State of the Market Report for PJM

Volume 2:
Detailed
Analysis

Monitoring Analytics, LLC

Independent
Market Monitor
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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 *2016 State of the Market Report for PJM*.[3]

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

2 OATT Attachment M § II(f).

3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2016 State of the Market Report for PJM*.

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Introduction

2016 in Review

The results of the energy market, the results of the capacity market and the results of the regulation market were competitive in 2016. The goal of competition is to provide customers wholesale power at the lowest possible price, but no lower. The PJM markets work. The PJM markets bring customers the benefits of competition. But the PJM markets, and wholesale power markets in the U.S., face new challenges that potentially threaten the viability of competitive markets.

Particularly in times of stress on markets and when some flaws in markets are revealed, nonmarket solutions may appear attractive. Top down, integrated resource planning approaches are tempting because it is easy to think that experts know exactly the right mix and location of generation resources and the appropriate definition of resource diversity and therefore which technologies should be favored through exceptions to market rules. The provision of subsidies to favored technologies, whether solar, wind, coal, batteries, demand side or nuclear, is tempting for those who would benefit, but subsidies are a form of integrated resource planning that is not consistent with markets. Subsidies to existing units are no different in concept than subsidies to planned units and are equally inconsistent with markets. Proposals for fuel diversity are generally proposals to subsidize an existing, uneconomic technology. Subsidies are tempting because they maintain existing resources and provide increased revenues to asset owners in uncertain markets. Cost of service regulation is tempting because cost of service regulation incorporates integrated resource planning and because guaranteed rates of return and fixed prices may look attractive to asset owners in uncertain markets.

It is essential that any approach to the PJM markets and the PJM Capacity Market incorporate a consistent view of how the preferred market design is expected to work 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 retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market. There are at least two broad paradigms that could result in such an outcome. The market paradigm includes a full set of markets, most importantly the energy market and capacity market, which together ensure that there are adequate revenues to incent new generation when it is needed and to incent retirement of units when appropriate. This approach will result in long term reliability at the lowest possible cost.

The quasi-market paradigm includes an energy market based on LMP but addresses the need for investment incentives via the long-term contract model or the cost of service model. In the quasi-market paradigm, competition to build capacity is limited and does not include the entire PJM footprint. In the quasi-market paradigm, customers absorb the risks associated with investment in and ownership of generation assets through guaranteed payments under either guaranteed long term contracts or the cost of service approach. In the quasi-market paradigm there is no market clearing pricing to incent investment in existing units or new units. In the quasi-market paradigm there is no incentive for entities without cost of service treatment to enter and thus competition is effectively eliminated.

The market paradigm and the quasi-market paradigm are mutually exclusive. Once the decision is made that market outcomes must be fundamentally modified, it will be virtually impossible to return to markets. While there are entities in the PJM markets that continue to operate under the quasi-market paradigm, those entities have made a long term decision on a regulatory model and the PJM rules generally limit any associated, potential negative impacts on markets. That consistent approach to the regulatory model is very different from current attempts to subsidize specific uneconomic market assets using various planning concepts as a rationale. The subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.

The issue of external subsidies emerged more fully in 2016. These subsidies are not directly part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings and the Illinois ZEC subsidy proceeding all originated 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. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market based mechanisms available to all market participants on a competitive basis and without discrimination.

The proposed subsidy solutions in all cases ignore the opportunity cost of subsidizing uneconomic units, which is the displacement of resources and technologies that would otherwise be economic. A decision to subsidize uneconomic units that are a significant source of energy and capacity has direct and significant impacts on other sources of energy; the opportunity costs of subsidies are substantial. Such subsidies suppress energy and capacity market prices and therefore suppress incentives for investments in new, higher efficiency thermal plants but also suppress investment incentives for the next generation of energy supply technologies and energy efficiency technologies. These impacts are long lasting but difficult to quantify precisely.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. PJM markets have no protection against this emergent threat. Accurate signals for entry and exit are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies. Fortunately, this can be accomplished quickly by expanding the coverage of an existing rule that already reflects stakeholder compromises.

The current proposals for subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources. The current minimum offer price rule (MOPR) only addresses subsidies for new entry. The MOPR should be expanded to address subsidies for existing units, and this should be done expeditiously. This issue will not become moot unless and until the MOPR is reformed. Action is needed to correct the MOPR immediately. An existing unit MOPR is the best means to defend the PJM markets from the threat posed by subsidies intended to forestall retirement of financially distressed assets. The role of subsidies to renewables should also be clearly defined and incorporated in this rule.

A MOPR for existing units should incorporate the key elements of the current MOPR which applies only to new gas-fired CT and CC units. This design would limit the impact of subsidies on markets while ensuring that existing forms of market participation by vertically integrated, cost of service companies could continue. An existing unit MOPR is a much better way to maintain PJM markets than the PJM proposal to incorporate public policy based subsidies that could result in the capacity market becoming a residual market. The PJM capacity market and PJM markets overall cannot function as markets if the capacity market is a residual market. The current design requires all capacity resources to offer and all load to buy capacity, except those companies that elect the FRR option and keep load and generation out of the capacity market.

While an existing unit MOPR would protect markets in the short run, the underlying issues that have resulted in the pressure on markets should also be examined. Unit owners are seeking subsidies because gas prices are low resulting in low energy market margins and because flaws in the PJM capacity design have led to very substantial price suppression over the past 10 years.

Much of the reason that market outcomes are subject to legitimate criticism is that the markets have not been permitted to reveal the underlying supply and demand fundamentals in prices. Before market outcomes are rejected in favor of nonmarket choices, markets should be permitted to work. It is more critical than ever to get capacity market prices correct. A number of capacity market design elements resulted in a substantial suppression of capacity market prices for multiple years.

These market design choices have and have had substantial impacts. Capacity prices that were suppressed substantially below the level consistent with supply and demand fundamentals affected some participants' long term decisions and led some market participants to seek subsidies. PJM has addressed the fundamental issues of the capacity market design in its Capacity Performance design, including price formation, product definition and performance incentives. But there are significant ongoing efforts to undo some of the key elements of the Capacity Performance design including performance incentives and product definition.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed. If society determines that carbon is a pollutant with a negative value, a market approach to carbon is preferred to a technology or unit specific subsidy approach. 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. 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 regulated business model with long term guaranteed contracts and the merchant generator market business model, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

Competitive markets were introduced as an alternative form of regulation to ensure that wholesale power is provided at the lowest possible price. The PJM market design does not incorporate a laissez faire approach. The PJM market remains regulated. The PJM market design incorporates a variety of rules designed to help ensure competitive outcomes. When basic elements of those rules are modified, e.g. the raising of the overall $1,000 per MWh offer cap and the introduction of hourly offers in place of daily offers, it is essential that effective market power mitigation be maintained. While the three pivotal supplier test addresses local market power associated with transmission constrained markets, it does not address aggregate market power. Aggregate market power exists when generation owners have the ability to raise market prices above competitive levels in the absence of transmission constraints, for example when demand is high and market conditions are tight. The failure to maintain limits on aggregate market power leads to the exercise of market power and the associated negative impacts on the competitiveness of PJM markets.

A primary market power mitigation rule in PJM is the three pivotal supplier (TPS) test. The TPS 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. The TPS test is a flexible, targeted real-time measure of market structure which replaced the prior approach of offer capping all units required to relieve a constraint. But there are some issues with the application of mitigation 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 mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market. In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid 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 with mitigation can and should be resolved by simple rule changes requiring that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer, that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer, and requiring cost-based and price-based PLS offers to be at least as flexible as price-based non-PLS offers. The significance of implementing these rule changes is substantially increased with the introduction of hourly offers.

The price of energy must reflect supply and demand fundamentals. The inclusion of gas costs and other fuel costs in energy market offers must be based on market prices. The fuel cost policy for every unit documents the process by which a unit owner calculates the fuel cost component of its cost-based offers. Fuel cost policies must be algorithmic, verifiable and systematic to ensure that only market-based short run marginal costs are included in fuel costs, especially when markets are stressed. FERC's order on hourly offers means that generators have the ability to appropriately reflect gas cost changes in energy offers during the operating day in order to permit the energy market to reflect the current cost of gas. But offer changes should be based only on algorithmic and verifiable changes in gas cost and therefore not permit the exercise of market power.

The application of market power mitigation rules in the Day-Ahead Energy Market and the Real-Time Energy Market helps ensure competitive market outcomes even in the presence of structural market power. But the efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as currently interpreted by PJM, is not correct. Some unit owners include costs that are not short run marginal costs in offers, including long term 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. PJM's 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 overall energy market results in 2016 support the conclusion that energy prices in PJM are set, generally, by marginal units offering at, or close to, their short run marginal costs, although this is not always the case during high demand hours. This is evidence of generally competitive behavior, although the behavior of some participants during high demand periods raises concerns about economic withholding. The performance of the PJM markets under high load conditions has raised a number of concerns related to aggregate market power, or the ability to increase markups substantially in tight market conditions, related to the uncertainties about the pricing and availability of natural gas, and related to the role of demand response and interchange transactions.

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. The load-weighted average real-time LMP was 19.2 percent lower in 2016 than in 2015, $29.23 per MWh versus $36.16 per MWh. PJM real-time load-weighted energy market prices were lower in 2016 than at any time in PJM history since the beginning of the competitive wholesale market on April 1, 1999. Energy prices were lower as a direct result of lower fuel prices and the resultant increased role of gas as the marginal fuel.

The markup conduct of individual owners and units has an identifiable impact on market prices. In the Real-Time Energy Market, the adjusted markup component of LMP increased from 4.8 percent of the real-time load-weighted average LMP in 2015 to 6.1 percent in 2016. Participant behavior was evaluated as competitive because marginal units generally made offers at, or close to, their short run marginal costs. But the markup results for high demand periods are a reminder that aggregate market power remains an issue when market conditions are tight and that market design choices must account for the potential to exercise aggregate market power. There are generation owners who routinely include high markups in price-based offers on some units. These markups do not affect prices under normal conditions but may affect prices during high demand conditions.

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. Natural gas prices decreased in 2016 and coal prices decreased or remained flat. Energy prices were lower in 2016 than in 2015. Capacity prices in 2016 were lower than in 2015 in all zones except PSEG. For gas fired units, the decrease in energy prices was offset by the decrease in gas prices and increased operating hours, resulting in higher energy net revenues for a new CT and a new CC. In 2016, average energy market net revenues increased by 21 percent for a new CT and 14 percent for a new CC. In 2016, average energy market net revenues decreased 54 percent for a new coal plant, 86 percent for a new diesel plant, 26 percent for a new nuclear plant, 19 percent for a new wind installation, and 28 percent for a new solar installation.

Load pays for the transmission system and contributes congestion revenues. For that reason, FTRs and later ARRs were intended to return congestion revenues to load.

The annual ARR allocation should be designed to ensure that load receives the rights to congestion revenues, without requiring contract path physical transmission rights that are impossible to define correctly and enforce in nodal, network LMP markets. The current ARR/FTR design does not serve as an efficient or effective way to ensure that load receives all the congestion revenues or that load receives the auction revenues associated with all the potential congestion revenues.

The goal of the design should be to assign the rights to 100 percent of the congestion revenues to load. But the actual results fall well short of that goal. The current allocation of congestion revenue resulted in a total shortfall of $1,780.6 million when comparing the revenues to ARR holders to congestion, a 70.9 percent congestion offset, over the last six planning periods. Total ARR and self scheduled FTR revenues offset only 44.7 percent of congestion costs in the 2013/2014 planning period, 63.8 percent in the 2014/2015 planning period and 86.5 percent in the 2015/2016 planning period. For the first seven months of the 2016/2017 planning period ARRs and self scheduled FTR revenues offset 82.3 percent of total congestion costs.

On September 15, 2016, FERC issued an order that moved the market design substantially further from the goal of returning congestion revenues to load. The order shifted costs to load and shifted revenues to FTR holders. The order assigned the costs of balancing congestion to load, assigned excess auction revenues to FTR holders and assigned all day-ahead congestion revenues in excess of target allocations to FTR holders. If the new rules had been in place beginning with the 2011/2012 planning period and the ARR/FTR allocations had remained the same, ARR holders would have received $996.7 million less in congestion offsets for the 2011/2012 through the 2016/2017 planning periods. The total overpayment to FTR holders for the 2011/2012 through 2016/2017 planning period would have been $896.1 million.

The FTR/ARR design should be significantly modified in order to return the design to its original purpose and function, which was to return congestion revenues to load.

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

PJM Market Summary Statistics

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

Table 1-1 PJM Market Summary Statistics: 2015 and 2016[1 2]

	2015	2016	Percent Change
Load	776,083 GWh	778,269 GWh	0.3%
Generation	786,698 GWh	812,544 GWh	3.3%
Net Actual Interchange	15,368 GWh	(7,967) GWh	(152%)
Losses	16,241 GWh	15,154 GWh	(6.7%)
Regulation Cleared MW*	641 MW	611 MW	(4.7%)
RTO Primary Reserve Requirement	2,175 MW	2,175 MW	0.0%
Total Billing	$42.63 Billion	$39.05 Billion	(8.4%)
Peak	Tue, July 28	Thu, August 11	
Peak Load	143,697 MW	152,177 MW	5.9%
Installed Capacity	As of 12/31/2015	As of 12/31/2016	
Installed Capacity	177,683 MW	182,449 MW	2.7%

* This is an hourly average stated in actual MW.

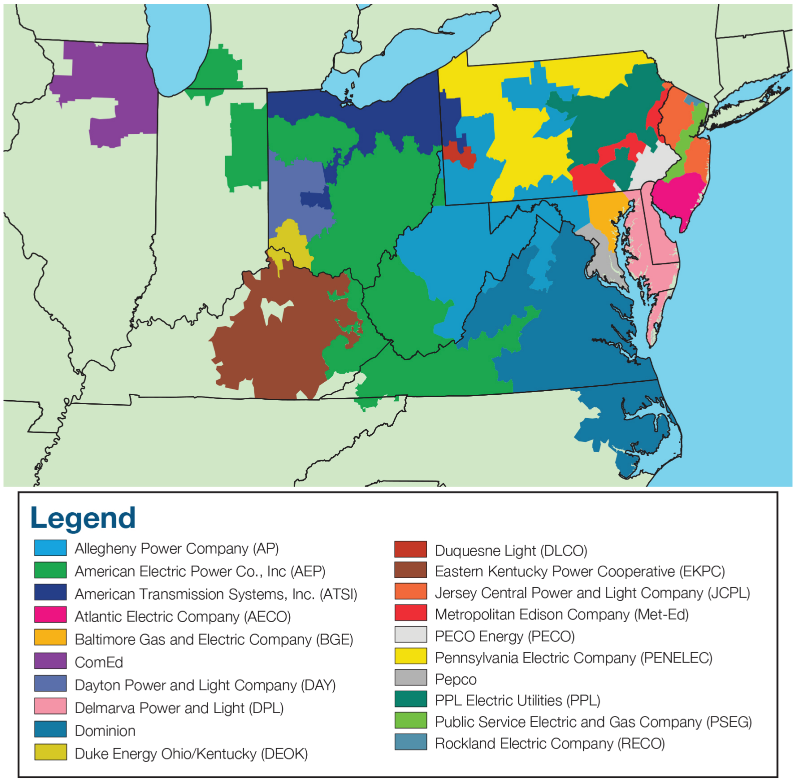
PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2016, had installed generating capacity of 182,449 megawatts (MW) and 986 members including market buyers, sellers and traders of electricity in a region including more than 65 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[3 4 5]

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 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."
2 Positive net interchange values represent imports and negative net interchange values represent exports. Imports and exports are reported in Section 9, "Interchange Transactions."
3 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
4 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
5 See the *2016 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2016.

Figure 1-1 PJM's footprint and its 20 control zones

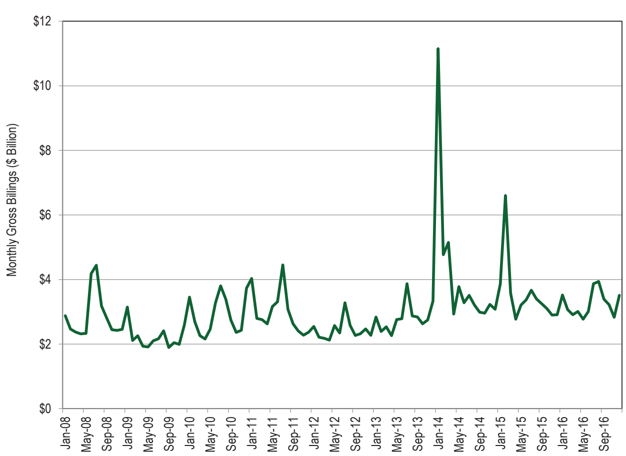


PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Market, the Day-Ahead Scheduling Reserve (DASR) Market and the Financial Transmission Rights (FTRs) Markets.

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.[7] [8] PJM introduced the Capacity Performance capacity market design effective on August 10, 2015, with the Base Residual Auction for 2018/2019.

In 2016, PJM had total billings of $39.05 billion, down 8.4 percent from $42.63 billion in 2015 (Figure 1-2).[6]

Figure 1-2 PJM reported monthly billings ($ Billion): 2008 through 2016



Conclusions

This report assesses the competitiveness of the markets managed by PJM in 2016, 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.

6 Monthly and annual billing values are provided by PJM.

7 See also the *2016 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

8 Analysis of 2016 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, the American Transmission Systems, Inc. (ATSI) Control Zone joined PJM. In January 2012, the Duke Energy Ohio/Kentucky Control Zone joined PJM. In June 2013, the Eastern Kentucky Power Cooperative (EKPC) joined PJM. 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 2016, see *2015 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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 ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for both the ownership of assets and the relationship between the pattern of ownership among multiple entities 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 outcome of the market. Market performance reflects the behavior of market participants within a market structure, mediated by market design.

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

The MMU concludes for 2016:

Table 1-2 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive. The hourly HHI (Herfindahl-Hirschman Index) results indicate that by the FERC standards, the PJM Energy Market in 2016 was moderately concentrated. Average HHI was 1024 with a minimum of 786 and a maximum of 1356 in 2016. The fact that the average HHI and the maximum hourly HHI were 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 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 PJM Energy Market peaking segment of supply was highly concentrated.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when mitigated.

- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants both routinely and during periods of high demand is consistent with economic withholding.
- 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 during periods of high demand did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the Day-Ahead Energy Market continues to cause concerns.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[9] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[10] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of variable operating and maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Now that generators will be allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the new rules permitting cost-based offers in excess of $1,000 per MWh.

9 PJM. OATT Attachment M (PJM Market Monitoring Plan).

Table 1-3 The Capacity Market results were competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[11]
- 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]

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

11 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS 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.

- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.

- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters and the inclusion of imports which are not substitutes for internal capacity resources.

Table 1-4 The Tier 2 Synchronized Reserve Market results were competitive

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

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

Table 1-5 The Day-Ahead Scheduling Reserve Market results were competitive

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

- The Day-Ahead Scheduling Reserve Market structure was evaluated as not competitive because market participants failed the three pivotal supplier test in 18.3 percent of all cleared hours in 2016.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices. Offers above $0.00 set the clearing price in 3,842 hours (43.8 percent).
- Market design was evaluated as mixed because the DASR product does not include performance obligations, and the three pivotal supplier test and appropriate market power mitigation should be added to the market to ensure that market power cannot be exercised at times of system stress.

Table 1-6 The Regulation Market results were competitive

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

- The regulation market structure was evaluated as not competitive for 2016 because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 92.2 percent of the hours in 2016.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for 2016 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in noncompetitive behavior.

- Market performance was evaluated as competitive, despite significant issues with the market design.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Table 1-7 The FTR Auction Markets results were competitive

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

- Market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility. But it is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable.
- Market design was evaluated as flawed because there are significant flaws with the basic ARR/FTR design. The market design is not an efficient way to ensure that all congestion revenues are returned to load.

Role of MMU

The 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]

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 the structure, behavior and performance of 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 the 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

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.

15 OATT Attachment M § IV.

16 OATT Attachment M § IV.K.3.

17 OATT Attachment M § IV.H.

the actual or potential exercise of market power.[18] The MMU will investigate and refer "Market Violations," which refers to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[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 automated 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.[28] Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent.[29] If the MMU has a concern about an offer, the MMU may raise that concern with the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals.[30] 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.[31] [32] With the introduction of competitive transmission development policy in Order No. 1000, a competitive procurement process for including projects in PJM Regional Transmission Expansion Plan is now in place.[33]

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.")

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

20 OATT § I.1.

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

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 § IV.

29 OATT § 12A.

30 OATT § 12A.

31 See OATT Attachment M–Appendix § II(p).

32 See OATT Attachment M–Appendix § III.

33 OA Schedule 6 § 1.5.

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.[34] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[35] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[36] 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.[37] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[38]

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

In this *2016 State of the Market Report for PJM*, the MMU includes 23 new recommendations from state of the market reports for 2016.[40]

New Recommendations from Section 3, Energy Market

- The MMU recommends that PJM require that the level of incremental costs includable in cost offers not exceed the unit's short run marginal cost. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that Manual 15 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. New recommendation. 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. New recommendation. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Medium. New recommendation. 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. New recommendation. Status: Not adopted.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply

34 OATT Attachment M § IV.D.
35 *Id.*
36 *Id.*
37 *Id.*
38 OATT Attachment M § VI.A.
39 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
40 New or modified recommendations include all MMU recommendations that were reported for the first time, or substantially modified, in the *2016 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2016.

limitations in Schedule 2. (Priority: Medium. New recommendation. 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 dispatcher to set the LMPs in the real-time market. (Priority: Low. New recommendation. Status: Not adopted.)

New Recommendations from Section 4, Energy Uplift

- The MMU recommends that if PJM believes it appropriate to modify the LMP price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff. (Priority: Medium. First Reported Q3, 2016. Status: Not adopted.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants should 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. New recommendation. Status: Not adopted.)

New Recommendations from Section 5, Capacity Market

- The MMU recommends the extension of minimum offer price rule (MOPR) to all existing and proposed units in order to protect competition in the capacity market from external subsidies. (Priority: High. New recommendation. Status: Not adopted.)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 as close to full substitutes for internal, physical capacity resources as possible. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported Q1, 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 that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. (Priority: Medium. First reported 2016. 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 but did not when EE was first added to the capacity market. 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.)

New Recommendation from Section 6, Demand Response

- The MMU recommends that PJM not remove any defined subzone and maintain a public record of all created and removed subzones. (Priority: Low. First reported Q3, 2016. Status: Not adopted.)

New Recommendations from Section 10, Ancillary Service Markets

- The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that 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, to prevent gaming. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that separate 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.)

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-8 shows the average price, by component, for 2015 and 2016.

Table 1-8 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 96.0 percent of the total price per MWh in 2016.

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

Components of Total Price

- The Energy component is the real time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and nonfirm point to point transmission service.[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 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 (AC^2) and OATT Schedule 9 funding of FERC, OPSI 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]

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 1-8 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 Reliability Assurance Agreement 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 1-8 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.

- 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 Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[56]
- The Emergency Energy component is the average cost per MWh of emergency energy.[57]

Table 1-8 Total price per MWh by category: 2015 and 2016[58]

Category	2015 $/MWh	2015 Percent of Total	2016 $/MWh	2016 Percent of Total	Percent Change Totals
Load Weighted Energy	$36.16	63.6%	$29.23	58.5%	(19.2%)
Capacity	$11.12	19.6%	$10.96	21.9%	(1.5%)
Transmission Service Charges	$7.09	12.5%	$7.81	15.6%	10.1%
Transmission Enhancement Cost Recovery	$0.51	0.9%	$0.52	1.0%	2.1%
PJM Administrative Fees	$0.44	0.8%	$0.45	0.9%	2.5%
Reactive	$0.37	0.7%	$0.39	0.8%	4.9%
Energy Uplift (Operating Reserves)	$0.38	0.7%	$0.17	0.3%	(54.8%)
Regulation	$0.23	0.4%	$0.11	0.2%	(53.2%)
Transmission Owner (Schedule 1A)	$0.09	0.2%	$0.09	0.2%	3.8%
Black Start	$0.08	0.1%	$0.08	0.2%	8.8%
Day Ahead Scheduling Reserve (DASR)	$0.10	0.2%	$0.07	0.1%	(24.4%)
Synchronized Reserves	$0.11	0.2%	$0.05	0.1%	(53.5%)
NERC/RFC	$0.03	0.1%	$0.03	0.1%	3.0%
Load Response	$0.02	0.0%	$0.01	0.0%	(38.9%)
Non-Synchronized Reserves	$0.02	0.0%	$0.01	0.0%	(48.3%)
RTO Startup and Expansion	$0.01	0.0%	$0.00	0.0%	(43.4%)
Transmission Facility Charges	$0.00	0.0%	$0.00	0.0%	(59.2%)
Capacity (FRR)	$0.13	0.2%	$0.00	0.0%	(100.0%)
Emergency Load Response	$0.00	0.0%	$0.00	0.0%	(100.0%)
Emergency Energy	$0.00	0.0%	$0.00	0.0%	0.0%
Total Price	$56.88	100.0%	$49.99	100.0%	(12.1%)

Table 1-9 shows the average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2016.

55 OA Schedule 1 § 5.3b.
56 OA Schedule 1 § 3.2.3A.001.
57 OA Schedule 1 §3.2.6.
58 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-9 Total price per MWh by category: Calendar Years 1999 through 2016[59]

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh
Load Weighted Energy	$34.07	$30.72	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35	$45.94
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.03	$0.03	$3.53	$7.80	$10.78	$12.15	$9.71
Transmission Service Charges	$3.41	$4.03	$3.48	$3.39	$3.57	$3.28	$2.71	$3.18	$3.45	$3.68	$4.03	$4.04	$4.49
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.11	$0.20	$0.27
PJM Administrative Fees	$0.23	$0.26	$0.71	$0.86	$1.05	$0.93	$0.72	$0.74	$0.72	$0.39	$0.31	$0.36	$0.38
Reactive	$0.26	$0.29	$0.22	$0.20	$0.24	$0.26	$0.26	$0.29	$0.29	$0.34	$0.36	$0.45	$0.41
Energy Uplift (Operating Reserves)	$0.52	$0.93	$1.27	$0.72	$0.89	$0.95	$1.07	$0.47	$0.65	$0.64	$0.48	$0.80	$0.78
Regulation	$0.15	$0.39	$0.53	$0.42	$0.50	$0.51	$0.80	$0.53	$0.63	$0.70	$0.34	$0.36	$0.32
Transmission Owner (Schedule 1A)	$0.07	$0.09	$0.08	$0.07	$0.07	$0.10	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
Black Start	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01	$0.05
Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.15	$0.13	$0.11	$0.08	$0.06	$0.08	$0.05	$0.07	$0.09
NERC/RFC	$0.00	-$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	-$0.00	$0.01	$0.01	$0.02	$0.02	$0.02
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.01	$0.01	$0.01
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.06	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Capacity (FRR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.53
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Price	$38.92	$36.98	$43.22	$37.39	$47.83	$50.66	$69.30	$58.82	$71.19	$85.00	$55.66	$66.93	$63.21

Category	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh
Load Weighted Energy	$35.23	$38.66	$53.14	$36.16	$29.23
Capacity	$6.05	$7.13	$9.01	$11.12	$10.96
Transmission Service Charges	$4.90	$5.21	$5.96	$7.09	$7.81
Transmission Enhancement Cost Recovery	$0.34	$0.36	$0.41	$0.51	$0.52
PJM Administrative Fees	$0.44	$0.42	$0.44	$0.44	$0.45
Reactive	$0.46	$0.76	$0.40	$0.37	$0.39
Energy Uplift (Operating Reserves)	$0.74	$0.61	$1.15	$0.38	$0.17
Regulation	$0.26	$0.25	$0.33	$0.23	$0.11
Transmission Owner (Schedule 1A)	$0.08	$0.08	$0.09	$0.09	$0.09
Black Start	$0.04	$0.14	$0.08	$0.08	$0.08
Day Ahead Scheduling Reserve (DASR)	$0.05	$0.06	$0.05	$0.10	$0.07
Synchronized Reserves	$0.04	$0.04	$0.12	$0.11	$0.05
NERC/RFC	$0.02	$0.02	$0.03	$0.03	$0.03
Load Response	$0.02	$0.01	$0.03	$0.02	$0.01
Non-Synchronized Reserves	$0.00	$0.00	$0.02	$0.02	$0.01
RTO Startup and Expansion	$0.01	$0.01	$0.01	$0.01	$0.00
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00
Capacity (FRR)	$0.52	$0.11	$0.20	$0.13	$0.00
Emergency Load Response	$0.01	$0.06	$0.06	$0.00	$0.00
Emergency Energy	$0.00	$0.00	$0.01	$0.00	$0.00
Total Price	$49.22	$53.93	$71.50	$56.88	$49.99

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

Table 1-10 shows the percent of average price, by component of the wholesale power price per MWh, for calendar years 1999 through 2016.

Table 1-10 Percent of total price per MWh by category: Calendar Years 1999 through 2016[60]

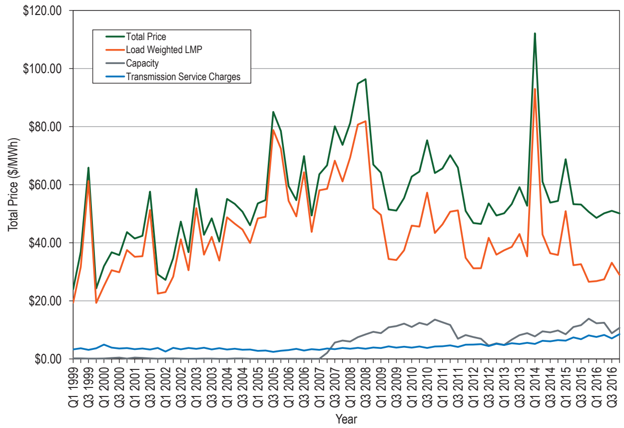
Category	Percent of Total Charges 1999	Percent of Total Charges 2000	Percent of Total Charges 2001	Percent of Total Charges 2002	Percent of Total Charges 2003	Percent of Total Charges 2004	Percent of Total Charges 2005	Percent of Total Charges 2006	Percent of Total Charges 2007	Percent of Total Charges 2008	Percent of Total Charges 2009
Load Weighted Energy	87.5%	83.1%	84.8%	84.5%	86.2%	87.5%	91.6%	90.7%	86.6%	83.7%	70.2%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.0%	0.0%	5.0%	9.2%	19.4%
Transmission Service Charges	8.8%	10.9%	8.0%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%
Transmission Enhancement Cost Recovery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%
PJM Administrative Fees	0.6%	0.7%	1.7%	2.3%	2.2%	1.8%	1.0%	1.3%	1.0%	0.5%	0.6%
Reactive	0.7%	0.8%	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%
Energy Uplift (Operating Reserves)	1.3%	2.5%	2.9%	1.9%	1.9%	1.9%	1.5%	0.8%	0.9%	0.8%	0.9%
Regulation	0.4%	1.1%	1.2%	1.1%	1.1%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%
Transmission Owner (Schedule 1A)	0.2%	0.2%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%
Black Start	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%
NERC/RFC	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity (FRR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Energy	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Category	Percent of Total Charges 2010	Percent of Total Charges 2011	Percent of Total Charges 2012	Percent of Total Charges 2013	Percent of Total Charges 2014	Percent of Total Charges 2015	Percent of Total Charges 2016
Load Weighted Energy	72.2%	72.7%	71.6%	71.7%	74.3%	63.6%	58.5%
Capacity	18.2%	15.4%	12.3%	13.2%	12.6%	19.6%	21.9%
Transmission Service Charges	6.0%	7.1%	9.9%	9.7%	8.3%	12.5%	15.6%
Transmission Enhancement Cost Recovery	0.3%	0.4%	0.7%	0.7%	0.6%	0.9%	1.0%
PJM Administrative Fees	0.5%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%
Reactive	0.7%	0.6%	0.9%	1.4%	0.6%	0.7%	0.8%
Energy Uplift (Operating Reserves)	1.2%	1.2%	1.5%	1.1%	1.6%	0.7%	0.3%
Regulation	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.2%
Transmission Owner (Schedule 1A)	0.1%	0.1%	0.2%	0.2%	0.1%	0.2%	0.2%
Black Start	0.0%	0.0%	0.1%	0.3%	0.1%	0.1%	0.2%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%
Synchronized Reserves	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%
NERC/RFC	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%
Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity (FRR)	0.0%	0.8%	1.1%	0.2%	0.3%	0.2%	0.0%
Emergency Load Response	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%
Emergency Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	99.9%	100.0%	100.0%	100.0%	100.0%	100.0%

60 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 2016[61]



Section Overviews

Overview: Section 3, "Energy Market"

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. The maximum of average offered real-time generation increased by 3,957 MW, or 2.4 percent, from 167,343 MW in the summer of 2015 to 171,300 MW in the summer of 2016. In 2016, 5,421.4 MW of new capacity resources were added. In 2016, 395.5 MW were retired.

  PJM average real-time cleared generation in 2016 increased by 2,676 MW, or 3.0 percent, from 2015, from 88,628 MW to 91,304 MW.

  PJM average day-ahead cleared supply in 2016, including INCs and up to congestion transactions, increased by 14.6 percent from 2015, from 114,889 MW to 131,634 MW, primarily as a result of an increase in UTC volumes.

- **Market Concentration.** The PJM Energy Market was moderately concentrated overall with moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segment.

- **Generation Fuel Mix.** In 2016, coal units provided 33.9 percent, nuclear units 34.4 percent and natural gas units 26.5 percent of total generation. Compared to 2015, generation from coal units decreased 3.3 percent, generation from natural gas units increased 18.3 percent and generation from nuclear units increased 0.2 percent.

- **Fuel Diversity.** In 2016, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), increased 0.9 percent over the 2015 FDI_e.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in 2016, coal units were 44.9 percent of marginal resources and natural gas units were 43.8 percent of marginal resources. In 2015, coal units were 51.7 percent and natural gas units were 35.5 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, in 2016, up to congestion transactions were 82.4 percent of marginal resources, INCs were 4.2 percent of marginal resources, DECs were 8.6 percent of marginal resources, and generation resources were 4.7 percent of marginal resources. In 2015, up to congestion transactions were 76.1 percent of marginal resources, INCs were 5.1 percent of marginal resources, DECs were 8.9 percent of marginal resources, and generation resources were 9.6 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM metered system peak load during 2016 was 152,177 MW in the HE 1500 on August 11, 2016, which was 8,480 MW, 5.9 percent, higher than the PJM peak load for 2015, which was 143,697 MW in the HE 1600 on July 28, 2015.

  PJM average real-time load in 2016 increased from 2015, from 88,594 MW to 88,601 MW. PJM average day-ahead demand in 2016, including DECs and up to congestion transactions, increased by 14.1 percent in 2015, from 111,644 MW to 127,390 MW.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. For 2016, 12.9 percent of real-time load was supplied by bilateral contracts, 23.9 percent by spot market purchases and 63.2 percent by self-supply. Compared with

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

2015, reliance on bilateral contracts increased by 2.3 percentage points, reliance on spot market purchases decreased by 5.4 percentage points and reliance on self-supply increased by 3.1 percentage points.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in 2016.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.2 percent in 2015 to 0.1 percent in 2016. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 0.4 percent in 2015 and 2016.

  In 2016, 11 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.4 percent in 2015 to 0.04 percent in 2016. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.4 percent in 2015 to 0.1 percent in 2016.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In 2016, in the PJM Real-Time Energy Market, 90.1 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 per MWh was negative when using unadjusted cost offers. The average dollar markups of units with offer prices less than $50 per MWh was negative when using unadjusted cost offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, implying a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM Market Rules. Some marginal units did have substantial markups. Using the unadjusted cost offers, the highest markup for any marginal unit in 2016 was $258.16 per MWh while the highest markup in 2015 was $792.21 per MWh.

  In the PJM Day-Ahead Energy Market, when using unadjusted cost offers, in 2016, 89.9 percent of marginal generating units had offer prices less than $50 per MWh and the average dollar markup was negative, and the 0.4 percent of marginal generating units had offers in the $75 to $125 per MWh range and the average dollar markup and the average markup index were both negative.

- **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 imply 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.

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

- Virtual Offers and Bids. Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In 2016, the average hourly increment offers submitted MW increased by 26.0 percent from 7,175 MW in 2015 to 9,043 MW in 2016, and cleared MW increased by 11.4 percent from 4,675 MW in 2015 to 5,207 MW in 2016. In 2016, the average hourly decrement bids submitted MW increased by 25.3 percent from 6,879 MW in 2015 to 8,618 MW in 2016, and cleared MW increased by 18.6 percent from 4,051 MW in 2015 to 4,805 MW in 2016. In 2016, the average hourly up to congestion submitted MW increased by 70.3 percent from 83,422 MW in 2015 to 142,075 MW in 2016, and cleared MW increased by 78.6 percent from 19,255 MW in 2015 to 34,385 MW in 2016.

- Generator Offers. Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in 2016, 53.7 percent were offered as available for economic dispatch, 4.4 percent were offered as emergency dispatch, 22.3 percent were offered as self scheduled, and 19.6 percent were offered as self scheduled and dispatchable.

Market Performance

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

  PJM real-time energy market prices decreased in 2016 compared to 2015. The load-weighted average real-time LMP was 19.2 percent lower in 2016 than in 2015, $29.23 per MWh versus $36.16 per MWh. PJM real-time load-weighted energy market prices were lower in 2016 that at any time in PJM history since the beginning of the competitive wholesale market on April 1, 1999.

  PJM day-ahead energy market prices decreased in 2016 compared to 2015. The load-weighted average day-ahead LMP was 19.2 percent lower in 2016 than in 2015, $29.68 per MWh versus $36.73 per MWh. PJM day-ahead load-weighted energy market prices were lower in 2016 that at any time in PJM history since the introduction of the PJM Day-Ahead Energy Market in June 2000.

- **Components of LMP.** In the PJM Real-Time Energy Market, in 2016, 45.4 percent of the load-weighted LMP was the result of coal costs, 27.2 percent was the result of gas costs and 1.89 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market in 2016, 36.4 percent of the load-weighted LMP was the result of the cost of coal, 26.7 percent was the result of DECs, 11.0 percent was the result of the cost of gas, 1.9 percent was the result of INCs, and 2.2 percent was the result of up to congestion transactions.

- **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 2016, the adjusted markup component of LMP was $1.77 per MWh or 6.1 percent of the PJM real-time, load-weighted average LMP. August had the highest adjusted peak markup component, $4.47 per MWh, or 10.24 percent of the real-time peak hour load-weighted average LMP. Using the unadjusted cost offers, the highest markup of a marginal unit in 2016 was $258.16 per MWh. There were 33 hours in 2016 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $54.51 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2016, the adjusted markup component of LMP resulting from generation resources was $0.21 per MWh or

0.7 percent of the PJM day-ahead load-weighted average LMP. August had the highest adjusted peak markup component, $5.65 per MWh or 16.5 percent of the day-ahead load-weighted average LMP.

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 is consistent with economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.73 per MWh in 2015 and -$0.53 per MWh in 2016. 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 no shortage pricing events in 2016.

Section 3 Recommendations

- The MMU recommends that the market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel type and parameters as that of their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require that the level of incremental costs includable in cost offers not exceed the unit's short run marginal cost. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that Manual 15 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. New recommendation. 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. New recommendation. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Medium. New recommendation. 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. New recommendation. Status: Not adopted.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply

limitations in Schedule 2. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. (Priority: High. First reported 2010. 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 offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available 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. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that under the capacity performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine nonperformance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM Energy Market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported 2014. 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: Not adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[62] (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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

62 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

be made transparent. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM include in the 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.[63] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[64] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM 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 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 continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Status: Adopted in full, 2014.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2016, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average PJM real-time cleared generation increased by 2,676 MW, 3.0 percent, and peak load increased by 8,480 MW, 5.9 percent, in 2016 compared to 2015. Market concentration levels remained moderate although there is high concentration in the peaking segment of the supply curve which adds to concerns about market power when market conditions are tight. The relationship between supply and demand, regardless of the specific market, balanced by market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate energy market remains reasonably competitive for most hours although aggregate market power does exist during high demand hours. Low average aggregate concentration does not mean that market power cannot be exercised. It is possible that market power can be exercised at times when individual suppliers or small groups of suppliers are pivotal even when the HHI level does not indicate that the market is highly concentrated. High markups for some units demonstrate the potential to exercise market power during high demand conditions.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an

63 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.

64 The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. 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 2016 generally reflected supply-demand fundamentals, although the behavior of some participants during high demand periods is consistent with economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

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.[65] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to require offer capping of owners when the local market structure is noncompetitive.

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. 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 have the ability to avoid 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 requiring that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer, that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer, and requiring cost-based and price-based PLS offers to be at least as flexible as price-based non-PLS offers.

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

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained

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

by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing net revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. PJM implemented scarcity pricing rules in 2012. There are significant issues with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs. 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 2014, 2015 or 2016. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods is consistent with economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the tighter market conditions and the change in some participants' behavior are sources of concern in the energy market and provide a reason to use cost as the sole basis for hourly changes in offers or offers greater than $1,000 per MWh. The MMU concludes that the PJM energy market results were competitive in 2016.

Overview: Section 4, "Energy Uplift"

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $175.4 million, or 56.1 percent, in 2016 compared to 2015, from $312.5 million to $137.1 million.
- **Energy Uplift Charges Categories.** The decrease of $175.4 million in 2016 is comprised of a $41.4 million decrease in day-ahead operating reserve charges, a $121.1 million decrease in balancing operating reserve charges, a $8.1 million decrease in reactive services charges, and a $4.9 million decrease in black start services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.071 per MWh, real-time load paid $0.031 per MWh, a DEC paid $0.418 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.347 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.071 per MWh, real-time load paid $0.023 per MWh, a DEC paid $0.372 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.302 per MWh.
- **Reactive Services Rates.** The DPL, PENELEC and EKPC control zones had the three highest local voltage support rates: $0.043, $0.015 and $0.013 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 13.0 percent of all day-ahead generator credits and 10.1 percent of all balancing generator credits. Combustion turbines and diesels received 76.8 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 36.0 percent of all credits. The top 10 organizations received 76.8 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves

HHI was 6102, balancing operating reserves HHI was 3231 and lost opportunity cost HHI was 5356.

