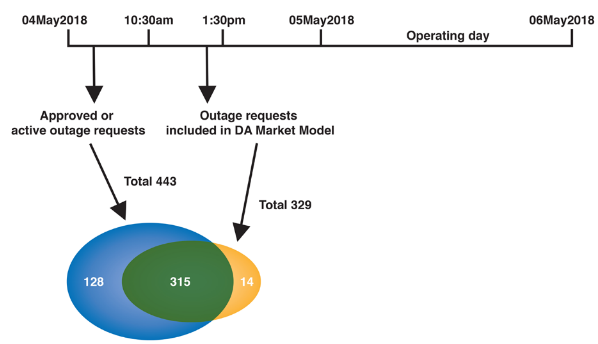
Transmission Facility Outage Analysis in the Day-Ahead Energy Market

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.[93]

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 12-6 shows that: there were 443 approved or active outages seen by market participants before the day-ahead market was closed; there were 329 outage requests included in the day-ahead market model; there were 315 outage requests included in both sets of outage; there were 128 outage requests approved or active before the day-ahead market was closed but not included as inputs in day-ahead market model; and there were 14 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

Figure 12-6 Illustration of day-ahead market analysis: May 5, 2018



93 PJM, "Manual 3: Transmission Operations," Rev. 58 (Jan. 19, 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 included as inputs to the day-ahead market by PJM.

Figure 12-7 Approved or active outage requests: January 2015 through December 2020

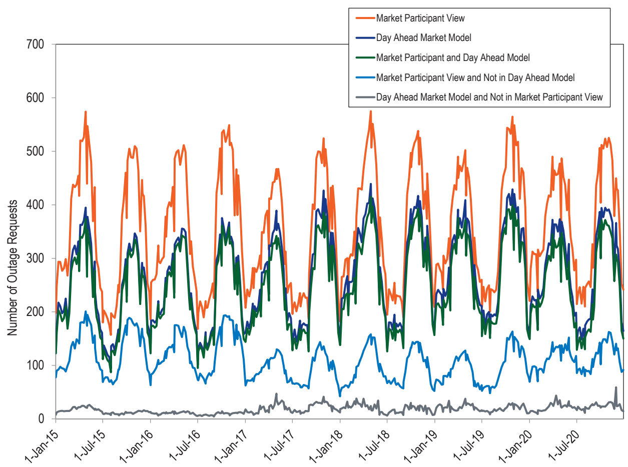


Figure 12-8 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-8 Day-ahead market model outages: January 2015 through December 2020

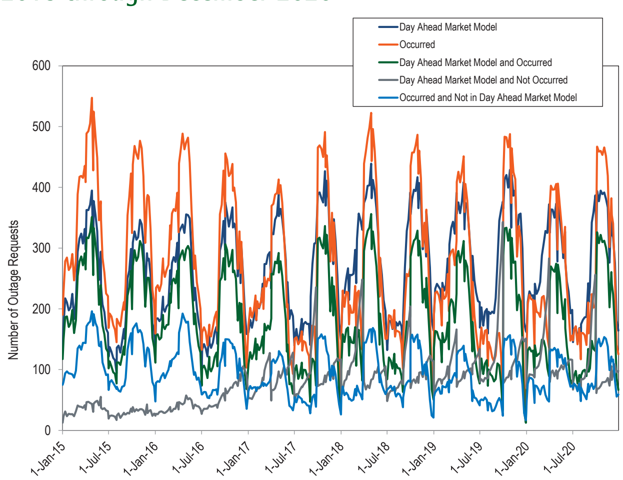


Figure 12-9 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-9 Approved or active outage requests: January 2015 through December 2020

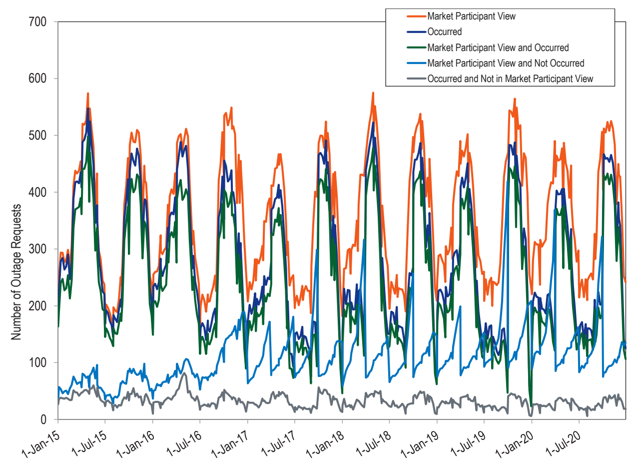


Figure 12-7, Figure 12-8, and Figure 12-9 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or 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 low cost generation receives payment only for its low local price and does not receive the payment made by load for the output of the low cost generation at the high local price. The result is that load pays the correct local price but pays too much in total for energy because it is paying more for the low cost generation than the low cost generation receives. Load pays the difference between the high local price and the low local price of the low cost generation. That payment is appropriately not made to the low cost generation which is paid its LMP. In an LMP market, load pays more than generation receives. FTRs are the mechanism for returning those excess payments to load. But the current FTR mechanism in PJM does not and cannot return all the excess payments to load. The FTR mechanism in PJM needs a significant redesign in order to achieve that objective. The FTR mechanism has become unduly complicated and has deviated significantly from its original purpose. Return of all the excess payments to load would result in a perfect hedge against congestion. The current FTR mechanism has significantly attenuated the value of the FTR/ARR design as a hedge against congestion for load.

The FTR mechanism should be a simple accounting method for assigning congestion rights to load. But PJM has 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. Some market participants have profited in various ways from these design flaws and those market participants 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, both under cost of service rates, and on contracts with specific remote generation outside the local zone and the associated point to point transmission contracts. 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 combined day-ahead and balancing (real-time) markets. FTRs permitted the loads, which pay for the transmission system, to continue to receive the benefits of access to either local or remote low cost generation by returning congestion to the load.[1] FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load was required to pay more for low cost generation than is paid to low cost generation. But there was a flaw built in from the very beginning of the FTR design that had no significant impact initially but which was ultimately the source of all the issues with the FTR mechanism. That flaw was the idea that congestion was based on contract paths in a network system rather than a result of the actual operation of the complex network. The flaw was especially ironic given that most load was served by intrazonal generation subject to cost of service regulation rather than contracts with extrazonal generation. That flaw was inconsistent with the most basic logic of LMP and the resultant fissure has continued to widen. The origin of FTRs was the recognition that the way to hold load harmless from making the excess payments created by the LMP system was to return the excess payments to load. The rights to congestion belong to load. If implemented correctly, FTRs would be the financial equivalent of firm transmission service for load. If implemented correctly, FTRs would be a perfect hedge against congestion for load. The result of the current FTR mechanism is a significant reduction in the value of FTRs as a hedge for load.

1 See 81 FERC ¶ 61,257 at 62,241 (1997).

The notion that FTRs exist in order to provide a hedge for generation is a fallacy. In an LMP system, the basic incentive structure for generation derives from the fact that generation is paid the LMP at the generator bus. If generation were to be guaranteed a price at a distant constrained load bus rather than at the generation bus, there would be no incentive for generation to locate where it is needed on the system. In addition, the payment of the price at the generator bus is fundamental to the logic of locational marginal pricing which produces local prices equal to the marginal value of generation at every point. There is no logical or theoretical basis in locational marginal pricing for the assertion that generation at low price nodes is underpaid and should be paid more from congestion dollars. Generation does not pay congestion. Some generation receives a price lower than the system marginal price (SMP) and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP. If a generating unit wants a hedge, it may enter into an arm's length transaction with a willing counter party as a hedge. That is the way hedges work in markets. That is not the purpose of FTRs.

In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. FTRs were the mechanism selected in PJM to offset the congestion costs that load pays in an LMP market. Congestion revenues are the source of the funds to pay FTRs. Congestion revenues are assigned to the load that paid them through FTRs.[2] The only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to ensure that all congestion revenues are returned to load or, more precisely, that the rights to all congestion revenues are assigned to load. In order to do that, congestion must be defined correctly based on the operation of the network and not on arbitrary contract paths.

Effective April 1, 1999, when FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and balancing (real-time) congestion to load. Congestion, in PJM's two settlement market, is the sum of day-ahead and balancing congestion. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). Under the ARR 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.

ARRs were an add on concept, defined based on a misunderstanding of FTRs, which had its roots in the assignment of congestion to load using contract paths (generation to load paths) rather than on the calculation of congestion actually paid. ARRs used assumed contract paths to assign congestion to load. The use of contract paths for ARRs was a more critical mistake than using contract paths for FTRs because contract paths did not and do not account for all congestion. The use of contract paths led to the mistaken conclusion that some congestion did not belong to load and could be sold to FTR buyers. The ARR concept, as it is currently implemented, does not allow the FTR sellers, load, to establish a price at which they are willing to sell, but forces load to accept whatever prices buyers are willing to pay. The revenue from the sale of congestion rights is not even paid in full to ARR holders. Sellers are required to return some of the cleared auction revenue to FTR buyers when FTR profits are not adequate. So called surplus revenue is paid to FTR holders to ensure payment despite the fact that willing FTR buyers paid the revenues in the auction for the rights to an uncertain level of congestion.

The use of generation to load contract paths rather than the direct calculation of congestion led to an increased divergence between the congestion on the generation to load contract paths and total congestion. This divergence between actual network use and

2 See *id.* at 62, 259–62,260 & n. 123.

historic contract paths was exacerbated as new zones were added with their own historic generation to load contract paths and as significant numbers of generating units retired and new units were added.[3] Rather than understanding that the divergence resulted from the fact that a contract path based approach did not correctly calculate congestion in a network system, especially as the system grew significantly, the issue was characterized as the existence of excess capacity on the transmission system. But congestion was never about capacity on the transmission system. Prior to the introduction of ARRs, the so called excess congestion that exceeded the congestion on the defined contract paths was returned to load, regardless of its source. There is no such thing as excess congestion. The overlay of ARRs on the FTR concept did not change the fundamental logic of congestion, but permitted the introduction of a system in which the divergence was formally created between the amount of congestion paid by load and the amount of congestion returned to load. Congestion belongs to the load, by definition. The introduction of ARRs based on a contract path fiction undermined the assignment of all congestion rights to load.

The contract path fiction is also the source of the incorrect definition of the product that is bought and sold as FTRs, the available supply of the product and the price paid to the buyers of the product. The product is defined as the difference in congestion prices across specific transmission contract paths. The difference in congestion prices across contract paths is not congestion and is not equal to congestion revenues. The quantity of the product made available for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. This fundamental confusion in the design of the market is the source of so called revenue shortfalls, of the redesign of the market to exclude balancing congestion, and of the need for PJM to intervene in the market. PJM has had to regularly intervene in the market because the market as designed cannot reach equilibrium based on the economic fundamentals. The product, the quantity of the product and the price of the product are all incorrectly defined.

The ARR/FTR design does not serve as an efficient mechanism for returning congestion to load, as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its introduction. The distortions include the definition of target allocations based on day-ahead congestion only, the fact that ARR holders cannot set the sale price for congestion revenue rights, the return of market revenues to FTR buyers when profit targets are not met, the failure to assign all FTR auction revenues to ARR holders, the differences between modeled and actual system capability, the definition and allocation of surplus, and the numerous cross subsidies among participants. The fundamental distortion was the assignment of the rights to congestion revenue based on specific generation to load transmission contract paths. This approach retained the contract path based view of congestion rooted in physical transmission rights and inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

The cumulative offset by ARRs for the 2011/2012 planning period through the first seven months of the 2020/2021 planning period, using the rules effective for each planning period, was 74.9 percent. Load has been underpaid by $2.2 billion from the 2011/2012 planning period through the first seven 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 contract paths, and if the distortions subsequently introduced into the FTR design had not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in

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>.

the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy. The design should simply have provided for the return of all congestion revenues to load. The design should have also provided for the ability of load to sell the rights to congestion revenue. That sale could be organized as an FTR auction with the product and the price clearly defined. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

The *2020 State of the Market Report for PJM* focuses on the 2020/2021 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2020, through December 31, 2020.

Table 13-1 The FTR/ARR markets results were partially competitive

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

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 2020/2023 Long Term FTR Auction, the 2020/2021 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and moderately concentrated for the 2020/2021 Annual FTR Auction. Ownership of FTRs is disproportionately (75.4 percent) by financial participants. The ownership of ARRs is unconcentrated.
- Participant behavior was evaluated as partially competitive as a result of the behavior of GreenHat Energy, LLC. Supply side participants are not permitted to participate in the market clearing.
- Market performance was evaluated as partially competitive because of the flaws in the market design. Sellers cannot set a sale price. Buyers can reclaim some of their purchase price after the market clears if the product does not meet a profitability target. The market resulted in a substantial shortfall in congestion payments to load and significant and unsupportable disparities among zones in the share of congestion returned to load. FTR purchases by financial entities remain persistently profitable in part as a result of the flaws in the market design.
- Market design was evaluated as flawed because there are significant and fundamental flaws with the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Buyers have the ability to reclaim some of the price paid for FTRs after the market clears. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. The product sold to FTR buyers is incorrectly defined as target allocations rather than a share of congestion revenue. ARR holders' rights to congestion revenues are not correctly defined because the contract path based assignment of congestion rights is inadequate and incorrect. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue and a symptom of the fundamental flaws in the design. The product, the quantity of the product and the price of the product are all incorrectly defined.
- The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs and the fact that sellers are required to return some of the cleared auction revenue to FTR buyers when FTR profits are not adequate, means that the FTR design does not actually function as a market and is evidence of basic flaws in the market design.

Overview

Auction Revenue Rights

Market Structure

- **ARR Ownership.** In the 2020/2021 planning period ARRs were allocated to 1,392 individual participants, held by 131 parent companies. ARR ownership for the 2020/2021 planning period was unconcentrated with an HHI of 851.

Market Behavior

- **Self Scheduled FTRs.** For the 2020/2021 planning period, 25.4 percent of eligible ARRs were self scheduled as FTRs.

Market Performance

- **ARRs as an Offset to Congestion.** ARRs have not served as an effective mechanism to return all congestion revenues to load. For the first seven months of the 2020/2021 planning period, ARRs offset only 55.8 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. Load has been underpaid congestion revenues by $2.2 billion from the 2011/2012 planning period through the first seven months of the 2020/2021 planning period. The cumulative offset for that period was 74.9 percent of total congestion.
- **Revenue Adequacy.** For the first seven 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 $511.2 million, while PJM collected $681.4 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. 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.
- **Residual ARRs.** Residual ARRs are only available on contract paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first seven months of the 2020/2021 planning period, PJM allocated a total of 13,601.8 MW of residual ARRs with a total target allocation of $5.7 million, down from 14,390.3 MW in the first seven months of the 2019/2020 planning period, with a total target allocation of $5.6 million.
- **ARR Reassignment for Retail Load Switching.** There were 21,833 MW of ARRs associated with $290,500 of revenue that were reassigned in the first seven months of the 2020/2021 planning period. There were 24,341 MW of ARRs associated with $404,700 of revenue that were reassigned for the same time frame of the 2019/2020 planning period.

Financial Transmission Rights

Market Design

- **Monthly Balance of Planning Period FTR Auctions.** The design of the Monthly Balance of Planning Period FTR Auctions was changed effective with the 2020/2021 planning period. The new design includes auctions for each remaining month in the planning period. The prior design included auctions for the next three individual months plus remaining quarters.

Market Structure

- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 86.0 percent of prevailing flow and 88.9 percent of counter flow FTRs for January through December, 2020. Financial entities owned 75.4 percent of all prevailing and counter flow FTRs, including 68.7 percent of all prevailing flow FTRs and 83.9 percent of all counter flow FTRs during the period from January through December 2020. Self scheduled FTRs account for 3.9 percent of all FTRs held.
- **Market Concentration.** For prevailing flow obligation FTRs in the Monthly Balance of Planning Period Auctions for the first seven months of the 2020/2021 planning period, all market periods were unconcentrated. For counter flow obligation FTRs for the first seven months of the 2020/2021 planning period, 87.3 of periods were unconcentrated and 12.7 percent of periods were moderately concentrated. All periods were highly concentrated for FTR options. FTR options in the Annual FTR Auction were moderately concentrated.

Market Behavior

- **Sell Offers.** In a given auction, market participants can sell FTRs acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2020/2021 planning period, total participant FTR sell offers were 12,730,496 MW.
- **Buy Bids.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2020/2021 planning were 27,360,901 MW.
- **FTR Forfeitures.** Total FTR forfeitures were $2.2 million for the first seven months of the 2020/2021 planning period.
- **Credit.** There were seven collateral defaults in 2020, for a total of $82,019. There were 27 payment defaults in 2020 not involving GreenHat Energy, LLC for a total of $113,643. GreenHat Energy accrued payment defaults of $14.8 million in 2020 for a total of $161.8 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 $179.3 million.

Market Performance

- **Quantity.** In the first seven months of the 2020/2021 planning period, Monthly Balance of Planning Period FTR Auctions cleared 4,200,340 MW (15.4 percent) of FTR buy bids and 2,085,566 MW (16.4 percent) of FTR sell offers. For the first seven months of the 2019/2020 planning period, Monthly Balance of Planning Period FTR Auctions cleared 2,690,460 (15.9 percent) of FTR buy bids and 1,390,171 MW (21.1 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 seven months of the 2020/2021 planning period was $0.14 per MWh.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $31.6 million in the first seven months of the 2020/2021 planning period, down from $42.6 million for the same time period in the 2019/2020 planning period.
- **Revenue Adequacy.** FTRs were paid at 99.6 percent of the target allocation level for the first seven 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 seven months of 2020/2021 planning period, physical entities made $39.1 million profits on FTRs purchased directly (not self scheduled), up from $4.5 million profits for the same time period in the 2019/2020 planning period and financial entities made $141.3 million, up from $25.0 million profits for the same time period in the 2019/2020 planning period.

Markets Timeline

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Table 13-2 shows the date of first availability and final closing date for all annual ARR and FTR products.

Table 13-2 Annual FTR product dates

Auction	Initial Open Date	Final Close Date
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

Market Design

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a network design in which the rights to actual congestion are assigned directly to load by node. (Priority: High. First reported 2015. Status: Partially adopted.)

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.

- The MMU recommends that, under the current FTR design, the rights to all congestion revenue be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately. (Priority: High. First reported Q3, 2020. Status: Adopted 2021.)
- 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 continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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.)

Surplus

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[5] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

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

5 See "PJM Manual 6: Financial Transmission Rights," Rev. 26 (Jan. 27, 2021).

throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

FTR Liquidation

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

Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to load, without requiring contract path 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 contract 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. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by ARR holders of their congestion revenue rights.

Issues

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

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

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

Load should never be required to subsidize payments to FTR holders, regardless of the reason.[6] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[7] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. When combined with the direct assignment of both surplus day-ahead congestion

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).

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

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

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

A subsequent rule change was implemented that modified the allocation of surplus auction revenue to 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 total target allocations, and then distributed to ARR holders.[8] ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. While this rule change increased the level of congestion revenues returned to load, the rules do not fully recognize ARR holders' rights to congestion revenue. With this rule in effect for the first seven months of the 2020/2021 planning period, ARRs and FTRs offset 55.8 percent of total congestion.

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 contract paths to assign Stage 1A rights that have nothing to do with actual power flows.

Proposed Design

To address the issues with the current contract path based ARR/FTR market design, the MMU recommends that the current design be replaced with a 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. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by ARR holders of their congestion revenue rights.

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

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical

8 163 FERC ¶61,165 (2018).

load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is defined as the 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 auctions.

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

Under the MMU proposal, the LSE would be able to set reservation prices in the auction for the sale of portions or all of its 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 annual and/or monthly.

Auction Revenue Rights

Auction Revenue Rights (ARRs) are the mechanism used to assign congestion rights to load, using an archaic contract path based approach, and sell those rights to FTR buyers in various auctions. ARR values are based on nodal price differences established by cleared FTR bids in the Annual FTR Auction. ARR sellers have no opportunity to define a price at which they are willing to sell and must accept the prices as defined by FTR buyers. ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available supply. But some auction revenues may be returned to FTR buyers, despite the fact that FTR buyers willingly paid a defined price for FTRs. PJM has significant discretion over the level of supply made available to FTR buyers. The appropriate goals of that discretion should be significantly limited and defined clearly in the tariff.

ARRs are available only as obligations (not options) and only as a 24 hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between the ARR sink and source from the Annual FTR Auction.[9] ARR target allocations are a set value at the time of the Annual FTR Auction. It is logically possible for ARRs to be revenue inadequate if the money collected from the FTR auction is not enough to pay the entirety of ARR target allocations for the planning period. This is extremely unlikely and can only happen if there is a modeling difference between the system model used for ARRs and the system model used for FTRs and the FTR MW are reduced. An ARR's target allocation, or value, which is established from the Annual FTR Auction, can be a benefit or liability depending on the price difference between sink and source.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives the rights to all congestion revenues. In the current design, all auction revenues should be paid to ARR holders.

The quantity of the product made available as ARRs or for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. The concept of system capability is not relevant to assigning the rights to congestion revenues to load. The use, or misuse, of the concept of system capability in assigning ARRs is derived entirely from the contract path approach used in the PJM design. The definition of ARRs based on contract

9 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints.

paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. In the current approach, system capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model. PJM's annual FTR transmission market model represents annual, expected system capability, modified by PJM to achieve PJM's goal of guaranteeing revenue equal to target allocations for FTRs, and subject to the requirement that all Stage1A ARR requests must be allocated. Stage 1A ARR right requests are guaranteed and system capability necessary to accommodate the rights must be included in PJM's annual FTR transmission system market model.

Market Design

ARRs have been available to network service and firm, point to point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003/2004 planning period. The initial allocation covered the Mid-Atlantic Region and the APS Control Zone. 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.

Each March, PJM allocates annual ARRs to eligible customers in a three stage process: Stage 1A, Stage 1B and Stage 2B. Stage 1A ARRs are assigned based on historic contract paths and Stage 1A ARRs must be preserved for at least 10 planning periods regardless of system or regulatory changes.[10]

In Stage 1A, LSEs can obtain ARRs, based on their lowest daily peak load in the prior twelve month period, and based on generation to load contract paths that reflect generation resources that had historically served load, or their qualified replacements if the resource has retired and PJM has replaced it. The historical reference year is the year in which PJM markets were implemented, which is 1999 for the original zones, or the year in which a zone joined PJM. Firm, point to point transmission service customers can obtain Stage 1A ARRs, up to 50 percent of the MW of firm, point to point transmission service provided between the receipt and delivery points for the historical reference year, subject to a cap of lowest daily peak load in the prior year. Network service customers can obtain Stage 1A ARRs based on the MW of firm service provided during the reference year, subject to a cap of lowest daily peak load in the prior year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[11]

In Stage 1B, network transmission service customers can obtain ARRs based on their share of zonal peak load, based on generation to load contract paths, up to the difference between their share of zonal peak load and Stage 1A allocations. Firm, point to point transmission service customers can obtain ARRs based on the MW of long-term, firm, point to point service provided between the receipt and delivery points for the historical reference year.

In Stage 2, network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone up to their total peak network load in that zone. Firm, point to point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

When ARR holders self schedule FTRs, the ARR holders choose to be paid based on variable target allocations rather than the fixed ARR value determined in the annual FTR auction. ARR holders can self schedule ARRs as FTRs during the Annual FTR Auction.[12] ARRs can be traded between LSEs prior to the first round of the Annual FTR Auction.

Effective for the 2015/2016 planning period, when residual zonal pricing was introduced, ARRs default to sinking at the load settlement point if different than the zone, but the ARR holder may elect to sink their ARR at the zone instead.[13]

In 2016, FERC ordered PJM to remove retired resources from the generation to load contract paths used to allocate Stage 1A ARRs.[14] PJM replaced retired units

10 See "PJM Manual 6: Financial Transmission Rights," Rev. 26(Jan 27, 2021 at 23.

11 See "PJM Manual 6: Financial Transmission Rights," Rev 26 (Jan. 27, 2021).
12 OATT Attachment K 7.1.1.(b).
13 See "PJM Manual 6: Financial Transmission Rights," Rev. 26 (Jan 27, 2021) at 35.
14 156 FERC ¶ 61,180 (2016).

with operating generators, termed qualified replacement resources (QRRs).[15] Existing Stage 1A resources retain their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources are prorated based on the feasibility of these ARRs after existing resources are allocated. As a result of this proration, ARRs for QRRs have lower priority than ARRs from generators that existed in 1998.

Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load contract paths should not be used as a basis for assigning the rights to congestion revenue. Contract paths are not an accurate representation of the reasons that congestion revenues are paid or of how load is served in a network and will, by definition, not accurately measure the exposure of load to congestion.

Market Structure

ARRs are allocated on an annual basis. For the 2020/2021 planning period there were 1,392 individual participants, held by 131 parent companies.

The ownership of ARRs was unconcentrated, with an HHI of 851, for the 2020/2021 planning period.