- **Economic and Noneconomic Generation.** In 2016, 85.9 percent of the day-ahead generation eligible for operating reserve credits was economic and 78.3 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2016, 1.5 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 47.4 percent received energy uplift payments.

Geography of Charges and Credits

- In 2016, 89.9 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions (at control zones or buses within a control zone), demand and generation, 4.4 percent by transactions at hubs and aggregates and 5.7 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 50.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 48.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Energy Uplift Issues

- **Lost Opportunity Cost Credits.** In 2016, lost opportunity cost credits decreased by $64.6 million compared to 2015. In 2016, resources in three control zones, AECO, AEP and ComEd, accounted for 59.1 percent of all lost opportunity cost credits, 35.5 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 51.3 percent of all day-ahead generation not committed in real time by PJM from those unit types and 50.7 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Closed Loop Interfaces.** PJM implemented closed loop interfaces to allow reactive constraints and emergency DR to set price when they would not otherwise set price under the LMP logic. This use of closed loop interfaces permits subjective price setting by PJM.
- **Price Setting Logic.** In November 2014, PJM implemented a software change to its day ahead and real time market solution tools that would enable PJM to reduce energy uplift by artificially selecting the marginal unit for any constraint. The goal is to make marginal any unit committed by PJM to provide reactive services, black start or transmission constraint relief if such unit would otherwise run with an incremental offer greater than the correctly calculated LMP. PJM calls this approach price setting logic. Price setting logic is a form of subjective pricing because it varies from fundamental LMP logic based on an administrative decision to reduce energy uplift.
- **Con Edison – PJM Transmission Service Agreements Support.** Certain units located near the boundary between New Jersey and New York City have been operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts. These units are often run out of merit and received substantial operating reserves credits.

Energy Uplift Recommendations

- **Impact of Quantifiable Recommendations.** The impact of implementing the recommendations related to energy uplift proposed by the MMU on the rates paid by participants would be significant. For example, in 2016, the average rate paid by a DEC in the Eastern Region would have been $0.027 per MWh under the MMU proposal, which is $0.391 per MWh, or 93.5 percent, lower than the actual average rate paid.

Section 4 Recommendations

The MMU recognizes that many of the issues addressed in the recommendations are being discussed in PJM stakeholder processes. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing market rules.

- The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to modify the LMP price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff. (Priority: Medium. First Reported Q3, 2016. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Not adopted.)
- The MMU recommends the elimination of the day-ahead operating reserve category 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. Stakeholder process.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted. Stakeholder process.)
- The MMU recommends not compensating self scheduled units 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 four additional modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours 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 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. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Not adopted. Stakeholder process.)
- 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: Not adopted. Stakeholder process.)
- 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 reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. 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 operating reserve credits 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, which is currently allocated solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- 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). In addition, the MMU recommends that PJM allow and wind units submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants should 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. New recommendation. 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 2014.)
- 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.)
- 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 2012. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)

Section 4 Conclusion

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Loss is defined to be receiving revenue less than the short run marginal costs incurred in order to generate energy. Referred to in PJM as day-ahead operating reserves, balancing operating reserves, energy lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at short run marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start charges.

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.

From the perspective of those participants paying energy uplift charges, these costs are an unpredictable and unhedgeable component of participants' costs in PJM. 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 that the allocation of these charges reflects the reasons that the costs are incurred to the extent possible.

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market energy uplift payments. When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted for more than ten years.

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.

The level of energy uplift paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters, the details of the rules which define payments and the decisions of PJM operators. Energy uplift payments result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, no load and startup costs. Energy uplift payments also result from units' operational parameters that may require PJM to schedule or commit resources during noneconomic hours. The balance of these costs not covered by energy revenues are collected as energy uplift rather than reflected in price as a result of the rules governing the determination of LMP.

PJM's goal should be to minimize the total level of energy uplift paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. For example, up to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated. Some uplift payments are the result of inflexible operating parameters included in offers by generating units. Operating parameters should reflect the flexibility of the benchmark new entrant unit in the PJM capacity market if the unit is to receive uplift payments from other market participants. 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.

But it is also important that the reduction of uplift payments not be a goal to be achieved at the expense of the fundamental logic of an 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 price setting logic.

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.[66]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[67] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[68] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[69]

The 2017/2018 RPM Second Incremental Auction and the 2018/2019 RPM First Incremental Auction were conducted in the third quarter of 2016.

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[70] For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for the 2016/2017 and 2017/2018 Delivery Years. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[71] Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant Delivery Year, the existing commitment was converted to a CP commitment which is subject to the CP performance requirements and Non-Performance Charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.

RPM prices are locational and may vary depending on transmission constraints.[72] 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

66 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
67 See 126 FERC ¶ 61,275 (2009) at P 86.
68 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
69 See 126 FERC ¶ 61,275 (2009) at P 88.
70 See Docket No. ER15-623-000 (December 12, 2014) and 151 FERC ¶ 61,208 (2015).
71 See "PJM Manual 18: PJM Capacity Market," Revision 36 (December 22, 2017) at 8.
72 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.

caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand Resources and Energy Efficiency Resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During 2016, PJM installed capacity increased 4,766.3 MW or 2.7 percent, from 177,682.8 MW on January 1 to 182,449.1 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2016, 36.5 percent was coal; 35.7 percent was gas; 18.1 percent was nuclear; 3.7 percent was oil; 4.9 percent was hydroelectric; 0.6 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Supply.** Total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year decreased 3,709.2 MW from 204,557.3 MW on June 1, 2015, to 200,848.1 MW on June 1, 2016. This decrease was the result of the integration of the East Kentucky Power Cooperative (EKPC) Zone resources (2,735.7 MW), new generation (5,517.4 MW), reactivated generation (751.8 MW), net generation capacity modifications (cap mods) (-3,373.3 MW), Demand Resource (DR) modifications (-10,690.1 MW), Energy Efficiency (EE) modifications (262.5 MW), the EFORd effect due to lower sell offer EFORds (1,039.0 MW), and higher load management UCAP conversion factor (47.8 MW).
- **Demand.** There was a 3,148.1 MW increase in the RPM reliability requirement from 177,184.1 MW on June 1, 2015, to 180,332.2 MW on June 1, 2016. The 3,148.1 MW increase in the RTO Reliability Requirement was a result of a 2,436.8 MW increase in the forecast peak load in UCAP terms holding the Forecast Pool Requirement (FPR) constant at the 2015/2016 level and a 711.3 MW increase attributable to the change in FPR. On June 1, 2016, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 67.8 percent, up from 65.1 percent on June 1, 2015.
- **Market Concentration.** In the 2016/2017 RPM Base Residual Auction, 2016/2017 RPM First Incremental Auction, 2016/2017 RPM Second Incremental Auction, 2016/2017 RPM Third Incremental Auction, 2017/2018 RPM Base Residual Auction, 2017/2018 RPM First Incremental Auction, 2017/2018 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2018/2019 RPM First Incremental Auction, and the 2019/2020 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[73] The TPS test was not applied in the 2016/2017 Capacity Performance (CP) Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. All offers in the CP Transition Auctions were subject to overall offer caps. 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.[74] [75] [76]
- **Imports and Exports.** Of the 4,343.4 MW of imports in the 2019/2020 RPM Base Residual Auction, 3,875.9 MW cleared. Of the cleared imports, 1,828.6 MW (47.2 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,248.9 MW for June 1, 2016, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2016/2017 Delivery Year (14,988.5 MW) less replacement capacity from sources other than Demand Resources and Energy Efficiency (4,739.6 MW).

Market Conduct

- **2016/2017 RPM Base Residual Auction.** Of the 1,199 generation resources which submitted offers, unit-

73 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 (Reliability Pricing Model) § 5.10(a)(ii).

74 See PJM. OATT Attachment DD § 6.5.

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

76 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).

specific offer caps were calculated for 152 generation resources (12.7 percent). The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 were based on the technology specific default (proxy) ACR values.

- **2016/2017 RPM First Incremental Auction.** Of the 115 generation resources which submitted offers, unit-specific offer caps were calculated for 37 generation resources (32.2 percent). The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM Second Incremental Auction.** Of the 101 generation resources that submitted offers, the MMU calculated offer caps for 45 generation resources (44.6 percent), of which 21 were based on the technology specific default (proxy) ACR values and 24 were unit-specific offer caps (23.8 percent).
- **2016/2017 Capacity Performance Transition Incremental Auction.** All 709 generation resources which submitted offers in the 2016/2017 CP Transition Incremental Auction were subject to an offer cap of $165.27 per MW-day, which is 50 percent of the Net Cost of New Entry (CONE) used in the 2016/2017 RPM Base Residual Auction.
- **2016/2017 RPM Third Incremental Auction.** Of the 296 generation resources that submitted offers, the MMU calculated offer caps for 52 generation resources (17.6 percent), of which 35 were based on the technology specific default (proxy) ACR values and 17 were unit-specific offer caps (5.7 percent).
- **2017/2018 RPM Base Residual Auction.** Of the 1,202 generation resources which submitted offers, unit-specific offer caps were calculated for 131 generation resources (10.9 percent). The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values.
- **2017/2018 Capacity Performance Transition Incremental Auction.** All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is 60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.
- **2017/2018 RPM First Incremental Auction.** Of the 118 generation resources that submitted offers, the MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 were based on the technology specific default (proxy) ACR values and 17 were unit-specific offer caps (14.4 percent).
- **2017/2018 RPM Second Incremental Auction.** Of the 95 generation resources that submitted offers, the MMU calculated offer caps for 35 generation resources (36.8 percent), of which 15 (15.8 percent) were based on the technology specific default (proxy) ACR values and 20 (21.1 percent) were unit-specific offer caps.
- **2018/2019 RPM Base Residual Auction.** Of the 473 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 (35.1 percent) were based on the technology specific default (proxy) ACR values and 53 were unit-specific offer caps (11.2 percent). Of the 992 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 35 generation resources (3.5 percent).
- **2018/2019 RPM First Incremental Auction.** Of the 80 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 (22.5 percent) were based on the technology specific default (proxy) ACR values and 12 (15.0 percent) were unit-specific offer caps. Of the 293 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for nine generation resources (3.1 percent).
- **2019/2020 RPM Base Residual Auction.** Of the 505 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 (33.9 percent) were based on the technology specific default (proxy) ACR values and 41 were unit-specific offer caps (8.1 percent). Of the 1,003 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 25 generation resources (2.5 percent).

Market Performance

- The 2016/2017 RPM Third Incremental Auction, 2019/2020 RPM Base Residual Auction, the

2017/2018 RPM Second Incremental Auction, and 2018/2019 RPM First Incremental Auction were conducted in 2016. The weighted average capacity price for the 2017/2018 Delivery Year is $141.93 per MW-day, including all RPM Auctions for the 2017/2018 Delivery Year held through 2016. The weighted average capacity price for the 2018/2019 Delivery Year is $177.38, including all RPM Auctions for the 2018/2019 Delivery Year held through 2016. The weighted average capacity price for the 2019/2020 Delivery Year is $114.30, including all RPM Auctions for the 2019/2020 Delivery Year held through 2016. RPM net excess increased 1,329.5 MW from 5,855.9 MW on June 1, 2015, to 7,185.4 MW on June 1, 2016.

- For the 2016/2017 Delivery Year, RPM annual charges to load are $7.7 billion.
- The delivery year weighted average capacity price was $160.01 per MW-day in 2015/2016 and $121.84 per MW-day in 2016/2017.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2016 was 6.3 percent, a decrease from 7.0 percent for 2015.[77]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2016 was 83.4 percent, a decrease from 83.6 percent for 2015.
- **Outages Deemed Outside Management Control (OMC).** In 2016, 4.0 percent of forced outages were classified as OMC outages, a decrease from 4.2 percent in 2015.

Section 5 Recommendations[78]

The MMU recognizes that PJM has implemented the Capacity Performance Construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance Construct addresses many of the MMU's recommendations. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[79]

- The MMU recommends the extension of minimum offer price rule (MOPR) to all existing and proposed units in order to protect competition in the capacity market from external subsidies. (Priority: High. New recommendation. Status: Not adopted.)
- 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.[80] [81] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- 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 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 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.[82] [83]

77 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data was downloaded from the PJM GADS database on January 28, 2016. 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.

78 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.

79 *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (June 9, 2015).

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

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

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

83 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

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 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, 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.[84] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends two changes to the RPM solution methodology related to make whole payments and the iterative reconfiguration of the VRR curve:
  - The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends the following changes with respect to capacity imports into PJM:
  - 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 as close to full substitutes for internal, physical capacity resources as possible. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported Q1, 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 improvements to the performance incentive requirements of RPM:
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted. Pending before FERC.)
  - The MMU recommends that retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported Q3, 2016. Status: Not adopted.)
- The MMU recommends that treatment of costs in RMR filings be emphasized. Customers should bear all 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. Generation owners should bear all other costs. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. (Priority: Medium. First reported 2016. 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 but did not when EE was first added to the capacity market. 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 if PJM releases capacity in Incremental Auctions, PJM should offer the capacity for sale at the BRA clearing price in order to

84 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).

avoid suppressing the IA price below the competitive level. If the PJM sale price is not the BRA clearing price, PJM should not reveal its proposed sale price. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM eliminate the requirement for First and Second Incremental Auctions and hold such auctions only if required based on increases in the Reliability Requirement above defined thresholds. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends 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 they need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)
- 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 2013. Status: Adopted 2015.)
- The MMU recommends that the definition of demand side resources be modified in order 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. Status: Adopted 2015.)
- The MMU recommends that all capacity imports have firm transmission to the PJM border acquired prior to offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- 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.[85] (Priority: Medium. First reported 2013. Status: Adopted 2015.)

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.

85 See OATT Attachment DD § 10(e). For more on this issue and related incentive issues, see the MMU's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

The MMU found serious market structure issues, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in 2016. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM capacity market results were competitive in 2016.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[86] [87] [88] [89] [90] In 2015 and 2016, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2. The capacity performance modifications to the RPM construct have significantly improved the capacity market and addressed many of the issues identified by the MMU. The MMU will publish more detailed reports on the CP Transition Incremental Auctions which include more specific issues and suggestions for improvements.

The issue of external subsidies emerged more fully in 2016. The subsidies are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings and the Illinois ZEC subsidy proceeding all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market based mechanisms available to all market participants on a competitive basis and without discrimination.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies. Fortunately, this can be accomplished quickly by expanding the coverage of an existing rule that already reflects stakeholder compromises.

PJM markets have no protection against this emergent threat. Accurate signals for entry and exit are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions. The current MOPR only addresses subsidies for new entry. The current subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources. The MOPR should be expanded to address subsidies for existing units, and this should be done expeditiously. This issue will not become moot unless and until the MOPR is reformed. Action is needed to correct the MOPR immediately. An existing unit MOPR is the best means to defend the PJM markets from the threat posed by subsidies intended to forestall retirement of financially distressed assets. The role of subsidies to renewables should also be clearly defined and be incorporated in this rule.

While the existing unit MOPR would protect markets in the short run, the underlying issues that have resulted in the pressure on markets should also be examined. Unit owners are seeking subsidies because gas prices are low resulting in low energy market margins and because flaws in the PJM capacity design have led to very substantial price suppression over the past 10 years.

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

86 See "Analysis of the 2016/2017 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_20162017_RPM_Base_Residual_Auction_20140418.pdf> (April 18, 2014).

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

88 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).

89 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).

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

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

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

Overview: Section 6, "Demand Response"

Overview

- **Demand Response Jurisdiction.** In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated Order No. 745, which provided for payment of demand-side resources at full LMP.[91] The court found that the FERC lacked jurisdiction to issue Order No. 745 because the "rule entails direct regulation of the retail market - a matter exclusively within state control."[92] On January 25, 2016, the U.S. Supreme Court voted 6-2 to reverse the decision of the lower court.[93] The result is that FERC retains jurisdiction over demand-side programs.
- **Demand Response Activity.** Demand response includes the economic program and the emergency program. The economic program includes the response to energy prices in the energy market. The emergency and pre-emergency program are part of the capacity market program which includes both capacity payments and associated energy revenues when the capacity is called on to respond.[94] In 2016, the emergency program accounted for 99.0 percent of all revenue received by demand response providers, the economic program for 0.5 percent and synchronized reserve for 0.5 percent. Total emergency revenue decreased by $163.2 million, or 20.1 percent, from $812.2 million in 2015 to $649.0 million in 2016. Capacity market revenue, which comprised 100.0 percent of the emergency demand response program in 2016, decreased by $162.7 million, or 20.0 percent, from $811.7 million in 2015 to $649.0 million in 2016.[95]

  Economic program revenue decreased by $4.7 million, from $8.0 million in 2015 to $3.3 million in 2016, a 58.8 percent decrease.[96] Synchronized reserve revenue decreased by $1.6 million, from $5.0 million in 2015 to $3.4 million in 2016, a 32.0 percent decrease.

  Total demand response revenue decreased by 169.5 million, from $825.2 million in 2015 to $655.7 million in 2016, a 20.5 percent decrease. Not all DR activities in 2016 had been reported to PJM at the time of this report.

  All demand response energy payments are uplift. LMP does not cover demand response energy payments although emergency demand response can and does set LMP. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Economic demand response energy costs are paid by 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 single system price determined under the net benefits test for that month.[97]

91 Electric Power Supply Association v. FERC, No. 11-1486, *petition for en banc review denied; see Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011); *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011); *order on reh'g*, Order No. 745-B, 138 FERC 61,148 (2012).

92 *Id.*

93 FERC v. Electric Power Supply Association, Slip Op. No. 14-840.

94 Throughout this document, emergency demand response refers to both emergency and pre-emergency demand response.

95 The total credits and MWh numbers for demand resources were calculated as of January 10, 2017 and may change as a result of continued PJM billing updates.

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

97 PJM: "Manual 28: Operating Agreement Accounting," Revision 75 (November 18, 2016), p 77.

- **Demand Response Market Concentration.** The ownership of economic demand response was highly concentrated in 2015 and 2016. The HHI for economic demand response reductions decreased from 7834 in 2015 to 7729 in 2016. The ownership of emergency demand response was moderately concentrated in 2016. The HHI for emergency demand response registrations was 1497 for the 2015/2016 Delivery Year and 1469 for the 2015/2016 Delivery Year. In the 2016/2017 Delivery Year, the four largest companies contributed 66.6 percent of all registered emergency demand response resources.
- **Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes, only if the subzone is defined at least one day before it is dispatched and only until PJM removes the definition of the subzone. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation resources.

Section 6 Recommendations

The MMU recognizes that PJM incorporated some of the recommendations related to Demand Response in the Capacity Performance filing. The status of each recommendation reflects the status at December 31, 2016.

- The MMU recommends, as a preferred alternative to having PJM demand side programs, that demand response be on the demand side of the markets and that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion and that customer payments be determined only by metered load. (Priority: High. First reported 2014. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the emergency load response program be treated as an economic resource, responding to economic price signals like other capacity resources and not an emergency program responding only after an emergency is called, and not triggering the definition of a PJM emergency and not triggering a Performance Assessment Hour under the new PJM Capacity Market rules. (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 a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[98] (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 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.)

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

- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[99] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Not 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 to terminate registrations that are no longer capable of responding to PJM dispatch directives because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzone and maintain a public record of all created and removed subzones. (Priority: Low. First reported Q3, 2016. Status: Not adopted.)
- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year. (Priority: High. First reported 2011. Status: Partially adopted.[100])
- 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 capping 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 capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted, 2014.)

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

99 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 June 29, 2016) 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.

100 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

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 the value of the uses of 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.

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 and not be limited to a small number of hours.

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

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

In order to be a substitute for generation, compliance by demand resources to 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 Hours (PAH) will be measured on an hourly 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 registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative, demand response should be on the demand side of the capacity market rather than on the supply side. Rather than complex 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.

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

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

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

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

This approach would work under the current RPM design and this approach would work under the CP design. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side. This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

Overview: Section 7, "Net Revenue"

Net Revenue

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Natural gas prices and energy prices were lower in 2016 than in 2015 which affected energy market revenue for all plant types. Capacity prices for calendar year 2016 were lower than in 2015 in all zones except PSEG which affected capacity market revenues for all plant types.
- In 2016, average energy market net revenues increased by 21 percent for a new CT and 14 percent for a new CC. In 2016, average energy market net revenues decreased 54 percent for a new CP, 86 percent for a new DS, 26 percent for a new nuclear plant, 19 percent for a new wind installation, and 28 percent for a new solar installation.
- The results are very sensitive to the relative prices of fuel. For example, gas prices increased in December. While the marginal cost of the new CC was still below that of the new CP, the marginal cost of the new CT was above that of coal in December. As a result, CT hours dropped significantly and CP hours increased in all zones and substantially in some zones.
- Capacity prices for calendar year 2016 were lower than in 2015 in all zones except PSEG. Capacity revenue accounted for 43 percent of total net revenues for a new CT, 32 percent for a new CC, 55 percent for a new CP, 96 percent for a new DS, and 23 percent for a new nuclear plant.
- In 2016, a new CT would have received sufficient net revenue to cover levelized total costs in 13 of the 20 zones. The zones in which a new CT would not have recovered levelized costs were western zones in which lower capacity prices were not offset by changes in energy net revenues.
- In 2016, a new CC would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional five zones.
- In 2016, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.

- In 2016, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2016, net revenues covered more than 33 percent of the annual levelized total costs of a new entrant wind installation in ComEd, 49 percent of the annual levelized total costs of a new entrant wind installation in PENELEC and 198 percent of the annual levelized total costs of a new entrant solar installation in PSEG. Renewable energy credits accounted for three percent of the total net revenue of a wind installation in ComEd and 37 percent of the total net revenue of a wind installation in PENELEC. Renewable energy credits accounted for 83 percent of the total net revenue of a solar installation in PSEG.
- In 2016, 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 2016, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for most units and technology types in PJM, with the exception of some coal units.
- The actual net revenue results show that 96 units with 14,500 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire. Of the 96 units, 55 are CTs and account for 1,408 MW and 25 are coal units and account for 11,282 MW.

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through 2016. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.

Section 7 Conclusion

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

Unlike cost of service regulation, markets do not guarantee that units will cover their costs. New CT and CC units that began operation in 2007 have not covered their total costs from energy market and capacity market revenues through December 2016 in the ComEd Zone, in the PSEG Zone and in the BGE Zone. New CT and CC units that began operation on June 1, 2012, have covered or more than covered their total costs in the PSEG Zone and the BGE Zone through December 2016 and have not covered their total costs in the ComEd Zone through December 2016.

Overview: Section 8, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[101]
- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine 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.[102] In January 2016, the EPA began the implementation of the Cross-State Air Pollution Rule (CSAPR) to address this issue through an interstate emissions trading regime.[103]
- **National Emission Standards for Reciprocating Internal Combustion Engines.** On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs.[104] On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. The provisions that allowed RICE participating in emergency demand response programs to operate for additional hours have been eliminated.[105] Zero hours are exempt.[106] As a result, the national emissions standards uniformly apply to all RICE.[107] All RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[108]
- **Greenhouse Gas Emissions Rule.** On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan).[109] The rule requires that individual state plans be submitted by September 6, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay of the rule that will prevent its taking effect until judicial review is completed.[110]
- **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.[111] The rule is implemented as National Pollutant Discharge Elimination System (NPDES) permits are issued, with exceptions in certain cases for permits expiring prior to July 14, 2018.
- **Waste Disposal.** On December 19, 2014, the EPA issued its Coal Combustion Residuals rule (CCRR), effective October 19, 2015. The rule sets nonbinding criteria for coal ash disposal facilities.

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** A New Jersey rule that imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on high electric demand days (HEDD).[112] 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.[113]

101 *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 (February 16, 2012).

102 CAA § 110(a)(2)(D)(i)(I).

103 Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) ("CSAPR").

104 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

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

106 *Id.*

107 *Id.*

108 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations); 0 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

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

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

111 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).

112 N.J.A.C. § 7:27–19.

113 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).

- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards ("MPS") and Combined Pollutants Standards ("CPS") that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA MATS rule.[114]
- **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. The auction price in the December 7, 2016, auction for the 2015-2017 compliance period was $3.55 per ton. The clearing price is equivalent to a price of $3.91 per metric tonne, the unit used in other carbon markets.

State Renewable Portfolio Standards

Many states in PJM have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of December 31, 2016, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky and Tennessee did not have renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[115]

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On December 31, 2016, 89.4 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 93.4 percent of fossil fuel fired capacity in PJM had NO_X emission control technology.

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.)

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. The extension of the RPS concept to include nuclear power as a zero emissions source in order to provide subsidies to nuclear power will increase this impact. 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.[116]

RECs, federal investment tax credits and federal production tax credits provide out of market payments to qualifying resources, primarily wind and solar, which create an incentive to generate MWh until the LMP is equal to the marginal cost of producing power minus the credit received for each MWh. The same is true for nuclear power credits, ZECs (zero emissions credits). The credits provide an incentive to make negative energy offers and more generally provide an incentive to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for

114 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

115 See Enr. Com. Sub. For H. B. No. 2001.

116 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.").

the ability to purchase or sell RECs. REC markets are not transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. 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 PJM 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 resources by reducing the risks associated with lack of transparent market data. This would be a significant improvement even if some unusual or unique types of RECs remained outside this market.

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 bids 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 ensure 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 for states to comply with the EPA's Clean Power Plan, for example by incorporating a 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 carbon price would be the most efficient way to implement that decision. It would also be an alternative to specific subsidies to individual nuclear power plants 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 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.

Overview: Section 9, "Interchange Transactions"

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2016, PJM was a monthly net importer of energy in the Real-Time Energy Market in January through May and a monthly net exporter of energy in the Real-Time Energy Market in the remaining months.[117] In 2016, the real-time net interchange of -9,153.6 GWh was lower than the net interchange of 15,717.4 GWh in 2015.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2016, PJM was a monthly net importer of energy in the Day-Ahead Energy Market in January, February, March, April and November and a monthly net exporter of energy in the Day-Ahead Energy Market in the remaining months. In 2016, the total day-ahead net interchange of -9,182.4 GWh was lower than net interchange of 1,603.1 GWh in 2015.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2016, gross imports in the Day-Ahead Energy Market were 135.4 percent of gross imports in the Real-Time Energy Market (81.7 percent in 2015). In 2016, gross exports in the Day-Ahead Energy Market were 127.8 percent of the gross exports in the Real-Time Energy Market (114.5 percent in 2015).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2016, there were net scheduled exports at nine of PJM's 20 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2016, there were net scheduled exports at ten of PJM's 18 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[118]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2016, there were net scheduled

117 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.
118 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

exports at nine of PJM's 20 interfaces in the Day-Ahead Energy Market.

- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2016, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Up to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2016, up to congestion transactions were net exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Market.
- **Inadvertent Interchange.** In 2016, net scheduled interchange was -9,154 GWh and net actual interchange was -7,967 GWh, a difference of 1,186 GWh. In 2015, the difference was 349 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 2016, the Wisconsin Energy Corporation (WEC) interface had the largest loop flows of any interface with -2,856 GWh of net scheduled interchange and 9,774 GWh of net actual interchange, a difference of 12,630 GWh. In 2016, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 13,849 GWh of net scheduled interchange and 27,584 GWh of net actual interchange, a difference of 13,735 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2016, 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 58.1 percent of the hours.
- **PJM and New York ISO Interface Prices.** In 2016, 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 56.3 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 2016, 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 62.2 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2016, 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 60.5 percent of the hours.
- **Hudson DC Line.** In 2016, 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 11.2 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued nine TLRs of level 3a or higher in 2016, compared to 22 such TLRs issued in 2015.
- **Up to congestion.** There was an increase in up to congestion volume starting in December 2015, coincident with the expiration of the fifteen month limit on the payment of prior uplift charges.[119] The average number of up to congestion bids submitted in the Day-Ahead Energy Market increased by 80.0 percent, from 86,656 bids per day in 2015 to 156,021 bids per day in 2016. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 78.5 percent, from 462,118 MWh per day in 2015, to 824,885 MWh per day in 2016.
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[120] [121] 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.[122]

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

119 148 FERC ¶ 61,144 (2014).*Order Instituting Section 206 Proceeding and Establishing Procedures*. 16 U.S.C. § 824e.

120 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).

121 See Letter Order, Docket No. ER14-381-000 (June 30, 2014).

122 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)

- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point-to-point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible

product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Adopted partially, 2015.)

- 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. Status: Adopted partially, 2013.)

Section 9 Conclusion

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

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.[123]

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off-line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. The primary reserve requirement in the RTO Zone was raised on January 8, 2015, to 2,175 MW of which at least 1,700 MW must be available within the Mid-Atlantic Dominion (MAD) Subzone. Adjustments to the primary reserve requirement can occur when grid maintenance or outages change the largest contingency. The hourly average primary reserve requirement in the RTO Zone in 2016 was 2,185.7 MW. The primary reserve requirement in the MAD Subzone was 1,710.7 MW.

Tier 1 Synchronized Reserve

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

Tier 1 synchronized reserve is part of primary reserve and 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 reserve. The market solution estimates tier 1

123 See PJM. "Manual 10: Pre-Scheduling Operations," Revision. 34 (July 1, 2016), p. 24.

synchronized reserve as available 10-minute ramp from the energy dispatch. In 2016, there was an average hourly supply of 1,263.1 MW of tier 1 for the RTO Synchronized Reserve Zone, and an average hourly supply of 1,081.8 MW of tier 1 in the Mid-Atlantic Dominion Subzone.

- **Demand.** The default hourly required synchronized reserve requirement is 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid the average of five minute LMPs during the event, rather than hourly integrated LMP, plus $50/MW. This is the Synchronized Energy Premium Price. The synchronized reserve event response credits for tier 1 response are independent of the tier 2 synchronized reserve market clearing price and independent of the nonsynchronized reserve market clearing price.

  Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 75.1 percent actually responded during the six distinct synchronized reserve events with duration of 10 minutes or longer in 2016.
- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is the five-minute LMP plus $50 per MWh. A tariff change included in the shortage pricing tariff changes (October 1, 2012) added the requirement to pay tier 1 synchronized reserve the tier 2 synchronized reserve market clearing price whenever the non-synchronized 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, resulting in a windfall payment of $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015 and in 2016, payments to tier 1 synchronized reserve resources when the NSRMCP was above $0.00 were $4,948,084.

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 incur costs to be synchronized, that have an obligation to respond with corresponding penalties, and that must be dispatched in order to satisfy the synchronized reserve requirement.

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

Market Structure

- **Supply.** In 2016, the supply of offered and eligible synchronized reserve was 21,090.2 MW in the RTO Zone of which 6,921.2 MW (including 1,506.0 MW of DSR) was available to the MAD Subzone.
- **Demand.** The default hourly required synchronized reserve requirement was 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves. After subtracting the tier 1 synchronized reserve estimate from the default requirement, the hourly average required tier 2 synchronized reserve was 315.6 MW in the MAD Subzone and 563.1 MW in the RTO.
- **Market Concentration.** In 2016, the weighted average HHI for tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 6116 which is classified as highly concentrated. The MMU calculates that 87.2 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone.

  In 2016, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 5092 which is classified as highly concentrated. The MMU calculates that 45.3 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone.

  The MMU concludes from these results that 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 2016.

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. 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. There has been less than complete compliance with the tier 2 synchronized reserve must offer requirement.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) Subzone was $4.15 per MW in 2016, a decrease of $5.97, 41.0 percent, from 2015.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $4.88 per MW in 2016, a decrease of $7.00, 58.9 percent, from 2015.

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. The market 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.

Market Structure

- **Supply.** In 2016, the supply of eligible nonsynchronized reserve was 2,358.2 MW in the RTO Zone and 1,726.9 MW in the MAD Subzone.
- **Demand.** Demand for nonsynchronized reserve is the remaining primary reserve requirement after tier 1 synchronized reserve is estimated and tier 2 synchronized reserve is scheduled.[124] In the RTO Zone, the market cleared an hourly average of 919.6 MW of nonsynchronized reserve in 2016. The MAD Subzone cleared an average of 341.0 MW in 2016.
- **Market Concentration.** In 2016, the weighted average HHI for cleared nonsynchronized reserve in the MAD Subzone was 3459 which is classified as highly concentrated. In the RTO Zone the weighted average HHI was 3436, which is also highly concentrated. The MMU calculates that 53.3 percent of hours would have failed a three pivotal supplier test in the MAD Subzone and 1.2 percent of hours would have failed a three pivotal supplier test in the RTO Zone.

Market Conduct

- **Offers.** No offers are made for nonsynchronized reserve by resource owners. 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 cleared hours (284 hours) in the RTO Reserve Zone was $0.21 per MW in 2016 and in 97.6 percent of hours the market clearing price was $0.00. The MAD Subzone cleared separately from the RTO Zone in 27 hours in 2016, with a weighted average price of $0.21.

Secondary Reserve

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve

124 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. "

requirement but does not have a goal to maintain this reserve requirement in real time.

PJM maintains a day-ahead, offer based market for 30-minute day-ahead secondary reserve.[125] The Day-Ahead Scheduling Reserves 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.[126]

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 thirty minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In 2016, the average available hourly DASR was 34,776 MW.
- **Demand.** The DASR requirement in 2016 was 5.70 percent of peak load forecast, down from 5.93 percent in 2015. The average DASR MW purchased was 4,996.8 MW per hour in 2016.
- **Concentration.** In 2016, the DASR Market failed the three pivotal supplier test in 18.3 percent of hours.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In 2016, a daily average of 36.2 percent of units offered above $0.00. In 2016, a daily average of 13.3 percent of units offered above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR.

Market Performance

- **Price.** In 2016, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.61, a decrease from $2.99 per MW in 2015.

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 lost opportunity cost. The RegA signal is designed for energy unlimited resources with physically constrained ramp ability. The RegD signal is designed for energy limited resources with very fast ramp rates. In the Regulation Market RegD MW are converted to marginal effective MW using a marginal rate of substitution (MRTS), called a marginal benefit function (MBF). Correctly implemented, the MBF would define and be used as 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 2016, the average hourly eligible supply of regulation for off peak hours was 1,243.6 actual MW (941.3 effective MW). This was an increase of 87.1 actual MW (an increase of 75.0 effective MW) from 2015, when the average hourly eligible supply of regulation was 1,156.5 actual MW (866.3 effective MW). In 2016, the average hourly eligible supply of regulation for on peak hours was 1,155.4 actual MW (920.2 effective MW). This was a decrease of 3.9 actual MW (an increase of 3.4 effective MW) from 2015, when the average hourly eligible supply of regulation was 1,159.3 actual MW (916.8 effective MW).
- **Demand.** The hourly regulation demand was set to 525.0 effective MW for off peak hours (00:00 to 04:59) and 700.0 effective MW for on peak hours (05:00 to 23:59).
- **Supply and Demand.** The off peak regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources totaling, on an hourly average basis, 516.1 actual

125 See PJM. "Glossary,"<http://www.pjm.com/Glossary.aspx>.
126 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 166 §11.1.

MW in 2016. This is an increase of 7.2 actual MW from 2015, when the average hourly total regulation cleared MW for off peak hours were 508.9 actual MW. The peak regulation requirement of 700.0 effective MW was provided by a combination of RegA and RegD resources totaling, on an hourly average basis, 635.9 actual MW in 2016. This is a decrease of 39.6 actual MW from 2015, where the average hourly regulation cleared MW for on peak hours were 675.5 actual MW.

The ratio of the average hourly eligible supply of regulation to average hourly regulation demand for on peak hours was 1.82 in 2016. This is an increase of 5.8 percent from 2015, when the ratio was 1.72. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required for off peak hours was 2.41 in 2016. This is an increase of 6.2 percent from the same period of 2015, when the ratio was 2.27.

- **Market Concentration.** In 2016, the three pivotal supplier test was failed in 92.2 percent of hours. In 2016, the weighted average HHI of RegA resources was 2748, which is highly concentrated and the weighted average HHI of RegD resources was 1864, which is highly concentrated. The weighted average HHI of all resources was 1156 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.[127] In 2016, there were 238 resources following the RegA signal and 55 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $15.72 per effective MW of regulation in 2016, a decrease of $16.20 per MW, or 50.8 percent, from the same period of 2015. The cost of regulation in 2016 was $18.13 per effective MW of regulation, a decrease of $20.23 per MW, or 52.7 percent, from 2015. The decreases in regulation price and regulation cost in 2016 resulted primarily from reductions in the LOC component of the regulation clearing prices due to lower energy prices in 2016 compared to 2015.

- **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, pricing, and settlement processes. If the Regulation Market were functioning efficiently, RegD and RegA resources would be paid the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the marginal benefit factor is not used in settlements. When the marginal benefit factor is above one, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the MBF is less than one, RegD resources are generally overpaid on a per effective MW basis. Currently, the MBF is less than one, resulting in persistent overpayment of RegD resources that creates an artificial incentive for inefficient entry of RegD resources. The MBF averaged less than one in each month of 2016, resulting in RegD resources being paid 1,565.7 percent more than they should have in 2016. In 2015, the MRTS averaged greater than one, resulting in RegD resources being paid 28.0 percent less than they should have been.

- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) is intended to measure the substitutability of RegD resources for RegA resources. The marginal benefit factor function is currently incorrectly defined and applied in the PJM market clearing and incorrectly describes the operational relationship between RegA and RegD regulation resources. Correctly defined, the MBF function represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation Market clearing and settlement. The current incorrect and inconsistent implementation of the MBF function has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours

127 See the *2016 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

and in a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. 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.

- **Interim changes to the MBF function.** On December 14, 2015, PJM changed the MBF curve in an attempt to reduce the over procurement of RegD. The modification to the marginal benefit curve did not correct the identified issues.
- **Changes to the Regulation Market.** Changes were approved by the Regulation Market Issues Senior Task Force ("RMISTF"), which went into effect in January of 2017. These include changing the definition of off-peak and on-peak hours (now called off-ramp and on-ramp hours) based on the season, increasing the effective MW requirement during on-ramp hours from 700 MW to 800 MW, 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 conditional neutrality requirement.

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).[128]

In 2016, total black start charges were $67.0 million with $66.7 million in revenue requirement charges and $278.0 thousand in 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. 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 for 2016 ranged from $0.08 per MW-day in the DLCO Zone (total charges were $78,423) to $4.09 per MW-day in the PENELEC Zone (total charges were $4,528,821).

128 OATT Schedule 1 § 1.3BB.

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 voltages on the transmission system and is essential to the flow of real power (measured in MW).

Reactive capability revenue requirements are based on FERC approved filings. Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing units in real time that provide reactive service. In 2016, total reactive charges were $303.7 million, a 5.7 percent increase from $287.2 million in 2015. Reactive capability revenue requirement charges increased from $276.7 million in 2015 to $301.2 million and reactive service charges fell from $10.5 million to $2.5 million in 2016. Total charges in 2016 ranged from $37 in the RECO Zone to $37.6 million in the AEP Zone.

Section 10 Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that 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, to prevent gaming. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated

using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.)

- The MMU recommends that the rule requiring the payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is above zero be eliminated immediately and that 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. 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: Not adopted.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM replace the DASR Market with a real-time secondary reserve product that is available and dispatchable in real time. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the three pivotal supplier test and market power mitigation be incorporated in the DASR Market. (Priority: Low. First reported 2009. 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 separate 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 a number of market design changes to improve the performance of the Regulation Market, including use of a single five minute clearing price based on actual LMP and actual LOC, modifications to the LOC calculation, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- The MMU recommends that PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM. (Priority: Low. First reported 2013. Status: Partially adopted, 2014.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted.)
- The MMU recommends that no payments be made to tier 1 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.)

Section 10 Conclusion

The design of the PJM Regulation Market is significantly flawed. The market design has failed to correctly incorporate the marginal benefit factor, or marginal rate of technical substitution, in optimization, pricing and settlement. The market design uses the marginal benefit factor in the optimization (incorrectly) and pricing (correctly), but a mileage ratio instead of the marginal benefit factor in settlement. This failure to correctly and consistently incorporate marginal benefit factor 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 have led to the MMU's conclusion that the regulation market design is flawed.

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, compliance with calls to respond to actual synchronized reserve events, while showing improvement in 2016 remains less than 100 percent. For the six spinning events 10 minutes or longer in 2016, the average tier 2 synchronized reserve response was 85.5 percent of all scheduled MW.

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. Such 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 paid for their response if they do respond. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations. Overpayment of tier 1 resources based on this rule added $89.7 million to the cost of primary reserve in 2014, $34.1 million in 2015, and $4.9 million in 2016.

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

The MMU concludes that the regulation market results were competitive, although the market design is flawed. The MMU concludes that the synchronized reserve market results were competitive. The MMU concludes that the DASR market results were competitive, although there is concern about offers above the competitive level affecting prices.

Overview: Section 11, "Congestion and Marginal Losses"

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $361.6 million or 26.1 percent, from $1,385.3 million in 2015 to $1,023.7 million in 2016.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $531.7 million or 32.6 percent, from $1,632.1 million in 2015 to $1,100.4 million in 2016.
- **Balancing Congestion.** Balancing congestion costs increased by $170.1 million or 68.9 percent, from -$246.9 million in 2015 to -$76.8 million in 2016.
- **Real-Time Congestion.** Real-time congestion costs decreased by $451.3 million or 30.0 percent, from $1,504.9 million in 2015 to $1,053.6 million in 2016.
- **Monthly Congestion.** Monthly total congestion costs in 2016 ranged from $48.0 million in November to $121.4 million in September.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Conastone – Northwest Line, the Graceton Transformer, the Bagley – Graceton Line, the Cherry Valley Transformer, and the Cherry Valley Flowgate.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2016. The number of congestion event hours in the Day-Ahead Energy Market was about ten times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion event hours decreased significantly after September 8, 2014. The decrease was the result of the reduction in up to congestion (UTC) activity which was a result of FERC's UTC uplift refund notice, retroactive to September 8, 2014. However, day-ahead congestion frequency increased by 48.9 percent from 184,851 congestion event hours in 2015 to 275,298 congestion event hours in 2016. The increase was a result of the increase in UTC transactions that followed the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[129]

Real-time congestion frequency decreased by 7.6 percent from 28,524 congestion event hours in 2015 to 26,369 congestion event hours in 2016.