Market Performance

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a year, but guaranteed for 10 years, with the ability for a participant to opt out of any planning period within the 10 years. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required to ensure that the long term ARRs can remain feasible. The rules provide that if a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process. But such transmission upgrades must pass PJM's RTEP process.

PJM's transmission planning process (RTEP) does not identify a need for new transmission associated with Stage 1A overallocations because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows. This continues to be true even with the replacement of retired generating units.

For the 2019/2020 planning period, Stage 1A of the Annual ARR Allocation was infeasible, resulting in an over allocation of ARRs on the affected facilities. As a result, modeled system capability, in excess of actual system capability, was provided to the Stage 1A ARRs and added to the FTR auction. According to Section 7.4.2 (i) of the OATT, the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and these increased limits must be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances.

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, an LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs and residual ARRs within the control zone based on the shifted load.[16] ARRs are reassigned to the nearest 0.001 MW and may be reassigned multiple times over a planning period. The reassignment of positively valued ARRs supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, the self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may result in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 31,683 MW of ARRs associated with $657,300 of revenue that were reassigned for the 2019/2020 planning period. There were 21,833 MW of ARRs associated with $290,500 of revenue that were reassigned in the first seven months of the 2020/2021 planning period.

15 See FERC Docket No. EL16-6-003.

16 See "PJM Manual 6: Financial Transmission Rights," Rev. 26 (Jan. 27, 2021).

Table 13-3 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2019 and December 2020.

Table 13-3 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2019 through December 2020

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2019/2020 (12 months)	2020/2021 (7 months)	2019/2020 (12 months)	2020/2021 (7 months)
AECO	373	311	$4.8	$1.7
AEP	5,435	1,987	$151.0	$13.0
APS	1,383	1,041	$39.4	$13.2
ATSI	2,865	1,909	$42.6	$11.3
BGE	2,252	1,802	$103.9	$126.3
ComEd	2,583	1,874	$27.1	$10.6
DAY	765	403	$9.3	$2.1
DEOK	839	559	$58.3	$13.7
DLCO	1,622	1,253	$5.8	$3.5
Dominion	632	420	$6.2	$4.1
DPL	702	533	$52.2	$8.5
EKPC	0	0	$0.0	$0.0
JCPL	1,032	629	$4.8	$2.2
Met-Ed	540	360	$5.6	$1.3
OVEC	0	0	$0.0	$0.0
PECO	3,196	3,022	$24.8	$18.0
PENELEC	570	396	$15.7	$4.2
Pepco	1,947	1,352	$35.4	$18.7
PPL	3,538	2,819	$38.3	$30.6
PSEG	1,340	1,069	$31.8	$7.5
RECO	69	95	$0.2	$0.1
Total	31,683	21,833	$657.3	$290.5

Residual ARRs

Introduced August 1, 2012, Residual ARRs are available for eligible ARR holders when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility returns to service during the planning period. Residual ARRs can only be allocated to participants whose ARRs were prorated in Stage 1B and only to a maximum of the prorated reduction, so not all available Residual ARRs are allocated. Residual ARRs are automatically assigned to eligible participants the month before the effective date, are effective for a single month and cannot be self scheduled. Residual ARR target allocations are based on the clearing prices from FTR obligations in the relevant monthly auction, may not exceed zonal network services peak load or firm transmission reservation levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation. For the following planning period, these Residual ARRs are available as ARRs in the annual ARR allocation. Residual ARRs are a separate product from incremental ARRs. Beginning with the June 2017 monthly auction, Residual ARRs that would have cleared with a negative target allocation are not assigned to participants.[17] In prior planning periods, PJM's modeling of excess outages in order to manage FTR market outcomes resulted in the allocation of some ARRs that would have been allocated in Stage 1B being allocated as Residual ARRs on a month to month basis without the option to self schedule.

Table 13-4 shows the Residual ARRs allocated to participants and the associated target allocations. The available volume is the total additional capacity available to be allocated as Residual ARRs. The cleared volume is the residual ARR capacity actually allocated to participants with prorated ARRs based on the level of prorated ARRs in Stage 1B and the affected paths. In the first seven months of the 2020/2021 planning period, PJM allocated a total of 13,601.8 MW of Residual ARRs with a target allocation of $5.7 million. In the same time period for the 2019/2020 planning period, PJM allocated a total of 14,390.3 MW of residual ARRs with a target allocation of $5.6 million.

Table 13-4 Residual ARR allocation volume and target allocation: 2014/2015 planning period through 2020/2021 planning period

Planning Period	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
2014/2015	65,095.3	22,532.9	34.6%	$8,160,918.27
2015/2016	61,807.0	37,042.4	59.9%	$8,620,353.27
2016/2017	71,000.7	35,034.9	49.3%	$6,986,723.44
2017/2018	81,040.8	39,597.4	48.9%	$17,497,625.78
2018/2019	49,646.9	27,335.6	55.1%	$11,817,002.00
2019/2020	48,286.5	27,233.2	56.4%	$12,369,580.58
2020/2021*	26,483.5	13,601.8	51.4%	$5,733,750.56

* First seven months of 2020/2021 planning period

IARRs

In theory, Incremental Auction Revenue Rights (IARRs) are ARRs made available by physical transmission system upgrades from customer funded transmission projects or from merchant transmission or generation interconnection requests. In order for a transmission project to result in IARRs, the project must create simultaneously feasible incremental market flow capability in PJM's ARR market model, over and above all system capability being used by existing allocated

17 See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

ARRs and/or would be used by granting any prorated outstanding ARR requests, in the ARR market model.[18]

There are three sources of IARRs: IARRs based on a specific transmission investment; IARRs based on merchant transmission or generation interconnection projects; and IARRs based on RTEP upgrades. In the case of a specific transmission investment, the participant elects desired IARR MW between a specified source and sink and PJM and the affected transmission owners determine the upgrades necessary to create incremental capability.[19] In the other two cases, the participants paying for the upgrades are assigned IARRs if any are created. There have been 13 successful IARR requests totaling 2,990.1 MW. One IARR path of 64.5 MW was terminated (June 1, 2012), leaving 12 unique source and sink combinations of 2,925.6 MW of IARRs. Of these 12 unique paths, three paths consisting of 1,200.0 MW were based on specific transmission investments requests, six paths consisting of 1,047.4 MW were based on merchant transmission requests and three paths consisting of 678.6 MW were based on customer funded (RTEP) transmission projects. The three paths based on specific transmission investments involved a generation company working with its affiliated transmission company. The other nine paths were based on projects that would have been built regardless of the addition of IARRs.

The MMU supports increased competition to provide transmission using market mechanisms. The IARR process is not a viable mechanism for facilitating competitive transmission investments. Maintaining the IARR process impedes the search for real solutions. PJM's process for creating and assigning IARRs is fundamentally flawed and cannot be made consistent with the requirements of Order No. 681 which established IARRs.[20]

Order No. 681 requires that long-term firm transmission rights made feasible by transmission upgrades or expansions be available upon request to the party that pays for such upgrades or expansions.[21] Order No. 681 also requires that the rights granted by upgrades/expansions cannot come at the expense of transmission rights held by others. IARRs are treated as Stage 1A rights, which are given first and absolute priority in PJM's annual allocation process. Granting Stage 1A status to IARRs is preferential treatment of IARR rights relative to the ARR rights belonging to load. If the annual market model used to assign existing ARR rights in a given year cannot simultaneously support all Stage 1A ARR requests, the system model is modified so as to make the Stage 1A ARR requests feasible. The result is an over allocation of congestion rights relative to expected congestion. To avoid having FTR target allocations exceed expected congestion, PJM reduces the annual supply (market model system capability) available to non-Stage 1A rights through selective line outages and line rating reductions. The resulting market model artificially supports all the Stage 1A ARR requests and artificially reduces the amount of remaining later tier ARRs from other rights holders. Stage 1A ARRs, including IARRs, are approved at the expense of other preexisting congestion rights. In the case of IARRs, this is in violation of Order No. 681.

The MMU recommends that IARRs be eliminated from the PJM tariff. If IARRs are not eliminated, the MMU recommends that IARRs be subject to prorating like all other ARR rights rather than being exempt from prorating.

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the day-ahead energy market across specific FTR transmission paths. These day-ahead congestion price differences, multiplied by the FTR position in MW, are termed the FTR target allocations. The FTR target allocations define the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in day-ahead congestion prices (CLMPs) rather than the difference in LMPs, which includes both congestion and marginal losses. Negative target allocations require the FTR holder to make payments rather than receive revenues in the FTR market. One of the fundamental flaws in the FTR design is the mismatch between congestion and the differences in day-ahead prices between nodes.

18 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>.

19 See Attachment EE of the PJM Open Access Transmission Tariff <https://www.pjm.com/directory/merged-tariffs/oatt.pdf>.

20 See November 7, 2019 Comments on TranSource, LLC v. PJM, 168 FERC ¶ 61,119 (2019) ("Opinion No. 566").

21 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).

The difference in day-ahead congestion prices is not congestion. Target allocations are not congestion.

Under the current rules, the revenue available to pay FTR holders' target allocations in a given month includes day-ahead congestion, payments by holders of negatively valued FTRs, auction revenues greater than ARR target allocations, and any charges made to day-ahead operating reserves which occur where there are hours with net negative congestion. Any such revenue above FTR target allocations from prior months in a planning period are used to pay any current month shortfalls. Target allocations are a cap on payments to FTR holders for each planning period. At the end of each planning period, any surplus revenue above the target allocations is distributed to ARR holders.

FTR funding is not on a path specific basis or on an hour to hour basis and treats all FTRs the same. For example, if the payout ratio is less than 1.0 at the end of the planning period, the payments to all FTRs are reduced. Payments are made pro rata based on target allocations. The result is widespread cross subsidies because assignment of path specific FTRs may exceed system capability and affect the payments to FTRs on other paths. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months within a planning period. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning period.

Auction market participants may offer to buy FTRs between any eligible pricing nodes on the system, as defined by PJM for each auction. For the Annual FTR Auction and FTRs bought in the monthly auctions, the available FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. For the Long Term FTR Auction there is a more restricted set of available hubs, control zones, aggregates, generator buses and interface pricing points available. PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path. FTRs are available to the nearest 0.1 MW.

FTRs are bought from supply defined by PJM. The fact that load is selling congestion revenue rights is not fully recognized in the FTR design, although FTR buyers can resell FTRs at a price they agree to accept. Load has no role in defining the price at which PJM sells FTRs on their behalf. PJM's objective in the auctions is to maximize auction revenue, given the total set of bid prices and bid MW, but absent reservation prices from load. The failure to allow sellers the ability to decide at what price to sell FTRs is a fundamental flaw in the FTR market. The result is that PJM cannot actually maximize auction revenue and that the FTR market is not really a market.

Once bought from PJM, FTRs can be bought and sold. Buy bids are bids to buy FTRs in the auctions. Sell offers are offers to sell existing FTRs in the auctions.

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. There is no requirement to report bilateral transactions, or any information about them, to PJM.

Supply and Demand

Total FTR supply in each auction is limited by the definition of the transmission system capacity included in the PJM FTR market model as modified, for example, by PJM assumptions about transmission outages, for which there are no clear rules. PJM may also limit available transmission capacity through subjective judgment exercised without any clear guidelines.

The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs.

The FTR auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages.[22] In addition, it is difficult to model in an annual auction two outages of similar significance and

22 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.

similar duration in different areas which do not overlap in time. The choice of which to model will generally have significant distributional consequences; they will affect different areas very differently. The fact that outages are modeled at significantly lower than historical levels results in selling too much FTR capacity, which creates downward pressure on ARR prices. To address this issue, the MMU recommends that PJM use probabilistic outage modeling to better align the supply of ARRs and FTRs with actual expected transmission capacity.

Long Term FTR Auctions

In July 2006, FERC 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). FERC's goal was that "load serving entities be able to request and obtain transmission rights up to a reasonable amount on a long-term firm basis, instead of being limited to obtaining exclusively annual rights." Despite that order and inconsistent with the directive in that order, LSEs are not able to request ARRs nor are LSEs guaranteed rights to the revenue from Long Term FTR Auctions in PJM's long term FTR auction market design. Excess system capability in years two and three of the long term FTR auction is never made available to load in the form of ARRs and are only made available to FTR buyers.

PJM conducts the Long Term FTR Auction for the next three consecutive planning periods. The Long Term FTR Auction consists of five rounds beginning in June of the preceding planning period and continuing through March. FTRs purchased in prior rounds or Long Term Auctions may be offered for sale in subsequent rounds of the long term, annual or monthly FTR auctions. FTRs obtained in the Long Term FTR Auctions have terms of one year. FTR products available in the Long Term Auction include 24 hour, on peak and off peak FTR obligations, with FTR options unavailable in the Long Term FTR Auctions.

Beginning with Round 2 of the 2019/2022 Long Term FTR Auction, PJM implemented revisions to the determination of residual system capability made available in the Long Term FTR Auctions, and eliminated the YRALL product, consistent with the MMU's recommendation. The revisions affect the determination of ARR rights reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM reruns the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year's ARR requests, prorated when necessary, and uses the resulting ARRs as the basis for reserving capability for ARR holders in the Long Term FTR Auction. The ARR requests are greater than the previously cleared ARRs. The difference between the requested ARRs and the ARR/FTR market model's transmission system capacity, both without outages, determines the residual capability offered in the Long Term FTR Auction. The revisions provide ARR holders with more congestion rights in the Long Term FTR Auction that will carry into the Annual FTR Auction.

But the revisions do not address the congestion revenue rights sold in years two and three of the Long Term FTR Auction, which remain unavailable to ARRs. Capacity awarded in the Long Term FTR Auction is unavailable as ARRs in years two and three. As a result, the rights to significant congestion revenues are still assigned to the Long Term FTR Auction without ever having been made available to ARR holders. That outcome is inconsistent with the basic logic of ARRs and inconsistent with the stated intent of the market design which is to return all congestion revenues to load.

Long Term FTR Auction transmission capacity is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids from the prior annual ARR allocation. Any ARR MW that clear in this offline model are reserved for ARR holders in the relevant planning periods, and are removed from the Long Term FTR Auction capability. Even this approach does not, and cannot, preserve all possible capacity for ARR holders in the first year of the Long Term Auction due to changes in system topology and outage selection between planning periods. PJM outage assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs in the Annual FTR Auction.

Annual FTR Auctions

Annual FTRs are effective for an entire planning period, June 1 through May 31. Outages expected to last two or more months, as well as any outages of a shorter duration that PJM decides would cause FTR revenue inadequacy if not modeled, are included in the determination of the simultaneous feasibility for the

Annual FTR Auction.[23] While the full list of outages selected is publicly posted, PJM exercises significant subjective judgment in selecting outages to accomplish FTR revenue adequacy goals and the process by which these outages are selected is not clear, is not defined and is not documented. ARR holders who wish to self schedule must inform PJM prior to round one of the annual auction. Any self scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. The Annual FTR Auction consists of four rounds that allow any PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24 hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

Monthly Balance of Planning Period FTR Auctions

Total Monthly FTR Auction capacity is based on the residual capacity available after the Long Term and Annual FTR auctions are conducted and adjustments are made to outages to reflect anticipated system conditions for the time periods auctioned. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Before the 2020/2021 planning period, the first three individual months, 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.[24]

Bilateral Market

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. There is currently no requirement to report bilateral transactions, or any information about them, to PJM. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system. Bilateral transactions not reported to PJM are dependent on the contract established between the parties.

For bilateral trades reported to PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. Bilateral FTRs reported to PJM can also include more restrictive start and end times, meaning that the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

FTR Bid Limits

PJM has the authority to limit participant's bids to 5,000 to avoid or mitigate significant system performance problems related to bid/offer volume.[25] 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. On December 11, 2019, PJM made an informational announcement to urge participants to respect the rule.[26] Some participants continued to exceed the limit in 2020 through the use of multiple affiliates, although the number of such participants was significantly reduced. On October 26, 2020, the MMU informed stakeholders that it had notified companies that violated the limits persistently that the companies should comply, and recommended that PJM enforce the limit.[27] On November 5, 2020, PJM proposed to add a language in PJM Manual 6 regarding the bid limit.[28] The MMU recommends that PJM enforce the FTR auction bid limits at the corporate family level starting immediately.

23 See "PJM Manual 6: Financial Transmission Rights," Rev. 26 (Jan. 27, 2021).
24 See "PJM Manual 6: Financial Transmission Rights," Rev. 26 (Jan. 27, 2021).

25 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.
26 *See* "Informational Update: FTR Auction Bid Limits," PJM Presentation to the Market Implementation Committee (December 11, 2019) <https://www.pjm.com/-/media/committees-groups/committees/mic/20191211/20191211-item-06-ftr-auction-bid-limits.ashx>.
27 *See* "Market Monitor Report," IMM Presentation to the Members Committee (October 26, 2020) <https://www.pjm.com/-/media/committees-groups/committees/mc/2020/20201026-webinar/20201026-item-07-imm-report.ashx>.
28 *See* "Manual 6, Revision 26: FTR Auction Bid Limits," PJM Presentation to the Market Implementation Committee (November 5, 2020) <https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20201105/20201105-item-05a-m6-updates-ftr-bid-limits.ashx>.

Market Structure

In order to evaluate the ownership of FTRs, the MMU categorizes all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks, trading firms and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 13-5 presents the monthly balance of planning period FTR auction cleared FTRs for 2020 by trade type, organization type and FTR direction. Financial entities purchased 86.0 percent of prevailing flow FTRs, up 11.7 percentage points, and 88.9 percent of counter flow FTRs, up 7.7 percentage points, from 2019, with the result that financial entities purchased 87.4 percent, up 11 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: 2020

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	14.0%	11.1%	12.6%
	Financial	86.0%	88.9%	87.4%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	8.3%	10.2%	8.9%
	Financial	91.7%	89.8%	91.1%
	Total	100.0%	100.0%	100.0%

Table 13-6 shows the HHI values for cleared obligation MW for the first seven months of the 2020/2021 planning period monthly auctions by month for prevailing flow FTRs. Cleared buy prevailing flow bids were unconcentrated in all of the months.[29]

Table 13-6 Monthly Balance of Planning Period FTR Auction HHIs by period for prevailing flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-20	359	415	446	591	720	625	855	686	763	752	686	768
Jul-20		322	370	434	505	506	675	602	577	629	585	565
Aug-20			349	390	404	435	539	505	512	538	514	507
Sep-20				343	398	436	519	614	621	591	648	571
Oct-20					400	398	409	393	442	623	659	682
Nov-20						393	488	480	610	809	793	929
Dec-20							423	417	444	512	561	586

Table 13-7 shows the HHI values for cleared obligation MW for the first seven months of the 2020/2021 planning period monthly auctions by month for counter flow FTRs. Cleared buy counter flow bids were unconcentrated in 87.3 percent and moderately concentrated in 12.7 percent of the months.

Table 13-7 Monthly Balance of Planning Period FTR Auction HHIs by period for counter flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-20	655	636	806	771	914	905	1012	772	831	939	1007	974
Jul-20		553	523	659	705	717	754	707	695	741	838	852
Aug-20			573	533	588	598	633	620	633	738	727	704
Sep-20				631	598	593	726	756	797	803	881	901
Oct-20					686	657	603	803	852	1020	994	970
Nov-20						819	778	836	914	1135	1303	1261
Dec-20							930	774	814	889	1091	1222

29 See *2020 Quarterly State of the Market Report for PJM*, Section 3: Energy Market, Competitive Assessment for HHI definitions.

Table 13-8 shows the average daily FTR ownership for all FTRs for 2020, by FTR direction and self scheduled FTRs.

Table 13-8 Daily FTR held position ownership by FTR direction: 2020

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	13.8%	7.0%	20.8%
Physical Self Scheduled	3.8%	0.1%	3.9%
Financial	38.6%	36.8%	75.4%
Total	56.2%	43.8%	100.0%

Market Performance

Volume

PJM regularly intervenes in the FTR market based on subjective judgment which is not based on clear or documented guidelines. Such intervention in the FTR, or any market, is not appropriate and not consistent with the operation of competitive markets. In an apparent effort to manage FTR revenues, PJM may adjust normal transmission limits in the FTR auction model. If, in PJM's judgment, the normal transmission limit is not consistent with revenue adequacy goals and simultaneous feasibility, then transmission limits are reduced pro rata based on the MW of Stage 1A infeasibility and the availability of auction bids for counter flow FTRs.[30] PJM may also remove or reduce infeasibilities caused by transmission outages by clearing counter flow bids without being required to clear the corresponding prevailing flow bids.[31] The use of both of these procedures is contingent on the conditions that: PJM actions not affect the revenue adequacy of allocated ARRs; all requested self scheduled FTRs clear; and net FTR auction revenue is positive.

Monthly Balance of Planning Period Auctions

Table 13-9 provides the monthly balance of planning period FTR auction market volume for the entire 2019/2020 and the first seven months of the 2020/2021 planning periods. There were 22,534,975 MW of FTR obligation buy bids and 9,961,365 MW of FTR obligation sell offers for all bidding periods in the first seven months of the 2020/2021 planning period. The monthly balance of planning period FTR auction cleared 3,925,039 (17.4 percent) of FTR obligation buy bids and 1,685,730 MW (16.9 percent) of FTR obligation sell offers.

There were 4,825,925 MW of FTR option buy bids and 2,769,131 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2020/2021 planning period. The ownership of options was highly concentrated in all periods. The monthly auctions cleared 275,301 MW (5.7 percent) of FTR option buy bids, and 399,836 MW (14.4 percent) of FTR option sell offers.

30 See "PJM Manual 6: Financial Transmission Rights," Rev. 27 (Jan. 27, 2021).
31 See *id.*

Table 13-9 Monthly Balance of Planning Period FTR Auction market volume: 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%
Oct-20	Obligations	Buy bids	635,571	2,994,497	528,759	17.7%	2,465,738	82.3%
		Sell offers	408,338	1,390,272	219,456	15.8%	1,170,816	84.2%
	Options	Buy bids	10,662	708,580	36,442	5.1%	672,138	94.9%
		Sell offers	51,216	369,217	49,746	13.5%	319,471	86.5%
Nov-20	Obligations	Buy bids	502,011	2,665,757	462,969	17.4%	2,202,788	82.6%
		Sell offers	357,028	1,272,840	205,630	16.2%	1,067,209	83.8%
	Options	Buy bids	8,246	630,368	27,818	4.4%	602,550	95.6%
		Sell offers	41,931	335,891	45,251	13.5%	290,640	86.5%
Dec-20	Obligations	Buy bids	474,537	2,208,554	398,153	18.0%	1,810,401	82.0%
		Sell offers	302,138	1,036,013	167,318	16.2%	868,695	83.8%
	Options	Buy bids	8,449	647,946	25,537	3.9%	622,409	96.1%
		Sell offers	34,237	292,582	40,212	13.7%	252,370	86.3%
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	4,950,577	22,534,975	3,925,039	17.4%	18,609,936	82.6%
		Sell offers	3,107,936	9,961,365	1,685,730	16.9%	8,275,635	83.1%
	Options	Buy bids	78,011	4,825,925	275,301	5.7%	4,550,625	94.3%
		Sell offers	441,708	2,769,131	399,836	14.4%	2,369,295	85.6%

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 40.7 percent of the prompt month bid volume.

Figure 13-1 Monthly Balance of Planning Period FTR Auction bid volume (MW per period): June through December, 2020 Auction

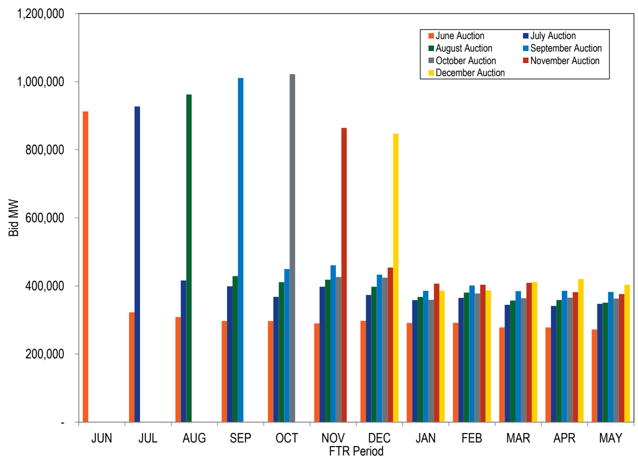
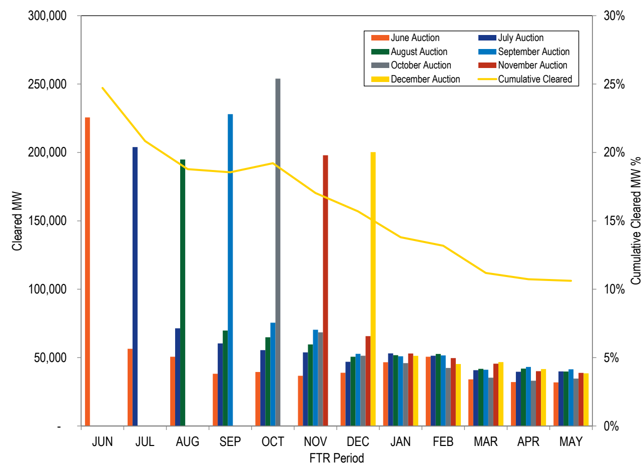


Figure 13-2 shows the cleared volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The cleared volume for non-prompt months is also significantly lower than in prompt months. On average, the non-prompt month cleared volume is 22.6 percent of the prompt month cleared volume.