- **Congested Facilities.** Day-ahead, congestion-event hours decreased on flowgates and interfaces and increased on lines and transformers. Real-time, congestion-event hours increased on flowgates and decreased on interfaces, lines and transformers.

  While Bedington - Black Oak, SENECA and AP South were in the list of constraints that were most frequently binding in the day-ahead market in 2015, interfaces did not bind as frequently in the day-ahead market in 2016.

  The Conastone – Northwest Line was the largest contributor to congestion costs in 2016. With $115.5 million in total congestion costs, it accounted for 11.3 percent of the total PJM congestion costs in 2016.

- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in 2016. ComEd had $303.6 million in total congestion costs, comprised of -$155.5 million in total load congestion payments, -$471.9 million in total generation congestion credits and -$12.8 million in explicit congestion costs. The Cherry Valley Transformer, the Cherry Valley Flowgate, the Braidwood - East Frankfort Line, the Mercer IP – Galesburg Flowgate, and the Byron - Cherry Valley Flowgate contributed $154.0 million, or 50.7 percent of the total ComEd control zone congestion costs.

- **Ownership.** In 2016, financial entities as a group were net recipients of congestion credits and physical entities were net payers of congestion charges. In 2016, financial entities received $9.4 million in congestion credits compared to $132.1 million in 2015. In 2016, physical entities paid $1,033.0 million in congestion charges, a decrease of $484.3 million or 31.9 percent compared to 2015.

129 *See* FERC Docket No. EL14-37.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $272.2 million or 28.1 percent, from $968.7 million in 2015 to $696.5 million in 2016. The loss MWh in PJM decreased by 1,087.4 GWh or 6.7 percent, from 16,241.3 GWh in 2015 to 15,153.9 GWh in 2016. The loss component of LMP decreased from $0.019 in 2015 to $0.015 or 22.8 percent in 2016.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2016 ranged from $36.6 million in May to $86.4 million in July.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $239.4 million or 23.6 percent, from $1,012.6 million in 2015 to $773.2 million in 2016.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $32.8 million or 74.9 percent, from -$43.9 million in 2015 to -$76.7 million in 2016.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2016 by $109.2 million or 32.5 percent, from $336.3 million in 2015, to $227.2 million in 2016.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $161.1 million or 25.7 percent, from -$627.4 million in 2015 to -$466.3 million in 2016.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $117.3 million or 15.5 percent, from -$757.9 million in 2015 to -$640.6 million in 2016.
- **Balancing Energy Costs.** Balancing energy costs increased by $56.3 million or 44.0 percent, from $127.8 million in 2015 to $184.0 million in 2016.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2016 ranged from -$57.8 million in July to -$26.1 million in May.

Section 11 Conclusion

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

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. Total ARR and self scheduled FTR revenue offset only 63.8 and 86.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 and 2015 to 2016 planning periods. For the first seven months of the 2016 to 2017 planning period ARRs and self scheduled FTRs offset 82.3 percent of total congestion costs.

Overview: Section 12, "Planning"

Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2016, 101,473.5 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 193,407.0 MW as of December 31, 2016. Of the capacity in queues, 13,110.5 MW, or 12.9 percent, are uprates and the rest are new generation. Wind projects account for 14,656.8 MW of nameplate capacity or 14.4 percent of the capacity in the queues. Combined cycle projects account for 69,264.4 MW of capacity or 68.3 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-5, 29,057.5 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 4,965.3 MW are planned to retire after 2016. In 2016, 395.5 MW were retired. Of the 4,965.3 MW pending retirement, 3,649.0 MW are coal units. The coal unit retirements were a result of low gas prices, low capacity prices and the investments required for compliance with the EPA's Mercury and Air Toxics Standards (MATS) for some units.
- **Generation Mix.** A significant shift in the distribution of unit types within the PJM footprint continues as natural gas fired units enter the queue and steam units retire. There are 277.0 MW of coal fired steam capacity and 69,264.4 MW of gas fired capacity in the queue. The replacement of coal steam units by units burning natural gas will significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Generation and Transmission Interconnection Planning Process

- 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.[130] 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 queue contains a substantial number of projects that are not likely to be built. Excluding currently active projects and projects currently under construction, 3,293 projects, representing 453,810.1 MW, have entered the queue process since its inception. Of those, 687 projects, 46,436.0 MW, went into service. Of the projects that entered the queue process, 67.4 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.
- Feasibility, impact and facilities studies may be delayed for reasons including disputes with developers, circuit and network issues and retooling as a result of projects being withdrawn. The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015 to address delays.[131] On May 12, 2016, The EQSTF presented proposed rule changes to the interconnection process. These changes were filed with FERC, and FERC approved the changes, and the PJM Open Access Transmission Tariff was modified effective October 31, 2016.
- 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

130 See PJM, OATT Parts IV & VI.

131 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/task-forces/eqstf.aspx>

in interstate commerce under the tariff."[132] Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of the parent company and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a merchant transmission developer which is a competitor of the transmission owner.

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek in the PSEG Zone. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues and operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. On July 30, 2015, the PJM Board of Managers accepted PJM's recommendation to assign the project to LS Power, a merchant developer, PSEG, and PHI with a total cost estimate between $263M and $283M.[133] [134] On August 5, 2016, PJM announced that the Artificial Island project was to be suspended immediately due to unanticipated project complexities and significant cost overruns. The PJM Board of Managers called for a new review of the project to be completed by PJM by February 2017 in order to assess how to proceed with the project.[135]
- On October 25, 2012, Schedule 12 of the tariff and Schedule 6 of the OA were changed to address FERC Order No. 1000 reforms to the cost allocation requirements for local and regional transmission planning projects that were formerly defined in Order No. 890. The new approach was applied for the first time to the 2013 RTEP. The allocation process has been upheld by the FERC despite repeated challenges.[136]

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects, which are intended to resolve multiple reliability criteria violations and congestion issues and which may have substantial impacts on energy and capacity markets. There are currently three backbone projects under development, Surry Skiffes Creek 500kV, the Northern New Jersey 345 kV Upgrades, and Byron Wayne 345 kV.[137]

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.[138]
- There were 20,214 transmission outage requests submitted in 2016. Of the requested outages, 77.5 percent were planned for five days or shorter and 6.6 percent were planned for longer than 30 days. Of the requested outages, 51.7 percent were late according to the rules in PJM's Manual 3.

132 See PJM, OATT, Part I, § 1 "Definitions"

133 See "Artificial Island Recommendations," presented at the TEAC meeting on April 28, 2015 at <http://www.pjm.com/~/media/committees-groups/committees/teac/20150428-ai/20150428-artificial-island-recommendations.ashx>.

134 See letter from Terry Boston concerning the Artificial Island Project at <http://www.pjm.com/~/media/documents/reports/board-statement-on-artificial-island-project.ashx>.

135 See "PJM Board Statement on Artificial Island Project Suspension." <http://pjm.com/~/media/documents/reports/20160805-artificial-island-update.ashx> Accessed November 7, 2016.

136 *See Delaware PSC v. PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,090 (2016); *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,089 (2016); *Consolidated Edison Company of New York, Inc. v. PJM Interconnection*, 155 FERC ¶ 61,088 (2016); *see also Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom.* S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41, 412 (D.C. Cir. 2014); *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,074 (2013) (accepting the proposed PJM cost allocation method, effective February 1, 2013, subject to the outcome of PJM's Order No. 1000 regional compliance filing proceeding); *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance*, 150 FERC ¶ 61,038 (2015), *order on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).

137 See "2016 RTEP Process Scope and Input Assumptions White Paper," P 23. <http://www.pjm.com/~/media/documents/reports/2016-rtep-process-scope-and-input-assumptions.ashx> Accessed November 7, 2016.

138 PJM. "Manual 03: Transmission Operations," Revision 50 (Dec. 1, 2016), Section 4.

Section 12 Recommendations

The MMU recommends improvements to the planning process.

- 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 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: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants 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 that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[139] (Priority: Low. First reported 2013. Status: Not 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.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends 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. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR

139 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

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.)
- 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 an 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.)

Section 12 Conclusion

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

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

The PJM queue evaluation process should be improved to 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.

The PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and merchant transmission providers. PJM should enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

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

Overview: Section 13, "FTRs and ARRs"

Auction Revenue Rights

Market Structure

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

  In the first seven months of the 2016 to 2017 planning period, PJM allocated a total of 39,233.4 MW of residual ARRs, up from 26,845.4 MW in the first seven months of the 2015 to 2016 planning period, with a total target allocation of $7.0 million for the first seven months of the 2016 to 2017 planning period, down from $7.5 million for the first seven months of the 2015 to 2016 planning period.

- **ARR Reassignment for Retail Load Switching.** There were 43,089 MW of ARRs associated with $504,600 of revenue that were reassigned in the first seven months of the 2015 to 2016 planning period. There were 27,920 MW of ARRs associated with $315,900 of revenue that were reassigned for the first seven months of the 2016 to 2017 planning period.

Market Performance

- **Revenue Adequacy.** For the 2016 to 2017 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $911.4 million, while PJM collected $935.7 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2015 to 2016 planning period, the ARR target allocations were $931.6 million while PJM collected $968.1 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. The year over year decrease in ARR target allocations and auction revenue is a result of decreased prices from the previous planning period resulting from continued reduced allocation of Stage 1B and Stage 2 ARRs. ARR revenue adequacy is also affected by PJM's clearing of additional counter flow FTRs to alleviate infeasibilities from Stage 1A.

- **ARRs as an Offset to Congestion.** ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenue offset only 63.8 percent of total congestion costs, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2014 to 2015 planning period. In the first seven months of the 2016 to 2017 planning period, total ARR and self scheduled FTR revenues offset 82.3 percent of total congestion costs. The total offset for the last six planning periods is 70.9 percent. The goal of the design should be to return 100 percent of the congestion revenues to the load.

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2017 to 2020 Long Term FTR Auction include the St. John's transformer in Dominion and the Elliott-Rosewood Line in AEP. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2016 to 2017 planning period include the Rockwell-Congress Line in AEP and the Graves Mills-Reusens Line in AEP.

  Market participants can sell FTRs. In the 2017 to 2020 Long Term FTR Auction, total participant FTR sell offers were 208,405 MW, down from 327,980 in the 2016 to 2017 Long Term FTR Auction. In the 2016 to 2017 Annual FTR Auction, total participant sell offers were 378, 431 MW, down from 378,744 MW in the 2015 to 2016 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2016 to 2017 planning period, total participant FTR sell offers were 3,173,126 MW, up from 2,078,673 MW for the same period during the 2015 to 2016 planning period.

- **Demand.** In the 2017 to 2020 Long Term FTR Auction, total FTR buy bids were 2,176,871 MW, down 11.5 percent from 2,459,946 MW the previous planning period. There were 2,592,183 MW of buy and self-scheduled bids in the 2016 to 2017 Annual FTR Auction, up 5.3 percent from 2,461,662 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2016 to 2017 planning period increased 51.9 percent from 1,081,644 MW for the same time period of the prior planning period, to 1,642,735 MW.
- **Patterns of Ownership.** For the 2017 to 2020 Long Term FTR Auction, financial entities purchased 77.5 percent of prevailing flow FTRs and 84.9 percent of counter flow FTRs. For the 2016 to 2017 Annual FTR Auction, financial participants purchased 56.9 percent of all prevailing flow FTRs and 79.7 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 71.3 percent of prevailing flow and 74.6 percent of counter flow FTRs for January through December of 2016. Financial entities owned 64.2 percent of all prevailing and counter flow FTRs, including 55.8 percent of all prevailing flow FTRs and 76.0 percent of all counter flow FTRs during the period from January through December 2016.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first seven months of the 2016 to 2017 planning period were $0.4 million for Increment Offers, Decrement Bids and UTC Transactions using PJM's method. Using the proposed MMU approach, total FTR forfeitures would have been $0.6 million.
- **Credit Issues.** There was one collateral default in 2016 which was promptly resolved.

Market Performance

- **Volume.** The 2017 to 2020 Long Term FTR Auction cleared 297,083 MW (13.6 percent) of demand of FTR buy bids, up 7.1 percent from 277,397 MW (11.3 percent) in the 2016 to 2019 Long Term FTR Auction. The Long Term FTR Auction also cleared 36,782 MW (17.6 percent) of FTR sell offers, compared to 61,210 (18.7 percent), a 40.0 percent decrease.

  In the Annual FTR Auction for the 2016 to 2017 planning period 420,198 MW (16.2 percent) of buy and self-schedule bids cleared, up 11.1 percent from 378,328 MW (15.4 percent) for the previous planning period. In the first seven months of the 2016 to 2017 planning period Monthly Balance of Planning Period FTR Auctions 1,642,735 MW (11.0 percent) of FTR buy bids and 707,646 MW (22.3 percent) of FTR sell offers cleared.
- **Price.** The weighted-average buy-bid FTR price in the 2017 to 2020 Long Term FTR Auction was $0.04 per MW, down from $0.05 per MW for the 2016 to 2019 planning period. The weighted-average buy-bid FTR price in the Annual FTR Auction for the 2016 to 2017 planning period was $0.49 per MW, up from $0.31 per MW in the 2015 to 2016 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2016 to 2017 planning period was $0.13, down from $0.25 per MW for the same period in the 2015 to 2016 planning period.
- **Revenue.** The 2017 to 2020 Long Term FTR Auction generated $26.7 million of net revenue for all FTRs, up from $23.2 million for the 2016 to 2019 Long Term FTR Auction. The 2016 to 2017 Annual FTR Auction generated $909.0 million in net revenue, down from $936.3 million for the 2015 to 2016 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $26.7 million in net revenue for all FTRs for the first seven months of the 2016 to 2017 planning period, up from $17.3 million for the same time period in the 2015 to 2016 planning period.
- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first seven months of the 2016 to 2017 planning period. This high level of revenue adequacy was primarily a result of actions taken by PJM to reduce the level of available ARRs and FTRs. PJM's actions included PJM's decision to include more outages and PJM's decision to include additional constraints (closed loop interfaces) in the model, both of which reduced system capability in the FTR auction model. PJM's actions led to a

significant reduction in the allocation of Stage 1B and Stage 2 ARRs.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In 2016, FTRs were profitable overall, with $244.1 million in profits for physical entities, of which $207.0 million was gross revenue from self-scheduled FTRs, and $47.5 million for financial entities.

Section 13 Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[140] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2012. Status: Not adopted.)
- 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 implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Pending before FERC.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013. Status: Adopted partially, 14/15 planning period.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Adopted partially, 14/15 planning period.)
- 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. Status: Adopted 2016.)

Section 13 Conclusion

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to firm transmission service customers, without requiring contract path physical transmission rights that are impossible to define and enforce in LMP markets. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service which results in load paying congestion revenues.

After the introduction of LMP markets, financial transmission rights (FTRs) permitted the loads which pay for the transmission system to continue to receive the benefits of firm low cost generation delivered using the transmission system in the form of revenues which offset congestion. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the

140 See PJM. "Manual 6: Financial Transmission Rights" Revision 17 (June 1, 2016), p. 55.

transmission system which permits low cost generation to be delivered to load and loads pay congestion. Another way of describing the result is that FTRs and the associated revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source congestion revenues in an LMP market. In other words, load payments in excess of generation revenues are the source of the funds to pay 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 to pay back to load the difference between the total load payments and the total generation revenues, which equals total congestion revenues.

With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy.

As a result of the creation of ARRs and other changes to the design, the current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all the congestion revenues and has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 63.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period. For the 2015 to 2016 planning period, ARRs and self scheduled FTRs offset 86.5 percent of total congestion costs. For the first seven months of the 2016 to 2017 planning period ARRs and self scheduled FTRs offset 82.3 percent of total congestion costs.

Load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[141] One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach would ignore the fact that loads must pay both day-ahead and balancing congestion and that congestion is defined, in an accounting sense, to equal the sum of day ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system, would have to continue paying in excess of generator revenues and not have balancing congestion included in the calculation of congestion in order to increase the payout to holders of FTRs who are not loads and who therefore did not receive an allocation of ARRs. In other words, load would have to continue providing all the funding of FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths and result in profits to FTR holders.

The Commission's order will shift substantial revenue from load to the holders of FTRs and reduce the ability of load to offset congestion. If these rules had been in place for the first seven months of the 2016 to 2017 planning period, and ARR/FTR allocations had remained constant, ARR holders would have gone from an offset of 82.3 percent under the current rule, to 77.4 percent under the new rule, a loss of $43.8 million for the first seven months. FTR holders would have received a corresponding windfall and revenues to FTR holder would have exceeded target allocations by $130.7 million.

If these rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received $996.7 million less in congestion offsets from the 2011/2012 through the 2016/2017 planning period. The total overpayment to FTR holders for the 2011/2012 through 2016/2017 planning period would have been $896.1 million. The underpayment to load and the overpayment to FTR holders is a result of several factors in the new rules all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is now required to pay for balancing congestion, which significantly increases costs to load and significantly increases revenues paid to FTR holders. PJM will continue to clear counter flow FTRs using excess auction revenues in order to make it possible to sell more prevailing flow FTRs. FTR holders will receive excess day-ahead congestion revenues in excess of target allocations. FTR holders will receive excess auction revenue, which is what FTR holders were

141 See "FirstEnergy Solutions Corp. Allegheny Energy Supply Company, LLC v PJM Interconnection, LLC," Docket No. EL13-47-000 (February 15, 2013).

willing to pay for FTRs in excess of what is provided to ARR holders.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reporting, distribution of and quantity of funding in the FTR market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy even when defined correctly. Load does have those rights based on load's payment for the transmission system and load's payment of total congestion.

Reported FTR revenue adequacy uses target allocations as the relevant benchmark. But target allocations are not the relevant benchmark. Target allocations are based on day-ahead congestion only, ignoring balancing congestion which is the other part of total congestion. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and balancing markets. When day-ahead congestion differs significantly from balancing congestion, as has occurred only in recent years, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences between the day-ahead and real-time markets. Such differences are not an indication that FTR holders are under paid.

PJM used a more conservative approach to modeling the transmission capability for the 2014 to 2015 through 2016 to 2017 planning periods compared to the 2013 to 2014 planning period. PJM simply used higher outage levels and included additional constraints, both of which reduced system capability in the FTR auction model. The result was a significant reduction in Stage 1B and Stage 2 ARR allocations, and a corresponding reduction in the available quantity of FTRs, an increase in FTR prices and an increase in ARR target allocations. The market response to the reduced supply of FTRs was increased bid prices, increased clearing prices and reduced clearing quantities.

Clearing prices fell and cleared quantities increased from the 2010 to 2011 planning period through the 2013 to 2014 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid volumes and offer volumes. In the 2014 to 2015 and 2015 to 2016 planning periods, due to reduced ARR allocations, FTR volume decreased relative to the 2013 to 2014 planning period. The reduction in ARR allocations and resulting FTR volume caused, by definition, an improvement in revenue adequacy, and also resulted in an increase in the prices of FTRs. Increased FTR prices resulted in increased ARR target allocations, because ARR target allocations are based on the Annual FTR Auction nodal prices.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge. The FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the portfolio subsidy would be a good first step in that direction.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2013 to 2014 planning period would have been 87.5 percent instead of the reported 72.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the impact of lower payouts among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. The FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the counter flow subsidy would be another good step in that direction.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would have increased the calculated payout ratio in the 2013 to 2014 planning period from the reported 72.8 percent to 91.0 percent. For the 2014 to 2015 and 2015 to 2016 planning period the payout ratio was 100 percent. The MMU recommends that counter flow and prevailing flow FTRs be treated symmetrically with respect to the application of a payout ratio.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. Stage 1A ARR overallocation is a source of revenue inadequacy and cross subsidy. The origin and basis for the requirement to assign Stage 1A ARRs needs further investigation. The issues associated with over allocation are based on the use of out of date generation to load ARR paths and on whether PJM has appropriately built transmission to meet the requirement.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit, that the role of out of date generation to load paths be reviewed and that the building of the transmission capability required to provide all defined Stage 1A allocations be reviewed. There is a reason that transmission is not built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR overallocation in the 2013 to 2014 planning period would have increased the payout ratio to 94.6 percent without reducing ARR allocations in Stage 1B and Stage 2.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. These reasons include the inadequate transmission outage modeling in the FTR auction model which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day-ahead and real-time markets, including reactive interfaces, which directly results in differences in congestion between day-ahead and real-time markets; differences in day-ahead and real-time modeling including different line ratings, the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load, which directly results in differences in congestion between day-ahead and real-time markets; the overallocation of ARRs which directly results in a difference between congestion revenue and the payment obligation; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up to congestion transactions to the differences between day-ahead and balancing congestion and thus to FTR payout ratios; the payment of congestion revenues to UTCs; and the continued sale of FTR capability on pathways with a persistent difference between FTRs and total congestion revenue. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion.

It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed away.

For the 2014 to 2015 and 2015 to 2016 planning periods FTRs have been revenue adequate. This is not because the underlying problems have been fixed. Revenue adequacy has been accomplished by limiting the amount of available ARRs and FTRs by arbitrarily decreasing the ARR allocations for Stage 1B and Stage 2 which also results in a redistribution of ARRs based on differences in allocations between Stage 1A and Stage 1B ARRs.

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. 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 or FERC action, that status is noted.

This section of the report presents:

- **New Recommendations:** the list of recommendations that have been reported for the first time in 2016;[6]
- **History of MMU Recommendations:** an analysis of all MMU recommendations from 1999 through 2016;
- **Complete List of Current MMU Recommendations:** the list of current MMU recommendations which are compiled from each of the main sections of the report;
- **Adopted Recommendations:** the list of MMU recommendations which the MMU assesses have been adopted by PJM.

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,"[7] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets

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

6 New or modified recommendations include all MMU recommendations that were reported for the first time, or substantially modified, in the *2016 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2016.
7 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

and for continued improvements in the functioning of PJM markets.

In this *2016 State of the Market Report for PJM*, the MMU includes 23 new recommendations made in 2016.[8]

New Recommendations from Section 3, Energy Market

- The MMU recommends that PJM require that the level of incremental costs includable in cost offers not exceed the unit's short run marginal cost. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that Manual 15 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. New recommendation. 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. New recommendation. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Medium. New recommendation. 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. New recommendation. Status: Not adopted.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. New recommendation. 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 dispatcher to set the LMPs in the real-time market. (Priority: Low. New recommendation. Status: Not adopted.)

New Recommendation from Section 4, Energy Uplift

- The MMU recommends that if PJM believes it appropriate to modify the LMP price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff. (Priority: Medium. First Reported Q3, 2016. Status: Not adopted.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants should 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. New recommendation. Status: Not adopted.)

8 New or modified recommendations include all MMU recommendations that were reported for the first time, or substantially modified, in the *2016 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2016.

New Recommendations from Section 5, Capacity Market

- The MMU recommends the extension of minimum offer price rule (MOPR) to all existing and proposed units in order to protect competition in the capacity market from external subsidies. (Priority: High. New recommendation. Status: Not adopted.)
- 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 as close to full substitutes for internal, physical capacity resources as possible. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported Q1, 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 that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. (Priority: Medium. First reported 2016. 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 but did not when EE was first added to the capacity market. 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.)

New Recommendation from Section 6, Demand Response

- The MMU recommends that PJM not remove any defined subzone and maintain a public record of all created and removed subzones. (Priority: Low. First reported Q3, 2016. Status: Not adopted.)

New Recommendation from Section 10, Ancillary Service Markets

- The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that 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, to prevent gaming. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that separate 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.)

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 over 220 recommendations in the State of the Market Reports. In 2014, the MMU began including a priority and status with each recommendation. In this *2016 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. In addition to the definitions of Adopted, Partially Adopted, and Not Adopted described above, the MMU includes the following 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 issued a different recommendation which superseded the first; and
- **Withdrawn:** The MMU no longer recommends the described action.

Table 2-1 shows the status of all recommendations reported by the MMU from 1999 through 2016. Over that time, 22 percent of all MMU recommendations have been adopted and 61 percent are not adopted. Of the 61 high priority recommendations, 19 (31 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 2016

Status	Priority High	Priority Medium	Priority Low	Total	Percent of Total
Adopted	19	12	18	49	21.7%
Partially Adopted (Continued Recommendation)	5	9	6	20	8.8%
Partially Adopted (Recommendation Closed)	2	4	4	10	4.4%
Partially Adopted (Total)	7	13	10	30	13.3%
Not Adopted	27	59	35	121	53.5%
Not Adopted (Pending before FERC)	3	1	0	4	1.8%
Not Adopted (Stakeholder Process)	4	6	2	12	5.3%
Not Adopted (Total)	34	66	37	137	60.6%
Replaced by Newer Recommendation	1	5	2	8	3.5%
Withdrawn	0	0	2	2	0.9%
Total	61	96	69	226	100.0%

Complete List of Current MMU Recommendations

The following recommendations are explained in greater detail in each section of the report.

Section 3, Energy Market

- The MMU recommends that the market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel-type and parameters as that of their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require that the level of incremental costs includable in cost offers not exceed the unit's short run marginal cost. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that Manual 15 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. New recommendation. 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. New recommendation. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Medium. New recommendation. 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. New recommendation. Status: Not adopted.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. (Priority: High. First reported 2010. 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 offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available 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. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that under the capacity performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine nonperformance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM Energy Market except when cost-based offers exceed $1,000 per

MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)

- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported 2014. 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: Not adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[9] (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted.)
- The MMU recommends that PJM include in the 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] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[11] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM 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 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 continue to enhance its posting of market data to promote

9 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

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 The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)

- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Status: Adopted in full, 2014.)

Section 4, Energy Uplift

- The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to modify the LMP price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff. (Priority: Medium. First Reported Q3, 2016. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Not adopted.)
- The MMU recommends the elimination of the day-ahead operating reserve category 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. Stakeholder process.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted. Stakeholder process.)
- The MMU recommends not compensating self scheduled units 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 four additional modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours 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 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. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of

the UTC. (Priority: High. First reported 2011. Status: Not adopted. Stakeholder process.)

- 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: Not adopted. Stakeholder process.)
- 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 reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. 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 operating reserve credits 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, which is currently allocated solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- 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). In addition, the MMU recommends that PJM allow and wind units submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants should 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. New recommendation. 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 2014.)
- 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.)
- 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 2012. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)

Section 5, Capacity[12]

- The MMU recommends the extension of minimum offer price rule (MOPR) to all existing and proposed units in order to protect competition in the capacity market from external subsidies. (Priority: High. New recommendation. Status: Not adopted.)
- 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.[13] [14] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- 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 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 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.[15] [16] 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 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, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[17] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends two changes to the RPM solution methodology related to make whole payments and the iterative reconfiguration of the VRR curve:
  - The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends the following changes with respect to capacity imports into PJM:
  - 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 as close to full substitutes for internal, physical capacity resources as possible. Pseudo ties alone are not adequate to ensure deliverability.

12 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.

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

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

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

16 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

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

(Priority: High. First reported Q1, 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 improvements to the performance incentive requirements of RPM:
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted. Pending before FERC.)
  - The MMU recommends that retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported Q3, 2016. Status: Not adopted.)
- The MMU recommends that treatment of costs in RMR filings be emphasized. Customers should bear all 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. Generation owners should bear all other costs. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. (Priority: Medium. First reported 2016. 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 but did not when EE was first added to the capacity market. 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 if PJM releases capacity in Incremental Auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sale price is not the BRA clearing price, PJM should not reveal its proposed sale price. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the requirement for First and Second Incremental Auctions and hold such auctions only if required based on increases in the Reliability Requirement above defined thresholds. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends 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 they need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)
- 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 2013. Status: Adopted 2015.)
- The MMU recommends that the definition of demand side resources be modified in order 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. Status: Adopted 2015.)

- The MMU recommends that all capacity imports have firm transmission to the PJM border acquired prior to offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- 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.[18] (Priority: Medium. First reported 2013. Status: Adopted 2015.)

Section 6, Demand Response

- The MMU recommends, as a preferred alternative to having PJM demand side programs, that demand response be on the demand side of the markets and that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion and that customer payments be determined only by metered load. (Priority: High. First reported 2014. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the emergency load response program be treated as an economic resource, responding to economic price signals like other capacity resources and not an emergency program responding only after an emergency is called, and not triggering the definition of a PJM emergency and not triggering a Performance Assessment Hour under the new PJM Capacity Market rules. (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 a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[19] (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 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.)

18 See OATT Attachment DD § 10(e). For more on this issue and related incentive issues, see the MMU's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

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

- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[20] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Not 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 to terminate registrations that are no longer capable of responding to PJM dispatch directives because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzone and maintain a public record of all created and removed subzones. (Priority: Low. First reported Q3, 2016. Status: Not adopted.)
- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year. (Priority: High. First reported 2011. Status: Partially adopted.[21])
- 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 capping 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 capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted, 2014.)

Section 7, Net Revenue

There are no recommendations in this section.

20 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 June 29, 2016) 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.

21 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

Section 8, Environmental

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)

Section 9, Interchange Transactions

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point-to-point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the

companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Adopted partially, 2015.)
- 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. Status: Adopted partially, 2013.)

Section 10, Ancillary Services

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that 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, to prevent gaming. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that the rule requiring the payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is above zero be eliminated immediately and that 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. 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: Not adopted.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM replace the DASR Market with a real-time secondary reserve product that is available and dispatchable in real time. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the three pivotal supplier test and market power mitigation be incorporated in the DASR Market. (Priority: Low. First reported 2009. 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 separate 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 a number of market design changes to improve the performance of the Regulation Market, including use of a single five minute clearing price based on actual LMP and actual LOC, modifications to the LOC calculation, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- The MMU recommends that PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM. (Priority: Low. First reported 2013. Status: Partially adopted, 2014.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted.)
- The MMU recommends that no payments be made to tier 1 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.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (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 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: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants 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 that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[22] (Priority: Low. First reported 2013. Status: Not 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.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission

22 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

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

- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends 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. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)
- 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 an 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.)

Section 13, FTRs and ARRs

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[23] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2012. Status: Not adopted.)
- 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 implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)

23 See PJM. "Manual 6: Financial Transmission Rights" Revision 17 (June 1, 2016), p. 55.

- 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. Status: Not adopted. Pending before FERC.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013. Status: Adopted partially, 14/15 planning period.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Adopted partially, 14/15 planning period.)
- 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. Status: Adopted 2016.)

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, and the section in the State of the Market Report in which it was last located.

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. 2000 Section: Summary.)
- Reevaluation of the criteria used to determine whether generating units qualify for capacity resource status. (Priority: Medium. First reported 1999. 1999 Section: Summary.)

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 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.)

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 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 2012

- The MMU recommends that PJM should, on an expedited basis, request that the tariff be modified to permit allocation of day-ahead operating reserve charges consistent with the prior allocation of these charges in real time. This would be a short term solution to the issue created by shifting operating reserve charges to the Day-Ahead Energy Market and therefore changing the allocation of those charges. In addition, PJM should start a stakeholder process to consider the market design and cost allocation issues in detail and propose a permanent tariff change that results from the process. (Priority: High. First reported 2012. Last reported: 2012-Q3 Section 3, Operating Reserve.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP and not the forecast LMP. (Priority: Low. First reported 2010. Last reported: 2016 Section 6, Ancillary Service Markets.)
- The MMU recommends that PJM conduct a detailed review of the Day-Ahead Market software in order to address the issue of occasional anomalous loss factors and their effect on the day-ahead market results. (Priority: Low. First reported 2011. Last reported: 2011 Section 10, Congestion and Marginal Losses.)

Adopted 2013

- The MMU recommends that the notification requirement for deactivations be modified to include required notification of six to twelve months prior to an auction in which the unit will not be offered due to deactivation. The purpose of this deadline is to allow adequate time for potential Capacity Market Sellers to offer new capacity in the auction. (Priority: Low. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- The MMU recommends modifying the evaluation criteria via a change to PJM's market software, to ensure that not willing to pay congestion

transactions are not permitted to flow in the presence of congestion. (Priority: Low. First reported 2009. Last reported: 2009 Section 4, Interchange Transactions.)

- The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions). (Priority: Low. First reported 2010. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. PJM should have responsibility to prepare the black start restoration plan for the region, with Members playing an advisory role. PJM should have the responsibility to procure required black start service on a least cost basis through a transparent process. (Priority: Low. First reported 2009. Last reported: 2011 Section 9, Ancillary Service Markets.)
- The MMU recommends that PJM document the reasons each time it changes the Tier 1 synchronized reserve transfer capability into the Mid-Atlantic subzone market because of the potential impacts on the market. (Priority: Low. First reported 2011. Last reported: 2011 Section 9, Ancillary Service Markets.)

Adopted 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: 2016 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 load drop method is designated as “Other” explicitly record the method of load drop. (Priority: Low. First reported 2013. Last reported: 2016 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 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. Last reported: 2016 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: 2016 Section 3, Energy Market.)
- 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: 2016 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: 2016 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: 2016 Section 5, Capacity Market.)
- The MMU recommends immediate elimination of lack of fuel as an acceptable basis for an OMC outage. (Priority: Medium. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- PJM should scrutinize OMC outages for low Btu coal carefully. (Priority: Medium. First reported 2003. Last reported: 2009 Section 5, 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: 2016 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: 2016 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.)
- 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: 2016 Section 5 Capacity Market.)
- The MMU recommends that the definition of demand side resources be modified in order 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: 2016 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 have firm transmission to the PJM border acquired prior to the offering in an RPM auction. (Priority: High. First reported 2014. Last reported: 2016 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: 2016 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: 2016 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: 2016 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 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: 2016 Section 13, Financial Transmission and Auction Revenue Rights.)

Adopted Date Not Determined

- Implementation of rules governing the definition of final prices to ensure certainty for market participants. (Priority: Low. First reported 2008. Last reported: 2009.)
- 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 two 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.)
- Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen. (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. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- 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. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- 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. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- 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. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)

Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance in 2016, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM energy market results were competitive in 2016.

Table 3-1 The energy market results were competitive

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

- The aggregate market structure was evaluated as competitive. The hourly HHI (Herfindahl-Hirschman Index) results indicate that by the FERC standards, the PJM Energy Market in 2016 was moderately concentrated. Average HHI was 1024 with a minimum of 786 and a maximum of 1356 in 2016. The fact that the average HHI and the maximum hourly HHI were 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 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 PJM Energy Market peaking segment of supply was highly concentrated.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when mitigated.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants both routinely and during periods of high demand is consistent with economic withholding.
- 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 during periods of high demand 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

1 Analysis of 2016 market results requires comparison to prior years. In 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2015 State of the Market Report for PJM*, Appendix A, "PJM Geography."

of UTCs in the Day-Ahead Energy Market continues to cause concerns.

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

2 PJM. OATT Attachment M (PJM Market Monitoring Plan).

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

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. The maximum of average offered real-time generation increased by 3,957 MW, or 2.4 percent, from 167,343 MW in the summer of 2015 to 171,300 MW in the summer of 2016. In 2016, 5,421.4 MW of new capacity resources were added. In 2016, 395.5 MW were retired.

  PJM average real-time cleared generation in 2016 increased by 2,676 MW, or 3.0 percent, from 2015, from 88,628 MW to 91,304 MW.

  PJM average day-ahead cleared supply in 2016, including INCs and up to congestion transactions, increased by 14.6 percent from 2015, from 114,889 MW to 131,634 MW, primarily as a result of an increase in UTC volumes.

- **Market Concentration.** The PJM Energy Market was moderately concentrated overall with moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segment.

- **Generation Fuel Mix.** In 2016, coal units provided 33.9 percent, nuclear units 34.4 percent and natural gas units 26.5 percent of total generation. Compared to 2015, generation from coal units decreased 3.3 percent, generation from natural gas units increased 18.3 percent and generation from nuclear units increased 0.2 percent.

- **Fuel Diversity.** In 2016, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), increased 0.9 percent over the 2015 FDI_e.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in 2016, coal units were 44.9 percent of marginal resources and natural gas units were 43.8 percent of marginal resources. In 2015, coal units were 51.7 percent and natural gas units were 35.5 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, in 2016, up to congestion transactions were 82.4 percent of marginal resources, INCs were 4.2 percent of marginal resources, DECs were 8.6 percent of marginal resources, and generation resources were 4.7 percent of marginal resources. In 2015, up to congestion transactions were 76.1 percent of marginal resources, INCs were 5.1 percent of marginal resources, DECs were 8.9 percent of marginal resources, and generation resources were 9.6 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM metered system peak load during 2016 was 152,177 MW in the HE 1500 on August 11, 2016, which was 8,480 MW, 5.9 percent, higher than the PJM peak load for 2015, which was 143,697 MW in the HE 1600 on July 28, 2015.

  PJM average real-time load in 2016 increased from 2015, from 88,594 MW to 88,601 MW. PJM average day-ahead demand in 2016, including DECs and up to congestion transactions, increased by 14.1 percent in 2015, from 111,644 MW to 127,390 MW.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. For 2016, 12.9 percent of real-time load was supplied by bilateral contracts, 23.9 percent by spot market purchases and 63.2 percent by self-supply. Compared with 2015, reliance on bilateral contracts increased by 2.3 percentage points, reliance on spot market purchases decreased by 5.4 percentage points and reliance on self-supply increased by 3.1 percentage points.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in 2016.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.2 percent in 2015 to 0.1 percent in 2016. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 0.4 percent in 2015 and 2016.

  In 2016, 11 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.4 percent in 2015 to 0.04 percent in 2016. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.4 percent in 2015 to 0.1 percent in 2016.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In 2016, in the PJM Real-Time Energy Market, 90.1 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 per MWh was negative when using unadjusted cost offers. The average dollar markups of units with offer prices less than $50 per MWh was negative when using unadjusted cost offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, implying a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM Market Rules. Some marginal units did have substantial markups. Using the unadjusted cost offers, the highest markup for any marginal unit in 2016 was $258.16 per MWh while the highest markup in 2015 was $792.21 per MWh.

  In the PJM Day-Ahead Energy Market, when using unadjusted cost offers, in 2016, 89.9 percent of marginal generating units had offer prices less than $50 per MWh and the average dollar markup was negative, and 0.4 percent of marginal generating units had offers in the $75 to $125 per MWh range and the average dollar markup and the average markup index were both negative.

- **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 imply 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.

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

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In 2016, the average hourly increment offers submitted MW increased by 26.0 percent from 7,175 MW in 2015 to 9,043 MW in 2016, and cleared MW increased by 11.4 percent from 4,675 MW in 2015 to 5,207 MW in 2016. In 2016, the average hourly decrement bids submitted MW increased by 25.3 percent from 6,879 MW in 2015 to 8,618 MW in 2016, and cleared MW increased by 18.6 percent from 4,051 MW in 2015 to 4,805 MW in 2016. In 2016, the average hourly up to congestion submitted MW increased by 70.3 percent from 83,422 MW in 2015 to 142,075 MW in 2016, and cleared MW increased by 78.6 percent from 19,255 MW in 2015 to 34,385 MW in 2016.

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in 2016, 53.7 percent were offered as available for economic dispatch, 4.4 percent were offered as emergency dispatch, 22.3 percent were offered as self scheduled, and 19.6 percent were offered as self scheduled and dispatchable.

Market Performance

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

  PJM real-time energy market prices decreased in 2016 compared to 2015. The load-weighted average real-time LMP was 19.2 percent lower in 2016 than in 2015, $29.23 per MWh versus $36.16 per MWh. PJM real-time load-weighted energy market prices were lower in 2016 that at any time in PJM history since the beginning of the competitive wholesale market on April 1, 1999.

  PJM day-ahead energy market prices decreased in 2016 compared to 2015. The load-weighted average day-ahead LMP was 19.2 percent lower in 2016 than in 2015, $29.68 per MWh versus $36.73 per MWh. PJM day-ahead load-weighted energy market prices were lower in 2016 that at any time in PJM history since the introduction of the PJM Day-Ahead Energy Market in June 2000.

- **Components of LMP.** In the PJM Real-Time Energy Market, in 2016, 45.4 percent of the load-weighted LMP was the result of coal costs, 27.2 percent was the result of gas costs and 1.89 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market in 2016, 36.4 percent of the load-weighted LMP was the result of the cost of coal, 26.7 percent was the result of DECs, 11.0 percent was the result of the cost of gas, 1.9 percent was the result of INCs, and 2.2 percent was the result of up to congestion transactions.

- **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 2016, the adjusted markup component of LMP was $1.77 per MWh or 6.1 percent of the PJM real-time, load-weighted average LMP. August had the highest adjusted peak markup component, $4.47 per MWh, or 10.24 percent of the real-time peak hour load-weighted average LMP. Using the unadjusted cost offers, the highest markup of a marginal unit in 2016 was $258.16 per MWh. There were 33 hours in 2016 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $54.51 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2016, the adjusted markup component of LMP resulting from generation resources was $0.21 per MWh or 0.7 percent of the PJM day-ahead load-weighted average LMP. August had the highest adjusted peak markup component, $5.65 per MWh or 16.5 percent of the day-ahead load-weighted average LMP.

  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 is consistent with economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.73 per MWh in 2015 and -$0.53 per MWh in 2016. 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 no shortage pricing events in 2016.

Recommendations

- The MMU recommends that the market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel-type and parameters as that of their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require that the level of incremental costs includable in cost offers not exceed the unit's short run marginal cost. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that Manual 15 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. New recommendation. 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. New recommendation. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Medium. New recommendation. 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. New recommendation. Status: Not adopted.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. (Priority: High. First reported 2010. 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 offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available 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. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that under the capacity performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine nonperformance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM Energy Market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported 2014. 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: Not adopted.)

- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[4] (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted.)
- The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[5] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[6] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM 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 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 continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Status: Adopted in full, 2014.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2016, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average PJM real-time cleared generation increased by 2,676 MW, 3.0 percent, and peak load increased by 8,480 MW, 5.9 percent, in 2016 compared to

4 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

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

6 The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

2015. Market concentration levels remained moderate although there is high concentration in the peaking segment of the supply curve which adds to concerns about market power when market conditions are tight. The relationship between supply and demand, regardless of the specific market, balanced by market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate energy market remains reasonably competitive for most hours although aggregate market power does exist during high demand hours. Low average aggregate concentration does not mean that market power cannot be exercised. It is possible that market power can be exercised at times when individual suppliers or small groups of suppliers are pivotal even when the HHI level does not indicate that the market is highly concentrated. High markups for some units demonstrate the potential to exercise market power during high demand conditions.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. 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 2016 generally reflected supply-demand fundamentals, although the behavior of some participants during high demand periods is consistent with economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[7] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to require offer capping of owners when the local market structure is noncompetitive.