Figure 13-2 Monthly Balance of Planning Period FTR Auction cleared volume (MW per period): June through December, 2020 Auction



Bilateral Market

Table 13-10 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 13-10 Secondary bilateral FTR market volume: 2019/2020 and 2020/2021[32]

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
		Off Peak	0.0
		Total	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

32 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 13-3 shows the FTR bid, net bid and cleared volume from June 2003 through December 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 December 2020

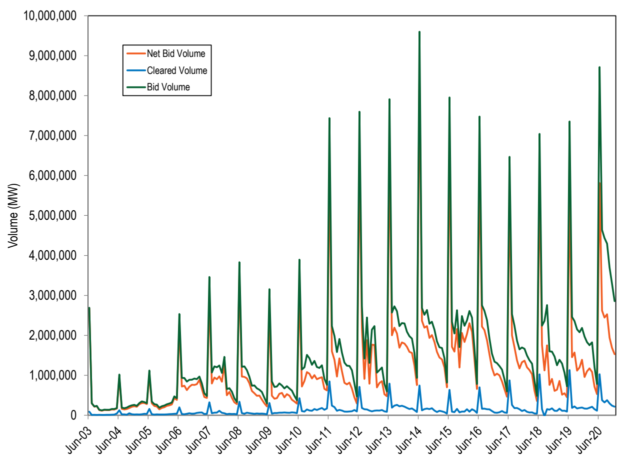
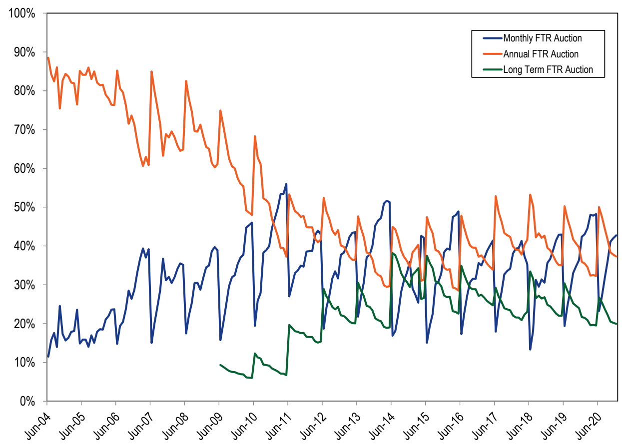


Figure 13-4 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through December 2020. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volumes spread equally to each month 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.

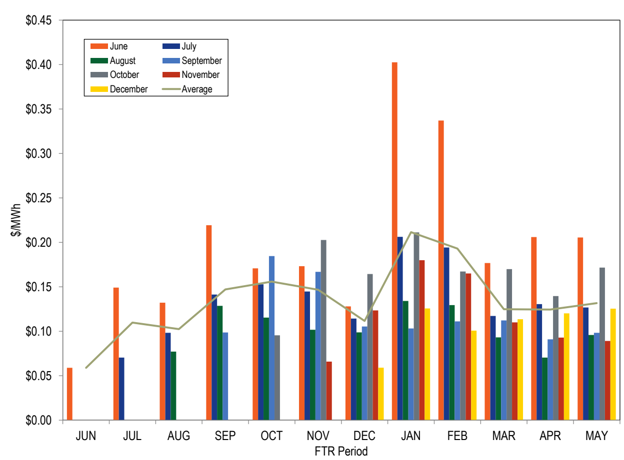
Figure 13-4 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through December 2020



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 seven 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. FTR profitability is relevant only to participants purchasing FTRs and is not relevant to self scheduled FTRs. For a prevailing flow FTR, the FTR revenue is the actual revenue that an FTR holder is paid as the target allocation plus the auction price from the sale of the FTR, if relevant, and the FTR cost is the auction price. For a counter flow FTR, the FTR revenue is the auction price that an FTR holder is paid to take the FTR plus the positive auction price from the sale of the FTR, if relevant, and the FTR cost is the target allocation that the FTR holder must pay plus the negative auction price from the sale of the FTR, if relevant. Profits include the payment of surplus to FTRs. Bilateral transactions are excluded from the profit calculations because there are inconsistent reporting requirements and no assurance that reported prices reflect the actual prices under the PJM rules. ARR holders that self schedule FTRs receive congestion revenues but do not receive profits from those FTRs because ARR holders are assigned the rights to congestion revenues which they choose to take directly as the congestion payments associated with the corresponding FTRs.

Hourly FTR profits are the sum of the hourly revenues minus the hourly costs for each FTR. 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. Revenues from the surplus are 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 13-13). 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 13-11 lists FTR profits, and the congestion returned through self scheduled FTRs, by organization type and FTR direction for the first seven 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 December 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 through December 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 $102.2 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 13-11 FTR profits and revenues by organization type and FTR direction: 2020/2021: June through December 2020

	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$90,794,341	$50,528,260	$141,322,601			
Financial without GreenHat	$90,793,495	$50,742,745	$141,536,240			
Physical	$30,623,624	($2,177,071)	$28,446,553			
Physical ARR	$18,981,886	($8,307,034)	$10,674,852	$102,175,029	($11,002)	$102,164,027
Total	$140,399,851	$40,044,155	$180,444,006	$102,175,029	($11,002)	$102,164,027

Table 13-12 lists the monthly FTR profits for the 2019/2020 planning period and the first seven months of the 2020/2021 planning period by organization type. FTR profits include revenue from FTR sales, but do not include any net end of planning period surplus distribution 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 seven months of the 2020/2021 planning period, profits for all participants were $180.4 million, up from $29.5 million 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 seven months of the 2020/2021 planning period, $116.4 million. The increase in profits was primarily a result of higher target allocations.

Table 13-12 Monthly FTR profits by organization type: 2019/2020 and 2020/2021[33]

	Organization Type				
Month	Financial	Financial without GreenHat	Physical	Physical ARR	Total
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
Oct-20	$9,277,479	$8,820,041	$5,351,521	($843,912)	$13,785,088
Nov-20	$7,421,871	$7,749,580	($3,695,203)	($2,396,979)	$1,329,689
Dec-20	$26,218,336	$26,428,773	$146,925	$2,536,264	$28,901,524
Summary for Planning Period 2020/2021					
Total	$141,322,601	$141,536,240	$28,446,553	$10,674,852	$180,444,006

33 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 13-13 lists the historical profits by calendar year by organization type beginning in the 2012/2013 planning period for purchased FTRs. (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 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 seven month of the 2020/2021 it was $82.6 million.

Table 13-13 FTR profits by organization type: 2012/2013 through 2020/2021[34]

		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)	$141,322,601
	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)	$141,322,601
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	$141,536,240
	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	$141,536,240
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)	$28,446,553
	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)	$28,446,553
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)	$10,674,852
	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)	$10,674,852
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)	$180,444,006

* Bilateral transactions are included in surplus allocation calculation but are not included in profits calculation
* The first seven months of the 2020/2021 planning period

Table 13-14 shows the profits and losses of the five most and the five least profitable participants by patterns of ownership. Total MWh is the sum of all MWh by ownership type regardless of profitability. The Top 5 Profit is the sum of the profits of the five most profitable participants by ownership type. The Top 5 Profit/MWh is the Top 5 Profit divided by the sum of the MWh of the top 5 participants by ownership type. The Top 5 Market Share of MWh is the sum of the MWh of the top 5 participants by ownership type divided by Total MWh. The Top 5 Profit Share Among Profitable Participants is the Top 5 Profit divided by the sum of the profits of all profitable participants by ownership type. The same logic applies for the statistics related to the Bottom 5 participants. The All row includes all participants including all ownership types when calculating the share of the profits and losses of the Top 5 and Bottom 5 participants. When all participants across ownership types are considered, all of the Top 5 participants are financial participants and three of the Bottom 5 participants are financial participants. Of all the ownership types, the Top 5 physical ARR participants' share of profits is the highest, 89.6 percent, as is their share of MWh, 57.5 percent. There are only a small number of physical ARR participants who directly purchase FTRs. The Bottom 5 financial participants' share of losses is the highest, 85.3 percent while and their share of MWh is 13.6 percent which is the same as the Bottom 5 physical participants' share of MWh. The losses from financial participants are concentrated in a small number of participants. The profit/MWh of the Top 5 physical participants was the highest, by ownership type. The loss/MWh of the Bottom 5 financial participants was the lowest, by ownership type while the loss/MWh of the Bottom 5 physical ARR participants was the largest.

34 Bilateral profits and losses net to zero in market total profits and losses.

Table 13-14 Top 5 and bottom 5 FTR profits by ownership type: 2020/2021, June through December

Organization Type	Total MWh	Top 5 Profit	Top 5 Profit/MWh	Top 5 Market Share in MWh	Top 5 Profit Share Among Profitable Participants	Bottom 5 Loss	Bottom 5 Loss/MWh	Bottom 5 Market Share in MWh	Bottom 5 Loss Share Among Unprofitable Participants
Financial	2,084,645,195	$63,691,590	$0.16	19.0%	35.2%	($33,770,710)	($0.12)	13.6%	85.3%
Financial without GreenHat	2,070,090,156	$63,691,590	$0.16	19.1%	35.2%	($33,770,710)	($0.12)	13.7%	85.8%
Physical	267,748,332	$26,841,579	$0.32	31.8%	59.9%	($10,367,525)	($0.28)	13.6%	63.5%
Physical ARR	249,499,763	$20,525,765	$0.14	57.5%	89.6%	($9,309,336)	($1.21)	3.1%	76.1%
All	2,601,893,290	$63,691,590	$0.16	15.2%	25.6%	($40,385,054)	($0.18)	8.6%	59.2%

Table 13-15 shows the shares of profitable and unprofitable FTR MWh by ownership type in the first seven months of the 2020/2021 planning period. All ownership type had more profitable MWh than unprofitable MWh.

Table 13-15 MWh share by profitability by ownership type: 2020/2021, June through December

Organization Type	Unprofitable	Profitable
Financial	17.8%	82.2%
Financial without GreenHat	17.2%	82.8%
Physical	25.2%	74.8%
Physical ARR	35.3%	64.7%
Total	20.2%	79.8%

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-16 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 seven months of the 2020/2021 planning period netted $31.6 million in revenue, the difference between buyers paying $189.0 million and sellers receiving $157.4 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 13-16 Monthly Balance of Planning Period FTR Auction revenue: 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
Oct-20	Obligations	Buy bids	$5,613,399	$6,564,945	$15,509,776	$27,688,120
		Sell offers	$940,976	$5,443,337	$12,777,260	$19,161,573
	Options	Buy bids	$7,279	$858,180	$1,067,208	$1,932,667
		Sell offers	$164,029	$1,836,917	$3,126,177	$5,127,122
Nov-20	Obligations	Buy bids	$3,177,603	$4,920,105	$9,841,409	$17,939,117
		Sell offers	$810,179	$3,045,305	$7,175,634	$11,031,119
	Options	Buy bids	$0	$496,305	$764,269	$1,260,574
		Sell offers	$60,356	$2,066,046	$2,715,436	$4,841,838
Dec-20	Obligations	Buy bids	$2,083,814	$3,242,885	$8,078,297	$13,404,996
		Sell offers	$957,012	$1,810,853	$5,642,246	$8,410,111
	Options	Buy bids	$54,774	$465,243	$508,638	$1,028,655
		Sell offers	$70,281	$1,414,743	$2,342,814	$3,827,838
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	$71,390,825	$38,521,237	$68,694,597	$178,606,659
		Sell offers	$4,912,877.77	$42,307,983	$70,367,541	$117,588,402
	Options	Buy bids	$167,756	$4,487,944	$5,736,091	$10,391,791
		Sell offers	$851,409	$16,711,342	$22,201,713	$39,764,464
	Net Total		$65,794,294	($16,010,145)	($18,138,565)	$31,645,584

* Shows Twelve Months for 2019/2020 **Shows seven 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 seven months of the 2020/2021 planning period. The top 10 sinks that produced financial benefit accounted for 36.6 percent of total positive target allocations with the Western Hub accounting for 10.7 percent of all positive target allocations. The top 10 sinks that created liability accounted for 15.4 percent of total negative target allocations with PSEG accounting for 4.3 percent of all negative target allocations.

Figure 13-6 Ten largest positive and negative FTR target allocations summed by sink: 2020/2021

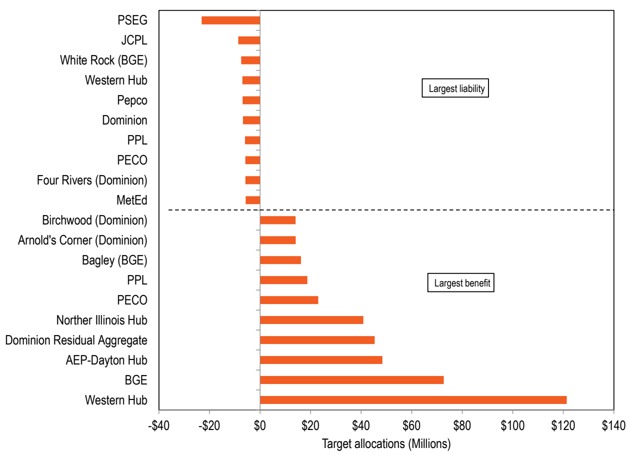
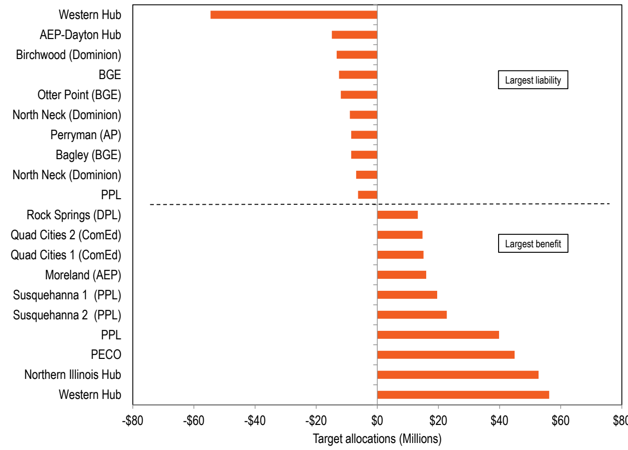


Figure 13-7 shows the 10 largest positive and negative FTR target allocations, summed by source, for the first seven months of the 2020/2021 planning period. The top 10 sources with a positive target allocation accounted for 26.0 percent of total positive target allocations with the Western Hub accounting for 5.0 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 27.1 percent of all negative target allocations, with the Western Hub accounting for 10.1 percent.

Figure 13-7 Ten largest positive and negative FTR target allocations summed by source: 2020/2021



Surplus Congestion Revenue

Surplus congestion revenue is a misnomer. In fact, there is no such thing as surplus congestion revenue. The rights to all congestion revenue belong to load. Surplus congestion revenue, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs.

In the current design, surplus congestion revenue should be allocated to ARR holders because such revenue is part of total congestion revenues. In addition, FTR Auction revenue results from the prices paid by willing FTR buyers and should not be returned to FTR buyers for any reason and should be settled monthly.

Surplus day-ahead congestion is defined as the difference between the day-ahead congestion collected and FTR target allocations. Surplus FTR auction revenue is defined as the difference between the sum of monthly FTR auction revenue from the Long Term, Annual and monthly auctions, and ARR target allocations. Surplus FTR auction revenue can result from high prices in the FTR auctions, and from FTR capacity sold in excess of assigned ARR capacity on specific paths, and FTR capacity sold on paths not available to ARR holders.

Surplus congestion revenue is defined as the sum of the surplus day-ahead congestion revenue and the surplus FTR auction revenue at the end of each month.[35] Beginning with the 2014/2015 planning period, PJM may use surplus FTR auction revenue to pay for the clearing of counter flow FTRs as part of the auction clearing process.[36] The remaining surplus is first used to ensure that ARR target allocations in the month are fully funded. Any remaining surplus is used to pay any shortfall in FTR target allocations for the current month or prior months in the planning period. Any remaining surplus is used to pay any shortfall in FTR target allocations for the entire planning period at the end of the planning period. Any remaining surplus is distributed to ARR holders.[37]

If, at the end of the planning period, all the surplus congestion revenue has been provided to FTR holders and target allocations for the year are not covered, an uplift charge is assigned to FTR holders to cover the net planning period deficiency. An individual participant's uplift charge allocation is the ratio of their share of net positive target allocations to the total net positive target allocations.

Figure 13-8 shows the distribution of the monthly surplus congestion revenue distributed to FTR holders as if it were settled monthly. The figure shows the portions of total monthly surplus, represented by the total height of the bar, that are from day-ahead congestion surplus, represented by the blue portion of the bar, and from auction surplus, represented by the orange portion of the bar. The horizontal green lines represent the amount of revenue that FTRs were paid from the surplus to be made whole for that month. The height of the bar below the green line is the portion of auction surplus that went to FTR holders, and the height of the bar above the green line is the portion that would have gone to ARR holders at the end of the planning period, if nothing changed and this surplus was not provided to FTRs. If a green line is above the bar that means there was not enough surplus congestion in that month to make FTRs whole. For example, September 2020 did not have enough surplus congestion to make FTRs whole. Those FTRs were made whole using surplus revenue from previous months.

The market rules should recognize that ARR holders have the right to all surplus congestion revenue, not just the remainder after funding FTRs. The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. In Figure 13-8 the amount represented by each bar would be assigned to ARR holders in every month. In the first seven months of the 2020/2021 planning period, $82.6 million of surplus congestion revenue was paid to FTR holders that would have been paid to ARR holders, under the MMU recommendation.

Figure 13-8 Monthly surplus congestion and auction revenue distributed to FTR holders: June 2017 through December 2020[38]

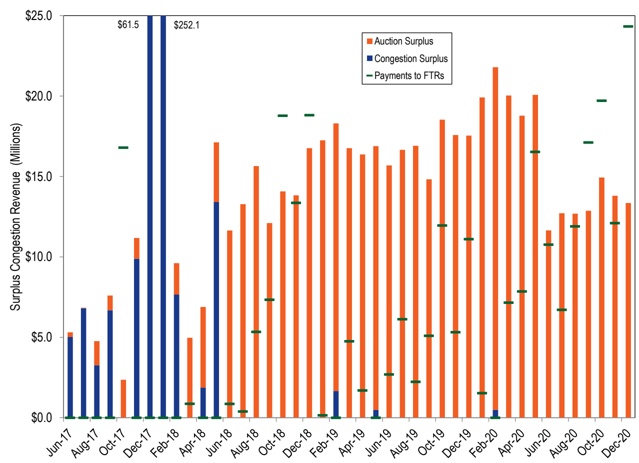


Figure 13-9 shows the surplus FTR auction revenue from the 2011/2012 planning period through the 2020/2021 planning period. Each new planning period introduces a new FTR model, including outages and PJM's discretionary adjustments for revenue adequacy. The differences in the assumptions in the market 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

35 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.

36 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 26 (Jan. 27, 2021).

37 On May 31, 2018, a rule change was implemented. Effective for the 2018/2019 planning period, surplus day-ahead congestion charges and surplus FTR auction revenue that remain at the end of the Planning Period allocated to ARR holders, rather than to FTR holders. 163 FERC ¶ 61,165 (2018).

38 The bars for December 2018 and January 2019 are truncated.

is no logical or market based reason to assign any part of that auction revenue back to the FTR buyers. It is inconsistent with the operation of a market that sellers are required to return some of the purchase price to buyers if the purchase is less profitable for buyers than expected. Auction revenue from the sale of FTRs should be distributed directly 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

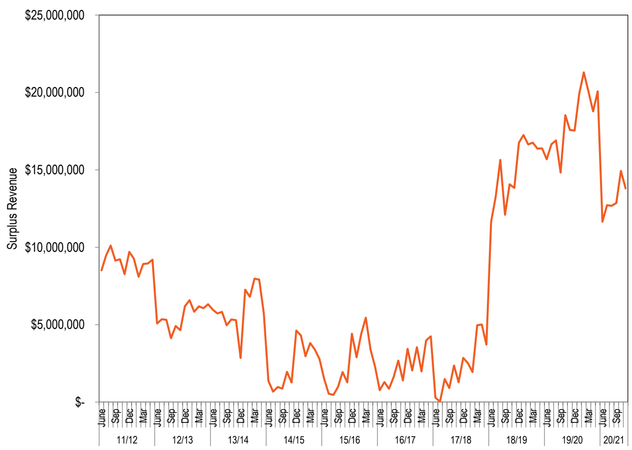


Table 13-17 shows the surplus FTR auction revenue, surplus day-ahead congestion revenue and surplus congestion revenue for planning periods 2010/2011 through the first seven months of the 2020/2021 planning period.

Table 13-17 Surplus FTR Auction Revenue: 2010/2011 through 2020/2021[39]

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**	$92.0	($104.6)	($10.4)
Total	$881.5	($2,346.5)	($744.4)

*Start of counter flow "buy back"
**First seven months

39 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.

Revenue Adequacy

FTR revenue adequacy, like surplus congestion revenue, is a misnomer. FTR revenue adequacy, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs.

As defined, FTR revenue adequacy simply compares congestion revenues to FTR target allocations. There is no reason to expect congestion revenues to equal FTR target allocations under the path based approach. Revenue adequacy is not a benchmark for how well the FTR process is working. Target allocations define the maximum payments to FTRs but target allocations are not congestion. FTR revenue adequacy is not equivalent to the adequacy of ARRs as an offset for load against total congestion. A path specific target allocation is not a guarantee of payment.

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 loop interfaces) both of which reduced the FTRs made available for sale in FTR auctions. PJM's actions have led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs and therefore a reduction in available FTRs.

While PJM's arbitrary decision to increase outages in the ARR allocation and in the Annual FTR Auction reduced FTR revenue inadequacy, it did not address the Stage 1A ARR over allocation issue directly because Stage 1A ARR allocations cannot be prorated. Instead, PJM's actions for the 2014/2015 through 2016/2017 planning periods resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability. The direct assignment of balancing congestion and M2M payments to load beginning in the 2017/2018 planning period increased the congestion revenue available to pay FTR holders. In response, PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing ARR allocations and FTR availability.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues in the current design. The reasons include: the use of generation to load paths rather than a measure of total congestion to assign congestion revenue rights; the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction; unavoidable modeling differences such as emergency outages; avoidable modeling differences such as outage modeling decisions; and cross subsidies among and between FTR participants and ARR holders.

Revenue adequacy for ARRs is, for practical purposes, a meaningless concept. Revenue adequacy for ARRs means that FTR buyers collectively pay more than zero for FTRs in FTR auctions, and that those payments were received by ARR holders. 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, or even much less.

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 seven months of the 2020/2021 planning period, total net FTR auction revenue was $681.4 million.

Table 13-18 presents the PJM FTR revenue detail for the 2019/2020 planning period and the first seven months of the 2020/2021 planning period. This includes ARR target allocations from the Annual ARR Allocation and net revenue sources from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[40] 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 13-18 Total annual 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	$511.2
ARR credits	$752.2	$511.2
FTR auction revenue	$982.0	$681.4
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	$31.6
Surplus auction revenue		
ARR Surplus	$217.8	$92.0
ARR payout ratio	100%	100%
FTR targets		
Positive target allocations	$904.3	$751.8
Negative target allocations	($224.3)	($158.2)
FTR target allocations	$680.1	$591.4
Adjustments:		
Adjustments to FTR target allocations	($7.9)	($1.8)
Total FTR targets	$673.5	$591.7
FTR payout ratio	100%	99%
FTR revenues		
ARR excess	$217.8	$92.0
Congestion		
Net Negative Congestion (enter as negative)	$0.0	$0.0
Hourly congestion revenue	$596.4	$488.9
M2M Payments(credit to PJM minus credit to M2M entity)	$0.0	$0.0
Adjustments:		
Surplus revenues carried forward into future months	$0.0	$8.4
Surplus revenues distributed back to previous months	$0.0	$1.2
Other adjustments to FTR revenues	$0.0	$0.0
Total FTR revenues		
Surplus revenues distributed to other months	$0.0	$9.6
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$814.2	$589.9
Total congestion credits(includes end of year distribution)	$814.2	$589.9
Remaining deficiency	($140.7)	$10.4

* First seven 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 13-19 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month.

40 The final ARR values may change if load shifts.

The total row in Table 13-19 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 September FTR target allocations were fully funded using surplus revenue from previous months. December 2020 had revenue shortfalls that could not be made whole using surplus revenues from previous months, the first month to not have enough surplus to cover FTR target allocations since May 2014.