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. 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 have the ability to avoid 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 requiring that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer, that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer, and requiring cost-based and price-based PLS offers to be at least as flexible as price-based non-PLS offers.

Another issue 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 is related to the definition of a competitive

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

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

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing net revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. PJM implemented scarcity pricing rules in 2012. There are significant issues with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs. 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 2014, 2015 or 2016. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods is consistent with economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the tighter market conditions and the change in some participants' behavior are sources of concern in the energy market and provide a reason to use cost as the sole basis for hourly changes in offers or offers greater than $1,000 per MWh. The MMU concludes that the PJM energy market results were competitive in 2016.

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM Energy Market in 2016 indicates moderate concentration in the base load and intermediate segments, but high concentration in the peaking segment.[8] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market during high demand periods. The fact that the average HHI and the maximum hourly HHI were 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 highly concentrated. It is possible to have an exercise of market power even when the HHI level does not indicate highly concentrated.

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

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 2016, 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 to short run marginal costs.

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

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

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

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

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[9]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2016 was moderately concentrated (Table 3-2).

Table 3-2 PJM hourly energy market HHI: 2015 and 2016[10]

	Hourly Market HHI (2015)	Hourly Market HHI (2016)
Average	1096	1024
Minimum	879	786
Maximum	1468	1356
Highest market share (One hour)	31%	28%
Average of the highest hourly market share	21%	20%
# Hours	8,760	8,784
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for 2015 and 2016. The PJM Energy Market was moderately concentrated overall with moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segment.

Table 3-3 PJM hourly energy market HHI (By supply segment): 2015 and 2016

	2015			2016		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	988	1132	1487	945	1106	1428
Intermediate	603	1863	6375	578	1371	5029
Peak	716	5728	10000	684	5620	10000

Figure 3-1 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in 2016.

9 77 FERC ¶ 61,263, pp. 64-70 (1996), "*Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement.*"
10 This analysis includes all hours in 2015 and 2016, regardless of congestion.

Figure 3-1 Fuel source distribution in unit segments: 2016[11]

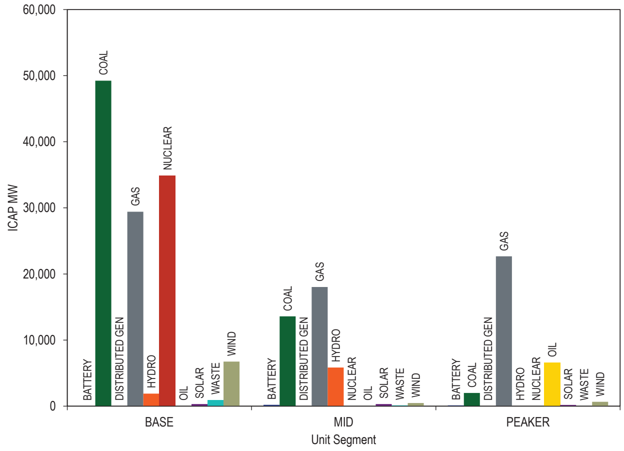
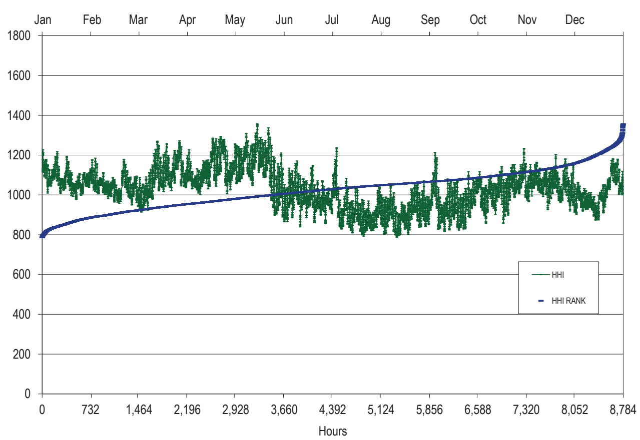


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for 2016.

Figure 3-2 PJM hourly energy market HHI: 2016



Ownership of Marginal Resources

Table 3-4 shows the contribution to real-time, load-weighted LMP by individual marginal resource owner.[12] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2016, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In 2016, the offers of one company resulted in 21.9 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies resulted in 58.8 percent of the real-time, load-weighted, average PJM system LMP. During 2015, the offers of one company resulted in 19 percent of the real time, load-weighted PJM system LMP and offers of the top four companies resulted in 55.2 percent of the real-time, load-weighted, average PJM system LMP. In 2016, the offers of one company resulted in 20.0 percent of the peak hour real-time, load weighted PJM system LMP. In 2015, the offers of one company resulted in 16.7 percent of the peak hour, real-time, load weighted PJM system LMP.

11 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) Action on Proposed Manual 28 Revisions," (July 26, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20120726/20120726-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

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

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): 2015 and 2016

2015						2016					
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	19.0%	19.0%	1	16.7%	16.7%	1	21.9%	21.9%	1	20.0%	20.0%
2	15.6%	34.5%	2	15.1%	31.8%	2	14.9%	36.9%	2	16.0%	36.0%
3	10.9%	45.5%	3	10.2%	42.0%	3	12.1%	48.9%	3	10.6%	46.6%
4	9.8%	55.2%	4	9.5%	51.5%	4	9.9%	58.8%	4	8.7%	55.3%
5	8.7%	63.9%	5	9.5%	61.0%	5	7.5%	66.3%	5	7.7%	63.0%
6	8.5%	72.4%	6	9.1%	70.1%	6	5.5%	71.8%	6	4.8%	67.8%
7	4.4%	76.8%	7	4.9%	75.0%	7	2.6%	74.5%	7	3.5%	71.3%
8	4.0%	80.7%	8	4.4%	79.4%	8	2.2%	76.7%	8	2.6%	73.9%
9	2.6%	83.4%	9	2.6%	82.0%	9	2.1%	78.8%	9	2.4%	76.3%
Other (59 companies)	16.6%	100.0%	Other (56 companies)	18.0%	100.0%	Other (72 companies)	21.2%	100.0%	Other (64 companies)	23.7%	100.0%

Table 3-5 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[13] 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 2016, the offers of one company contributed 22.0 percent of the day-ahead, load-weighted PJM system LMP and that the offers of the top four companies contributed 50.4 percent of the day-ahead, load-weighted, average PJM system LMP. In 2015, the offers of one company contributed 12.5 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 39.6 percent of the day-ahead, load-weighted, average PJM system LMP.

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): 2015 and 2016

2015						2016					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Culmulative Percent	Company	Percent of Price	Culmulative Percent	Company	Percent of Price	Culmulative Percent	Company	Percent of Price	Culmulative Percent
1	12.5%	12.5%	1	11.6%	11.6%	1	22.0%	22.0%	1	36.0%	36.0%
2	11.3%	23.7%	2	10.9%	10.9%	2	13.4%	35.5%	2	10.9%	46.9%
3	10.0%	33.7%	3	9.7%	9.7%	3	7.6%	43.0%	3	9.4%	56.3%
4	5.9%	39.6%	4	6.6%	6.6%	4	7.4%	50.4%	4	9.3%	65.6%
5	5.4%	45.0%	5	4.9%	4.9%	5	6.8%	57.3%	5	7.0%	72.6%
6	5.1%	50.1%	6	4.7%	4.7%	6	5.8%	63.0%	6	5.2%	77.8%
7	4.0%	54.2%	7	3.8%	3.8%	7	4.4%	67.5%	7	5.0%	82.8%
8	3.7%	57.8%	8	3.8%	3.8%	8	4.3%	71.7%	8	3.3%	86.1%
9	3.6%	61.4%	9	3.6%	3.6%	9	3.0%	74.8%	9	3.2%	89.3%
Other (153 companies)	38.6%	100.0%	Other (148 companies)	40.4%	40.4%	Other (170 companies)	25.2%	100.0%	Other (162 companies)	10.7%	100.0%

Type of Marginal Resources

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

Table 3-6 shows the type of fuel used 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 2016, coal units were 44.9 percent and natural gas units were 43.9 percent of marginal resources. In 2015, coal units were 51.7 percent and natural gas units were 35.5 percent of the total marginal resources. In 2016, 86.6 percent of the wind marginal units had negative offer prices, 11.2 percent had zero offer prices and 2.1 percent had positive offer prices.

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

The results reflect the dynamics of an LMP market. When there is a single constraint, there are two marginal units. For example, a significant west to east constraint could be binding with a gas unit marginal in the east and a coal unit marginal in the west. As a result, although the dispatch of natural gas units has increased and gas units set price for more hours as marginal resources in the Real-Time Energy Market, this does not necessarily reduce the proportion of hours in which coal units are marginal.[14]

The proportion of marginal nuclear units increased from 0.03 percent in 2015 to 1.03 percent in 2016. The increase was primarily due to a small number of nuclear units offering with a dispatchable range. Most nuclear units are offered as fixed generation in the PJM market. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-6 Type of fuel used (By real-time marginal units): 2012 through 2016

	Year				
Type/Fuel	2012	2013	2014	2015	2016
Coal	58.84%	56.94%	52.90%	51.74%	44.90%
Gas	30.35%	34.72%	35.80%	35.52%	43.86%
Oil	6.00%	3.27%	7.45%	8.99%	7.08%
Wind	4.19%	4.76%	3.29%	3.27%	2.98%
Uranium	0.02%	0.02%	0.04%	0.03%	1.03%
Other	0.47%	0.20%	0.43%	0.39%	0.14%
Municipal Waste	0.13%	0.07%	0.05%	0.06%	0.01%
Emergency DR	0.00%	0.02%	0.04%	0.00%	0.00%

Figure 3-3 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 3-3 Type of fuel used (By real-time marginal units): 2004 through 2016

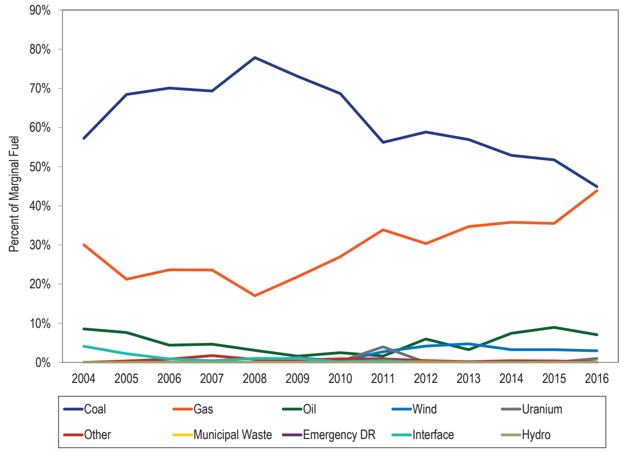


Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In 2016, up to congestion transactions were 82.38 percent of marginal resources. Up to congestion transactions were 76.14 percent of marginal resources in 2015.

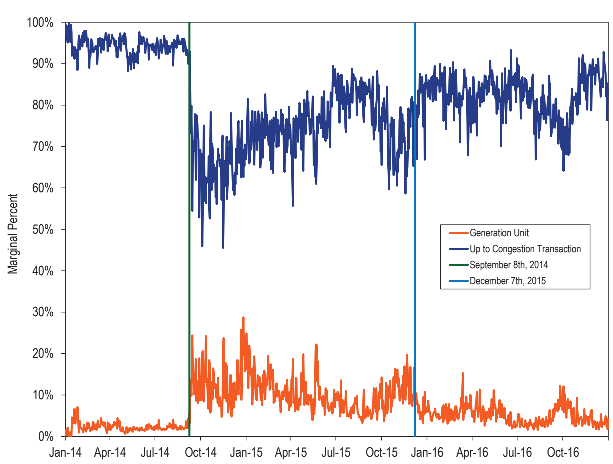
14 Prior to April 1, 2015, for the generation units that are capable of using multiple fuel types, PJM did not require the participants to disclose the fuel type associated with their offer schedule. For these units, the cleared offer schedules on a given day were compared to the cost associated with each fuel to determine the fuel type most likely to have been the basis for the cleared schedule.

Table 3-7 Day-ahead marginal resources by type/fuel: 2011 through 2016

Type/Fuel	2011	2012	2013	2014	2015	2016
Up to Congestion Transaction	73.40%	88.40%	96.44%	91.05%	76.14%	82.38%
DEC	12.38%	4.30%	1.27%	3.28%	8.87%	8.64%
INC	7.54%	3.81%	1.05%	2.28%	5.08%	4.18%
Coal	4.66%	2.31%	0.78%	2.03%	5.50%	2.14%
Gas	1.54%	1.04%	0.36%	1.16%	3.31%	1.99%
Oil	0.00%	0.00%	0.00%	0.05%	0.56%	0.42%
Uranium	0.00%	0.00%	0.00%	0.00%	0.00%	0.11%
Wind	0.07%	0.03%	0.04%	0.05%	0.12%	0.06%
Dispatchable Transaction	0.17%	0.07%	0.05%	0.08%	0.26%	0.05%
Municipal Waste	0.01%	0.01%	0.00%	0.01%	0.01%	0.01%
Price Sensitive Demand	0.23%	0.04%	0.01%	0.01%	0.02%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-4 shows, for the Day-Ahead Market from January 1, 2014, through December 31, 2016, the daily proportion of marginal resources that were up to congestion transaction and/or generation units. The percent of marginal up to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on that date.[15] The percent of marginal up to congestion transaction decreased and that of generation units increased. That trend has begun to reverse as a result of the expiration of the fifteen month uplift refund period for UTC transactions.

Figure 3-4 Day-ahead marginal up to congestion transaction and generation units: 2014 through 2016

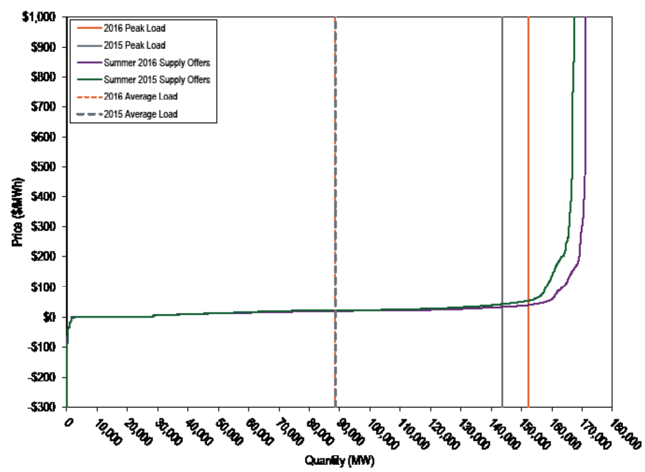


Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-5 shows the average PJM aggregate real-time generation supply curves by offer price, peak load and average load for the summer of 2015 and 2016. The maximum of average offered real-time generation increased by 3,957 MW, or 2.4 percent, from 167,343 MW in the summer of 2015 to 171,300 MW in the summer of 2016.

Figure 3-5 Average PJM aggregate real-time generation supply curves by offer price: summer of 2015 and 2016



Energy Production by Fuel Source

Table 3-8 shows PJM generation by fuel source in GWh for 2015 and 2016. In 2016, generation from coal units decreased 3.3 percent and generation from natural gas units increased 18.8 percent compared to 2015.[16]

15 See 18 CFR § 385.213 (2014).

16 Generation data are the sum of MWh for each fuel by source at every generation bus in PJM with positive output and reflect gross generation without offset for station use of any kind.

Table 3-8 PJM generation (By fuel source (GWh)): 2015 and 2016[17] [18]

	2015		2016		Change in
	GWh	Percent	GWh	Percent	Output
Coal	284,757.4	36.2%	275,281.7	33.9%	(3.3%)
Bituminous	257,700.0	32.8%	241,050.2	29.7%	(6.5%)
Sub Bituminous	22,528.7	2.9%	28,949.7	3.6%	28.5%
Other Coal	4,528.6	0.6%	5,281.7	0.7%	16.6%
Nuclear	279,106.5	35.5%	279,546.4	34.4%	0.2%
Gas	183,650.7	23.3%	217,214.5	26.7%	18.3%
Natural Gas	180,948.7	23.0%	215,022.4	26.5%	18.8%
Landfill Gas	2,275.8	0.3%	2,176.2	0.3%	(4.4%)
Other Gas	426.3	0.1%	15.9	0.0%	(96.3%)
Hydroelectric	13,067.2	1.7%	13,686.8	1.7%	4.7%
Pumped Storage	4,660.2	0.6%	4,840.2	0.6%	3.9%
Run of River	6,736.3	0.9%	7,332.8	0.9%	8.9%
Other Hydro	1,670.8	0.2%	1,513.8	0.2%	(9.4%)
Wind	16,609.7	2.1%	17,716.0	2.2%	6.7%
Waste	4,365.1	0.6%	4,139.8	0.5%	(5.2%)
Solid Waste	4,175.4	0.5%	4,139.8	0.5%	(0.9%)
Miscellaneous	189.7	0.0%	0.0	0.0%	(100%)
Oil	3,276.2	0.4%	2,163.6	0.3%	(34.0%)
Heavy Oil	622.9	0.1%	270.6	0.0%	(56.6%)
Light Oil	1,122.0	0.1%	341.1	0.0%	(69.6%)
Diesel	163.8	0.0%	59.4	0.0%	(63.7%)
Gasoline	0.0	0.0%	0.0	0.0%	NA
Kerosene	413.0	0.1%	74.8	0.0%	(81.9%)
Jet Oil	0.0	0.0%	0.0	0.0%	NA
Other Oil	954.5	0.1%	1,417.7	0.2%	48.5%
Solar, Net Energy Metering	548.4	0.1%	1,019.4	0.1%	85.9%
Energy Storage	7.6	0.0%	15.7	0.0%	106.7%
Battery	7.6	0.0%	15.7	0.0%	106.7%
Compressed Air	0.0	0.0%	0.0	0.0%	NA
Biofuel	1,309.6	0.2%	1,760.3	0.2%	34.4%
Geothermal	0.0	0.0%	0.0	0.0%	NA
Other Fuel Type	0.0	0.0%	0.0	0.0%	NA
Total	786,698.5	100.0%	812,544.1	100.0%	3.3%

17 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps.

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

Table 3-9 Monthly PJM generation (By fuel source (GWh)): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal	25,328.3	21,848.4	15,326.5	17,832.4	17,160.0	25,275.1	30,485.4	30,935.7	24,840.8	19,955.1	18,363.5	27,930.4	275,281.7
Bituminous	22,444.6	19,659.8	13,958.0	15,568.4	15,706.1	21,748.2	26,378.3	26,653.9	21,741.7	17,207.8	15,860.3	24,123.1	241,050.2
Sub Bituminous	2,366.8	1,723.9	998.4	1,909.9	1,125.9	3,082.2	3,535.5	3,713.3	2,663.8	2,424.1	2,122.3	3,283.7	28,949.8
Other Coal	516.9	464.8	370.1	354.1	328.0	444.7	571.6	568.5	435.3	323.2	380.9	523.6	5,281.8
Nuclear	25,876.0	22,914.1	22,788.2	21,022.7	23,790.7	22,579.5	23,324.2	24,804.7	22,793.1	21,577.2	23,065.1	25,010.8	279,546.4
Gas	16,134.0	15,639.3	17,215.8	13,748.5	15,022.1	20,441.7	25,681.8	25,858.0	19,752.7	16,206.2	15,867.0	15,647.3	217,214.5
Natural Gas	15,950.9	15,468.1	17,034.7	13,572.8	14,852.5	20,267.1	25,498.9	25,671.8	19,573.3	16,025.4	15,674.8	15,432.1	215,022.4
Landfill Gas	183.1	171.2	181.1	175.7	169.6	174.7	182.6	186.2	179.5	180.5	192.2	200.0	2,176.2
Other Gas	0.0	0.0	0.1	0.0	0.0	0.0	0.3	0.0	0.0	0.3	0.0	15.2	15.9
Hydroelectric	1,456.2	1,422.0	1,278.6	1,071.6	1,269.7	1,178.0	1,146.0	1,240.5	867.4	942.7	740.5	1,073.6	13,686.8
Pumped Storage	358.6	304.3	322.8	298.7	310.8	537.5	581.7	644.8	503.0	348.6	276.3	353.1	4,840.2
Run of River	987.5	1,014.2	859.7	666.1	851.4	465.2	362.4	368.3	207.6	506.7	408.8	635.1	7,332.8
Other Hydro	110.2	103.4	96.1	106.7	107.6	175.4	202.0	227.4	156.9	87.4	55.5	85.4	1,513.8
Wind	2,095.6	1,925.5	1,781.6	1,588.0	1,230.6	1,029.1	691.7	603.5	1,017.7	1,647.4	1,851.4	2,254.1	17,716.0
Waste	344.8	297.0	337.5	344.3	366.7	366.0	349.9	361.0	321.6	336.1	353.0	361.6	4,139.8
Solid Waste	344.8	297.0	337.5	344.3	366.7	366.0	349.9	361.0	321.6	336.1	353.0	361.6	4,139.8
Miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	226.6	228.6	161.9	125.6	168.9	198.0	244.4	246.4	152.1	143.7	115.5	151.8	2,163.6
Heavy Oil	91.4	45.3	1.0	0.0	0.0	30.3	45.8	40.2	2.0	2.4	2.8	9.4	270.7
Light Oil	88.1	23.2	30.7	22.7	27.7	7.8	34.8	34.0	29.2	20.6	8.0	14.3	341.1
Diesel	11.6	13.6	1.3	0.7	3.3	1.8	6.1	9.8	2.0	0.2	0.6	8.5	59.4
Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kerosene	8.3	57.1	0.0	0.4	0.4	0.6	0.5	0.5	0.6	0.1	0.2	6.1	74.8
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	27.2	89.4	128.9	101.8	137.5	157.5	157.2	161.8	118.4	120.5	104.0	113.5	1,417.7
Solar, Net Energy Metering	45.6	50.4	85.2	98.5	89.7	114.9	114.9	114.2	85.8	82.2	79.7	58.2	1,019.4
Energy Storage	1.3	1.5	1.4	1.4	1.2	1.3	1.3	1.5	1.2	1.2	1.2	1.3	15.7
Battery	1.3	1.5	1.4	1.4	1.2	1.3	1.3	1.5	1.2	1.2	1.2	1.3	15.7
Compressed Air	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biofuel	182.9	166.7	167.4	109.5	96.2	149.0	181.6	188.1	173.0	91.2	91.1	163.6	1,760.3
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fuel Type	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	71,691.4	64,493.4	59,144.2	55,942.4	59,195.8	71,332.7	82,221.4	84,353.5	70,005.5	60,982.9	60,528.1	72,652.9	812,544.1

Figure 3-6 shows the fuel diversity index (FDI_e) for PJM energy generation.[19]

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 is achieved 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 ten primary fuel sources in Table 3-8 with nonzero generation values. The FDI_e exhibits seasonality with most of the peaks occurring in the spring and summer months, and the valleys occurring in the fall and winter months. A significant drop in the FDI_e occurred in 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.[20] The increasing trend that begins in 2008 corresponds with a period of decreasing coal generation and increasing gas generation. Coal generation as a share of total generation dropped 20.5 percentage points from 2008 to 2016, and gas generation as a share of total generation increased 19.3 percentage points. Wind generation, at 2.2 percent of total generation in 2016, also contributes to the rising trend. The FDI_e increased on average 0.0061 (0.9 percent) from 2015 to 2016.

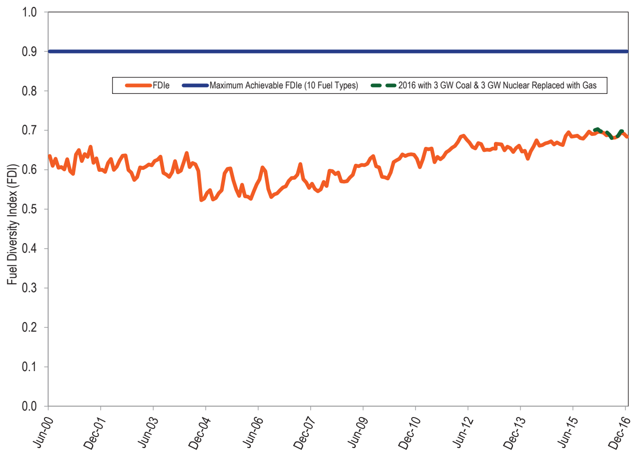
The FDI_e was used to measure the impact of potential retirements of coal and nuclear generators. The dotted line in Figure 3-6 shows the FDI_e calculated assuming that 3,000 MW of coal generation and 3,000 MW of nuclear generation were replaced by gas generation in 2016. The FDI_e under the coal and nuclear retirement

19 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.

20 See the *2016 State of the Market Report for PJM*, Volume II, 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.

assumptions would have increased in nine of twelve months. The coal and nuclear retirements would have increased the FDI_e by 0.6 percent over the actual 2016 FDI_e.

Figure 3-6 Fuel diversity index for PJM monthly generation: 2000 through 2016



Net Generation and Load

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

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

The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Real-Time Supply

The maximum of average offered real-time generation increased by 3,957 MW, or 2.4 percent, from 167,343 MW in the summer months of 2015 to 171,300 MW in the summer months 2016.[21]

In 2016, 5,421.4 MW of new capacity resources were added. In 2016, 395.5 MW were retired.

PJM average real-time cleared generation in 2016 increased by 3.0 percent from 2015, from 88,628 MW to 91,304 MW.[22]

PJM average real-time cleared supply including imports increased by 0.8 percent in 2016 from 2015, from 94,329 MW to 95,054 MW.

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

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

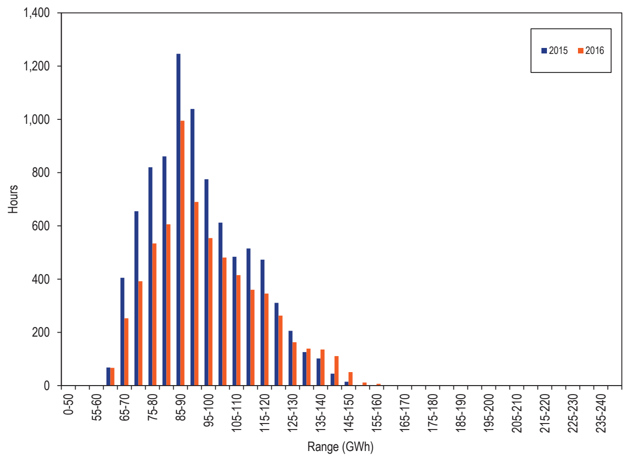
PJM Real-Time Supply Duration

Figure 3-7 shows the hourly distribution of PJM real-time generation plus imports for 2015 and 2016.

21 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

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

Figure 3-7 Distribution of PJM real-time generation plus imports: January through December, 2015 and 2016[23]



PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for each year for the 17-year period from 2000 through 2016.[24]

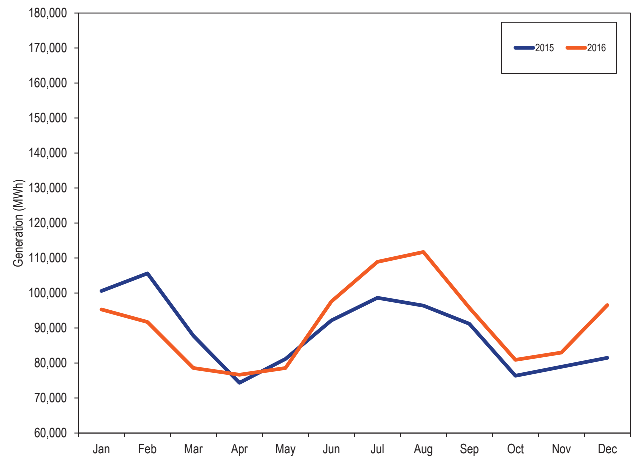
Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: 2000 through 2016

	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
2000	30,301	4,980	33,256	5,456	NA	NA	NA	NA
2001	29,553	4,937	32,552	5,285	(2.5%)	(0.9%)	(2.1%)	(3.1%)
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	94,329	17,312	(2.5%)	6.4%	(2.0%)	6.9%
2016	91,304	17,731	95,054	17,979	3.0%	10.0%	0.8%	3.9%

PJM Real-Time, Monthly Average Generation

Figure 3-8 compares the real-time, monthly average hourly generation in 2016 to 2015.

Figure 3-8 PJM real-time average monthly hourly generation: 2015 through 2016



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

24 The import data in this table is not available before June 1, 2000. The data that includes imports in 2000 is calculated from the last six months of that year.

Day-Ahead Supply

PJM average day-ahead supply in 2016, including INCs and up to congestion transactions, increased by 14.6 percent from 2015, from 114,889 MW to 131,634 MW.

PJM average day-ahead supply in 2016, including INCs, up to congestion transactions, and imports, increased by 13.8 percent from 2015, from 117,146 MW to 133,262 MW. The increase in PJM day-ahead supply was a result of an increase in UTCs beginning in December 2015 based on a FERC order setting December 8, 2015, as the last effective date for any uplift charges subsequently assigned to UTCs.[25]

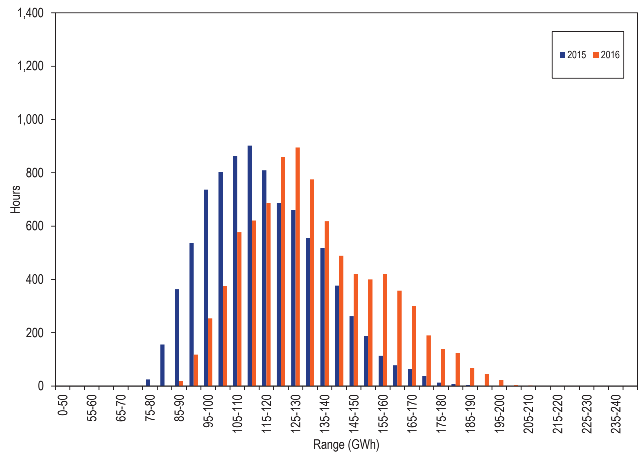
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

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

PJM Day-Ahead Supply Duration

Figure 3-9 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for 2015 and 2016. There was an increase in up to congestion volume, which resulted in an increase in day-ahead supply, as a result of the expiration of the fifteen month potential refund period for uplift charges for UTC transactions on December 7, 2015.

Figure 3-9 Distribution of PJM day-ahead supply plus imports: 2015 and 2016[26]



PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for each year of the 17-year period from 2000 through 2016.[27]

25 148 FERC ¶ 61,144 (2014).

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

27 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 six months of that year.

Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: 2000 through 2016

	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
2000	27,135	4,858	27,589	4,895	NA	NA	NA	NA
2001	26,762	4,595	27,497	4,664	(1.4%)	(5.4%)	(0.3%)	(4.7%)
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	114,889	19,164	117,146	19,405	(21.7%)	(42.2%)	(21.3%)	(41.8%)
2016	131,634	22,342	133,262	22,381	14.6%	16.6%	13.8%	15.3%

PJM Day-Ahead, Monthly Average Supply

Figure 3-10 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions, for 2015 and 2016.

Figure 3-10 PJM day-ahead monthly average hourly supply: 2015 and 2016

Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for 2015 and 2016, for day-ahead and real-time supply. All data are cleared MW. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In 2016, up-to congestion transactions were 25.4 percent of the total day-ahead supply compared to 16.4 percent in 2015.

Table 3-12 Day-ahead and real-time supply (MW): 2015 and 2016

		Day Ahead					Real Time		Day Ahead Less Real Time	
		Generation	INC	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2015	90,959	4,675	19,255	2,257	117,146	88,628	94,329	22,817	2,331
	2016	93,714	5,171	34,201	1,792	134,881	92,799	96,907	37,974	915
Median	2015	88,874	4,599	18,435	2,215	114,964	85,989	91,318	23,647	2,885
	2016	90,172	5,027	33,655	1,727	130,994	89,013	93,041	37,953	1,159
Standard Deviation	2015	17,341	791	5,230	503	19,405	16,118	17,312	2,093	1,223
	2016	19,435	1,054	6,936	651	23,403	19,003	19,067	4,336	432
Peak Average	2015	100,528	4,765	20,779	2,416	128,487	96,809	103,211	25,275	3,718
	2016	104,030	5,281	36,337	1,835	147,495	101,857	106,350	41,145	2,173
Peak Median	2015	97,480	4,714	19,777	2,428	126,042	93,304	99,485	26,558	4,176
	2016	102,122	5,146	35,655	1,722	146,045	98,442	103,478	42,567	3,680
Peak Standard Deviation	2015	14,481	715	5,336	504	16,480	14,438	15,379	1,102	43
	2016	17,542	1,019	6,660	722	21,042	18,233	17,897	3,145	(691)
Off-Peak Average	2015	82,242	4,594	17,867	2,112	106,815	81,176	86,238	20,578	1,067
	2016	84,307	5,071	32,254	1,753	123,379	84,539	88,296	35,082	(232)
Off-Peak Median	2015	79,108	4,485	17,186	2,059	103,524	78,333	82,832	20,692	775
	2016	81,898	4,903	31,398	1,735	120,145	81,922	85,881	34,264	(24)
Off-Peak Standard Deviation	2015	14,976	847	4,722	455	15,757	13,787	14,832	925	1,189
	2016	16,002	1,075	6,602	575	19,134	15,630	15,735	3,399	372

Figure 3-11 shows the average hourly cleared volumes of day-ahead supply and real-time supply for 2016. The day-ahead supply consists of cleared MW of day-ahead generation, imports, increment offers and up to congestion transactions. The real-time generation includes generation and imports.

Figure 3-11 Day-ahead and real-time supply (Average hourly volumes): 2016

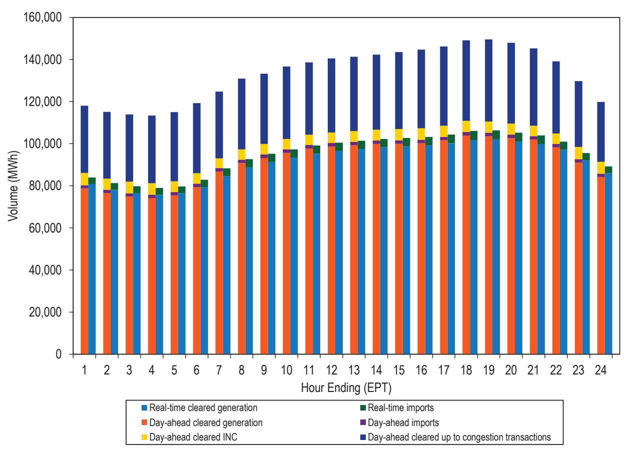


Figure 3-12 shows the difference between the day-ahead and real-time average daily supply for 2015 and 2016.

Figure 3-12 Difference between day-ahead and real-time supply (Average daily volumes): 2015 and 2016

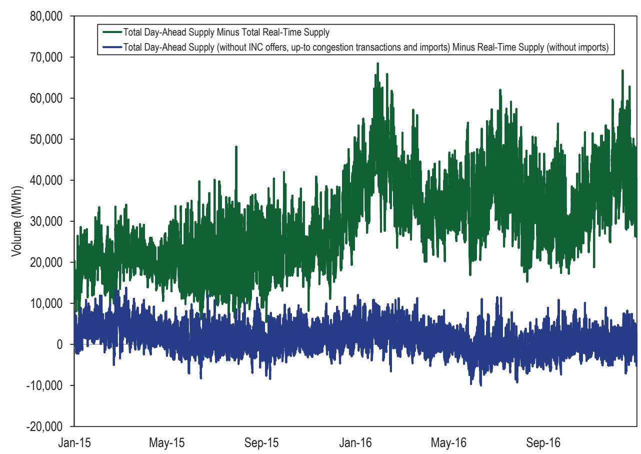
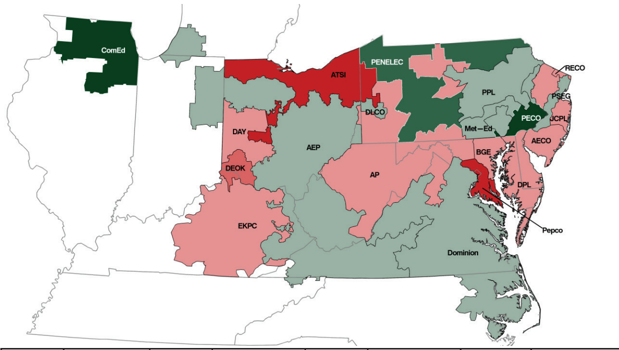


Figure 3-13 shows the difference between the PJM real-time generation and real-time load by zone in 2016. Figure 3-13 is color coded on a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in 2015 and 2016.

Figure 3-13 Map of PJM real-time generation less real-time load by zone: 2016[28]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(3,427)	ComEd	31,369	DPL	(9,806)	PENELEC	20,307
AEP	14,986	DAY	(1,908)	EKPC	(2,765)	Pepco	(20,204)
AP	(574)	DEOK	(10,616)	JCPL	(4,712)	PPL	9,668
ATSI	(24,444)	DLCO	3,361	Met-Ed	6,937	PSEG	1,800
BGE	(9,363)	Dominion	264	PECO	24,506	RECO	(1,481)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): 2015 and 2016

	Zonal Generation and Load (GWh)					
	2015			2016		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	6,208.5	10,436.1	(4,227.6)	6,712.8	10,140.1	(3,427.3)
AEP	134,241.8	126,850.3	7,391.5	141,703.3	126,717.0	14,986.3
AP	44,431.4	48,207.0	(3,775.5)	47,489.1	48,063.0	(573.9)
ATSI	48,684.8	66,651.7	(17,966.9)	42,776.0	67,220.3	(24,444.3)
BGE	22,244.0	32,072.4	(9,828.5)	22,065.3	31,428.3	(9,363.0)
ComEd	125,658.7	95,365.1	30,293.6	129,371.6	98,002.4	31,369.2
DAY	13,661.1	16,884.0	(3,223.0)	15,380.9	17,288.8	(1,907.9)
DEOK	17,115.3	26,843.3	(9,727.9)	16,659.5	27,275.5	(10,616.0)
DLCO	16,604.9	14,167.8	2,437.1	17,258.8	13,897.4	3,361.3
Dominion	88,335.4	95,884.1	(7,548.8)	96,504.9	96,240.9	264.1
DPL	7,479.8	18,578.0	(11,098.2)	8,398.6	18,204.8	(9,806.2)
EKPC	8,603.7	12,169.1	(3,565.4)	9,799.9	12,564.8	(2,764.9)
JCPL	14,415.1	23,172.8	(8,757.7)	18,119.0	22,831.3	(4,712.3)
Met-Ed	22,081.5	15,208.6	6,872.9	22,197.7	15,260.5	6,937.2
PECO	60,404.2	40,056.7	20,347.4	64,614.9	40,109.1	24,505.8
PENELEC	37,224.2	17,105.7	20,118.5	37,177.8	16,870.8	20,307.0
Pepco	8,868.6	30,398.5	(21,529.9)	10,135.6	30,339.2	(20,203.6)
PPL	52,504.7	40,586.7	11,918.0	50,035.8	40,368.0	9,667.8
PSEG	47,617.7	43,664.3	3,953.4	45,616.5	43,816.1	1,800.4
RECO	0.0	1,521.2	(1,521.2)	0.0	1,481.2	(1,481.2)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to metered physical load and exports and in the Day-Ahead Energy Market also includes virtual transactions.[29]

The PJM system real-time peak load for 2016 was 152,177 MW in the HE 15 on August 11, 2016, which was 8,480 MW, or 5.9 percent, higher than the peak load for 2015, which was 143,697 MW in the HE 16 on July 28, 2015.

Table 3-14 shows the peak loads for 1999 through 2016.

28 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>.

29 PJM reports peak load including metered 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 actual metered values. PJM's load drop estimate is based PJM Manual 19: Load Forecasting and Analysis Attachment A: Load Drop Estimate Guidelines at <http://www.pjm.com/~/media/documents/manuals/m19.ashx>.

Table 3-14 Actual PJM footprint peak loads: 1999 to 2016[30]

	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Fri, July 30	17	120,227	NA	NA
2000	Wed, August 09	17	114,036	(6,191)	(5.1%)
2001	Wed, August 08	17	128,535	14,499	12.7%
2002	Thu, August 01	17	130,159	1,625	1.3%
2003	Thu, August 21	17	126,259	(3,900)	(3.0%)
2004	Wed, June 09	17	120,218	(6,041)	(4.8%)
2005	Tue, July 26	16	133,761	13,543	11.3%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012	Tue, July 17	17	154,344	(3,672)	(2.3%)
2013	Thu, July 18	17	157,508	3,165	2.1%
2014	Tue, June 17	17	141,673	(15,835)	(10.1%)
2015	Tue, July 28	17	143,697	2,023	1.4%
2016	Thu, August 11	16	152,177	8,480	5.9%

Figure 3-14 shows the peak loads for 1999 through 2016.

Figure 3-14 PJM footprint calendar year peak loads: 1999 to 2016

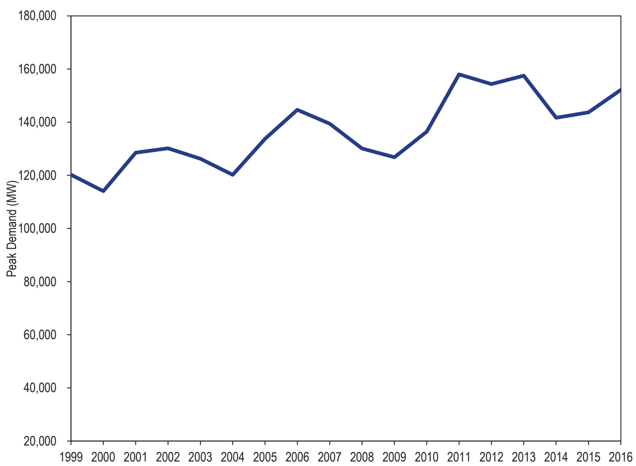
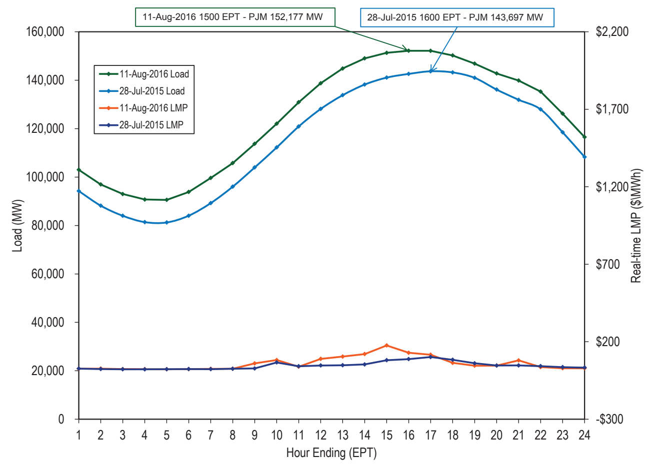


Figure 3-15 compares the peak load days of 2015 and 2016. The highest average hourly real-time LMP on August 11, 2016 was $175.88 and on July 28, 2015 was $101.40.