Table 13-19 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 2019/2020				
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
Oct-20	$67.5	$72.2	93.1%	$72.2	100.0%	$0.0
Nov-20	$55.1	$53.4	100.0%	$55.1	100.0%	($1.7)
Dec-20	$79.6	$90.5	87.5%	$81.3	89.8%	$10.4
		Summary for Planning Period 2020/2021				
Total	$580.9	$591.4		$592.0		$10.4

Figure 13-10 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through December 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: 2004 through 2020

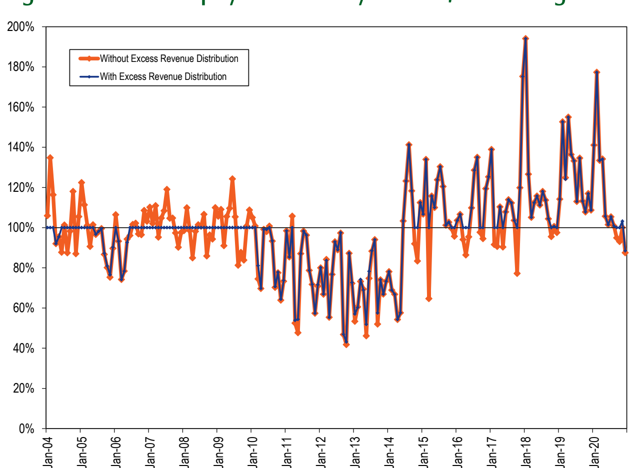


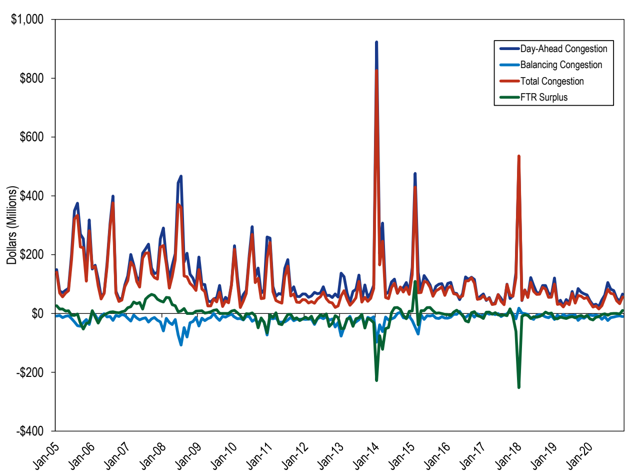
Table 13-20 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. Planning period 2013/2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. Beginning with the 2018/2019 planning period payments to FTRs are limited to 100 percent of the target allocations.

Table 13-20 Reported FTR payout ratio by planning period[41]

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	72.8%
2014/2015	116.2%
2015/2016	106.8%
2016/2017	112.6%
2017/2018	138.5%
2018/2019	100.0%
2019/2020	100.0%
2020/2021	99.5%

Figure 13-11 shows the FTR surplus, day-ahead, balancing and total congestion payments from January 2005 through December 2020.

Figure 13-11 FTR surplus and day-ahead, balancing and total congestion: 2005 through 2020



41 The actual payout ratios for planning periods 2006/2007, 2007/2008, and 2008/2009 may have exceeded 100 percent.

ARRs as an Offset to Congestion for Load

Load pays for the transmission system and pays congestion revenues. FTRs, and later ARRs, were intended to return congestion revenues to load to offset an unintended consequence of locational marginal pricing. With the implementation of the current, path based FTR/ARR design, the purpose of FTRs has subverted. The inconsistencies between actual network solutions used to serve load and path based rights available to load cause a misalignment of congestion paid by load and the congestion paid to load, in aggregate and on a specific load basis. These inconsistencies between actual network use and path based rights cause cross subsidies between ARR holders and FTR holders and among ARR holders. One result of this misalignment is that individual zones have very different offsets due to the location of their path based ARRs compared to their actual congestion costs from actual network use.

Table 13-21 shows the ARR and FTR revenue paid to load, the congestion offset available to load with and without allocating balancing congestion to load and the congestion offset when surplus congestion revenue is allocated to load. The highlighted offsets are the actual offsets based on the rules that were effective in that planning period. The pre 2017/2018 offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total day-ahead congestion and the load share of balancing and M2M payments.

The allocation of balancing congestion and M2M payments to load went into effect for 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 $1,351.4 million less in congestion offsets from the 2011/2012 through the 2019/2020 planning period. The total overpayment to FTR holders for the 2011/2012 through 2019/2020 planning period would have been $1,534.3 million.

Total ARR and self scheduled FTR revenue offset 55.8 percent of total congestion costs for the first seven months of the 2020/2021 planning period. For the 2019/2020 planning period, FTR bidders paid more in the auctions than the actual day-ahead target allocations for the same paths. The unexpected reduction in energy prices in 2020 led to a corresponding unexpected reduction in target allocations and in actual congestion. This resulted in an offset over 100 percent because the resulting total ARR value was greater than actual congestion costs. FTR prices were lower in the Annual FTR Auction for 2020/2021, reducing the offset for the first seven months of the 2020/2021 planning period.

Table 13-21 ARR and FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2020/2021

			Revenue						Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Balancing and Surplus)	
Planning Period	ARR Credits	Unadjusted FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue Pre 2017/2018 Rules	Surplus Revenue 2017/2018 Rules	Post 2017/2018 Rules	Total ARR/ FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset
2011/2012	$512.2	$310.0	$1,025.4	($275.7)	$749.7	($50.6)	$35.6	$113.9	$771.6	102.9%	$582.1	77.6%	$660.4	88.1%
2012/2013	$349.5	$268.4	$904.7	($379.9)	$524.8	($94.0)	$18.4	$62.1	$523.9	99.8%	$256.4	48.9%	$300.1	57.2%
2013/2014	$337.7	$626.6	$2,231.3	($360.6)	$1,870.6	($139.4)	($49.0)	($49.0)	$824.8	44.1%	$554.6	29.7%	$554.6	29.7%
2014/2015	$482.4	$348.1	$1,625.9	($268.3)	$1,357.6	$36.7	$111.2	$400.6	$867.2	63.9%	$673.4	49.6%	$962.8	70.9%
2015/2016	$635.3	$209.2	$1,098.7	($147.6)	$951.1	$9.2	$42.1	$188.9	$853.7	89.8%	$739.0	77.7%	$885.9	93.1%
2016/2017	$640.0	$149.9	$885.7	($104.8)	$780.8	$15.1	$36.5	$179.0	$805.0	103.1%	$721.6	92.4%	$864.0	110.7%
2017/2018	$427.3	$212.3	$1,322.1	($129.5)	$1,192.6	$52.3	$80.4	$370.7	$692.0	58.0%	$590.6	49.5%	$880.9	73.9%
2018/2019	$529.1	$130.1	$832.7	($152.6)	$680.0	($5.8)	$16.2	$112.2	$653.34	96.1%	$522.7	76.9%	$618.8	91.0%
2019/2020	$542.0	$91.9	$612.1	($169.4)	$442.7	($1.6)	$21.6	$157.8	$632.3	142.8%	$486.1	109.8%	$622.2	140.6%
2020/2021*	$217.9	$102.2	$488.9	($103.2)	$385.7	($19.6)	($1.8)	($1.8)	$300.49	77.9%	$215.2	55.8%	$215.2	55.8%
Total	$4,673.5	$2,448.7	$11,027.3	($2,091.6)	$8,935.7	($197.8)	$311.1	$1,534.3	$6,924.4	77.5%	$5,341.7	59.8%	$6,564.9	73.5%

Table 13-21 illustrates the inadequacies of the ARR/FTR design. The goal of the design should be to give the rights to 100 percent of the congestion revenues to the load.

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 13-22 also 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 73.5 percent if the 2017/2018 surplus allocation rules had been in place for the entire period.

Table 13-22 ARR and FTR cumulative offset for ARR holders using 2017/2018 surplus allocation: 2011/2012 through 2020/2021

Planning Period	Percent Offset	Cumulative Shortfall (Millions)
2011/2012	88.1%	($89.3)
2012/2013	75.4%	($314.0)
2013/2014	48.2%	($1,630.0)
2014/2015	55.0%	($2,024.8)
2015/2016	61.7%	($2,090.0)
2016/2017	67.8%	($2,006.8)
2017/2018	68.8%	($2,318.5)
2018/2019	70.6%	($2,379.8)
2019/2020	74.3%	($2,200.2)
2020/2021*	73.5%	($2,370.8)

*First seven months of the 20/21 planning period

Table 13-23 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 74.9 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 seven months of the 2020/2021 planning period. The amount of underpayment would have been even greater, $3.6 billion, if the 2017/2018 surplus allocation rules had been in place for the entire period.

Table 13-23 ARR and FTR cumulative offset for ARR holders using effective surplus allocation rules: 2011/2012 through 2020/2021

Planning Period	Percent Offset	Cumulative Shortfall (Millions)
2011/2012	102.9%	$21.9
2012/2013	101.6%	$21.0
2013/2014	67.4%	($1,024.8)
2014/2015	66.3%	($1,515.2)
2015/2016	70.4%	($1,612.6)
2016/2017	74.5%	($1,588.4)
2017/2018	70.5%	($2,190.4)
2018/2019	72.2%	($2,251.7)
2019/2020	75.8%	($2,072.1)
2020/2021*	74.9%	($2,242.6)

* First seven months of the 20/21 planning period

Zonal ARR Congestion Offset

Zonal ARR congestion offsets vary significantly across zones. There is no reason that this should be the result. This outcome is a direct result of the flawed definition of congestion and of the method for assigning rights to congestion to ARR holders. The results show that path based ARR assignments in the current path based ARR/FTR design are not aligned with actual network use by load, and are therefore not aligned with how congestion is actually paid by load on actual network usage. Due to this misalignment of ARR rights relative to actual network usage, individual loads cannot claim the congestion they paid through assigned ARRs. The misalignment of path based ARR rights produces cross subsidies among ARR holders.

ARRs are allocated to zonal load based on historical generation to load transmission contract paths, in many cases based on 1999 contract paths. ARRs are allocated within zones based on zonal base load (Stage 1A) and zonal peak loads (other stages). ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays in congestion charges net of payments to the generation that serves the zonal load, including generation in the zone and outside the zone.[42]

Table 13-24 shows the day-ahead congestion and balancing congestion and M2M charges paid by load in each zone along with the congestion offsets paid to load: FTR auction revenue; self scheduled FTR revenue adjusted by the payout ratio for FTRs if below 100 percent; and the allocation of end of planning period surplus.[43] The offset for the 2020/2021 planning period assigns the current surplus revenue at the end of the quarter to ARR holders. Table 13-24 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 13-24 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.

42 *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>.

43 See *2019 State of the Market Report for PJM*, Volume 2, Section 11: Congestion and Marginal Losses

Table 13-24 Zonal ARR and FTR total congestion offset (in millions) for ARR holders: 2020/2021 planning period

Zone	ARR Credits	Adjusted FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
AECO	$2.5	$0.0	($1.3)	($0.1)	$1.2	$4.8	($0.9)	($0.3)	$3.6	33.5%
AEP	$23.5	$16.5	($15.4)	($1.7)	$24.6	$83.7	($10.7)	($3.9)	$69.1	35.6%
APS	$19.3	$10.7	($5.9)	($1.0)	$24.1	$31.4	($4.2)	($1.5)	$25.8	93.2%
ATSI	$11.9	$0.1	($8.0)	($0.4)	$4.0	$37.6	($5.7)	($2.0)	$29.8	13.6%
BGE	$34.3	$2.0	($3.9)	($1.2)	$32.4	$18.7	($2.6)	($1.0)	$15.1	213.9%
ComEd	$21.3	$7.7	($11.9)	($0.9)	$17.2	$56.7	($8.1)	($3.0)	$45.6	37.7%
DAY	$3.5	$0.3	($2.1)	($0.1)	$1.7	$9.0	($1.5)	($0.5)	$7.0	24.1%
DEOK	$14.2	$1.6	($3.3)	($0.6)	$12.5	$13.3	($2.3)	($0.8)	$10.2	122.5%
DLCO	$3.3	$0.1	($2.3)	($0.1)	$1.1	$5.9	($1.3)	($0.6)	$4.1	27.1%
Dominion	$4.4	$49.9	($1.7)	($1.3)	$52.7	$68.0	($14.6)	($0.4)	$52.9	99.5%
DPL	$16.6	$3.8	($13.0)	($0.6)	$7.4	$25.9	($2.0)	($3.3)	$20.6	35.9%
EKPC	$1.8	$0.0	($1.6)	($0.1)	$0.2	$6.7	($1.1)	($0.4)	$5.2	4.1%
EXT	$0.3	$0.0	($6.5)	($0.0)	($6.2)	$13.7	($3.4)	($1.6)	$8.6	(72.4%)
JCPL	$3.5	$0.0	($2.9)	($0.1)	$0.6	$11.0	($2.0)	($0.7)	$8.2	7.5%
Met-Ed	$2.0	$0.4	($1.9)	($0.1)	$0.5	$13.2	($2.1)	($0.5)	$10.5	4.4%
OVEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.8	($0.1)	$0.0	$0.7	0.0%
PECO	$8.8	$0.2	($4.9)	($0.3)	$4.0	$17.5	($3.2)	($1.2)	$13.0	30.7%
PENELEC	$3.5	$2.9	($2.1)	($0.2)	$4.4	$12.0	($1.6)	($0.5)	$9.8	44.6%
Pepco	$15.1	$2.2	($3.5)	($0.6)	$13.8	$15.1	($2.4)	($0.9)	$11.8	116.9%
PPL	$13.6	$1.8	($5.0)	($0.5)	$10.4	$21.8	($3.3)	($1.3)	$17.3	60.5%
PSEG	$14.3	$0.0	($5.6)	($0.5)	$8.8	$21.3	($3.9)	($1.4)	$16.0	54.8%
RECO	$0.1	$0.0	($0.2)	($0.0)	($0.1)	$0.8	($0.2)	($0.0)	$0.6	(11.3%)
Total	$217.9	$100.4	($103.2)	($10.4)	$215.2	$488.9	($77.3)	($25.9)	$385.7	55.8%

The total congestion offset paid to loads in the first seven months of the 2020/2021 planning period was 55.8 percent of congestion costs. The results vary significantly by zone. Loads in some zones, like BGE, receive substantially more in offsets than their total congestion payments. Loads in other zones, like ATSI, receive substantially less in offsets than their total congestion payments. The offsets are a function of the assignment of ARRs and the valuation of ARRs in the FTR auctions.

Offset Available from Self Scheduling

It is not possible for load to recover all of the congestion that they pay under the current design in which the rights to congestion revenues are assigned based on fictitious contract paths. Table 13-25 shows the total congestion offset that would be available to ARR holders, by zone, if the ARR holders self scheduled all their allocated ARRs as FTRs in the 2016/2017 through 2019/2020 planning periods. The results also show that the recovery of congestion varies significantly by zone and that some zones recover more than the congestion they pay and some zones recover less. This is not consistent with a rational FTR/ARR design based on the fundamentals of the way that congestion costs are paid. The total offset available to ARR holders if they were to self schedule all of their ARRs in aggregate is less than total congestion paid by load in aggregate.

Table 13-25 Offset available to load if all ARRs self scheduled: 2016/2017 through 2019/2020 planning periods

	17/18 Planning Period				18/19 Planning Period				19/20 Planning Period			
	SS FTR	Bal+M2M	Congestion+M2M	Offset	SS FTR	Bal+M2M	Congestion+M2M	Offset	SS FTR	Bal+M2M	Congestion+M2M	Offset
AECO	$1.8	($1.6)	$13.2	1.4%	$11.5	($1.9)	$9.7	99.3%	$2.6	($2.0)	$3.7	16.3%
AEP	$203.3	($20.4)	$189.3	96.6%	$84.9	($23.7)	$102.0	60.0%	$62.7	($26.2)	$79.9	45.7%
APS	$78.7	($7.8)	$57.2	123.9%	$37.4	($9.2)	$43.0	65.5%	$31.2	($10.1)	$30.9	68.2%
ATSI	$54.1	($10.6)	$71.2	61.0%	$45.3	($12.4)	$50.7	65.0%	$27.9	($13.5)	$35.8	40.3%
BGE	$83.1	($5.0)	$42.6	183.3%	$49.0	($5.8)	$19.2	224.9%	$53.7	($6.4)	$14.9	316.6%
ComEd	$110.9	($15.4)	$181.0	52.8%	$51.4	($17.8)	$95.9	35.1%	$40.6	($19.6)	$66.9	31.4%
DAY	$10.5	($2.8)	$21.2	36.7%	$11.2	($3.2)	$12.2	65.0%	$5.6	($3.5)	$9.5	21.3%
DEOK	$72.2	($4.3)	$37.6	180.5%	$50.4	($5.0)	$22.7	199.9%	$30.5	($5.6)	$14.5	171.6%
DLCO	$10.6	($2.2)	$12.2	68.9%	$7.2	($2.5)	$7.4	63.5%	$8.1	($3.8)	$5.0	86.2%
Dominion	$42.4	($15.8)	$133.8	19.9%	$55.8	($18.7)	$63.5	58.5%	$32.8	($2.8)	$57.7	52.1%
DPL	$38.0	($2.9)	$68.6	51.1%	$57.7	($3.4)	$58.5	92.8%	$27.3	($21.0)	$17.6	35.9%
EKPC	($3.5)	($2.1)	$20.5	(27.2%)	$0.9	($2.4)	$9.0	(16.8%)	$4.1	($2.7)	$7.2	20.3%
EXT	$3.4	($5.2)	$28.7	(6.3%)	$1.7	($7.5)	$13.6	(42.7%)	$0.9	($9.0)	$7.0	(115.0%)
JCPL	$2.7	($3.6)	$32.1	(2.7%)	$2.6	($4.2)	$19.7	(7.9%)	$2.3	($4.6)	$9.0	(25.3%)
Met-Ed	$7.6	($2.5)	$26.5	19.3%	$5.0	($2.9)	$14.0	14.9%	$0.8	($3.2)	$8.6	(27.8%)
OVEC	$0.0	$0.0	$0.0	0.0%	$0.0	$0.0	$0.0	0.0%	$0.0	$0.0	$0.3	0.0%
PECO	$15.7	($6.4)	$57.7	16.2%	$15.7	($7.5)	$28.7	28.5%	$16.8	($8.1)	$12.5	68.9%
PENELEC	$15.4	($2.7)	$30.5	41.7%	$17.5	($3.2)	$18.3	78.2%	$11.2	($3.5)	$10.6	72.2%
Pepco	$38.1	($4.8)	$39.2	84.9%	$19.5	($5.5)	$17.4	80.3%	$23.2	($6.0)	$13.3	128.9%
PPL	$14.7	($6.4)	$65.3	12.7%	$4.3	($7.6)	$35.3	(9.2%)	$39.2	($8.4)	$19.8	155.7%
PSEG	$58.6	($6.9)	$62.4	82.9%	$35.6	($8.1)	$37.5	73.5%	$21.3	($8.9)	$17.8	69.6%
RECO	($0.1)	($0)	$1.9	(17.1%)	$0.2	($0.3)	$1.7	(6.2%)	$0.2	($0.3)	$0.7	(18.0%)
Total	$858.0	($129.5)	$1,192.6	61.1%	$565.0	($152.7)	$680.2	60.6%	$443.0	($169.4)	$443.1	61.8%

Credit

There were seven collateral defaults in 2020 for a total of $82,019. There were seven payment defaults in 2020 not involving GreenHat Energy, LLC for a total of $113,643. GreenHat Energy accrued payment defaults of $14.8 million in 2020 for a total of $161.8 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.[44] In addition, PJM added the settlement fee and claimant payee funds to the default allocation, resulting in a total of $179.3 million to date.

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.[45] FERC recognized "...there are multiple complexities associated with implementing the Waiver Order Directive that should be addressed in a paper hearing..."[46] 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."[47]

By delegated order issued December 30, 2019, the Commission approved a settlement agreement between PJM and the interested parties.[48] The result of the settlement was 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 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 additional payments, will be recovered via the default allocation assessment fund, which is allocated to all PJM members in proportion to their total net bill.

44 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.

45 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).

46 See 167 FERC ¶ 61, 2019 at P 27 (2019).

47 See *Id.* at P 28.

48 See 169 FERC ¶ 61,260 (2019).

Default Portfolio Considerations

Under the method applied to the GreenHat default, when an FTR participant defaults on their positions, their portfolio remains in the FTR market and will continue to accrue revenues and/or charges and must be reconciled. Under this method, PJM leaves the participant's positions unchanged, lets the positions settle at day-ahead prices, and charges any net losses to the default allocation assessment. This method exposes all members in PJM to an uncertain charge for the default allocation assessment that will not be known until those FTRs settle.

The MMU recommends a method under which defaulted FTRs would be canceled rather than holding or liquidating them. Canceling the FTRs would release the FTRs to the FTR market. The market would then decide the value of the capacity released and the timing of its release. There would be no discretion necessary to settle the defaulted position and the losses would be contained within the ARR/FTR market.

Cancellation of a defaulting portfolio does not change congestion. But cancellation of a defaulting portfolio can affect ARR/FTR funding as a result of changes in auction revenue, changes in the net target allocations, and potential simultaneous feasibility violations, while any collateral collected from the defaulted participant is available to offset losses from the cancelled FTRs. However, PJM can and does address similar issues routinely. PJM has tools available, such as the counter flow buyback and Stage 1A over allocation rules, and uses them regularly in the Annual FTR Auction, to improve funding as well as address feasibility concerns. Cancellation of FTRs would isolate the costs of the default to those participating in and benefitting from the FTR market.

FTR Forfeitures

In the Forfeiture Rule Directive, the Commission determined that the Forfeiture Rule is just and reasonable and "...serves to deter such manipulation" related to virtual transaction cross product manipulation.[49] The Commission identified four main tenets with which the Forfeiture Rule must comply, including that it: (i) deter manipulation, (ii) provide transparency allowing participants to modify their behavior, (iii) base forfeitures on an individual participant's actions and (iv) is not punitive.[50]

The point of the Forfeiture Rule is to avoid an inefficient and costly process and to establish an objective rule that prevents profiting from virtual trading on one's own FTR positions. The Forfeiture Rule operates to remove the incentive to engage in manipulation; the rule does not involve findings of manipulation.[51]

The FTR forfeiture rule considers the impact of a participant's net virtual transaction portfolio on all constraints.[52] 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, metric that the participant's net virtual portfolio increased the value of the FTR, then the FTR is subject to FTR forfeiture.

The FTR Forfeiture Rule does not penalize FTR holders. The FTR forfeiture rule does not affect the profits or losses of virtual activity. The FTR Forfeiture Rule, if triggered by a participant's virtual portfolio, results in forfeiting only FTR profits and only in the specific hours for which the rule is violated. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost. Even when FTR profits are forfeited, the value that the buyer assigned to congestion in the FTR auction (the price paid) is not affected. For example, if a buyer paid $5.00/MWh for congestion and congestion was $5.00/MWh, the forfeiture would be zero. If congestion were $7.00/MWh, the forfeiture would be $2.00/MWh. Market participants understand the relationship between FTR and virtual positions in detail and can avoid violating the FTR forfeiture rule if they choose to do so.

The FTR forfeiture rule has not reduced participation in the PJM FTR market or participation in virtual activity. There has been an increase in the number of participants in the FTR market since the implementation of the new FTR forfeiture rule, and a decrease in the number of participants with forfeitures.

49 Forfeiture Rule Directive at P 33.

50 Forfeiture Rule Directive at P 62.

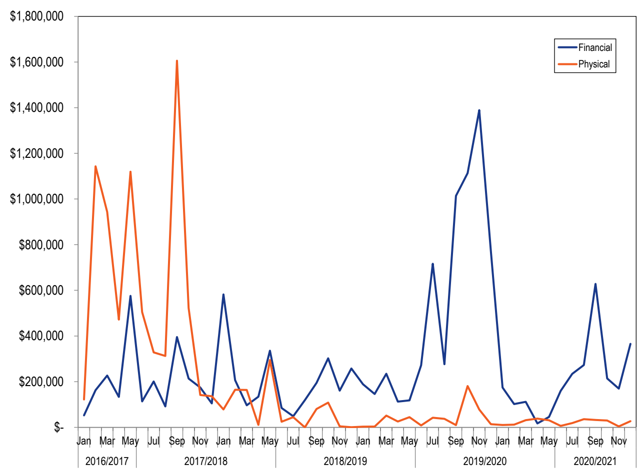
51 *See* "Protest and Motion for Rejection of the Independent Market Monitor for PJM," Docket No. EL20-41 (June 1, 2020).

52 A modified FTR forfeiture rule was implemented effective January 19, 2017. See *2019 State of the Market Report for PJM*, Volume 2, Section 13: Financial Transmission Rights for the full history.

Figure 13-12 shows the monthly FTR forfeitures under the modified FTR forfeiture rule from January 19, 2017, through December 31, 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.[53] Beginning with the September 2019 bill, PJM began billing using the correct hourly cost calculation. For the first seven months of the 2020/2021 planning period, total FTR forfeitures were $2.2 million.

Figure 13-12 Monthly FTR forfeitures for physical and financial participants



53 *See* "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).