Figure 3-15 PJM peak-load comparison Thursday, August 11, 2016 and Tuesday, July 28, 2015



Real-Time Demand

PJM average real-time load in 2016 increased from 2015, from 88,594 MW to 88,601MW.[31]

PJM average real-time demand in 2016 increased 1.0 percent from 2015, from 92,665 MW to 93,551 MW.

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 checkout process.

PJM Real-Time Demand Duration

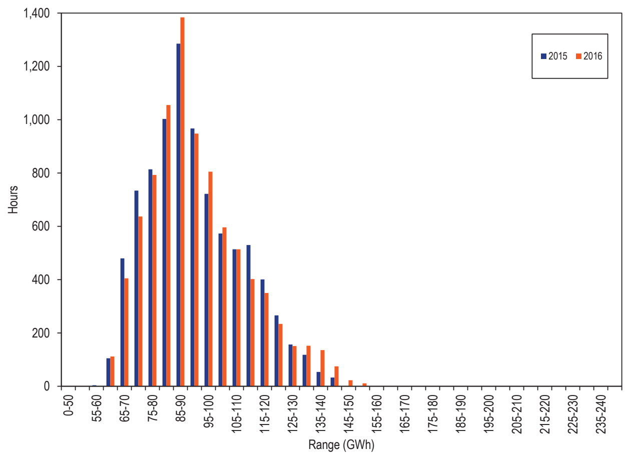
Figure 3-16 shows the hourly distribution of PJM real-time load plus exports for 2015 and 2016.[32]

30 Peak loads shown are Power Meter 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>.

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

32 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>.

Figure 3-16 Distribution of PJM real-time accounting load plus exports: January through December, 2015 and 2016[33]



PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for 1998 to 2016. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[34]

Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January through December, 1998 through 2016[35]

	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
1998	28,578	5,511	28,578	5,511	NA	NA	NA	NA
1999	29,641	5,955	29,641	5,955	3.7%	8.1%	3.7%	8.1%
2000	30,113	5,529	31,341	5,728	1.6%	(7.2%)	5.7%	(3.8%)
2001	30,297	5,873	32,165	5,564	0.6%	6.2%	2.6%	(2.9%)
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%

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

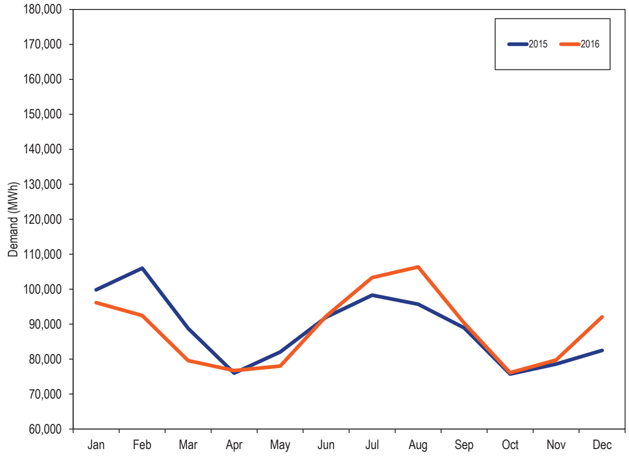
34 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excluded losses prior to June 1 and includes losses after June 1.

35 Export data are not available before June 1, 2000. The export data for 2000 are for the last six months of 2000.

PJM Real-Time, Monthly Average Load

Figure 3-17 compares the real-time, monthly average hourly loads for 2015 and 2016.

Figure 3-17 PJM real-time monthly average hourly load: January 2015 through December 2016



PJM real-time load is significantly affected by temperature. Figure 3-18 and Table 3-16 compare the PJM monthly heating and cooling degree days in 2015 and 2016.[36] Heating degree days decreased 6.4 percent, and cooling degree days increased 16.2 percent from 2015 to 2016.

Figure 3-18 PJM heating and cooling degree days: 2015 and 2016

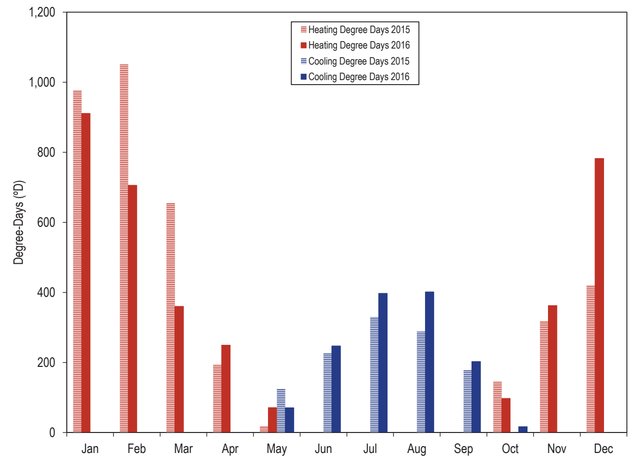


Table 3-16 PJM heating and cooling degree days: 2015 and 2016

	2015		2016		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	977	0	911	0	(6.7%)	0.0%
Feb	1,051	0	706	0	(32.8%)	0.0%
Mar	656	0	360	0	(45.1%)	0.0%
Apr	193	0	250	1	29.1%	0.0%
May	18	125	71	71	299.6%	(43.7%)
Jun	1	228	0	247	(100%)	8.6%
Jul	0	330	0	397	0.0%	20.2%
Aug	0	289	0	402	0.0%	39.0%
Sep	0	179	0	203	0.0%	13.6%
Oct	145	0	98	17	(32.8%)	0.0%
Nov	319	0	363	0	13.7%	0.0%
Dec	421	0	782	0	85.8%	0.0%
Total	3,781	1,151	3,541	1,337	(6.4%)	16.2%

Day-Ahead Demand

PJM average day-ahead demand in 2016, including DECs and up to congestion transactions, increased by 14.1 percent from 2015, from 111,644 MW to 127,390 MW.

PJM average day-ahead demand in 2016, including DECs, up to congestion transactions, and exports, increased by 15.0 percent from 2015, from 115,007 MW to 131,006 MW.

The reduction in up to congestion transactions (UTC) that had followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration

36 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.

of the 15 month refund period for the proceeding related to uplift charges for UTC transactions.[37]

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

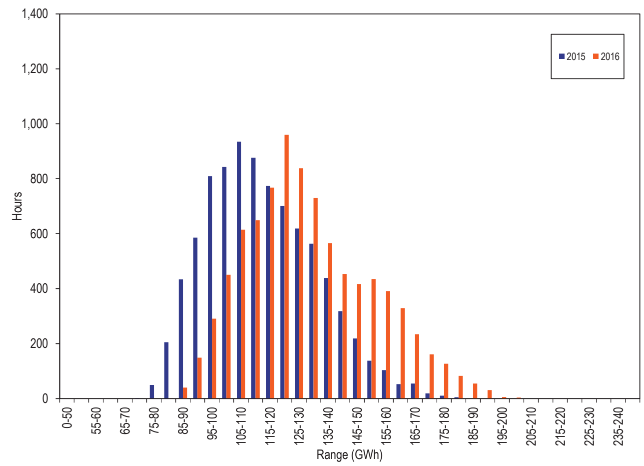
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An export energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

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

PJM Day-Ahead Demand Duration

Figure 3-19 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for 2015 and 2016.

Figure 3-19 Distribution of PJM day-ahead demand plus exports: January through December 2015 and 2016[38]



PJM Day-Ahead, Average Demand

Table 3-17 presents summary day-ahead demand statistics for each year from 2000 to 2016.[39]

37 148 FERC ¶ 61,144 (2014).

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

39 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 six months of that year.

Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: 2000 through 2016

	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
2000	33,039	6,852	33,411	6,757	NA	NA	NA	NA
2001	33,370	6,562	33,757	6,431	1.0%	(4.2%)	1.0%	(4.8%)
2002	42,305	10,161	42,413	10,208	26.8%	54.9%	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%	5.9%
2014	142,251	32,664	146,120	32,671	(1.8%)	76.7%	(1.4%)	75.9%
2015	111,644	18,715	115,007	18,867	(21.5%)	(42.7%)	(21.3%)	(42.3%)
2016	127,390	21,527	131,006	21,817	14.1%	15.0%	13.9%	15.6%

PJM Day-Ahead, Monthly Average Demand

Figure 3-20 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions, for 2015 and 2016.

Figure 3-20 PJM day-ahead monthly average hourly demand: 2015 and 2016

Real-Time and Day-Ahead Demand

Table 3-18 presents summary statistics for 2015 and 2016 day-ahead and real-time demand. All data are cleared MW. The last two columns of Table 3-18 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load.

Table 3-18 Cleared day-ahead and real-time demand (MWh): 2015 and 2016

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
	Year	Fixed Demand	Price Sensitive	Dec	Up to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2015	85,171	3,167	4,051	19,255	3,363	115,007	88,596	92,664	22,343	66,253
	2016	86,989	3,134	4,743	34,201	3,536	132,607	90,599	95,340	37,266	53,332
Median	2015	82,980	3,214	3,821	18,435	3,213	112,811	86,029	89,791	23,019	63,009
	2016	83,781	3,122	4,494	33,655	3,332	128,866	86,646	91,595	37,271	49,375
Standard Deviation	2015	15,726	553	1,311	5,230	926	18,867	16,643	16,764	2,103	14,540
	2016	16,989	412	1,422	6,936	1,081	22,817	18,183	18,571	4,246	13,937
Peak Average	2015	94,077	3,438	4,428	20,779	3,327	126,049	97,395	101,295	24,754	72,641
	2016	96,483	3,398	5,124	36,337	3,552	144,907	99,962	104,538	40,369	59,593
Peak Median	2015	90,912	3,481	4,213	19,777	3,138	123,781	94,082	97,709	26,073	68,009
	2016	94,579	3,364	4,950	35,655	3,328	143,460	97,178	101,755	41,705	55,473
Peak Standard Deviation	2015	13,302	512	1,241	5,336	969	16,062	14,507	14,887	1,175	13,332
	2016	15,104	323	1,411	6,660	1,058	20,531	16,657	17,443	3,088	13,568
Off-Peak Average	2015	77,057	2,921	3,706	17,867	3,396	104,947	80,580	84,801	20,146	60,434
	2016	78,331	2,893	4,395	32,254	3,522	121,390	82,061	86,953	34,437	47,624
Off-Peak Median	2015	74,197	2,924	3,445	17,186	3,283	101,821	77,617	81,568	20,253	57,364
	2016	76,211	2,843	4,145	31,398	3,340	118,189	79,399	84,686	33,503	45,896
Off-Peak Standard Deviation	2015	13,166	466	1,277	4,722	883	15,263	14,242	14,335	928	13,314
	2016	13,662	329	1,340	6,602	1,102	18,634	15,043	15,314	3,321	11,722

Figure 3-21 shows the average hourly cleared volumes of day-ahead demand and real-time demand for 2016. 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 3-21 Day-ahead and real-time demand (Average hourly volumes): 2016

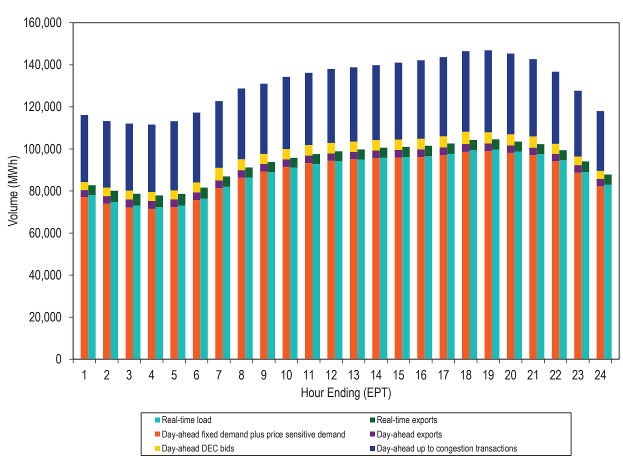
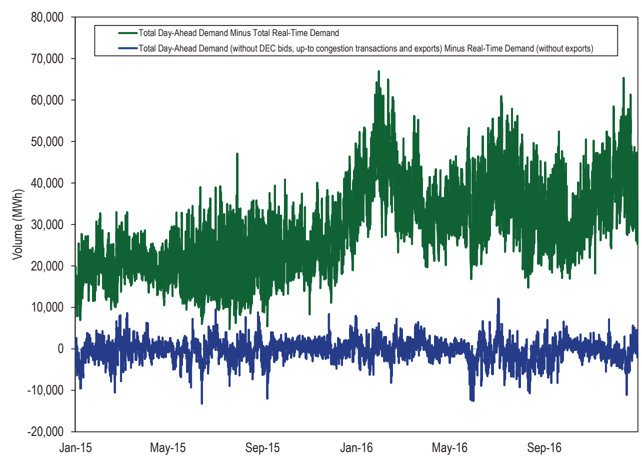


Figure 3-22 shows the difference between the day-ahead and real-time average daily demand from 2015 through 2016. There was an increase in up to congestion volume as a result of the expiration of the fifteen month potential refund period for the proceeding related to uplift charges for UTC transactions on December 7, 2015.

Figure 3-22 Difference between day-ahead and real-time demand (Average daily volumes): 2015 through 2016



Supply and Demand: Load and Spot Market

Real-Time Load and Spot Market

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a nonaffiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is generating less power from owned plants and/or purchasing less power under bilateral contracts than required to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 3-19 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2015 and 2016 based on parent company. In 2016, 12.9 percent of real-time load was supplied by bilateral contracts, 23.9 percent by spot market purchase and 63.2 percent by self-supply. Compared with 2015, reliance on bilateral contracts increased by 2.3 percentage points, reliance on spot supply decreased by 5.4 percentage points and reliance on self-supply increased by 3.1 percentage points.

Table 3-19 Monthly average percent of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2015 through 2016[40]

	2015			2016			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	11.1%	29.0%	59.8%	11.1%	25.9%	63.0%	(0.0%)	(3.1%)	3.2%
Feb	10.4%	29.7%	59.9%	11.5%	25.5%	63.0%	1.0%	(4.2%)	3.2%
Mar	9.7%	32.1%	58.2%	11.7%	26.4%	61.9%	2.0%	(5.7%)	3.7%
Apr	10.4%	34.4%	55.3%	12.7%	24.0%	63.4%	2.3%	(10.4%)	8.1%
May	9.3%	32.8%	58.1%	12.6%	24.5%	62.9%	3.3%	(8.2%)	4.7%
Jun	10.1%	30.0%	59.9%	12.5%	24.2%	63.2%	2.4%	(5.8%)	3.4%
Jul	10.5%	28.1%	61.4%	12.8%	23.3%	63.9%	2.3%	(4.8%)	2.5%
Aug	10.5%	27.3%	62.3%	12.7%	23.6%	63.7%	2.3%	(3.7%)	1.4%
Sep	10.3%	28.0%	61.7%	12.4%	22.7%	64.9%	2.1%	(5.2%)	3.2%
Oct	11.1%	27.3%	61.6%	14.6%	21.4%	64.0%	3.5%	(5.9%)	2.4%
Nov	10.9%	27.0%	62.1%	14.3%	23.2%	62.4%	3.4%	(3.8%)	0.4%
Dec	12.2%	26.0%	61.8%	15.6%	22.3%	62.1%	3.4%	(3.7%)	0.2%
Annual	10.5%	29.3%	60.2%	12.9%	23.9%	63.2%	2.3%	(5.4%)	3.1%

Day-Ahead Load and Spot Market

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

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead demand (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-20 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in 2015 through 2016, based on parent companies. In 2016, 8.9 percent of day-ahead demand was supplied by bilateral contracts, 25.0 percent by spot market purchases, and 66.1 percent by self-supply. Compared with 2015, reliance on bilateral contracts remained the same, reliance on spot supply

40 Table 3-19 and Table 3-20 were calculated as of January 26, 2017. The values may change slightly as billing values are updated by PJM.

decreased by 2.0 percentage points, and reliance on self-supply increased by 2.0 percentage points.

Table 3-20 Monthly average share of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: 2015 through 2016

	2015			2016			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	10.5%	25.5%	64.0%	8.2%	26.2%	65.7%	(2.3%)	0.7%	1.7%
Feb	9.9%	25.2%	64.9%	8.4%	25.8%	65.7%	(1.5%)	0.6%	0.9%
Mar	9.3%	27.8%	62.9%	7.9%	27.8%	64.3%	(1.4%)	(0.1%)	1.4%
Apr	9.5%	30.3%	60.2%	9.9%	24.5%	65.7%	0.3%	(5.8%)	5.5%
May	9.1%	27.9%	63.0%	9.6%	24.6%	65.8%	0.5%	(3.2%)	2.7%
Jun	8.1%	28.2%	63.8%	8.5%	24.2%	67.3%	0.4%	(4.0%)	3.6%
Jul	8.5%	27.2%	64.3%	8.8%	24.3%	66.9%	0.3%	(2.9%)	2.6%
Aug	8.2%	26.9%	64.9%	8.6%	24.5%	66.8%	0.4%	(2.3%)	1.9%
Sep	7.9%	27.6%	64.4%	8.1%	24.3%	67.7%	0.2%	(3.4%)	3.2%
Oct	8.5%	26.5%	65.0%	9.5%	25.6%	64.9%	1.1%	(1.0%)	(0.1%)
Nov	8.3%	26.1%	65.6%	9.4%	25.7%	64.9%	1.1%	(0.4%)	(0.7%)
Dec	9.3%	25.8%	64.9%	10.4%	23.5%	66.1%	1.2%	(2.4%)	1.2%
Annual	8.9%	27.0%	64.0%	8.9%	25.0%	66.1%	(0.0%)	(2.0%)	2.0%

Market Behavior

Offer Capping for Local Market Power

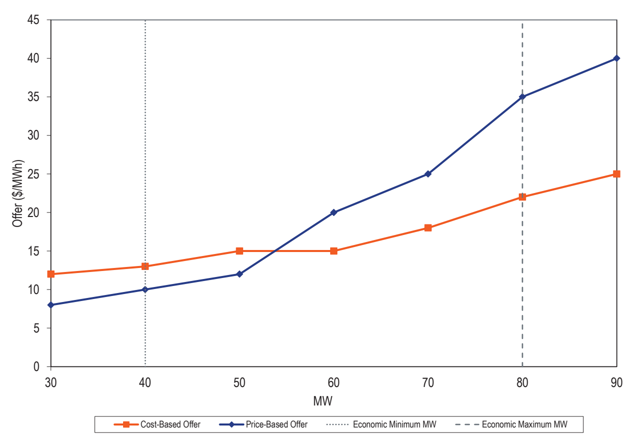
In the PJM Energy Market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and 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. PJM's market power mitigation goals have focused on market designs that promote competition and that limit local market power mitigation to situations where the local market structure is not competitive and thus where market design alone cannot mitigate market power.

The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive. However, there are some issues with the application of mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time Energy Market.

In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid 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.

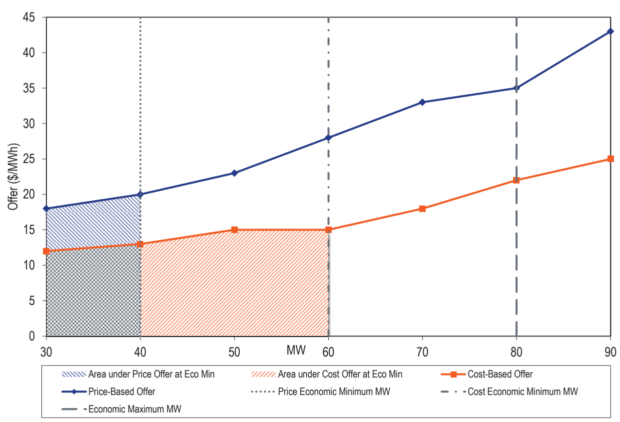
When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost or price-based offers. With the ability to submit offer curves with varying markups at different output levels in the price-based offer, units can avoid mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-23 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 even though the price-based offer is higher than cost at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-23 Offers with varying markups at different MW output levels



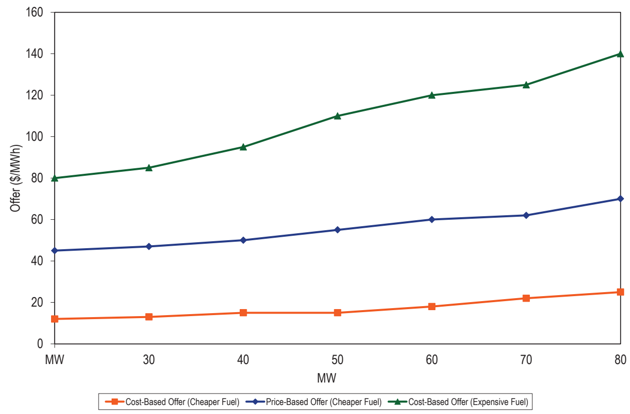
Offering a different economic minimum MW level, different minimum run times, different start up and notification times on the cost-based and price-based offers can also be used to avoid mitigation. For example, a unit may offer its price-based offer with a negative markup, but have a longer minimum run time (MRT) on the price-based offer. For example, 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 because the total cost of commitment (calculated as a product of MW and the offer in dollars per MWh plus the startup and no-load cost) can be lower on price-based offer at the lower economic minimum level compared to cost-based offer at a higher economic minimum level. Figure 3-24 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. The cost of commitment (area under the curve) 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 3-24 Offers with a positive markup but different economic minimum MW



In case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be lower cost even when it includes a markup. Figure 3-25 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 3-25 Dual fuel unit offers



These issues can be solved by simple rule changes.[41] 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 3-21. The offer capping percentages shown in Table 3-21 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market as well as units committed as part of conservative operations, excluding units that were committed for providing black start and reactive service.

Table 3-21 Offer capping statistics – energy only: 2012 to 2016

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2012	0.8%	0.4%	0.1%	0.1%
2013	0.4%	0.2%	0.1%	0.0%
2014	0.5%	0.2%	0.2%	0.1%
2015	0.4%	0.2%	0.2%	0.1%
2016	0.4%	0.2%	0.1%	0.0%

Table 3-22 shows the offer capping percentages including units committed to provide constraint relief and units committed to provide black start service and reactive support. The units that are committed and

41 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.

offer capped for black start service and reactive support reasons increased from 2012 through 2013. Before 2011, the units that ran to provide black start service and reactive support were generally economic in the energy market. From 2011 through 2013, the percentage of hours when these units were not economic (and were therefore committed on their cost schedule for reliability reasons) increased. This trend reversed in 2014, 2015 and 2016 because higher LMPs (in the first six months) resulted in the increased economic dispatch of black start and reactive service resources. As of April 2015, the Automatic Load Rejection (ALR) units that were committed for black start previously no longer provide black start service, and are not included in the offer capping statistics for black start. PJM also created closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs, 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 3-21.

Table 3-22 Offer capping statistics for energy and reliability: 2012 to 2016

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2012	1.7%	1.0%	0.9%	0.5%
2013	2.9%	2.4%	3.2%	2.1%
2014	0.8%	0.5%	0.6%	0.4%
2015	0.7%	0.8%	0.6%	0.7%
2016	0.4%	0.3%	0.1%	0.1%

Table 3-23 shows the offer capping percentages for units committed to provide black start service and reactive support. The data in Table 3-23 is the difference between the offer cap percentages shown in Table 3-22 and Table 3-21.

Table 3-23 Offer capping statistics for reliability: 2012 to 2016

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2012	0.9%	0.6%	0.8%	0.4%
2013	2.5%	2.2%	3.1%	2.1%
2014	0.3%	0.3%	0.4%	0.3%
2015	0.4%	0.6%	0.4%	0.6%
2016	0.1%	0.1%	0.0%	0.0%

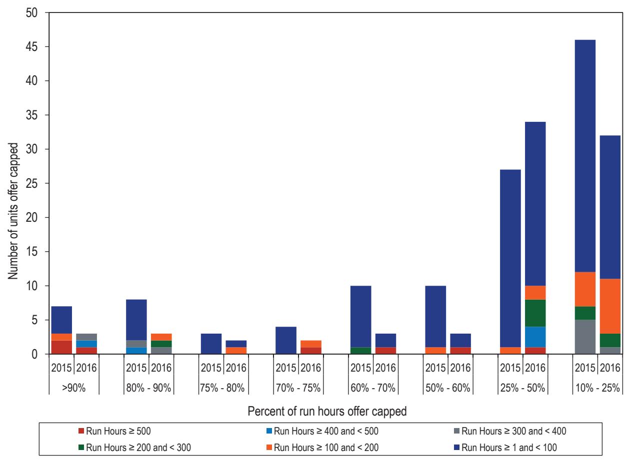
Table 3-24 presents data on the frequency with which units were offer capped in 2015 and 2016 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market. Table 3-24 shows that three units were offer capped for 90 percent or more of their run hours in 2016 compared to seven in 2015.

Table 3-24 Real-time offer capped unit statistics: 2015 and 2016

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Year	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
	2016	1	1	1	0	0	0
90%	2015	2	0	0	0	1	4
	2016	0	0	1	1	1	0
80% and < 90%	2015	0	1	1	0	0	6
	2016	0	0	0	0	1	1
75% and < 80%	2015	0	0	0	0	0	3
	2016	1	0	0	0	1	0
70% and < 75%	2015	0	0	0	0	0	4
	2016	1	0	0	0	0	2
60% and < 70%	2015	0	0	0	1	0	9
	2016	1	0	0	0	0	2
50% and < 60%	2015	0	0	0	0	1	9
	2016	1	3	0	4	2	24
25% and < 50%	2015	0	0	0	0	1	26
	2016	0	0	1	2	8	21
10% and < 25%	2015	0	0	5	2	5	34

Figure 3-26 shows the frequency with which units were offer capped in 2015 and 2016 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Figure 3-26 Real-time offer capped unit statistics: 2015 and 2016



TPS Test Statistics

In 2016, the AECO, AEP, ATSI, BGE, ComEd, Dominion, DPL, JCPL, PECO, PENELEC, and PPL control zones experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint (Table 3-25). The AP, DAY, DEOK, DLCO, EKPC, Met-Ed, Pepco, PSEG and RECO control zones did not have constraints binding for 100 or more hours in 2016. Table 3-25 shows that BGE, ComEd, and PPL were the control zones that experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint that was binding for one or more hours in every year from 2009 through 2016.

Table 3-25 Numbers of hours when control zones experienced congestion resulting from one or more constraints binding for 100 or more hours or from an interface constraint: 2009 through 2016

	2009	2010	2011	2012	2013	2014	2015	2016
AECO	149	172	234	0	208	0	394	439
AEP	1,045	1,192	2,253	0	2,611	2,710	1,274	796
AP	509	1,714	0	206	0	170	167	0
ATSI	157	0	0	208	270	489	242	141
BGE	152	470	1,041	2,970	1,760	6,255	9,601	11,434
ComEd	1,212	2,080	1,134	4,554	5,143	4,119	5,878	7,336
DEOK	0	0	0	109	0	0	112	0
DLCO	156	475	206	209	0	223	617	0
Dominion	468	905	1,179	1,020	664	0	1,172	459
DPL	0	122	0	1,542	639	3,071	2,066	2,719
JCPL	0	0	0	0	0	0	0	398
Met-Ed	0	180	162	0	0	0	222	0
PECO	247	0	788	386	732	1,953	895	692
PENELEC	103	284	0	0	176	4,281	1,683	451
Pepco	149	1	0	143	245	41	0	0
PPL	176	118	40	350	452	148	266	936
PSEG	303	549	1,107	913	3,021	4,688	2,665	0

The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in 2016.[42] The three pivotal supplier (TPS) test is

42 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.

applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

Table 3-26 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 3-26 Three pivotal supplier test details for interface constraints: 2016

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	423	684	10	0	10
	Off Peak	372	548	10	0	10
AP South	Peak	282	539	11	3	8
	Off Peak	187	638	12	8	3
Bedington - Black Oak	Peak	149	238	12	3	10
	Off Peak	89	119	10	2	8
Western	Peak	157	232	12	4	8
	Off Peak	89	106	11	1	10
Cleveland	Peak	107	108	1	0	1
	Off Peak	0	0	0	0	0
Warren	Peak	37	38	1	0	1
	Off Peak	49	57	1	0	1

The three pivotal supplier test is applied every time the PJM market system 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 capping. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 3-27 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units.

Table 3-27 Summary of three pivotal supplier tests applied for interface constraints: 2016

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	8	3	38%	2	25%	67%
	Off Peak	19	3	16%	2	11%	67%
AP South	Peak	23	2	9%	1	4%	50%
	Off Peak	11	6	55%	0	0%	0%
Bedington - Black Oak	Peak	246	24	10%	5	2%	21%
	Off Peak	155	11	7%	5	3%	45%
Western	Peak	12	2	17%	1	8%	50%
	Off Peak	5	0	0%	0	0%	0%
Cleveland	Peak	6	0	0%	0	0%	0%
	Off Peak	0	0	0%	0	0%	0%
Warren	Peak	149	0	0%	0	0%	0%
	Off Peak	13	0	0%	0	0%	0%

Parameter Limited Schedules

Cost-Based Offers

All capacity resources in PJM are required to submit at least one cost-based offer. During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by resources that are not capacity performance resources, are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or with the level of an approved exception.[43] During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by capacity performance resources, are parameter limited in accordance with predetermined unit specific parameter limits. During the 2016/2017 and 2017/2018 delivery years, there was no base capacity procured.

For the 2018/2019 and 2019/2020 delivery years, PJM procured two types of capacity resources, capacity performance resources and base capacity resources. Beginning June 1, 2018, there will no longer be any resources committed as the current annual capacity product. All cost-based offers, submitted by capacity performance resources and base capacity resources, are parameter limited in accordance with predetermined unit specific parameter limits.

Price-Based Offers

All capacity resources that choose to offer price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). For resources that are not capacity performance resources or not base capacity resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared. For base capacity resources (during the 2018/2019 and 2019/2020 delivery years only), the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts are declared.

Parameter Limits

During the extreme cold weather conditions in the first three months of 2016, as well as 2015 and 2014, a number of gas fired generators requested temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters that were affected because of gas pipeline restrictions include minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This led to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not included in the PLS matrix in 2016 and prior periods for annual resources that do not have capacity performance obligations. 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. Startup and notification times are limited for capacity performance resources beginning June 1, 2016, in accordance with predetermined unit specific parameter limits. The unit specific parameter limits for capacity performance resources were based on default minimum operating parameter limits posted by PJM by technology type. These default parameters were based on analysis by the MMU. Market participants could request an adjustment to the default values by submitting supporting documentation, which was reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance 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 steam units based on historical performance and existing equipment while

43 See PJM, OATT, § 6.6 Minimum Generator Operating Parameters - Parameter-Limited Schedules, (September 10, 2014), pp. 1937- 1940.

holding CTs and CCs to higher standards based on OEM documentation and up to date equipment configuration.

Currently, there are no rules in the PJM tariff or manuals that limit the nonparameter 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 rigorous market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer.

Parameter Limited Schedules under Capacity Performance

Beginning in the 2016/2017 delivery year, resources that have capacity performance (CP) commitments are required to submit, in their parameter limited schedules (cost-based offers and price-based PLS offers), unit specific parameters that reflect the physical capability of the technology type of the resource. For the 2018/2019 and 2019/2020 delivery years, resources that have base capacity commitments are also required to submit, in their parameter limited schedules, unit specific parameters that reflect the physical capability of the technology type of the resource. In its order on capacity performance, the Commission determined that capacity performance resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[44] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[45] 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.[46]

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

The fact that a contract may be just and reasonable because it was an arm's length contract entered into by two willing parties does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome or that such a contract can reasonably impose costs on customers who were not party to the contract. The actual contractual terms are a function of the incentives and interests of the parties. The fact that a just and reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 9th Order will increase energy market uplift payments

44 *PJM Interconnection, L.L.C. et al.*, 151 FERC ¶ 61,208 at P 437 (June 9th Order).

45 *Id* at P 439.

46 *Id* at P 440.

substantially. Uplift costs are unpredictable, opaque and unhedgeable. 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 the revised rules recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are reflected in uplift payments. The parameters provided to PJM dispatchers each day should reflect what units are physically capable of. That is an operational necessity. 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.

The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during high demand conditions. The proposed operating parameters should be based on the physical capability of the Reference Resource used in the Cost of New Entry, currently two GE Frame 7FA turbines with dual fuel capability. All resources that are less flexible than the Reference Resource are expected to be scheduled and running during high demand conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch instructions. CCs would also have the capability to be as flexible as the reference resource. These units will be exempt from nonperformance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during high demand conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

Such an approach is consistent with the Commission's no excuses policy for nonperformance because the flexibility target is set based on the optimal OEM-defined capability for the marginal resource that is expected to meet peak demand, which is consistent with the level of performance that customers are paying for in the capacity market. Any resource that is less flexible is not excused for nonperformance and any resource that meets the flexibility target is performing according to the commitments made in the capacity market.

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Markup Index

Markup is a summary measure of participant offer behavior or conduct for individual units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[47] The markup index is normalized and can vary from -1.00 when the offer price is less than short run marginal cost, to 1.00 when the offer price is higher than short run marginal cost. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup

Table 3-28 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost offers. Table 3-29

47 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.

shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost offers. The unadjusted markup is the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. The adjusted markup is calculated only for coal units because coal units have consistently had price-based offers less than cost-based offers.[48] The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

In 2016, 90.1 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was negative (-$0.56 per MWh) when using unadjusted cost offers. The average dollar markups of units with offer prices less than $50 was negative (-$1.18 per MWh) when using unadjusted cost offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, implying a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in 2016, none had offer prices above $400 per MWh. Among the units that were marginal in 2015, 0.17 percent of units had offer prices greater than $400 per MWh, with an average dollar markup of $56.87 per MWh. Using the unadjusted cost offers, the highest markup for any marginal unit in 2016 was $258.16 while the highest markup in 2015 was $792.21.

Table 3-30 shows the percentage of marginal units that had markups, calculated using unadjusted cost offers, below, above and equal to zero for coal, gas and oil fuel types.[49] Table 3-31 shows the percentage of marginal units that had markups, calculated using adjusted cost offers, below, above and equal to zero for coal, gas and oil fuel types. In 2016, nearly 58.41 percent of marginal coal units had negative markups. In 2016, using adjusted cost-based offers for coal units, 38.56 percent of coal units had negative markups.

Table 3-28 Average, real-time marginal unit markup index (By offer price category unadjusted): 2015 and 2016

	2015			2016		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.04)	($2.45)	47.1%	0.03	($0.56)	64.2%
$25 to $50	(0.02)	($1.32)	38.9%	(0.01)	($1.18)	25.9%
$50 to $75	0.08	$4.39	2.8%	0.18	$9.94	1.6%
$75 to $100	0.13	$10.46	1.1%	0.28	$24.07	0.6%
$100 to $125	0.11	$11.48	1.2%	0.05	$5.13	1.8%
$125 to $150	0.03	$3.33	3.1%	0.01	$1.74	4.3%
>= $150	0.05	$12.54	5.8%	0.05	$9.47	1.6%

Table 3-29 Average, real-time marginal unit markup index (By offer price category adjusted): 2015 and 2016

	2015			2016		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.00)	($1.45)	47.1%	0.06	$0.28	64.2%
$25 to $50	0.03	$0.31	38.9%	0.04	$0.52	25.9%
$50 to $75	0.10	$5.44	2.8%	0.20	$10.94	1.6%
$75 to $100	0.14	$10.93	1.1%	0.29	$24.49	0.6%
$100 to $125	0.11	$11.75	1.2%	0.05	$5.16	1.8%
$125 to $150	0.03	$3.40	3.1%	0.01	$1.75	4.3%
>= $150	0.05	$12.75	5.8%	0.05	$9.54	1.6%

48 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.

49 Other fuel types were excluded based on data confidentiality rules.

Table 3-30 Percent of marginal units with markup below, above and equal to zero (by fuel type unadjusted): 2015 and 2016

	2015			2016		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	57.59%	24.11%	18.30%	58.41%	22.29%	19.30%
Gas	25.98%	27.82%	46.19%	22.51%	16.51%	60.98%
Oil	6.19%	80.09%	13.72%	11.90%	84.49%	3.61%

Table 3-31 Percent of marginal units with markup below, above and equal to zero (by fuel type adjusted): 2015 and 2016

	2015			2016		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	39.26%	24.85%	35.89%	38.56%	18.06%	43.37%
Gas	25.98%	27.82%	46.19%	22.51%	16.51%	60.98%
Oil	6.19%	80.09%	13.72%	11.90%	84.49%	3.61%

Figure 3-27 shows the frequency distribution of hourly markups for all gas units offered in 2015 and 2016. The highest markup within the economic operating range of the unit's offer curve was used for creating the frequency distributions.[50] Of the gas units offered in the PJM market in 2016, nearly 25 percent of gas unit-hours had a maximum markup that was negative. More than 5 percent of gas fired unit-hours had a highest markup within the economic operating range above $100 per MWh.

Figure 3-27 Frequency distribution of highest markup of gas units offered in 2015 and 2016

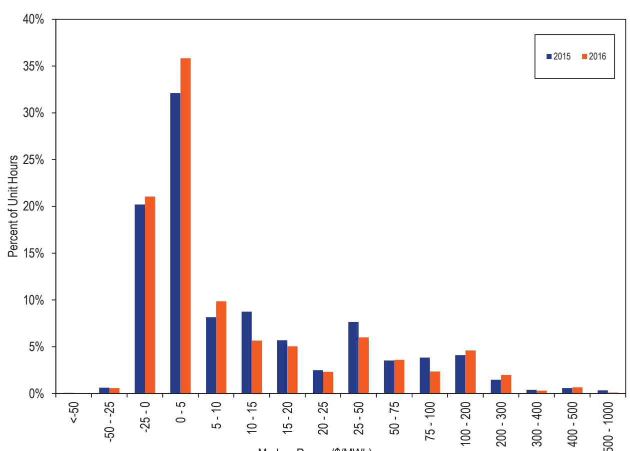


Figure 3-28 shows the frequency distribution of hourly markups for all coal units offered in 2015 and 2016. Of the coal units offered in the PJM market in 2016, nearly 40 percent of coal unit-hours had a maximum markup that was negative.

Figure 3-28 Frequency distribution of highest markup of coal units offered in 2015 and 2016

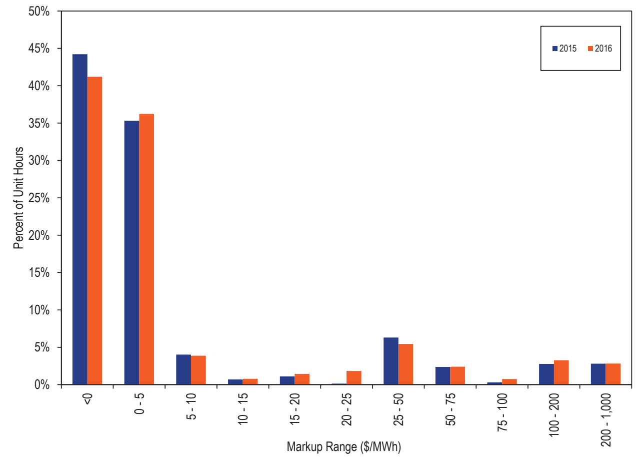
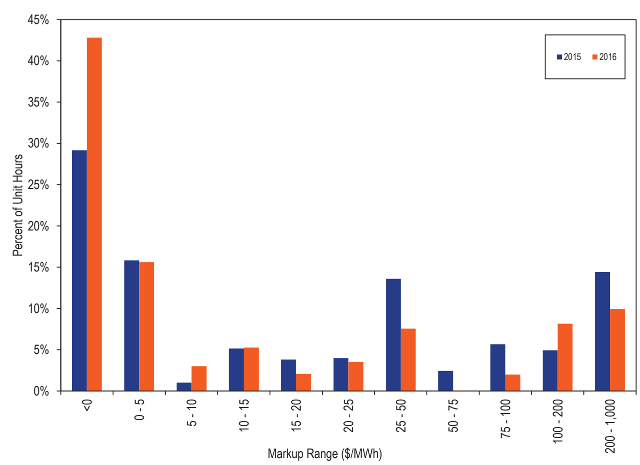


Figure 3-29 shows the frequency distribution of hourly markups for all offered oil units in 2015 and 2016. Of the oil units offered in the PJM market in 2016, nearly 40 percent of oil unit-hours had a maximum markup that was negative.

Figure 3-29 Frequency distribution of highest markup of oil units offered in 2015 and 2016



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

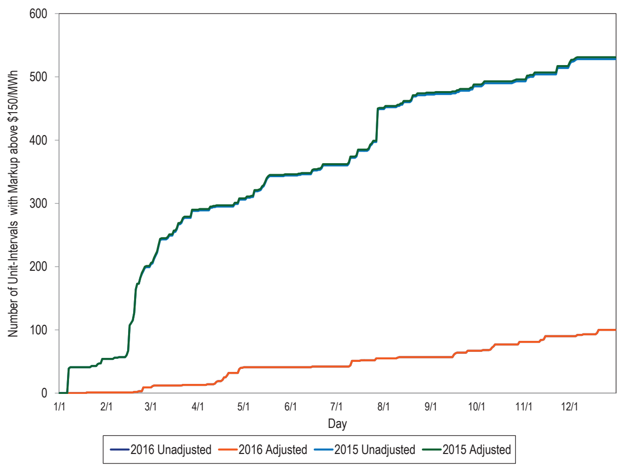
50 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

price-based offers reveal actual unit marginal costs and imply 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 3-30 and Table 3-32 show the number of marginal unit intervals in 2016 and 2015 with markup above $150 per MWh. Compared to 2015, 2016 had fewer marginal unit intervals with high markups.

Figure 3-30 Cumulative Number of Unit Intervals with markups above $150 per MWh: 2015 and 2016



Day-Ahead Markup

Table 3-32 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using unadjusted offers. The majority of marginal units are virtual transactions, which do not have markup. In the PJM Day-Ahead Energy Market, when using unadjusted cost offers, in 2016, 89.9 percent of marginal generating units had offer prices less than $50 per MWh and the average dollar markup was negative, and 0.4 percent of marginal generating units had offers in the $75 to $125 per MWh range and the average dollar markup and the average markup index were both negative.

Table 3-32 Average day-ahead marginal unit markup index (By offer price category, unadjusted): 2015 and 2016

	2015			2016		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.01	($1.54)	44.2%	0.18	($0.98)	62.3%
$25 to $50	0.00	($0.89)	45.3%	0.03	($0.09)	27.6%
$50 to $75	0.12	$7.01	2.4%	0.09	$4.94	1.5%
$75 to $100	0.07	$5.37	1.0%	(0.02)	($2.70)	0.1%
$100 to $125	(0.00)	($2.40)	0.8%	(0.01)	($0.72)	0.3%
$125 to $150	0.00	($0.51)	3.2%	0.00	$0.00	7.2%
>= $150	0.02	$3.07	3.1%	0.01	$2.62	1.0%

Table 3-33 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using adjusted offers. In 2016, 0.4 percent of marginal generating units had offers in the $75 to $125 per MWh range and the average dollar markup and the average markup index were both negative. The average markup index increased from 0.06 in 2015, to 0.22 in 2016 in the offer price category less than $25.

Table 3-33 Average day-ahead marginal unit markup index (By offer price category, adjusted): 2015 and 2016

	2015			2016		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.06	($0.19)	44.2%	0.22	$0.04	62.3%
$25 to $50	0.06	$1.16	45.3%	0.07	$1.68	27.6%
$50 to $75	0.15	$8.59	2.4%	0.14	$7.74	1.5%
$75 to $100	0.08	$5.69	1.0%	(0.02)	($2.70)	0.1%
$100 to $125	(0.00)	($2.08)	0.8%	(0.01)	($0.72)	0.3%
$125 to $150	0.00	($0.51)	3.2%	0.00	$0.00	7.2%
>= $150	0.02	$3.08	3.1%	0.01	$2.62	1.0%

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

Short Run Marginal Costs

There are three types of costs identified under PJM rules:

- Short run marginal costs (or incremental costs). Short run costs incurred directly as a result of producing energy for an hour;
- Avoidable costs. Annual costs that would be avoided if energy were not produced over an annual period;
- Fixed costs. Costs associated with an investment in a facility including the return on and of capital.

Marginal costs are the only costs relevant to the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production.

The MMU recommends that PJM require that the level of incremental costs includable in cost-based offers not exceed the unit's short run marginal cost.

Fuel Cost Policies

The fuel cost policy documents the process by which the Market Seller calculates the fuel cost component of its cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel. Fuel handling costs and fuel additive costs are included in the cost-based offer as variable operations and maintenance (VOM) costs. The fuel cost policy documents the frequency with which the Market Seller updates VOM and other nonfuel cost inputs.

The verification of accurate fuel costs in cost-based offers is not possible unless the fuel cost policy is algorithmic, verifiable, and systematic. Algorithmic means that the fuel cost policy must use a set of defined, logical steps to use defined inputs to get to defined outputs. Verifiable means that the fuel cost policy must provide a fuel price that can be calculated by the Market Monitor after the fact with the same data available to the generation owner at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the fuel cost policy must document a standardized method or methods for calculating fuel costs including objective triggers for each method.

The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

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 Manual 15 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.

FERC System of Accounts

PJM Manual 15 relies heavily on the FERC System of Accounts, which predates markets and does not define costs consistently with market economics.

The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines.

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 cost 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.

The MMU recommends the removal of all cyclic starting and peaking factors from the Cost Development Guidelines.

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 avoidable costs, not short run marginal costs, and are correctly includable in the RPM Avoidable Cost Rate.

The MMU recommends the removal of all labor costs from the Cost Development Guidelines.

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the resource is compensated in the energy market.

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.

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 Cost Development Guidelines.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation contains an error in the calculation of the weighted average pumping cost, and it does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Energy Market Opportunity Costs

The calculation of energy market opportunity costs for energy limited units in Section 12 of PJM Manual 15 fails to account for a number of physical unit characteristics and environmental restrictions that influence opportunity costs. These include start up time, notification time, minimum down time, multiple fuel capability, multiple emissions limitations, and fuel usage limitations.

The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output.

The use of Catastrophic Force Majeure as the criterion for the use of opportunity costs for fuel supply limitations in Schedule 2 of the Operating Agreement is overly restrictive. This criterion would not allow the use of opportunity costs to allocate limited fuel in the case of regional fuel transportation disruptions or extreme weather events.

The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2.

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. The results reported here include units that were mitigated for any reason, including both structural market power in the energy market and units called on for reliability reasons, including reactive and black start service.

The FMU adder was filed with FERC in 2005, and approved effective February 2006.[51] The goal, in 2005, was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the PJM Capacity Market). That function became unnecessary with the introduction of the RPM capacity market design in 2007, and changes to the scarcity pricing rules in 2012. Under the RPM design, units can make offers in the capacity market that include their ACR net of net revenues. Thus, if there is a shortfall in ACR recovery, that shortfall is included in the RPM offer. If the unit clears in RPM, it covers its shortfall in ACR costs. If the unit does not clear, then the market result means that PJM can provide reliability without the unit and no additional revenue is needed.

For those reasons, the MMU recommended the elimination of FMU and AU adders.[52] FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

The MMU and PJM proposed a compromise on the elimination of FMU adders that maintains the ability of generating units to qualify for FMU adders when units have net revenues less than unit going forward costs or ACR. PJM submitted the joint MMU/PJM proposal to the Commission pursuant to section 206 of the Federal Power Act. On October 31, 2014, the Commission conditionally approved the filing and the new rule became effective November 1, 2014.

The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. Units capped for 60 percent or more of their run hours and less than 70 percent are eligible for an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped for 70 percent or more of their run hours and less than 80 percent are eligible for an adder of either 10 percent of their cost-based offer or $30 per MWh. Units capped for 80 percent or more of their run hours are eligible for an adder of either 10 percent of their cost-based offer or $40 per MWh. These categories are designated Tier 1, Tier 2 and Tier 3.

In addition to being offer capped for the designated percent of run hours, in order to qualify for an FMU adder, a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) must be less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.) No portion of the unit may be included in an FRR capacity plan or be receiving compensation under Part V of the PJM Tariff and the unit must be internal to the PJM Region and subject only to PJM dispatch.[53]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU adder based on the number of run-hours the unit is offer capped.[54] For example, if a generating station had two identical units with identical electrical impacts on the system, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU.

51 110 FERC ¶ 61,053 (2005).

52 See the "*FMU Problem Statement and Issue Charge*," <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_FMU_Problem_Statement_and_Issue_Charge_20130306.pdf>.

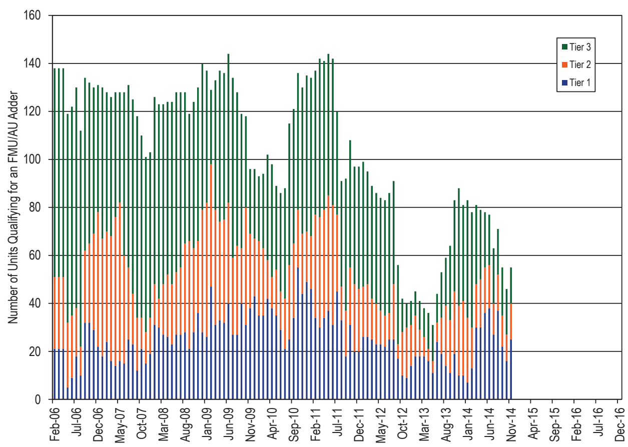
53 PJM. OA, Schedule 1 § 6.4.2.

54 An associated unit (AU) must belong to the same design class (where a design class includes generation that is the same size and uses the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU.

If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site. The AU designation was implemented to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

Figure 3-31 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006. The new rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[55] The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero since December 2014.

Figure 3-31 Frequently mitigated units and associated units (By month): February, 2006 through December, 2016



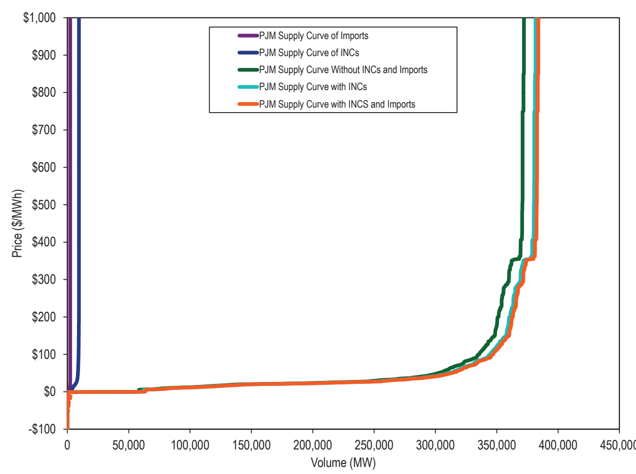
Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Energy Market and such offers and bids may be marginal, based on the way in which the PJM optimization algorithm works.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Up to congestion transactions may be submitted between any two buses on a list of 431 buses, eligible for up to congestion transaction bidding.[56] Financial Transaction Rights (FTRs) bids may be submitted at any bus on a list of selected buses that change every planning period, eligible for FTRs. 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 3-32 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 2016.

Figure 3-32 PJM day-ahead aggregate supply curves: 2016 example day



55 PJM. OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

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

Table 3-34 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2015 and 2016. The hourly average submitted and cleared increment MW increased by 26.0 and 11.4 percent, from 7,175 MW and 4,675 MW in 2015 to 9,043 MW and 5,207 MW in 2016. The hourly average submitted and cleared decrement MW increased by 25.3 percent and 18.6 percent, from 6,879 MW and 4,051 MW in 2015 to 8,618 MW and 4,805 MW in 2016.

Table 3-34 Hourly average number of cleared and submitted INCs, DECs by month: 2015 and 2016

		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
2015	Jan	4,350	6,447	78	398	5,153	7,320	76	295
2015	Feb	4,754	7,109	116	578	4,511	7,445	72	409
2015	Mar	4,973	8,689	142	760	4,305	8,894	101	648
2015	Apr	4,511	6,351	187	558	3,453	6,990	84	451
2015	May	5,089	7,459	181	656	4,171	6,823	94	404
2015	Jun	4,592	7,043	143	697	4,196	6,696	89	410
2015	Jul	4,101	6,534	128	745	3,335	5,830	86	448
2015	Aug	4,457	6,956	135	749	3,433	5,506	74	398
2015	Sep	4,527	6,772	148	733	4,391	7,030	112	437
2015	Oct	4,631	7,112	199	846	3,990	6,757	112	462
2015	Nov	5,022	7,822	223	1,008	3,671	6,435	109	482
2015	Dec	5,102	7,775	189	1,010	4,028	6,869	129	486
2015	Annual	4,675	7,175	156	729	4,051	6,879	95	444
2016	Jan	5,035	8,093	174	1,066	4,286	7,569	100	534
2016	Feb	4,831	8,710	178	1,150	4,259	8,158	113	572
2016	Mar	5,715	8,548	208	1,045	3,690	6,357	101	502
2016	Apr	5,630	8,343	186	964	4,115	7,066	101	509
2016	May	5,113	7,652	161	976	4,321	6,256	103	477
2016	Jun	5,130	8,291	153	1,054	5,344	8,107	128	585
2016	Jul	5,238	9,857	176	1,316	5,528	9,901	134	880
2016	Aug	4,872	9,873	191	1,408	5,516	10,521	147	952
2016	Sep	4,961	10,952	204	1,519	5,624	10,368	149	926
2016	Oct	5,227	9,660	260	1,345	5,224	10,207	148	792
2016	Nov	5,473	9,294	222	1,169	4,446	8,521	130	653
2016	Dec	5,250	9,238	196	1,262	5,283	10,344	128	760
2016	Annual	5,207	9,043	193	1,190	4,805	8,618	123	679

Table 3-35 shows the average hourly number of up to congestion transactions and the average hourly MW in 2015 and 2016. In 2016, the average hourly up to congestion submitted MW increased 70.3 percent and cleared MW increased 78.6 percent, compared to 2015, as a result of the expiration of the fifteen month potential refund period for the proceeding related to uplift charges for UTC transactions in December 2015.[57]

57 See 148 FERC ¶ 61,144 (2014); 16 U.S.C. § 824e.

Table 3-35 Hourly average of cleared and submitted up to congestion bids by month: 2015 and 2016

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2015	Jan	15,903	46,626	806	2,132
2015	Feb	17,255	57,318	892	2,695
2015	Mar	18,407	73,004	979	2,913
2015	Apr	16,300	73,446	811	2,734
2015	May	18,929	81,358	941	3,219
2015	Jun	17,714	81,452	896	3,220
2015	Jul	18,883	88,543	952	3,502
2015	Aug	18,490	102,084	1,126	4,291
2015	Sep	20,779	108,730	1,451	4,909
2015	Oct	20,183	100,673	1,493	4,736
2015	Nov	20,852	86,740	1,466	4,062
2015	Dec	27,124	99,083	1,933	4,841
2015	Annual	19,255	83,422	1,147	3,611
2016	Jan	39,639	135,369	2,466	6,015
2016	Feb	38,814	152,891	2,091	5,748
2016	Mar	31,817	147,963	1,703	5,094
2016	Apr	29,212	128,349	2,689	6,079
2016	May	32,883	120,132	2,977	6,006
2016	Jun	35,469	151,414	2,528	6,406
2016	Jul	37,668	181,720	2,413	7,158
2016	Aug	32,986	147,289	2,294	6,774
2016	Sep	29,368	129,498	2,309	6,065
2016	Oct	28,250	121,377	2,612	6,498
2016	Nov	36,506	141,688	2,927	7,335
2016	Dec	40,090	147,343	3,552	8,803
2016	Annual	34,387	142,075	2,549	6,503

Table 3-36 Hourly average day-ahead number of cleared and submitted import and export transactions by month: 2015 and 2016

		Imports				Exports			
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
2015	Jan	2,579	2,716	15	17	4,473	4,559	26	26
2015	Feb	2,588	2,726	17	19	4,383	4,469	23	25
2015	Mar	2,484	2,668	16	18	3,268	3,302	16	17
2015	Apr	2,531	2,638	18	21	2,624	2,626	13	13
2015	May	2,339	2,482	18	20	2,612	2,623	17	17
2015	Jun	2,269	2,349	14	16	2,895	2,906	14	14
2015	Jul	2,319	2,445	16	18	2,961	2,983	14	14
2015	Aug	2,410	2,549	14	16	3,209	3,239	15	15
2015	Sep	1,854	2,015	11	14	3,873	3,913	18	18
2015	Oct	1,889	1,485	12	9	2,802	2,197	15	15
2015	Nov	1,840	1,988	15	17	2,715	2,734	15	15
2015	Dec	1,998	2,137	18	20	2,475	2,483	13	13
2015	Annual	2,257	2,348	15	17	3,183	3,160	16	17
2016	Jan	2,633	2,103	20	20	3,044	2,571	16	16
2016	Feb	2,396	2,480	20	22	2,634	2,653	13	13
2016	Mar	2,097	2,145	17	18	2,324	2,330	11	11
2016	Apr	2,150	2,180	16	16	2,620	2,635	13	13
2016	May	1,889	1,947	12	14	2,484	2,492	14	15
2016	Jun	1,335	1,366	6	7	4,428	4,471	23	24
2016	Jul	1,315	1,247	6	6	4,327	3,389	21	21
2016	Aug	1,384	1,424	6	7	4,331	4,351	20	20
2016	Sep	939	956	5	5	3,997	4,004	21	21
2016	Oct	1,104	997	6	6	3,800	2,902	22	22
2016	Nov	1,012	1,030	6	7	2,883	2,894	17	17
2016	Dec	1,302	1,354	8	9	4,284	4,306	22	22
2016	Annual	1,628	1,600	11	11	3,434	3,250	18	17

Table 3-36 shows the average hourly number of import and export transactions and the average hourly MW in 2015 and 2016. In 2016, the average hourly submitted and cleared import transaction MW decreased by 31.9 and 27.9 percent, and the average hourly submitted and cleared export transaction MW increased 2.9 and 3.4 percent, compared to 2015.

Table 3-37 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal in 2015 and 2016.

Table 3-37 Type of day-ahead marginal units: 2015 and 2016

	2015						2016					
	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	14.2%	0.5%	71.9%	6.9%	6.3%	0.08%	5.3%	0.1%	85.2%	5.6%	3.8%	0.00%
Feb	13.1%	0.4%	73.1%	7.6%	5.6%	0.12%	5.5%	0.0%	83.5%	7.4%	3.6%	0.00%
Mar	10.0%	0.7%	73.3%	10.6%	5.3%	0.01%	7.0%	0.1%	80.6%	7.7%	4.7%	0.00%
Apr	10.4%	0.3%	73.2%	10.8%	5.3%	0.00%	5.8%	0.0%	82.3%	8.1%	3.7%	0.00%
May	10.2%	0.1%	75.2%	9.2%	5.3%	0.02%	6.2%	0.1%	83.8%	6.5%	3.4%	0.01%
Jun	8.0%	0.1%	78.2%	9.5%	4.1%	0.01%	3.5%	0.0%	84.2%	8.5%	3.7%	0.00%
Jul	7.2%	0.1%	81.1%	7.8%	3.8%	0.01%	3.0%	0.0%	83.1%	10.1%	3.7%	0.01%
Aug	6.0%	0.1%	83.4%	7.1%	3.3%	0.01%	3.1%	0.0%	78.4%	13.1%	5.4%	0.00%
Sep	7.2%	0.2%	80.0%	7.5%	5.1%	0.01%	6.1%	0.0%	76.3%	11.4%	6.2%	0.01%
Oct	9.8%	0.1%	72.4%	11.2%	6.6%	0.00%	6.1%	0.1%	77.0%	10.9%	5.9%	0.01%
Nov	11.8%	0.1%	72.0%	10.7%	5.3%	0.00%	4.0%	0.0%	86.5%	6.3%	3.1%	0.00%
Dec	7.3%	0.1%	79.8%	8.0%	4.8%	0.01%	3.1%	0.0%	86.6%	6.9%	3.3%	0.00%
Annual	9.6%	0.3%	76.1%	8.9%	5.1%	0.02%	4.7%	0.0%	82.4%	8.6%	4.2%	0.00%

Figure 3-33 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month for 2005 through 2016.

Figure 3-33 Monthly bid and cleared INCs, DECs and UTCs (MW): 2005 through 2016

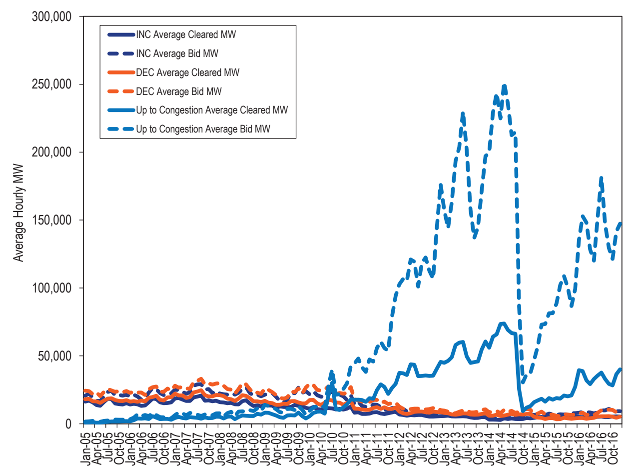
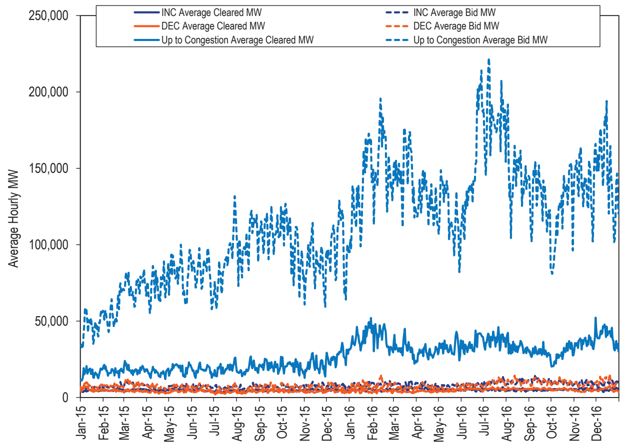


Figure 3-34 shows the daily volume of bid and cleared INC, DEC and up to congestion bids for the period 2015 through 2016.

Figure 3-34 Daily bid and cleared INCs, DECs, and UTCs (MW): 2015 through 2016



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 3-38 shows, in 2015 and 2016, the total increment offers and decrement bids and cleared MW by whether the parent organization is financial or physical.

Table 3-38 PJM INC and DEC bids and cleared MW by type of parent organization (MW): 2015 and 2016

	2015				2016			
Category	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent
Financial	54,424,992	44.2%	15,669,170	22.4%	85,011,917	54.8%	31,255,057	35.5%
Physical	68,682,193	55.8%	54,194,529	77.6%	70,123,047	45.2%	56,693,484	64.5%
Total	123,107,185	100.0%	69,863,698	100.0%	155,134,964	100.0%	87,948,540	100.0%

Table 3-39 shows, in 2015 and 2016, the total up to congestion bids and cleared MW by whether the parent organization was financial or physical.

Table 3-39 PJM up to congestion transactions by type of parent organization (MW): 2015 and 2016

	2015				2016			
Category	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent
Financial	643,199,888	88.0%	134,523,544	79.8%	1,199,246,273	96.1%	283,295,621	93.8%
Physical	87,572,419	12.0%	34,149,529	20.2%	48,737,575	3.9%	18,744,457	6.2%
Total	730,772,307	100.0%	168,673,073	100.0%	1,247,983,848	100.0%	302,040,077	100.0%

Table 3-40 shows, in 2015 and 2016, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-40 PJM import and export transactions by type of parent organization (MW): 2015 and 2016

		2015		2016	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	19,015,698	39.9%	18,842,285	42.4%
	Physical	28,635,508	60.1%	25,620,597	57.6%
	Total	47,651,206	100.0%	44,462,883	100.0%
Real-Time	Financial	25,595,400	30.4%	26,873,422	35.8%
	Physical	58,569,000	69.6%	48,147,619	64.2%
	Total	84,164,400	100.0%	75,021,041	100.0%

Table 3-41 shows increment offers and decrement bids bid by top ten locations in 2015 and 2016.

Table 3-41 PJM virtual offers and bids by top ten locations (MW): 2015 and 2016

2015					2016				
Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	19,527,215	21,691,683	41,218,898	WESTERN HUB	HUB	23,814,905	22,211,825	46,026,730
SOUTHIMP	INTERFACE	7,136,144	0	7,136,144	MISO	INTERFACE	394,038	4,965,920	5,359,958
N ILLINOIS HUB	HUB	905,858	2,733,941	3,639,799	SOUTHIMP	INTERFACE	3,883,473	0	3,883,473
IMO	INTERFACE	3,530,900	70,753	3,601,653	N ILLINOIS HUB	HUB	1,157,102	2,568,493	3,725,595
NYIS	INTERFACE	1,895,475	400,046	2,295,521	NYIS	INTERFACE	1,644,784	1,492,322	3,137,107
BGE	ZONE	223,721	1,750,290	1,974,011	BGE	ZONE	589,850	2,524,058	3,113,908
MISO	INTERFACE	414,835	1,216,550	1,631,385	AEP-DAYTON HUB	HUB	1,795,772	1,095,818	2,891,591
BAGLEY 34 KV 230-1LD	LOAD	403,792	912,882	1,316,673	PEPCO	ZONE	573,729	899,139	1,472,868
AEP-DAYTON HUB	HUB	651,596	649,136	1,300,732	PECO	ZONE	995,878	314,897	1,310,775
DOMINION HUB	HUB	365,184	811,772	1,176,956	IMO	INTERFACE	1,087,467	66,638	1,154,105
Top ten total		35,054,718	30,237,052	65,291,770			35,936,998	36,139,112	72,076,110
PJM total		62,628,496	60,111,808	122,740,304			79,422,390	75,700,997	155,123,387
Top ten total as percent of PJM total		56.0%	50.3%	53.2%			45.2%	47.7%	46.5%

Table 3-42 shows up to congestion transactions by import bids for the top ten locations and associated profits at each path in 2015 and 2016.[58]

Table 3-42 PJM cleared up to congestion import bids by top ten source and sink pairs (MW): 2015 and 2016

2015							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
SOUTHIMP	INTERFACE	NAGELAEP	EHVAGG	1,480,928	$2,329,200	$2,030,590	$4,359,789
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	445,796	$589,628	$41,074	$630,703
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	413,115	$877,279	$27,768	$905,047
NORTHWEST	INTERFACE	COMED	ZONE	412,351	$731,599	($76,144)	$655,455
SOUTHEAST	INTERFACE	HALIFXDP TX1	AGGREGATE	364,808	$1,026,764	($831,029)	$195,735
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	356,720	($42,397)	$77,601	$35,205
SOUTHIMP	INTERFACE	WOLF HILLS 1-5	AGGREGATE	342,579	$579,140	$374,141	$953,282
SOUTHEAST	INTERFACE	DOM	ZONE	277,721	$51,806	$174,166	$225,972
OVEC	INTERFACE	MALISZEWSKI	EHVAGG	258,387	$217,635	($131,660)	$85,975
MISO	INTERFACE	21 KINCA ATR24304	AGGREGATE	244,650	$215,385	$529,247	$744,632
Top ten total				4,597,055	$6,576,039	$2,215,755	$8,791,794
PJM total				19,561,806	$22,964,465	$3,098,774	$26,063,239
Top ten total as percent of PJM total				23.5%	28.6%	71.5%	33.7%
2016							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	COOK	EHVAGG	924,623	$324,666	($116,950)	$207,716
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	621,050	$823,501	($790,051)	$33,450
SOUTHWEST	INTERFACE	DUMONT	EHVAGG	496,135	$183,774	($96,395)	$87,378
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	493,953	$374,916	($111,860)	$263,056
SOUTHWEST	INTERFACE	COOK	EHVAGG	446,275	$341,360	($62,815)	$278,544
SOUTHIMP	INTERFACE	NAGELAEP	EHVAGG	424,592	$580,390	($661,851)	($81,460)
MISO	INTERFACE	112 WILTON	EHVAGG	414,904	$534,468	($438,828)	$95,640
OVEC	INTERFACE	DEOK	ZONE	376,077	$226,257	($177,879)	$48,378
OVEC	INTERFACE	BUCKEYE - AEP	AGGREGATE	352,277	$344,727	($308,143)	$36,584
OVEC	INTERFACE	ATSI	ZONE	333,697	$83,965	$139,439	$223,405
Top ten total				4,883,581	$3,818,025	($2,625,333)	$1,192,692
PJM total				27,794,147	$19,515,405	($13,793,283)	$5,722,122
Top ten total as percent of PJM total				17.6%	19.6%	19.0%	20.8%

58 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 3-43 shows up to congestion transactions by export bids for the top ten locations and associated profits at each path in 2015 and 2016.

Table 3-43 PJM cleared up to congestion export bids by top ten source and sink pairs (MW): 2015 and 2016

			2015				
			Exports				
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	460,314	$677,890	($483,724)	$194,166
FOWLER 34.5 KV FWLR1AWF	AGGREGATE	SOUTHWEST	INTERFACE	378,483	$1,224,460	($580,052)	$644,408
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	367,085	$325,308	($177,390)	$147,918
FOWLER RIDGE II WF	AGGREGATE	SOUTHWEST	INTERFACE	360,994	$558,913	$175,675	$734,589
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	303,419	$372,743	($202,796)	$169,947
COMED	ZONE	NIPSCO	INTERFACE	274,034	$49,989	$162,774	$212,762
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	270,867	$12,820	$120,330	$133,149
SULLIVAN-AEP	EHVAGG	SOUTHWEST	INTERFACE	222,668	($124,221)	$347,221	$223,000
21 KINCA ATR24404	AGGREGATE	SOUTHWEST	INTERFACE	217,732	$312,596	($437,928)	($125,332)
SULLIVAN-AEP	EHVAGG	MISO	INTERFACE	167,996	$423,665	($260,111)	$163,554
Top ten total				3,023,589	$3,834,163	($1,336,002)	$2,498,161
PJM total				9,849,007	$12,605,146	($1,387,105)	$11,218,042
Top ten total as percent of PJM total				30.7%	30.4%	96.3%	22.3%
			2016				
			Exports				
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED	ZONE	NIPSCO	INTERFACE	1,427,296	$1,150,528	$271,313	$1,421,841
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	984,202	$1,074,369	($776,386)	$297,984
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	865,527	$964,583	($657,405)	$307,179
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	766,929	$745,474	$47,324	$792,799
POWERTON 5	AGGREGATE	NORTHWEST	INTERFACE	550,217	$736,607	($596,755)	$139,852
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	521,855	$21,884	$45,506	$67,390
STMARYSGEN	AGGREGATE	NIPSCO	INTERFACE	452,574	$333,034	($241,863)	$91,170
EAST BEND 2	AGGREGATE	SOUTHWEST	INTERFACE	398,268	$393,612	($305,651)	$87,962
GRAND RIDGE WF	AGGREGATE	NIPSCO	INTERFACE	361,733	$168,945	$39,281	$208,226
21 KINCA ATR24404	AGGREGATE	SOUTHWEST	INTERFACE	361,040	($62,242)	$222,140	$159,898
Top ten total				6,689,640	$5,526,794	($1,952,495)	$3,574,299
PJM total				21,121,645	$13,506,455	($5,059,150)	$8,447,305
Top ten total as percent of PJM total				31.7%	40.9%	38.6%	42.3%

Table 3-44 shows up to congestion transactions by wheel bids and associated profits at each path for the top ten locations in 2015 and 2016.

Table 3-44 PJM cleared up to congestion wheel bids by top ten source and sink pairs (MW): 2015 and 2016

2015							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NORTHWEST	INTERFACE	361,210	$81,340	$660,033	$741,373
NORTHWEST	INTERFACE	MISO	INTERFACE	232,735	$559,645	($161,761)	$397,884
MISO	INTERFACE	NIPSCO	INTERFACE	221,536	$16,028	$137,545	$153,572
NYIS	INTERFACE	IMO	INTERFACE	129,966	($17,939)	$84,447	$66,508
IMO	INTERFACE	NYIS	INTERFACE	113,455	($31,774)	$130,923	$99,149
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	47,741	$49,972	$13,339	$63,311
SOUTHWEST	INTERFACE	IMO	INTERFACE	33,166	$140,955	($39,290)	$101,665
NIPSCO	INTERFACE	IMO	INTERFACE	29,379	$55,483	($13,026)	$42,456
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	21,292	$133,495	($86,234)	$47,262
MISO	INTERFACE	SOUTHWEST	INTERFACE	20,984	$30,255	($81,670)	($51,415)
Top ten total				1,211,465	$1,017,459	$644,306	$1,661,765
PJM total				1,453,602	$961,914	$1,516,081	$2,477,995
Top ten total as percent of PJM total				83.3%	105.8%	42.5%	67.1%
2016							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	MISO	INTERFACE	483,587	$205,487	($138,661)	$66,826
MISO	INTERFACE	NIPSCO	INTERFACE	456,491	$407,571	($101,219)	$306,352
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	355,456	$712,746	($580,097)	$132,648
MISO	INTERFACE	NORTHWEST	INTERFACE	249,915	$248,663	($15,678)	$232,985
NYIS	INTERFACE	IMO	INTERFACE	235,084	$17,499	$41,318	$58,817
IMO	INTERFACE	NYIS	INTERFACE	125,377	$92,270	($146,944)	($54,673)
SOUTHWEST	INTERFACE	NIPSCO	INTERFACE	89,731	$111,695	($63,301)	$48,394
IMO	INTERFACE	MISO	INTERFACE	76,985	$33,213	($103,413)	($70,200)
MISO	INTERFACE	SOUTHEXP	INTERFACE	40,226	$104,721	($76,174)	$28,547
NEPTUNE	INTERFACE	NYIS	INTERFACE	33,963	$41,687	($35,445)	$6,242
Top ten total				2,146,815	$1,975,552	($1,219,614)	$755,937
PJM total				2,492,100	$2,189,382	($1,291,897)	$897,485
Top ten total as percent of PJM total				86.1%	90.2%	94.4%	84.2%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up to congestion transaction. The top ten internal up to congestion transaction locations were 4.4 percent of the PJM total internal up to congestion transactions in 2016.

Table 3-45 shows up to congestion transactions by internal bids for the top ten locations and associated profits at each path in 2015 and 2016. The total UTC profit by top ten locations decreased by $20.6 million, or 89.6 percent, from $23.0 million in 2015 to $2.4 million in 2016. The total internal cleared MW increased by 112.8 million MW, or 81.9 percent, from 137.8 million MW in 2015 to 250.6 million MW in 2016.

Table 3-45 PJM cleared up to congestion internal bids by top ten source and sink pairs (MW): 2015 and 2016

2015							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	2,362,692	($6,122,031)	$22,202,119	$16,080,088
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	1,763,337	$1,787,375	($912,169)	$875,206
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	1,465,725	$1,275,618	$944,399	$2,220,017
BERGEN 2CC	AGGREGATE	LEONIA 230 T-2	AGGREGATE	1,017,317	($1,177,921)	$3,924,751	$2,746,830
JEFFERSON	EHVAGG	COOK	EHVAGG	958,975	$444,466	$98,393	$542,860
MARYSVILLE	EHVAGG	MALISZEWSKI	EHVAGG	892,606	$1,253,142	($219,667)	$1,033,476
BLACKOAK	EHVAGG	BEDINGTON	EHVAGG	718,298	$152,573	($940,892)	($788,319)
PSEG	ZONE	WESTERN HUB	HUB	711,099	$330,764	($291,938)	$38,826
WHIPPANY BK 7	AGGREGATE	TRAYNOR	AGGREGATE	686,989	$1,019,109	($976,308)	$42,801
21 KINCA ATR24304	AGGREGATE	DUMONT - OLIVE	AGGREGATE	673,830	($242,743)	$486,655	$243,912
Top ten total				11,250,868	($1,279,647)	$24,315,342	$23,035,695
PJM total				137,808,658	$149,441,842	($5,136,252)	$144,305,590
Top ten total as percent of PJM total				8.2%	(.9%)	(473.4%)	16.0%
2016							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
21 KINCA ATR24304	AGGREGATE	MICHFE	AGGREGATE	1,723,607	$152,078	$417,191	$569,268
21 KINCA ATR24404	AGGREGATE	MICHFE	AGGREGATE	1,376,889	($261,431)	$444,443	$183,012
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	1,238,324	$1,483,047	($1,494,384)	($11,337)
WHIPPANY BK 7	AGGREGATE	TRAYNOR	AGGREGATE	1,134,144	$806,939	($745,745)	$61,194
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	1,092,315	$712,354	$187,518	$899,873
AEP-DAYTON HUB	HUB	N ILLINOIS HUB	HUB	970,055	$249,345	($453,393)	($204,048)
BLACKOAK	EHVAGG	BEDINGTON	EHVAGG	927,715	$702,188	($1,303,092)	($600,904)
BRISTERS	EHVAGG	OX	EHVAGG	900,322	$1,344,558	($1,275,869)	$68,689
WAUKEGAN TR412	AGGREGATE	COMED	ZONE	871,975	$435,670	($175,527)	$260,142
CLOVERDALE	EHVAGG	CLOVERD2 138 KV T4	AGGREGATE	870,196	$627,455	$534,600	$1,162,055
Top ten total				11,105,541	$6,252,202	($3,864,258)	$2,387,944
PJM total				250,632,186	$166,288,531	($133,865,767)	$32,422,766
Top ten total as percent of PJM total				4.4%	3.8%	2.9%	7.4%

Table 3-46 shows the number of source-sink pairs that were offered and cleared monthly in 2013 through 2016. The annual row in Table 3-46 is the average hourly number of offered and cleared source-sink pairs for the year for the average columns and the maximum hourly number of offered and cleared source-sink pairs for the year for the maximum columns. The increase in average offered and cleared source-sink pairs beginning in January 2013 and continuing through the first eight months of 2014 illustrates that PJM's modification of the rules governing the location of up to congestion transactions bids resulted in a significant increase in the number of offered and cleared up to congestion transactions. The subsequent reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions on December 7, 2015.[59]

59 See 148 FERC ¶ 61,144 (2014)..

Table 3-46 Number of PJM offered and cleared source and sink pairs: 2013 through 2016

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2013	Jan	6,580	10,548	3,291	5,060
2013	Feb	4,891	7,415	2,755	3,907
2013	Mar	4,858	7,446	2,868	4,262
2013	Apr	6,426	9,064	3,464	4,827
2013	May	5,729	7,914	3,350	4,495
2013	Jun	6,014	8,437	3,490	4,775
2013	Jul	5,955	9,006	3,242	4,938
2013	Aug	6,215	9,751	3,642	5,117
2013	Sep	3,496	4,222	2,510	3,082
2013	Oct	4,743	7,134	3,235	4,721
2013	Nov	8,605	14,065	5,419	8,069
2013	Dec	8,346	11,728	6,107	7,415
2013	Annual	5,996	14,065	3,620	8,069
2014	Jan	7,977	11,191	5,179	7,714
2014	Feb	10,087	11,688	7,173	8,463
2014	Mar	11,360	14,745	7,284	9,943
2014	Apr	11,487	14,106	8,589	10,253
2014	May	11,215	13,477	7,734	9,532
2014	Jun	10,613	14,112	7,374	10,143
2014	Jul	10,057	12,304	7,202	8,486
2014	Aug	10,877	12,863	7,609	9,254
2014	Sep	5,618	11,269	4,281	8,743
2014	Oct	2,871	4,092	1,972	2,506
2014	Nov	2,463	3,988	1,812	3,163
2014	Dec	2,803	3,672	2,197	2,786
2014	Annual	8,109	10,614	5,690	7,570
2015	Jan	3,337	5,422	2,263	3,270
2015	Feb	4,600	7,041	2,775	4,147
2015	Mar	4,061	5,799	2,625	3,244
2015	Apr	3,777	6,967	2,343	3,378
2015	May	4,025	5,513	2,587	3,587
2015	Jun	3,852	5,967	2,781	3,748
2015	Jul	3,957	5,225	2,786	4,044
2015	Aug	4,996	6,143	3,702	4,378
2015	Sep	5,775	7,439	4,222	5,462
2015	Oct	6,000	7,414	4,221	5,397
2015	Nov	5,846	7,148	4,494	5,842
2015	Dec	7,097	8,250	5,709	6,610
2015	Annual	4,259	6,152	2,897	3,912
2016	Jan	7,714	8,793	6,174	7,374
2016	Feb	9,200	11,172	7,203	7,957
2016	Mar	8,826	11,572	6,338	8,126
2016	Apr	7,697	8,473	5,958	6,767
2016	May	8,521	9,398	6,707	7,273
2016	Jun	9,261	10,948	6,913	7,770
2016	Jul	12,401	16,103	8,571	11,695
2016	Aug	12,464	13,576	8,725	9,224
2016	Sep	12,297	16,324	7,736	9,230
2016	Oct	11,248	13,114	7,648	8,539
2016	Nov	13,151	16,725	8,173	11,581
2016	Dec	12,688	15,868	8,101	9,630
2016	Annual	10,455	12,672	7,354	8,764

Table 3-47 and Figure 3-35 show total cleared up to congestion transactions by type in 2015 and 2016. Total up to congestion transactions in 2016 increased by 79.1 percent from 168.7 million MW in 2015 to 302.0 million MW in 2016. Internal up to congestion transactions in 2016 were 83.0 percent of all up to congestion transactions compared to 81.7 percent in 2015.

Table 3-47 PJM cleared up to congestion transactions by type (MW): 2015 and 2016

	2015				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	4,597,055	3,023,589	1,211,465	11,250,868	20,082,977
PJM total (MW)	19,561,806	9,849,007	1,453,602	137,808,658	168,673,073
Top ten total as percent of PJM total	23.5%	30.7%	83.3%	8.2%	11.9%
PJM total as percent of all up to congestion transactions	11.6%	5.8%	0.9%	81.7%	100.0%
	2016				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	4,883,581	6,689,640	2,146,815	11,105,541	24,825,577
PJM total (MW)	27,794,147	21,121,645	2,492,100	250,632,186	302,040,078
Top ten total as percent of PJM total	17.6%	31.7%	86.1%	4.4%	8.2%
PJM total as percent of all up to congestion transactions	9.2%	7.0%	0.8%	83.0%	100.0%

Figure 3-35 shows the initial increase and continued increase in internal up to congestion transactions by month following the November 1, 2012 rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions.[60]

Figure 3-35 PJM monthly cleared up to congestion transactions by type (MW): 2005 through 2016

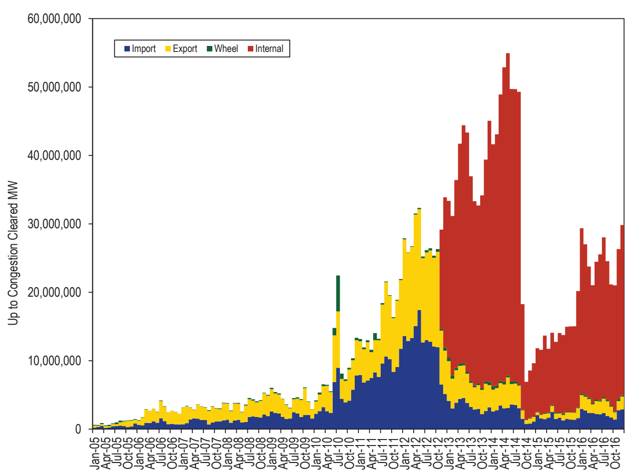
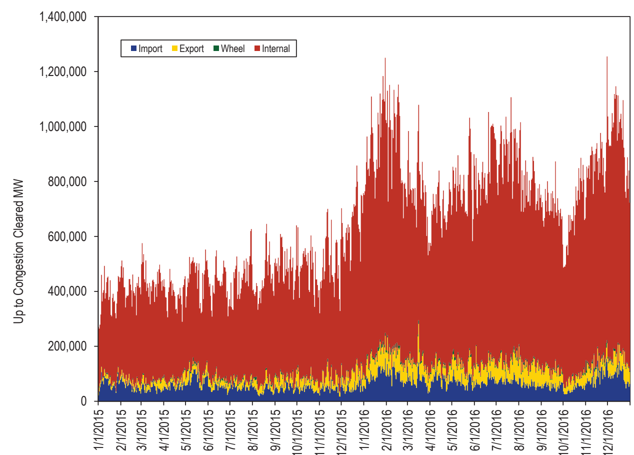


Figure 3-36 shows the daily cleared up to congestion MW by transaction type for the period from January 2015 through December 2016.

Figure 3-36 PJM daily cleared up to congestion transaction by type (MW): 2015 through 2016



Generator Offers

Generator offers are categorized as dispatchable (Table 3-48) or self scheduled (Table 3-49).[61] Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are self scheduled and must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are self scheduled and dispatchable. Table 3-48 and Table 3-49 do not include units that did not indicate their offer status and units that were offered as available to run only during emergency events. Units that do not indicate their offer status are unavailable for dispatch by PJM. The MW offered beyond the economic range

60 See 148 FERC ¶ 61,144 (2014).

61 Each range in the tables is greater than or equal to the lower value and less than the higher value. The unit type battery is not included in these tables because batteries do not make energy offers. The unit type fuel cell is not included in these tables because of the small number owners and the small number of units of this type of generation.

of a unit are categorized as emergency MW. Emergency MW are included in both tables.

Table 3-48 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, in 2016. For example, 77.8 percent of CC offers were dispatchable and in the $0 to $200 per MWh price range. The total column is the proportion of all MW offers by unit type that were dispatchable. For example, 85.0 percent of all CC MW offers were dispatchable, including the 6.7 percent of emergency MW offered by CC units. The all dispatchable offers row is the proportion of MW that were offered as available for economic dispatch within a given range by all unit types. For example, 49.7 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The total column in the all dispatchable offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in 2016, 53.7 percent were offered as available for economic dispatch.

Table 3-48 Distribution of MW for dispatchable unit offer prices: 2016

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.0%	77.8%	0.3%	0.2%	0.0%	0.0%	6.7%	85.0%
CT	0.0%	82.2%	4.7%	0.7%	0.3%	0.0%	10.4%	98.2%
Diesel	1.5%	33.0%	18.6%	3.9%	0.0%	0.0%	16.7%	73.7%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	5.4%	0.0%	0.0%	0.0%	0.0%	0.1%	5.4%
Pumped Storage	62.7%	0.2%	0.0%	0.0%	0.0%	0.0%	2.2%	65.2%
Run of River	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	38.3%	5.0%	0.0%	0.0%	0.0%	0.0%	0.8%	44.1%
Steam	0.1%	50.4%	0.5%	0.0%	0.0%	0.3%	3.0%	54.3%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	51.3%	9.7%	0.0%	0.0%	0.0%	0.0%	0.5%	61.5%
All Dispatchable Offers	2.5%	49.7%	1.1%	0.2%	0.0%	0.1%	4.4%	58.1%

Table 3-49 shows the proportion of MW offers by unit type that were self scheduled to generate fixed output and by unit type and price range for self-scheduled and dispatchable units, for 2016. For example, 10.1 percent of CC offers were self scheduled and dispatchable and in the $0 to $200 price range. The total column is the proportion of all MW offers by unit type that were self scheduled to generate fixed output and are self scheduled and dispatchable. For example, 15.0 percent of all CC MW offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 0.8 percent of emergency MW offered by CC units. The all self scheduled offers row is the proportion of MW that were offered as either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum within a given range by all unit types. For example, units that were self scheduled to generate at fixed output accounted for 20.9 percent of all offers and self scheduled and dispatchable units accounted for 18.1 percent of all offers. The total column in the all self scheduled offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW. Among all the generator offers in of 2016, 22.4 percent were offered as self scheduled and 19.5 percent were offered as self scheduled and dispatchable.

Table 3-49 Distribution of MW for self scheduled and dispatchable unit offer prices: 2016

	Self Scheduled		Self Scheduled and Dispatchable (Range)							
Unit Type	Must Run	Emergency	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	2.9%	0.9%	0.3%	10.1%	0.0%	0.0%	0.0%	0.0%	0.8%	15.0%
CT	0.5%	0.1%	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.1%	1.8%
Diesel	20.0%	0.9%	2.7%	1.5%	0.0%	0.0%	0.0%	0.0%	1.1%	26.3%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	86.4%	1.1%	4.5%	2.5%	0.0%	0.0%	0.0%	0.0%	0.1%	94.6%
Pumped Storage	17.9%	9.3%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%	4.2%	34.8%
Run of River	60.0%	13.7%	0.3%	20.8%	0.0%	0.0%	0.0%	0.4%	4.7%	99.8%
Solar	39.0%	14.4%	2.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	55.9%
Steam	4.6%	1.5%	0.1%	36.8%	0.0%	0.0%	0.0%	0.0%	2.6%	45.7%
Transaction	76.2%	23.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	4.9%	4.0%	22.8%	3.1%	0.0%	0.0%	0.0%	0.0%	3.5%	38.5%
All Self-Scheduled Offers	20.9%	1.4%	1.5%	16.6%	0.0%	0.0%	0.0%	0.0%	1.4%	41.9%

Market Performance

The PJM average locational marginal price (LMP) reflects the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

Markup

The markup index is a measure of participant conduct for individual marginal 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 translate to different impacts on total system price. Markup can also affect prices when units with high markups are not marginal.

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 offer and the cost-based offer of each actual marginal unit on the system.[62]

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP using the mathematical relationships among LMPs given the market solution. The markup impact includes the impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the energy market.

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full 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. The results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at short run marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the

62 This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

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 3-50 shows the average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 3-50 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-28.

All generating units, including coal units, are allowed to add an additional 10 percent to their cost offer. The additional 10 percent was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the additional 10 percent in the cost offer for coal units. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the additional 10 percent from the cost offer. Even the adjusted markup overestimates the negative markup because coal units facing increased competitive pressure have excluded both the 10 percent and some or all components of operating and maintenance cost. While both these elements are permitted under the definition of cost-based offers in the PJM Market Rules, they are not part of a competitive offer because they are not actually short run marginal costs, and actual market behavior reflected that fact.[63]

Table 3-50 shows the mark-up component of the load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $1.75 per MWh in 2015 to $1.77 per MWh in 2016. The adjusted markup contribution of coal units in 2016 was $0.04 per MWh. The mark-up component of gas-fired units in 2016 was $1.75 per MWh, a decrease of $0.55 per MWh from 2015. The markup component of wind units was $0.02 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In 2016, among the wind units that were marginal, 2.13 percent had positive offer prices. Almost three quarters of the positive markup component of day ahead LMP was a result of the markup in the offers of combined cycle gas generators.

Table 3-50 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: 2015 and 2016[64]

		2015		2016	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.26)	$0.37	($1.33)	$0.04
Gas	CC	$1.29	$1.29	$1.29	$1.29
Gas	CT	($0.13)	($0.13)	$0.19	$0.19
Gas	Diesel	$0.02	$0.02	$0.01	$0.01
Gas	Steam	$0.02	$0.02	$0.26	$0.26
Municipal Waste	Steam	($0.01)	($0.01)	$0.00	$0.00
Oil	CC	$0.05	$0.05	$0.00	$0.00
Oil	CT	$0.03	$0.03	$0.01	$0.01
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.12	$0.12	$0.07	$0.07
Other	Steam	($0.04)	($0.04)	($0.12)	($0.12)
Uranium	Steam	$0.00	$0.00	$0.00	$0.00
Wind	Wind	$0.03	$0.03	$0.02	$0.02
Total		$0.13	$1.76	$0.40	$1.77

63 See PJM. "Manual 15: Cost Development Guidelines," Revision 27 (April 20, 2016).

64 The Unit Type Diesel refers to power generation using reciprocating internal combustion engines. Such Diesel units can use a variety of fuel types including diesel, natural gas, oil and gas from municipal waste.

Markup Component of Real-Time Price

Table 3-51 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-52 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In 2016, when using unadjusted cost offers, $0.40 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost offers, $1.77 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In 2016, the peak markup component was highest in August, $3.34 per MWh using unadjusted cost offers and $4.47 per MWh using adjusted cost offers. This corresponds to 7.67 percent and 10.24 percent of the real-time peak load-weighted average LMP in August.

Table 3-51 Monthly markup components of real-time load-weighted LMP (Unadjusted): 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($1.42)	($2.62)	($0.15)	($1.65)	($1.56)	($1.74)
Feb	$4.62	$1.72	$7.46	($1.06)	($0.84)	($1.26)
Mar	$1.84	$1.82	$1.86	($0.35)	($1.22)	$0.42
Apr	($0.42)	($0.69)	($0.18)	$0.45	($0.90)	$1.74
May	($1.85)	($3.59)	($0.01)	($1.20)	($1.14)	($1.26)
Jun	($0.43)	($1.20)	$0.21	$0.81	$0.62	$0.97
Jul	($0.46)	($1.29)	$0.21	$0.22	($0.92)	$1.36
Aug	($0.90)	($0.96)	($0.83)	$1.92	$0.16	$3.34
Sep	($0.55)	($0.64)	($0.47)	$1.76	$1.46	$2.03
Oct	($0.13)	($0.35)	$0.08	$1.48	($0.05)	$2.99
Nov	$0.57	($0.42)	$1.62	$1.26	$0.28	$2.22
Dec	$0.38	($0.22)	$0.95	$1.06	($0.10)	$2.29
Total	$0.12	($0.72)	$0.92	$0.40	($0.37)	$1.14

Table 3-52 Monthly markup components of real-time load-weighted LMP (Adjusted): 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$0.61	($0.61)	$1.90	($0.01)	($0.13)	$0.12
Feb	$6.44	$3.57	$9.24	$0.53	$0.58	$0.48
Mar	$3.71	$3.69	$3.74	$0.97	$0.01	$1.82
Apr	$1.22	$0.72	$1.65	$2.08	$0.61	$3.50
May	($0.45)	($2.41)	$1.64	$0.27	($0.06)	$0.60
Jun	$1.18	$0.06	$2.10	$2.17	$1.65	$2.60
Jul	$1.17	$0.16	$1.97	$1.60	$0.35	$2.84
Aug	$0.65	$0.43	$0.86	$3.18	$1.59	$4.47
Sep	$0.86	$0.71	$1.00	$2.98	$2.66	$3.27
Oct	$1.43	$0.91	$1.91	$2.82	$1.37	$4.24
Nov	$2.06	$0.80	$3.39	$2.33	$1.28	$3.37
Dec	$1.79	$0.84	$2.68	$2.20	$1.14	$3.31
Total	$1.75	$0.75	$2.70	$1.77	$0.91	$2.59

Hourly Markup Component of Real-Time Prices

Figure 3-37 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in 2016 and 2015. Figure 3-38 shows the markup contribution to the hourly load-weighted LMP using adjusted cost offers in 2016 and 2015. In 2015, high markups were seen during the cold winter days observed in February and March. In contrast, the first six months of 2016 had low markups. Markups increased during the summer high demand days.

Figure 3-37 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2015 and 2016

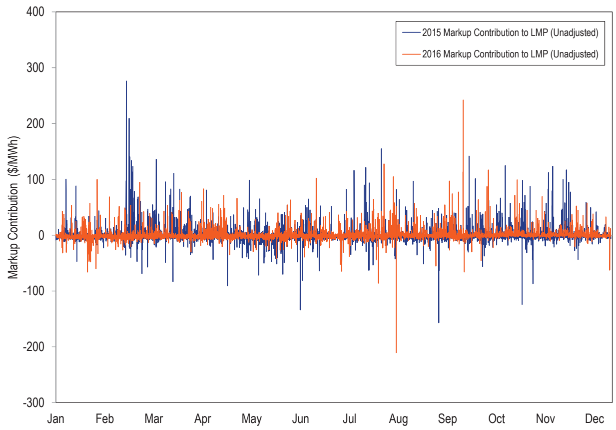
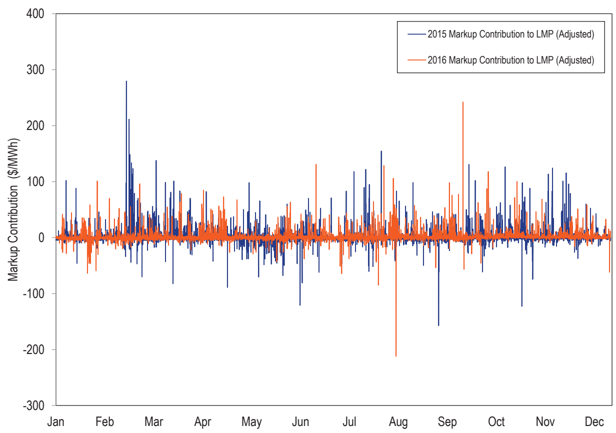


Figure 3-38 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2015 and 2016



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 2015 and 2016 in Table 3-53 and for adjusted offers in Table 3-54. The smallest zonal all hours average markup component using unadjusted offers in 2016 was in the BGE Zone, -$0.61 per MWh, while the highest was in the DPL Control Zone, $1.59 per MWh. The smallest zonal on peak average markup was in the Pepco Control Zone, $0.39 per MWh, while the highest was in the DPL Control Zone, $2.34 per MWh.

Table 3-53 Average real-time zonal markup component (Unadjusted): 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($0.62)	($1.32)	$0.05	$1.48	$0.69	$2.25
AEP	$0.04	($0.97)	$1.00	$0.07	($0.71)	$0.83
APS	$0.56	($0.31)	$1.41	$0.22	($0.60)	$1.03
ATSI	$0.03	($0.89)	$0.89	$0.28	($0.63)	$1.13
BGE	$1.64	$1.00	$2.26	($0.61)	($1.70)	$0.44
ComEd	($0.22)	($1.04)	$0.53	$0.26	($0.49)	$0.95
DAY	$0.10	($0.97)	$1.09	$0.05	($0.67)	$0.71
DEOK	($0.01)	($1.10)	$1.03	$0.09	($0.65)	$0.80
DLCO	($0.15)	($0.98)	$0.63	$0.43	($0.54)	$1.35
DPL	($0.67)	($1.11)	($0.25)	$1.59	$0.81	$2.34
Dominion	$0.79	$0.09	$1.46	($0.04)	($0.75)	$0.65
EKPC	$0.05	($1.16)	$1.27	$0.01	($0.47)	$0.50
JCPL	($0.60)	($1.24)	($0.02)	$1.50	$0.77	$2.16
Met-Ed	($0.52)	($1.22)	$0.13	$1.08	$0.57	$1.55
PECO	($0.61)	($1.26)	($0.00)	$1.38	$0.71	$2.02
PENELEC	$0.20	($0.77)	$1.11	$0.57	($0.20)	$1.29
PPL	($0.27)	($1.10)	$0.50	$1.24	$0.59	$1.86
PSEG	($0.19)	($1.10)	$0.63	$1.42	$0.69	$2.10
Pepco	$1.19	$0.36	$1.94	($0.35)	($1.13)	$0.39
RECO	$0.04	($1.28)	$1.17	$1.50	$0.62	$2.28

Table 3-54 Average real-time zonal markup component (Adjusted): 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$0.44	($0.32)	$1.16	$2.18	$1.38	$2.96
AEP	$1.78	$0.59	$2.93	$1.56	$0.67	$2.42
APS	$2.32	$1.28	$3.33	$1.74	$0.82	$2.64
ATSI	$1.76	$0.66	$2.79	$1.69	$0.71	$2.62
BGE	$4.13	$3.16	$5.06	$1.84	$0.65	$3.00
ComEd	$1.34	$0.33	$2.27	$1.64	$0.75	$2.46
DAY	$1.90	$0.60	$3.10	$1.56	$0.73	$2.32
DEOK	$1.75	$0.43	$3.00	$1.53	$0.71	$2.31
DLCO	$1.54	$0.53	$2.49	$1.80	$0.77	$2.79
DPL	$0.44	($0.05)	$0.92	$2.27	$1.49	$3.04
Dominion	$2.77	$1.89	$3.62	$1.76	$0.93	$2.58
EKPC	$1.77	$0.42	$3.14	$1.51	$0.92	$2.11
JCPL	$0.47	($0.24)	$1.10	$2.21	$1.43	$2.93
Met-Ed	$0.53	($0.24)	$1.25	$1.79	$1.21	$2.32
PECO	$0.42	($0.26)	$1.05	$2.05	$1.36	$2.71
PENELEC	$1.67	$0.57	$2.69	$1.70	$0.87	$2.48
PPL	$0.79	($0.09)	$1.61	$1.97	$1.25	$2.65
PSEG	$0.95	($0.03)	$1.85	$2.13	$1.35	$2.87
Pepco	$3.39	$2.29	$4.41	$1.70	$0.79	$2.56
RECO	$1.34	($0.05)	$2.52	$2.26	$1.31	$3.09

Markup by Real Time Price Levels

Table 3-55 shows 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 average LMP was in the identified price range.

Table 3-55 Average real-time markup component (By price category, unadjusted): 2015 and 2016

	2015		2016	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.14)	89.9%	$0.03	86.8%
$25 to $50	($0.01)	9.2%	$0.17	12.2%
$50 to $75	$0.11	0.6%	$0.12	0.7%
$75 to $100	$0.09	0.2%	$0.07	0.1%
$100 to $125	$0.02	0.1%	$0.03	0.0%
$125 to $150	$0.04	0.1%	$0.00	0.0%
>= $150	$0.01	0.0%	$0.01	0.0%

Table 3-56 Average real-time markup component (By price category, adjusted): 2015 and 2016

	2015		2016	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$1.32	89.9%	$1.26	86.8%
$25 to $50	$0.15	9.2%	$0.33	12.2%
$50 to $75	$0.12	0.6%	$0.12	0.7%
$75 to $100	$0.10	0.2%	$0.07	0.1%
$100 to $125	$0.02	0.1%	$0.03	0.0%
$125 to $150	$0.04	0.1%	$0.00	0.0%
>= $150	$0.01	0.0%	$0.00	0.0%

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 3-57. INC, DEC and up to congestion transactions have zero markups. INCs were 4.2 percent of marginal resources and DECs were 8.6 percent of marginal resources in 2016. The share of marginal up to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on September 8, 2014.[65] However, the share of marginal up to congestion transactions increased from 76.1 percent in 2015 to 82.4 percent in 2016 due to the expiration of the fifteen months resettlement period for the proceeding related to uplift charges for UTC transactions.

The adjusted markup of coal units is calculated as the difference between the price offer, and the cost offer excluding the 10 percent adder. Table 3-57 shows the markup component of LMP for marginal generating resources. Generating resources were only 4.7 percent of marginal resources in 2016. Using adjusted offers, the markup component of LMP for marginal generating resources increased for coal-fired steam units from a negative markup to a less negative markup and for gas-fired steam units from a negative markup to a small positive markup. The markup component of LMP for coal-fired steam units increased from -$1.28 in 2015 to -$1.11 in 2016 using unadjusted offers. The markup component of LMP for gas-fired steam units increased from -$0.38 in 2015 to $0.15 in 2016 using adjusted offers.

65 See 18 CFR § 385.213 (2014).

Table 3-57 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: 2015 and 2016

		2015		2016	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.28)	$0.04	($1.11)	$0.13
Gas	CT	$0.07	$0.07	$0.03	$0.03
Gas	Diesel	$0.01	$0.01	$0.00	$0.00
Gas	Steam	($0.38)	($0.38)	$0.15	$0.15
Municipal Waste	Steam	$0.00	$0.00	($0.12)	($0.12)
Oil	CT	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.04	$0.04	($0.00)	($0.00)
Other	Steam	($0.00)	($0.00)	$0.00	$0.00
Wind	Wind	$0.05	$0.05	$0.02	$0.02
Total		($1.49)	($0.17)	($1.03)	$0.21

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 3-58 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. In 2016, when using unadjusted cost-based offers, -$1.03 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In 2016, the peak markup component was highest in July, $3.41 per MWh using unadjusted cost offers.

Table 3-58 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.10)	($1.38)	($2.79)	($2.40)	($1.94)	($2.80)
Feb	$1.15	$3.03	($0.78)	($1.94)	($2.11)	($1.77)
Mar	($1.34)	($1.41)	($1.27)	($3.16)	($3.19)	($3.14)
Apr	($2.15)	($1.84)	($2.51)	($1.21)	$0.21	($2.68)
May	($2.43)	($3.83)	($1.10)	($1.50)	($1.06)	($1.94)
Jun	($2.26)	($2.07)	($2.49)	($1.07)	($1.34)	($0.76)
Jul	($3.09)	($2.46)	($3.89)	$0.76	$3.41	($1.88)
Aug	($2.00)	($1.40)	($2.62)	($0.17)	$0.01	($0.40)
Sep	($0.88)	($0.35)	($1.49)	($1.53)	($0.82)	($2.33)
Oct	$0.93	$2.61	($0.91)	($0.22)	$0.26	($0.70)
Nov	($2.01)	($1.72)	($2.28)	($0.79)	($0.88)	($0.70)
Dec	($1.51)	($1.70)	($1.30)	$0.26	$0.89	($0.34)
Annual	($1.49)	($1.04)	($1.97)	($1.03)	($0.49)	($1.61)

Table 3-59 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers. In 2016, when using adjusted cost-based offers, $0.21 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In 2016, the peak markup component was highest in August, $5.65 per MWh using adjusted cost offers.

Table 3-59 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.41)	$0.07	($0.86)	($1.01)	($0.64)	($1.34)
Feb	$2.58	$4.21	$0.90	($0.75)	($0.84)	($0.65)
Mar	$0.13	($0.05)	$0.32	($2.04)	($2.02)	($2.05)
Apr	($0.84)	($0.71)	($0.99)	($0.20)	$1.00	($1.44)
May	($0.85)	($2.03)	$0.28	($0.57)	($0.18)	($0.96)
Jun	($1.00)	($0.81)	($1.23)	($0.15)	($0.39)	$0.14
Jul	($1.88)	($1.18)	($2.77)	$1.71	$4.12	($0.69)
Aug	($0.79)	($0.16)	($1.44)	$3.42	$5.65	$0.62
Sep	$0.27	$0.77	($0.30)	($0.69)	($0.16)	($1.30)
Oct	$1.97	$3.32	$0.49	$0.63	$0.75	$0.50
Nov	($0.78)	($0.46)	($1.09)	$0.06	($0.19)	$0.32
Dec	($0.42)	($0.36)	($0.47)	$1.01	$1.35	$0.68
Annual	($0.17)	$0.22	($0.60)	$0.21	$0.88	($0.50)

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted offers is shown for each zone in Table 3-60. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-61. Using unadjusted offers, the markup component of the average day-ahead price increased in all zones from 2015 to 2016 except BGE, ComEd, DLCO, EKPC and Pepco control zones. The smallest zonal all hours average markup component using adjusted offers for 2016 was in the ComEd Zone, -$0.56 per MWh, while the highest was in the BGE Control Zone, $1.35 per MWh. The smallest zonal on peak average markup using adjusted offers was in the ComEd Control Zone, -$0.71 per MWh, while the highest was in the DPL Control Zone, $2.92 per MWh.

Table 3-60 Day-ahead, average, zonal markup component (Unadjusted): 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($2.19)	($1.94)	($2.45)	($0.55)	$0.45	($1.61)
AEP	($1.64)	($1.29)	($2.01)	($0.99)	($0.39)	($1.61)
AP	($1.33)	($0.93)	($1.75)	($0.91)	($0.17)	($1.68)
ATSI	($1.55)	($0.99)	($2.16)	($1.12)	($0.55)	($1.73)
BGE	($0.72)	($0.14)	($1.35)	($0.76)	($0.20)	($1.34)
ComEd	($1.43)	($0.83)	($2.09)	($1.63)	($1.72)	($1.54)
DAY	($1.62)	($1.02)	($2.26)	($1.34)	($1.06)	($1.64)
DEOK	($1.66)	($1.27)	($2.08)	($1.53)	($1.46)	($1.62)
DLCO	($1.41)	($0.67)	($2.22)	($1.76)	($1.83)	($1.67)
Dominion	($1.31)	($1.07)	($1.56)	($1.14)	($0.73)	($1.55)
DPL	($1.71)	($1.35)	($2.09)	$0.18	$1.97	($1.69)
EKPC	($1.41)	($0.89)	($1.94)	($1.45)	($1.34)	($1.56)
JCPL	($1.88)	($1.53)	($2.27)	($0.38)	$0.70	($1.59)
Met-Ed	($1.92)	($1.74)	($2.11)	($0.51)	$0.52	($1.63)
PECO	($1.81)	($1.38)	($2.26)	($1.36)	($1.09)	($1.65)
PENELEC	($1.34)	($0.80)	($1.92)	($0.91)	($0.15)	($1.69)
Pepco	($0.73)	$0.01	($1.53)	($0.88)	($0.03)	($1.78)
PPL	($1.75)	($1.40)	($2.12)	($0.59)	$0.41	($1.66)
PSEG	($1.72)	($1.23)	($2.28)	($0.53)	$0.50	($1.65)
RECO	($1.52)	($1.02)	($2.12)	($0.31)	$0.80	($1.57)

Table 3-61 Day-ahead, average, zonal markup component (Adjusted): 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.95)	($0.66)	($1.26)	$0.41	$1.56	($0.80)
AEP	($0.19)	$0.17	($0.56)	$0.33	$1.06	($0.43)
AP	($0.04)	$0.27	($0.36)	$0.41	$1.28	($0.49)
ATSI	($0.18)	$0.29	($0.69)	$0.07	$0.65	($0.57)
BGE	$0.64	$1.06	$0.18	$1.35	$2.64	($0.02)
ComEd	($0.12)	$0.43	($0.72)	($0.56)	($0.71)	($0.39)
DAY	($0.20)	$0.32	($0.76)	$0.05	$0.50	($0.44)
DEOK	($0.25)	$0.11	($0.63)	($0.01)	$0.36	($0.39)
DLCO	($0.14)	$0.47	($0.79)	($0.56)	($0.62)	($0.50)
Dominion	$0.10	$0.33	($0.16)	$0.25	$0.84	($0.36)
DPL	($0.59)	($0.29)	($0.90)	$1.09	$2.92	($0.82)
EKPC	($0.02)	$0.44	($0.49)	($0.29)	($0.23)	($0.36)
JCPL	($0.72)	($0.43)	($1.05)	$0.63	$1.84	($0.71)
Met-Ed	($0.78)	($0.65)	($0.93)	$0.40	$1.45	($0.74)
PECO	($0.69)	($0.32)	($1.10)	($0.49)	($0.22)	($0.77)
PENELEC	($0.16)	$0.23	($0.57)	$0.18	$0.97	($0.62)
Pepco	$0.63	$1.28	($0.08)	$1.06	$2.57	($0.51)
PPL	($0.57)	($0.25)	($0.93)	$0.32	$1.33	($0.75)
PSEG	($0.59)	($0.13)	($1.09)	$0.48	$1.61	($0.77)
RECO	($0.42)	$0.02	($0.93)	$0.75	$2.01	($0.68)

Markup by Day-Ahead Price Levels

Table 3-62 and Table 3-63 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 3-62 Average, day-ahead markup (By LMP category, unadjusted): 2015 and 2016

	2015		2016	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.55)	30.3%	($2.13)	49.1%
$25 to $50	($1.78)	59.9%	($1.10)	47.5%
$50 to $75	($0.58)	5.3%	$6.14	2.9%
$75 to $100	($0.66)	2.3%	$2.17	0.4%
$100 to $125	$1.62	1.1%	($9.87)	0.1%
$125 to $150	$8.99	0.5%	$0.00	0.0%
>= $150	$12.34	0.7%	$0.00	0.0%

Table 3-63 Average, day-ahead markup (By LMP category, adjusted): 2015 and 2016

	2015		2016	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.17)	30.3%	($0.79)	49.1%
$25 to $50	($0.21)	59.9%	($0.06)	47.5%
$50 to $75	$0.60	5.3%	$13.90	2.9%
$75 to $100	($0.06)	2.3%	$2.20	0.4%
$100 to $125	$2.26	1.1%	($4.39)	0.1%
$125 to $150	$9.64	0.5%	$0.00	0.0%
>= $150	$12.86	0.7%	$0.00	0.0%

Prices

The conduct of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power.

Real-time and day-ahead energy market load-weighted prices were 19.2 percent and 19.2 percent lower in 2016 than in 2015 as a result of lower fuel costs and lower demand in 2016.

PJM real-time energy market prices decreased in 2016 compared to 2015. The average LMP was 1percent lower in 2016 than in 2015, $27.57 per MWh versus $33.39 per MWh. The load-weighted average LMP was 19.2 percent lower in 2016 than in 2015, $29.23 per MWh versus $36.16 per MWh. PJM real-time load-weighted energy market prices were lower in 2016 that at any time in PJM history since the beginning of the competitive wholesale market on April 1, 1999.

The fuel-cost adjusted, load-weighted, average LMP in 2016 was 1.7 percent higher than the load-weighted, average LMP for 2016. If fuel and emission costs in 2016 had been the same as in 2015, holding everything else constant, the load-weighted LMP would have been slightly higher, $29.72 per MWh instead of the observed $29.23 per MWh.

PJM day-ahead energy market prices decreased in 2016 compared to 2015. The average LMP was 17.7 percent lower in 2016 than in 2015, $28.10 per MWh versus $34.12 per MWh. The day-ahead load-weighted average

LMP was 19.2 percent lower in 2016 than in 2015, $29.68 per MWh versus $36.73 per MWh. PJM day-ahead load-weighted energy market prices were lower in 2016 that at any time in PJM history since the introduction of the PJM Day-Ahead Energy Market in June 2000.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply stack.[66] 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.[67]

Real-Time LMP

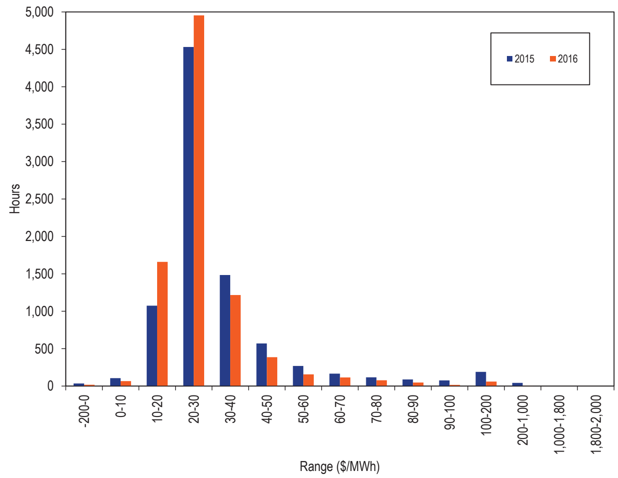
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[68]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-39 shows the hourly distribution of PJM real-time average LMP for 2015 and 2016.

Figure 3-39 Average LMP for the PJM Real-Time Energy Market: 2015 and 2016



PJM Real-Time, Average LMP

Table 3-64 shows the PJM real-time, average LMP for each year from 1998 through 2016.[69]

Table 3-64 PJM real-time, average LMP (Dollars per MWh): 1998 through 2016

	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%)

66 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): pp 19-27.

67 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, 153 FERC ¶ 61,289 (2015).

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

69 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load. The real-time, load-weighted, average LMP decreased by 19.2 percent compared to 2015.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-65 shows the PJM real-time, load-weighted, average LMP in 1998 through 2016.

Table 3-65 PJM real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2016

	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%)

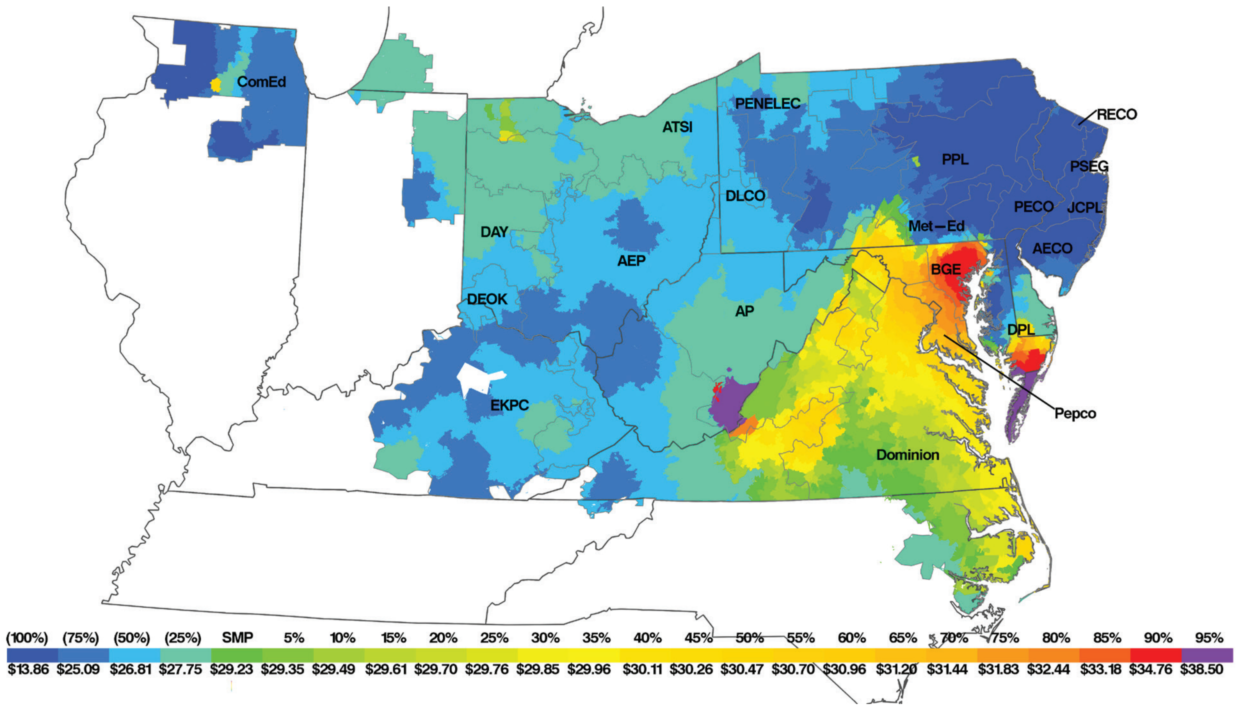
Table 3-66 shows zonal real-time, and real-time, load-weighted, average LMP in 2015 and 2016.

Table 3-66 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): 2015 and 2016

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2015	2016	Percent Change	2015	2016	Percent Change
AECO	$32.86	$24.42	(25.7%)	$35.85	$26.93	(24.9%)
AEP	$31.76	$27.82	(12.4%)	$33.90	$29.14	(14.1%)
AP	$34.78	$28.25	(18.8%)	$38.04	$29.75	(21.8%)
ATSI	$32.10	$28.19	(12.2%)	$34.00	$29.78	(12.4%)
BGE	$42.84	$36.07	(15.8%)	$47.22	$38.62	(18.2%)
ComEd	$28.21	$26.05	(7.7%)	$29.85	$27.66	(7.3%)
Day	$32.11	$27.90	(13.1%)	$34.20	$29.36	(14.2%)
DEOK	$31.19	$27.12	(13.1%)	$33.28	$28.62	(14.0%)
DLCO	$30.45	$27.51	(9.6%)	$32.21	$29.20	(9.3%)
Dominion	$37.24	$30.27	(18.7%)	$41.42	$32.15	(22.4%)
DPL	$36.79	$26.65	(27.6%)	$42.27	$29.66	(29.8%)
EKPC	$30.10	$26.79	(11.0%)	$32.93	$28.21	(14.3%)
JCPL	$32.36	$23.86	(26.3%)	$35.65	$26.36	(26.1%)
Met-Ed	$32.17	$24.13	(25.0%)	$35.79	$26.04	(27.2%)
PECO	$31.80	$23.52	(26.0%)	$35.11	$25.57	(27.2%)
PENELEC	$33.47	$26.28	(21.5%)	$36.13	$27.57	(23.7%)
Pepco	$39.21	$32.16	(18.0%)	$43.04	$34.12	(20.7%)
PPL	$31.93	$23.77	(25.6%)	$35.95	$25.43	(29.3%)
PSEG	$34.38	$24.25	(29.5%)	$36.97	$26.24	(29.0%)
RECO	$35.02	$24.54	(29.9%)	$37.58	$27.05	(28.0%)
PJM	$33.39	$27.57	(17.4%)	$36.16	$29.23	(19.2%)

Figure 3-40 is a contour map of the real-time, load-weighted, average LMP in 2016. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP. The LMP for each five percent increment is the highest nodal average LMP for that set of nodes. Each increment to the left of the SMP is the lowest nodal average LMP for that set of nodes.

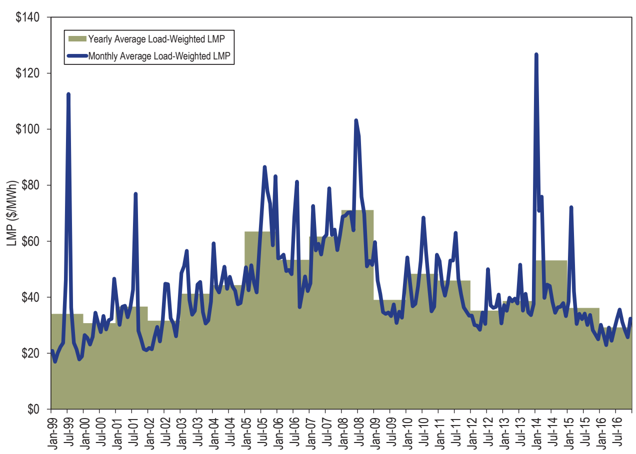
Figure 3-40 PJM real-time, load-weighted, average LMP: 2016



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

Figure 3-41 shows the PJM real-time monthly and annual load-weighted LMP in 1999 through 2016. PJM real-time monthly load-weighted average LMP in March 2016 was $22.90, which is the lowest real-time monthly load-weighted average LMP since February 2002 at $21.39.

Figure 3-41 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 2016



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

Figure 3-42 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP for 1998 through 2016.[70] PJM real-time inflation adjusted monthly load-weighted average LMP in March 2016 was $15.54, which is the lowest real-time monthly load-weighted average real LMP observed since PJM real-time markets started on April 1, 1999. Table 3-67 shows the PJM real-time yearly load- weighted average LMP and inflation adjusted yearly load-weighted average LMP for 1998 through 2016.

Figure 3-42 PJM real-time, monthly, load-weighted, average LMP and real-time, monthly inflation adjusted load-weighted, average LMP: 1998 through 2016

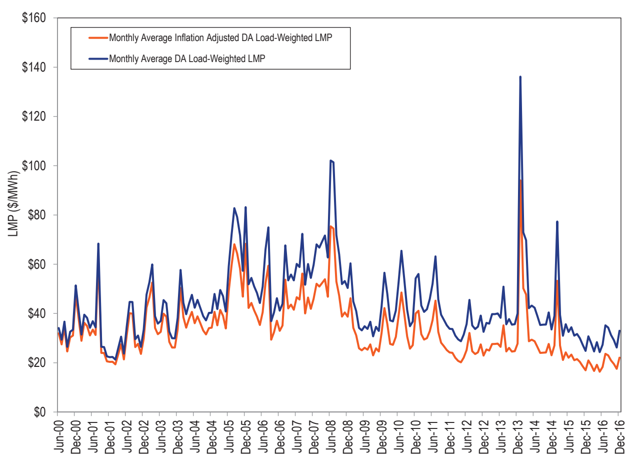


Table 3-67 PJM real-time, yearly, load-weighted, average LMP and real-time, yearly inflation adjusted load-weighted, average LMP: 1998 through 2016

Year	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

Fuel Price Trends and LMP

Changes in LMP can result from 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 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 are another contributor to changes in the marginal cost of marginal units. Natural gas prices decreased in 2016 and coal prices decreased or remained constant. Comparing fuel prices in 2016 to 2015, the price of Northern Appalachian coal was 10.1 percent lower; the price of Central Appalachian coal was 0.1 percent higher; the price of Powder River Basin coal was 5.1 percent lower; the price of eastern natural gas was 35.6 percent lower; and the price of western natural gas was 4.2 percent lower. Figure 3-43 shows monthly average spot fuel prices.[71]

70 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> (January27, 2017)

71 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago Citygate daily fuel price indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Figure 3-43 Spot average fuel price comparison with fuel delivery charges: 2012 through 2016 ($/MMBtu)

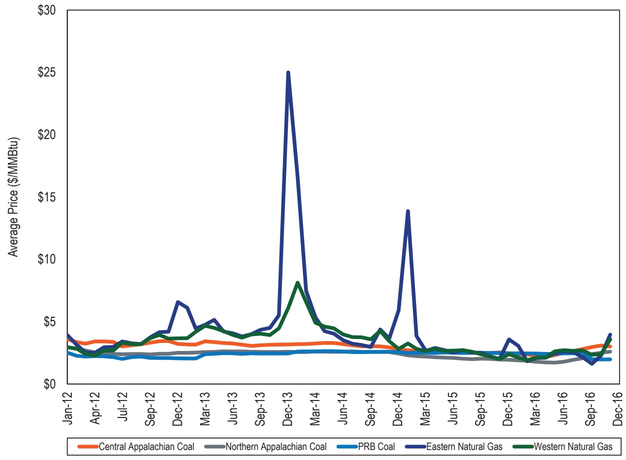


Table 3-68 compares the 2016 PJM real-time fuel-cost adjusted, load-weighted, average LMP to 2016 load-weighted, average LMP.[72] The real-time fuel-cost adjusted, load-weighted, average LMP for 2016 was 1.7 percent higher than the real-time load-weighted, average LMP for 2016. The real-time, fuel-cost adjusted, load-weighted, average LMP for 2016 was 17.8 percent lower than the real-time load-weighted LMP for 2015. If fuel and emissions costs in 2016 had been the same as in 2015, holding everything else constant, the real-time load-weighted LMP in 2016 would have been slightly higher, $29.72 per MWh, than the observed $29.23 per MWh.

Table 3-68 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): year over year

	2016 Load-Weighted LMP	2016 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	$29.23	$29.72	1.7%
	2015 Load-Weighted LMP	2016 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	$36.16	$29.72	(17.8%)
	2015 Load-Weighted LMP	2016 Load-Weighted LMP	Change
Average	$36.16	$29.23	(19.2%)

Table 3-69 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 2016. Table 3-69 shows that slightly lower coal and natural gas prices explain almost all of the fuel-cost related decrease in the real-time annual load-weighted average LMP in 2016.

Table 3-69 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by fuel type: year over year

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	($0.19)	38.2%
Gas	($0.28)	57.2%
Municipal Waste	$0.00	0.0%
Oil	($0.02)	4.4%
Other	$0.00	(0.0%)
Uranium	($0.00)	0.0%
Wind	$0.00	(0.0%)
Total	($0.49)	100.0%

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and five minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[73] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and ancillary services. In periods of scarcity when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal

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

73 New Jersey withdrew from RGGI, effective January 1, 2012.

resource in the energy market, this opportunity cost will contribute to LMP. In addition, in periods when generators providing energy cannot meet the reserve requirements, PJM can invoke shortage pricing. PJM invoked shortage pricing on January 6 and January 7 of 2014.[74] During the shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Table 3-72 shows the frequency and average shadow price of transmission constraints in PJM. In 2016, there were 205,243 transmission constraints in the real time market with a non-zero shadow price. For nearly 10 percent of these transmission constraints, the line limit was violated, meaning that the flow exceeded the facility limit.[75] In 2016, the average shadow price of transmission constraints when the line limit was violated was nearly five times higher than when transmission constraint was binding at its limit.

Transmission penalty factors should be stated explicitly and publicly and applied without discretion. Penalty factors should be set high enough so that they do not act to suppress prices based on available generator solutions. But rather than permit the transmission penalty factor to set the shadow price when line limits are violated, PJM uses a procedure called constraint relaxation logic to prevent the penalty factors from directly setting the shadow price of the constraint. The result is that the transmission penalty factor does not directly set the shadow price. The details of PJM's logic and practice are not entirely clear. But in 2016, for all transmission constraints for which the penalty factor was greater than or equal to $2,000 per MWh, 41 percent of the constraints' shadow prices were within ten percent of the penalty factor.

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.

The components of LMP are shown in Table 3-70, including markup using unadjusted cost offers.[76] Table 3-70 shows that in 2016, 45.4 percent of the load-weighted LMP was the result of coal costs, 27.2 percent was the result of gas costs and 1.89 percent was the result of the cost of emission allowances. Using adjusted cost offers, markup was 6.1 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. Occasionally, PJM fails to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The cumulative effect of excluding those five-minute intervals is the component NA. In 2016, nearly 14.9 percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between 2016 and 2015.

74 PJM triggered shortage pricing on January 6, 2015, following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, 2014, due to a RTO-wide shortage of synchronized reserve.

75 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.

76 These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/Unit Participation Factors." <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-70 Components of PJM real-time (Unadjusted), load-weighted, average LMP: 2015 and 2016

	2015		2016		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$15.62	43.2%	$13.28	45.4%	2.2%
Gas	$9.85	27.2%	$7.96	27.2%	(0.0%)
Ten Percent Adder	$3.02	8.4%	$2.43	8.3%	(0.0%)
VOM	$2.38	6.6%	$2.04	7.0%	0.4%
NA	$0.89	2.4%	$1.23	4.2%	1.8%
NO_x Cost	$0.29	0.8%	$0.42	1.4%	0.6%
Markup	$0.12	0.3%	$0.40	1.4%	1.0%
Increase Generation Adder	$0.24	0.7%	$0.35	1.2%	0.5%
Ancillary Service Redispatch Cost	$1.06	2.9%	$0.33	1.1%	(1.8%)
LPA Rounding Difference	$0.94	2.6%	$0.29	1.0%	(1.6%)
Oil	$1.25	3.5%	$0.29	1.0%	(2.5%)
Other	$0.15	0.4%	$0.14	0.5%	0.1%
SO_2 Cost	$0.35	1.0%	$0.07	0.3%	(0.7%)
CO_2 Cost	$0.21	0.6%	$0.06	0.2%	(0.4%)
Market-to-Market Adder	$0.01	0.0%	$0.01	0.0%	(0.0%)
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
FMU Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
Municipal Waste	$0.01	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	($0.00)	(0.0%)	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.11)	(0.3%)	($0.01)	(0.0%)	0.3%
Decrease Generation Adder	($0.06)	(0.2%)	($0.03)	(0.1%)	0.1%
Wind	($0.07)	(0.2%)	($0.05)	(0.2%)	0.0%
Total	$36.16	100.0%	$29.23	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 3-70 and Table 3-77), markup is simply the difference between the price offer and the cost offer (unadjusted markup). In the second approach (Table 3-71 and Table 3-78), the 10 percent markup is removed from the cost offers of coal units (adjusted markup).

The components of LMP are shown in Table 3-71, including markup using adjusted cost offers.

Table 3-71 Components of PJM real-time (Adjusted), load-weighted, average LMP: 2015 and 2016

	2015		2016		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$15.62	43.2%	$13.28	45.4%	2.2%
Gas	$9.85	27.2%	$7.96	27.2%	(0.0%)
VOM	$2.38	6.6%	$2.04	7.0%	0.4%
Markup	$1.75	4.8%	$1.77	6.1%	1.2%
NA	$0.89	2.4%	$1.23	4.2%	1.8%
Ten Percent Adder	$1.40	3.9%	$1.06	3.6%	(0.2%)
NO_x Cost	$0.29	0.8%	$0.42	1.4%	0.6%
Increase Generation Adder	$0.24	0.7%	$0.35	1.2%	0.5%
Ancillary Service Redispatch Cost	$1.06	2.9%	$0.33	1.1%	(1.8%)
LPA Rounding Difference	$0.94	2.6%	$0.29	1.0%	(1.6%)
Oil	$1.25	3.5%	$0.29	1.0%	(2.5%)
Other	$0.15	0.4%	$0.14	0.5%	0.1%
SO_2 Cost	$0.35	1.0%	$0.07	0.3%	(0.7%)
CO_2 Cost	$0.21	0.6%	$0.06	0.2%	(0.4%)
Market-to-Market Adder	$0.01	0.0%	$0.01	0.0%	(0.0%)
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
FMU Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
Municipal Waste	$0.01	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	($0.00)	(0.0%)	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.11)	(0.3%)	($0.01)	(0.0%)	0.3%
Decrease Generation Adder	($0.06)	(0.2%)	($0.03)	(0.1%)	0.1%
Wind	($0.07)	(0.2%)	($0.05)	(0.2%)	0.0%
Total	$36.16	100.0%	$29.23	100.0%	0.0%

Table 3-72 Frequency and average shadow price of transmission constraints in PJM: 2015 and 2016

	Frequency		Average Shadow Price	
Description	2015	2016	2015	2016
PJM Internal Binding Transmission Constraints	140,545	130,855	$159.27	$120.13
PJM Internal Violated Transmission Constraints	20,255	19,536	$957.49	$643.04
Market to Market Transmission Constraints	51,683	54,852	$281.89	$264.34
All Transmission Constraints	212,483	205,243	$265.19	$208.44

Day-Ahead LMP

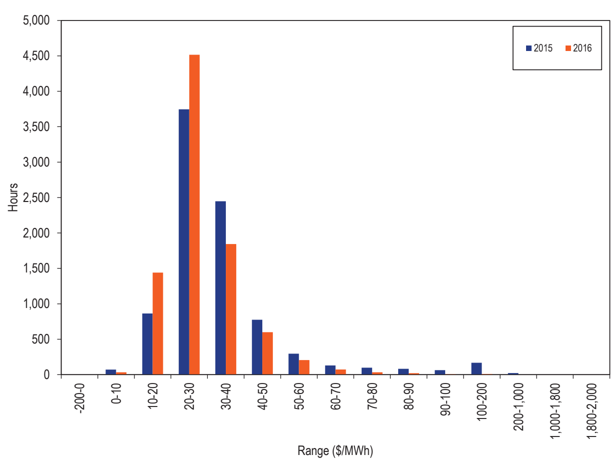
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[77]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-44 shows the hourly distribution of PJM day-ahead average LMP in 2015 and 2016.

Figure 3-44 Average LMP for the PJM Day-Ahead Energy Market: 2015 and 2016



PJM Day-Ahead, Average LMP

Table 3-73 shows the PJM day-ahead, average LMP in each year of the 16-year period 2001 through 2016.

Table 3-73 PJM day-ahead, average LMP (Dollars per MWh): 2001 through 2016

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$32.75	$27.05	$30.42	NA	NA	NA
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%)

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 3-74 shows the PJM day-ahead, load-weighted, average LMP in each year of the 16-year period 2001 through 2016.

77 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>.

Table 3-74 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): 2001 through 2016

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.01	$29.02	$37.48	NA	NA	NA
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
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%)

Table 3-75 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in 2015 and 2016.

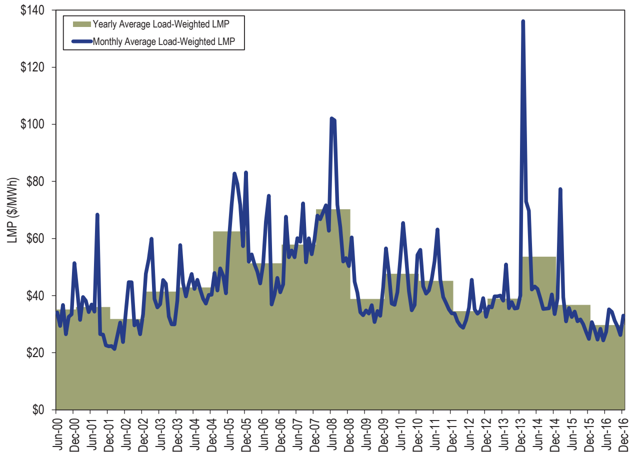
Table 3-75 Zone day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): 2015 and 2016

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2015	2016	Percent Change	2015	2016	Percent Change
AECO	$33.98	$24.91	(26.7%)	$36.86	$27.48	(25.4%)
AEP	$32.21	$28.19	(12.5%)	$34.20	$29.46	(13.8%)
AP	$35.01	$28.79	(17.8%)	$37.95	$30.18	(20.5%)
ATSI	$32.63	$28.35	(13.1%)	$34.34	$29.77	(13.3%)
BGE	$43.73	$36.77	(15.9%)	$47.92	$39.59	(17.4%)
ComEd	$28.01	$26.49	(5.4%)	$29.45	$28.00	(4.9%)
Day	$32.45	$28.33	(12.7%)	$34.39	$29.67	(13.7%)
DEOK	$31.82	$27.78	(12.7%)	$33.90	$29.30	(13.6%)
DLCO	$30.94	$27.62	(10.7%)	$32.57	$29.12	(10.6%)
Dominion	$38.67	$31.08	(19.6%)	$43.09	$33.02	(23.4%)
DPL	$37.48	$27.93	(25.5%)	$42.28	$31.00	(26.7%)
EKPC	$30.61	$27.17	(11.3%)	$33.42	$28.62	(14.4%)
JCPL	$33.80	$24.30	(28.1%)	$36.86	$26.52	(28.1%)
Met-Ed	$32.94	$24.68	(25.1%)	$35.82	$26.22	(26.8%)
PECO	$33.13	$24.01	(27.5%)	$35.96	$25.90	(28.0%)
PENELEC	$33.65	$26.77	(20.4%)	$35.90	$27.86	(22.4%)
Pepco	$40.81	$33.08	(18.9%)	$44.38	$34.95	(21.2%)
PPL	$33.01	$24.24	(26.6%)	$36.62	$25.68	(29.9%)
PSEG	$35.17	$24.87	(29.3%)	$37.82	$26.83	(29.1%)
RECO	$35.37	$25.00	(29.3%)	$38.10	$27.28	(28.4%)
PJM	$34.12	$28.10	(17.7%)	$36.73	$29.68	(19.2%)

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 3-45 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 2000 through December 2016.[78] The PJM day-ahead monthly load-weighted average LMP in May 2016 was $24.32, which is the lowest day-ahead monthly load-weighted average since May 2002 at $23.74.

Figure 3-45 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through 2016



PJM Day-Ahead, Monthly, Inflation Adjusted Load-Weighted, Average LMP

Figure 3-48 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through December 2016.[79] The PJM day-ahead inflation adjusted monthly load-weighted average LMP in May 2016 was $16.36, which is the lowest day-ahead monthly load-weighted average real LMP observed since PJM day-ahead markets started in 2000. Table 3-76 shows the PJM day-ahead yearly load- weighted average LMP and inflation adjusted yearly load-weighted average LMP for 2000 through 2016.

78 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 six months of that year.

79 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>.(January 27, 2017).

Figure 3-46 PJM day-ahead, monthly, load-weighted, average LMP and day-ahead, monthly inflation adjusted load-weighted, average LMP: June 2000 through 2016

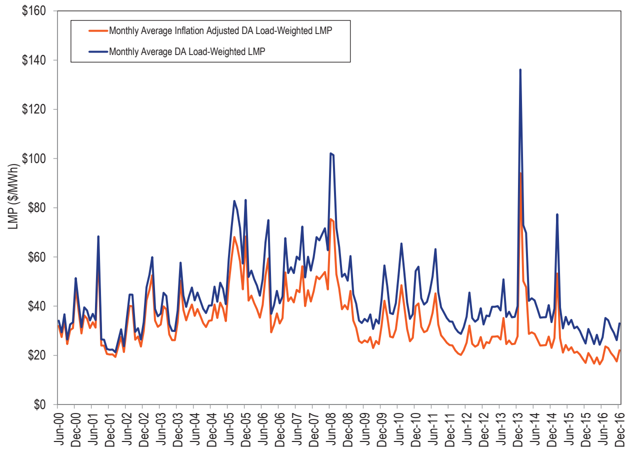


Table 3-76 PJM day-ahead, yearly, load-weighted, average LMP and day-ahead, yearly inflation adjusted load-weighted, average LMP: 2000 through 2016

Year	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

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, FMU adder, day-ahead scheduling reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Energy Market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_X, SO_2 and CO_2 emission credits, emission rates for NO_X, emission rates for SO_2 and emission rates for CO_2. CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[80] Day-ahead scheduling reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. 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 cost.

Table 3-77 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In 2016, 36.4 percent of the load-weighted LMP was the result of coal cost, 11.0 percent of the load-weighted LMP was the result of gas cost, 2.2 percent was the result of the up to congestion transaction cost, 26.7 percent was the result of DEC bid cost and 1.9 percent was the result of INC bid cost.

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

Table 3-77 Components of PJM day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): 2015 and 2016

	2015		2016		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$11.63	31.7%	$10.81	36.4%	4.8%
DEC	$8.27	22.5%	$7.92	26.7%	4.2%
Gas	$6.42	17.5%	$3.28	11.0%	(6.4%)
DASR LOC Adder	$0.28	0.7%	$2.06	6.9%	6.2%
Ten Percent Cost Adder	$2.04	5.6%	$1.63	5.5%	(0.1%)
Dispatchable Transaction	$1.05	2.9%	$1.61	5.4%	2.6%
VOM	$1.64	4.5%	$1.31	4.4%	(0.1%)
Up to Congestion Transaction	$1.56	4.3%	$0.65	2.2%	(2.1%)
INC	$4.27	11.6%	$0.57	1.9%	(9.7%)
CO_2	$0.10	0.3%	$0.29	1.0%	0.7%
NO_x	$0.19	0.5%	$0.28	1.0%	0.4%
Oil	$0.23	0.6%	$0.12	0.4%	(0.2%)
Municipal Waste	$0.00	0.0%	$0.12	0.4%	0.4%
SO_2	$0.25	0.7%	$0.06	0.2%	(0.5%)
Price Sensitive Demand	$0.04	0.1%	$0.03	0.1%	(0.0%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.04)	(0.1%)	($0.01)	(0.0%)	0.1%
DASR Offer Adder	$0.17	0.5%	($0.02)	(0.1%)	(0.5%)
Markup	($1.49)	(4.0%)	($1.03)	(3.5%)	0.6%
Other	$0.00	0.0%	$0.00	0.0%	(0.0%)
NA	$0.11	0.3%	$0.00	0.0%	(0.3%)
Total	$36.73	100.0%	$29.68	100.0%	0.0%

Table 3-78 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 units.

Table 3-78 Components of PJM day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): 2015 and 2016

	2015		2016		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$11.63	31.7%	$10.81	36.4%	4.8%
DEC	$8.27	22.5%	$7.92	26.7%	4.2%
Gas	$6.42	17.5%	$3.28	11.0%	(6.4%)
DASR LOC Adder	$0.28	0.7%	$2.06	6.9%	6.2%
Dispatchable Transaction	$1.05	2.9%	$1.61	5.4%	2.6%
VOM	$1.64	4.5%	$1.31	4.4%	(0.1%)
Up to Congestion Transaction	$1.56	4.3%	$0.65	2.2%	(2.1%)
INC	$4.27	11.6%	$0.57	1.9%	(9.7%)
Ten Percent Cost Adder	$0.73	2.0%	$0.38	1.3%	(0.7%)
CO_2	$0.10	0.3%	$0.29	1.0%	0.7%
NO_x	$0.19	0.5%	$0.28	1.0%	0.4%
Markup	($0.17)	(0.5%)	$0.21	0.7%	1.2%
Oil	$0.23	0.6%	$0.12	0.4%	(0.2%)
Municipal Waste	$0.00	0.0%	$0.12	0.4%	0.4%
SO_2	$0.25	0.7%	$0.06	0.2%	(0.5%)
Price Sensitive Demand	$0.04	0.1%	$0.03	0.1%	(0.0%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.04)	(0.1%)	($0.01)	(0.0%)	0.1%
DASR Offer Adder	$0.17	0.5%	($0.02)	(0.1%)	(0.5%)
Other	$0.00	0.0%	$0.00	0.0%	(0.0%)
NA	$0.11	0.3%	$0.00	0.0%	(0.3%)
Total	$36.73	100.0%	$29.68	100.0%	0.0%

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge more than would be the case without virtuals. Convergence is not the goal of virtual trading, but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market. Price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences, such as differences in modeled contingencies and marginal loss calculations, between the Day-Ahead and Real-Time Energy Market.

Where arbitrage opportunities are created by differences between day-ahead and real-time energy market expectations, reactions by market participants may lead to more efficient market outcomes but there is no guarantee that the results of virtual bids and offers will result in more efficient market outcomes.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions. This is termed false arbitrage.

INCs, DECs and UTCs allow participants to profit from price differences between the Day-Ahead and Real-Time Energy Market. Absent a physical position in real time, the seller of an INC must buy energy in the Real-Time Energy Market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, the INC makes a profit. Absent a physical position in real time, the buyer of a DEC must sell energy in the Real-Time Energy Market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, the DEC makes a profit.

The profitability of a UTC transaction is the net of the separate profitability of the component INC and DEC. A UTC can be net profitable if the profit on one side of the UTC transaction exceeds the losses on the other side.

Table 3-79 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 2015 and 2016. In 2016, 48.3 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 64.4 percent were profitable on the source side and 35.0 were profitable on the sink side but only 5.6 percent were profitable on both the source and sink side.

Table 3-79 Cleared UTC profitability by source and sink point: 2015 and 2016[81]

	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2015	10,052,055	5,198,147	6,771,210	3,394,829	51.7%	67.4%	33.8%
2016	22,382,027	10,807,587	14,409,047	7,844,293	48.3%	64.4%	35.0%

81 Calculations exclude PJM administrative charges.

Figure 3-47 shows total UTC daily gross profits and losses and net profits and losses in 2016.

Figure 3-47 UTC daily gross profits and losses and net profits: 2016[82]

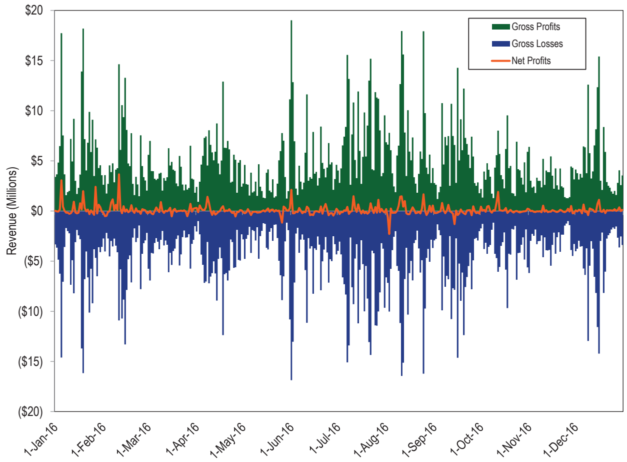


Figure 3-48 shows the cumulative UTC daily profits for the years 2013 through 2016. UTC profits during this period were primarily a result of significant unanticipated price differences between day ahead and real time LMPs. For example, the cumulative daily UTC profits in 2014 were greater than for the other three years as a result of profits from the significant and unanticipated day-ahead and real-time price differences that resulted from the polar vortex conditions in January 2014. Similarly, cumulative daily UTC profits increased during late February 2015 as a result of profits from the significant day-ahead and real-time prices differences that resulted from cold weather conditions. The cumulative daily UTC profits for 2016 are the lowest of these four years as a result of low and stable LMPs and stable prices during 2016.

Figure 3-48 Cumulative daily UTC profits: 2013 through 2016

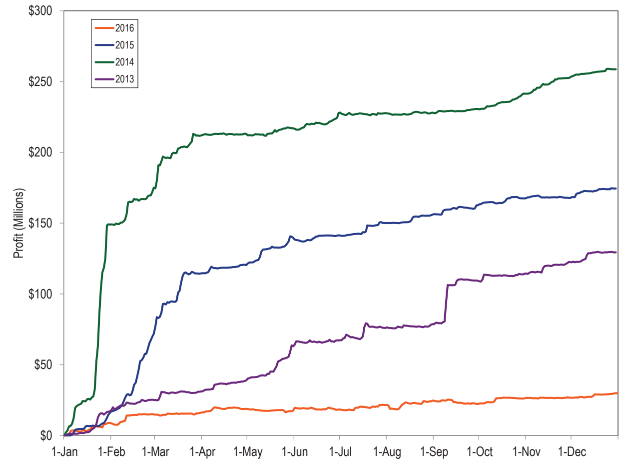


Table 3-80 shows UTC profits by month for 2013 through 2016. May and September 2016 were the only months in the past four years where the total monthly profits were negative.

There are incentives to use virtual transactions to profit from price differences between the Day-Ahead and Real-Time Energy Markets, but there is no guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both day-ahead and real-time energy market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes.

Table 3-80 UTC profits by month: 2013 through 2016

	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

82 Calculations exclude PJM administrative charges.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 3-50).

Analysis of the data from September 1, 2013, through September 30, 2015, does not support the conclusion that UTCs contribute in any measurable way to price convergence. In addition, the sudden and significant reduction in UTC activity in September of 2014 did not cause a measurable change in price convergence.

Table 3-81 shows that the difference between the average real-time price and the average day-ahead price was -\$0.73 per MWh in 2015, and -\$0.53 per MWh in 2016. The difference between average peak real-time price and the average peak day-ahead price was -\$1.53 per MWh in 2015 and -\$0.73 per MWh in 2016.

Table 3-81 Day-ahead and real-time average LMP (Dollars per MWh): 2015 and 2016[83]

	2015				2016			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$34.12	$33.39	($0.73)	(2.2%)	$28.10	$27.57	($0.53)	(1.9%)
Median	$29.09	$26.61	($2.47)	(9.3%)	$25.76	$24.10	($1.66)	(6.9%)
Standard deviation	$22.59	$27.80	$5.22	18.8%	$10.68	$14.76	$4.08	27.7%
Peak average	$40.97	$39.44	($1.53)	(3.9%)	$33.43	$32.71	($0.73)	(2.2%)
Peak median	$33.69	$29.95	($3.74)	(12.5%)	$30.36	$27.33	($3.03)	(11.1%)
Peak standard deviation	$26.30	$30.23	$3.93	13.0%	$11.16	$17.05	$5.89	34.5%
Off peak average	$28.11	$28.08	($0.03)	(0.1%)	$23.47	$23.12	($0.35)	(1.5%)
Off peak median	$24.51	$23.62	($0.90)	(3.8%)	$22.15	$21.60	($0.55)	(2.5%)
Off peak standard deviation	$16.54	$24.28	$7.74	31.9%	$7.66	$10.57	$2.91	27.5%

The price difference between the Real-Time and the Day-Ahead Energy Markets results in part, from conditions in the Real-Time Energy Market that are difficult, or impossible, to anticipate in the Day-Ahead Energy Market.

Table 3-82 shows the difference between the real-time and the day-ahead energy market prices for each year from 2001 through 2016.

Table 3-82 Day-ahead and real-time average LMP (Dollars per MWh): 2001 through 2016

	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%)

Table 3-83 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for 2007 through 2016.

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

Table 3-83 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2007 through 2016

	2007		2008		2009		2010		2011	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	2	0.03%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	49	0.59%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	5,614	64.68%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	2,880	97.56%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	185	99.67%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	21	99.91%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.93%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	3	99.97%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.97%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.97%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

	2012		2013		2014		2015		2016	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	2	0.02%	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	3	0.06%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	1	0.07%	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	6	0.14%	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	5	0.19%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	5	0.25%	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	6	0.32%	0	0.00%	0	0.00%
($250) to ($200)	1	0.01%	1	0.01%	14	0.48%	1	0.01%	0	0.00%
($200) to ($150)	4	0.06%	3	0.05%	14	0.64%	4	0.06%	0	0.00%
($150) to ($100)	6	0.13%	5	0.10%	45	1.15%	17	0.25%	0	0.00%
($100) to ($50)	17	0.32%	9	0.21%	91	2.19%	65	0.99%	13	0.15%
($50) to $0	5,576	63.80%	5,994	68.63%	5,829	68.73%	6,034	69.87%	5,780	65.95%
$0 to $50	3,061	98.65%	2,659	98.98%	2,525	97.56%	2,467	98.04%	2,919	99.18%
$50 to $100	82	99.58%	64	99.71%	120	98.93%	126	99.47%	58	99.84%
$100 to $150	17	99.77%	12	99.85%	39	99.37%	34	99.86%	13	99.99%
$150 to $200	12	99.91%	10	99.97%	18	99.58%	7	99.94%	1	100.00%
$200 to $250	5	99.97%	1	99.98%	9	99.68%	3	99.98%	0	100.00%
$250 to $300	1	99.98%	2	100.00%	8	99.77%	1	99.99%	0	100.00%
$300 to $350	2	100.00%	0	100.00%	3	99.81%	1	100.00%	0	100.00%
$350 to $400	0	100.00%	0	100.00%	3	99.84%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	2	99.86%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	99.86%	0	100.00%	0	100.00%
$500 to $750	0	100.00%	0	100.00%	7	99.94%	0	100.00%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	99.94%	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	1	99.95%	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	4	100.00%	0	100.00%	0	100.00%

Figure 3-49 shows the hourly differences between day-ahead and real-time hourly LMP in 2016.

Figure 3-49 Real-time hourly LMP minus day-ahead hourly LMP: 2016

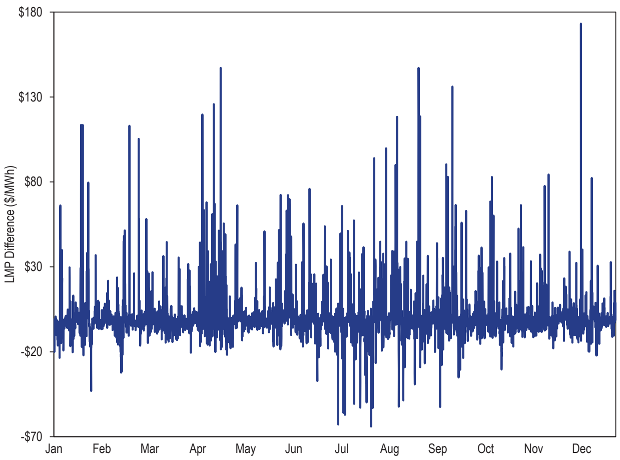


Figure 3-50 shows the monthly average of the differences between the day-ahead and real-time PJM average LMPs from January 2013, through December, 2016.

Figure 3-50 Monthly average of real-time minus day-ahead LMP: 2013 through 2016

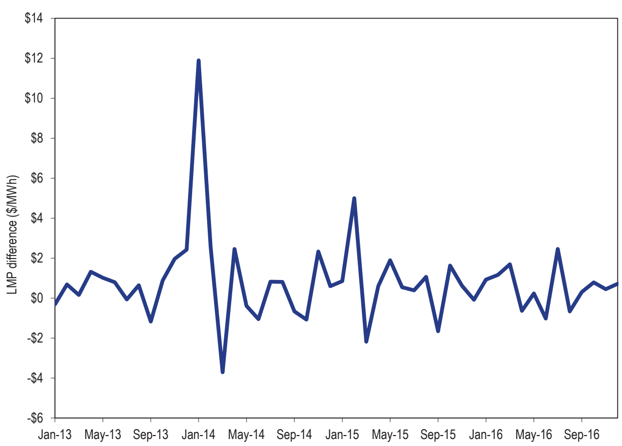


Figure 3-51 shows the monthly average of the absolute value of the differences between the day-ahead and real-time hourly, nodal LMPs from January 2013, through December 2016.

Figure 3-51 Monthly average of the absolute value of real-time minus day-ahead LMP by pnode: 2013 through 2016

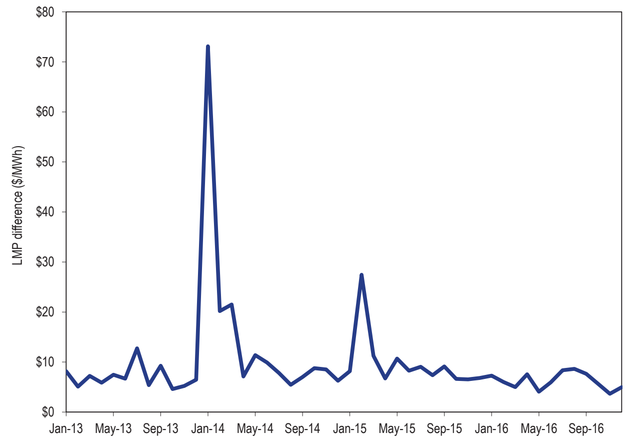
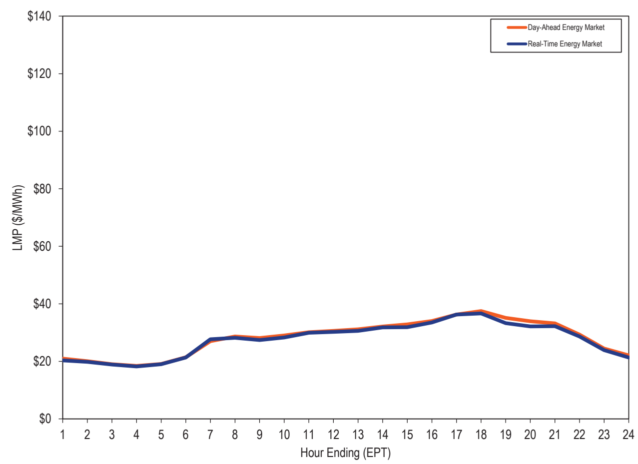


Figure 3-52 shows day-ahead and real-time LMP on an average hourly basis for 2016.

Figure 3-52 PJM system hourly average LMP: 2016



Scarcity

PJM's Energy Market experienced no shortage pricing events in 2016. Table 3-84 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in 2015 and 2016.

Table 3-84 Summary of emergency events declared: 2015 and 2016

	Number of days events declared	
Event Type	2015	2016
Cold Weather Alert	26	8
Hot Weather Alert	19	22
Maximum Emergency Generation Alert	1	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	2	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	2	0
Maximum Emergency Action	1	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	0	0
Energy export recalls from PJM capacity resources	0	0

Emergency procedures

PJM declares alerts at least a day prior to the operating day to warn members of possible emergency actions that could be taken during the operating day. In real time on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

PJM declared cold weather alerts on eight days in 2016 compared to 26 days in 2015.[84] The purpose of a cold weather alert is to prepare personnel and facilities for expected extreme cold weather conditions, generally when temperatures are forecast to approach minimums or fall below 10 degrees Fahrenheit.

PJM declared hot weather alerts on 22 days in 2016 compared to 19 days in 2015.[85] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

PJM did not declare any maximum emergency generation alert in 2016 compared to one day in 2015. The purpose of a maximum emergency generation alert is to provide an alert at least one day prior to the operating day that system conditions may require use of PJM emergency actions. It is called to alert PJM members that maximum emergency generation may be requested in the operating capacity.[86] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM did not declare any primary reserve alerts in 2016 and 2015. The purpose of a primary reserve alert is to alert members at least one day prior to the operating day that available primary reserves are anticipated to be short of the primary reserve requirement on the operating day. It is issued when the estimated primary reserves are less than the forecast primary reserve requirement.

PJM did not declare any voltage reduction alert in 2016 and 2015. The purpose of a voltage reduction alert is to alert members at least one day prior to the operating day that a voltage reduction may be required on the operating day. It is issued when the estimated operating reserve is less than the forecast synchronized reserve requirement.

PJM did not declare any primary reserve warning in 2016 and 2015. The purpose of a primary reserve warning is to warn members that available primary reserves are less than the primary reserve requirement but greater than the synchronized reserve requirement.

PJM did not declare any voltage reduction warnings and reductions of noncritical plant load in 2016 and 2015. The purpose of a voltage reduction warning and reduction of noncritical plant load is to warn members that available synchronized reserves are less than the synchronized reserve requirement and that a voltage

84 See PJM. "Manual 13: Emergency Operations," Revision 61 (January 1, 2017), Section 3.3 Cold Weather Alert, p. 54.

85 See PJM. "Manual 13: Emergency Operations," Revision 61 (January 1, 2017), Section 3.4 Hot Weather Alert, p. 58.

86 See PJM. "Manual 13: Emergency Operations," Revision 61 (January 1, 2017), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 18.

reduction may be required. It can be issued for the RTO or for specific control zones.

PJM did not declare any emergency mandatory load management reductions in 2016, compared to two days in 2015 in all or parts of the PJM service territory. The purpose of emergency mandatory load management is to request curtailment service providers (CSP) to implement load reductions from demand resources registered in PJM demand response programs that have a lead time of between one and two hours (long lead time) and a lead time of up to one hour (short lead time). Starting in June 2014, PJM combined the long lead and short lead emergency load management action procedures into Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time). PJM dispatch declares NERC Energy Emergency Alert level 2 (EEA2) concurrent with Emergency Mandatory load Management Reductions. PJM also added a Pre-Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time) step to request load reductions before declaring emergency load management reductions.

PJM did not declare any maximum emergency generation actions in 2016 compared to one day in 2015. The purpose of a maximum emergency generation action is to request generators to increase output to the maximum emergency level which unit owners may define at a level above the maximum economic level. A maximum emergency generation action can be issued for the RTO, for specific control zones or for parts of control zones.

PJM did not request any offers for emergency energy purchases in 2016 and 2015.

PJM did not declare any voltage reduction actions in 2016 and 2015. The purpose of a voltage reduction is to reduce load to provide sufficient reserves, to maintain tie flow schedules, and to preserve limited energy sources. When a voltage reduction action is issued for a reserve zone or subzone, the primary reserve penalty factor and synchronized reserve penalty factor are incorporated into the synchronized and nonsynchronized reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

PJM declared 16 synchronized reserve events in 2016 compared to 21 synchronized reserve events in 2015.[87] Synchronized reserve events may occur at any time of the year due to sudden loss of generation or transmission facilities and do not necessarily coincide with capacity emergency conditions such as maximum generation emergency events or emergency load management events.

Table 3-85 provides a description of PJM declared emergency procedures.

87 See *2016 State of the Market Report for PJM*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-85 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.

Table 3-86 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in 2016.

Table 3-86 PJM declared emergency alerts, warnings and actions: 2016

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
1/18/2016	PJM Western Region											
1/19/2016	PJM Western Region											
2/13/2016	PJM Western Region											
2/15/2016	PJM except Dominion											
7/7/2016		Mid Atlantic Region										
7/8/2016		Mid Atlantic and Dominion Regions										
7/14/2016		Mid Atlantic and Dominion Regions										
7/15/2016		Mid Atlantic and Dominion Regions										
7/18/2016		Mid Atlantic and Dominion Regions										
7/21/2016		ComEd										
7/22/2016		PJM RTO										
7/23/2016		PJM RTO										
7/24/2016		PJM RTO										
7/25/2016		PJM RTO										
7/26/2016		Mid Atlantic and Dominion Regions										
7/27/2016		Mid Atlantic and Dominion Regions										
7/28/2016		Mid Atlantic and Dominion Regions										
8/12/2016		Mid Atlantic Region										
8/13/2016		Mid Atlantic Region										
8/14/2016		Mid Atlantic Region										
8/15/2016		Mid Atlantic and Dominion Regions										
8/16/2016		Mid Atlantic and Dominion Regions										
8/29/2016		Mid Atlantic Region										
9/8/2016		Mid Atlantic and Dominion Regions										
9/9/2016		Mid Atlantic and Dominion Regions										
9/10/2016		Mid Atlantic and Dominion Regions										
12/15/2016	PJM Western Region											
12/16/2016	PJM Western Region											
12/17/2016	PJM Western Region											
12/19/2016	PJM Western Region											

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, including reserve requirements, is nearing the limits of the available capacity of the system. Under the PJM rules that were in place through September 30, 2012, high prices, or scarcity pricing, resulted from high offers by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage scarcity pricing and made it difficult to distinguish between market power and scarcity pricing.

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. Under the current PJM Market Rules, shortage pricing conditions are triggered when there is a shortage of synchronized or primary reserves in the RTO or in the Mid-Atlantic and Dominion (MAD) Subzone. In times of reserve shortage, the value of reserves is included as a penalty factor in the optimization and in the price of energy.[88] Shortage pricing is also triggered when PJM issues a voltage reduction action or a manual load dump action for a reserve zone or a reserve subzone. When shortage pricing is triggered, the primary reserve penalty factor and the synchronized reserve penalty factor are incorporated in the calculation of the synchronized and nonsynchronized reserve market clearing prices and the locational marginal price.

In 2016, there were no shortage pricing events triggered in PJM.

88 See PJM OATT, 2.2 (d) General, (February 25, 2014), pp. 1815, 1819.

Final Rule on Shortage Pricing and Settlement Intervals

On September 17, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) in which the Commission proposed to address price formation issues in RTOs/ISOs ("price formation NOPR").[89] In particular, the price formation NOPR proposed (i) to require the alignment of settlement and dispatch intervals for energy and operating reserves; and (ii) to require that each RTO/ISO trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs. These proposed reforms are intended to ensure that resources have price signals that provide incentives to conform their output to dispatch instructions, and that prices reflect operating needs at each dispatch interval.[90]

On June 16, 2016, the Commission issued a Final Rule in which it required each RTO/ISO to settle energy, operating reserves and intertie transactions using the same time intervals that it uses for to dispatch units or schedule these transactions.[91] In PJM, the energy market dispatch and pricing interval is five minutes, and the order requires PJM to settle energy transactions on a five minute basis. In PJM, the synchronized reserve and regulation market dispatch and pricing interval is five minutes, and the order requires PJM to settle these reserves on a five minute basis. In PJM, intertie transactions are scheduled on fifteen minute intervals, and the order requires PJM to settle intertie transactions on a fifteen minute basis. However, the Commission allowed PJM to propose a shorter time interval for settling intertie transactions.[92]

The Commission also 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.[93] In PJM, the rule would require PJM to trigger shortage pricing for any five minute interval when the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. Currently in PJM, if the dispatch tools (Intermediate-Term and Real-Time SCED) reflect a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes) due to ramp limitations or unit startup delays, it is considered a transient shortage, a shortage event is not declared, and shortage pricing is not implemented. Currently, both Real-Time SCED and Intermediate-Term SCED have to consistently identify that a shortage of a particular reserve product exists for a period of at least 30 minutes to trigger the shortage pricing penalty factor for that reserve product. For example, if Real-Time SCED indicates a shortage of RTO wide primary reserve for an interval but the Intermediate-Term SCED forecasts that the reserve shortage does not extend beyond its first look ahead interval (15 minutes ahead of the Real-Time SCED interval), it is considered a transient shortage, and shortage pricing is not implemented. If Real-Time SCED indicates a shortage of RTO wide primary reserve for an interval and the Intermediate-Term SCED forecasts that the reserve shortage extends for at least two look ahead intervals (30 minutes ahead of the Real-Time SCED interval), shortage pricing is implemented. The rationale for including voltage reduction actions and manual load dump actions as triggers for shortage pricing is to reflect the fact that when dispatchers need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data does not show a shortage of reserves.[94]

Accuracy of Reserve Measurement

If PJM were to move to a shortage pricing mechanism that is triggered by five minute shortages, there needs to be accurate measurement of real-time reserves that can support such a definition. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot implement that capability. Without very accurate measurement of reserves at minute by minute granularity, system operators cannot know with certainty that there is a shortage condition and therefore an appropriate trigger for five minute shortage pricing does not exist. The advantages of five minute shortage pricing are all implicitly based on the premise that the RTO knows accurately whether it is in a shortage condition. If PJM cannot demonstrate that it can accurately measure reserves at minute by minute granularity, it should not implement or continue five

89 152 FERC ¶ 61,218 (September 17, 2015).
90 *Id* at P 5.
91 155 FERC ¶ 61,276 (June 16, 2016).
92 *Id* at P 90.
93 *Id* at P 162.
94 *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)

minute shortage pricing until it can demonstrate that capability.[95]

The Commission directed in the Final Rule that, to the extent an RTO/ISO needs to enhance its measurement capabilities to implement the shortage pricing requirement, it should propose to do so in its compliance filing.[96]

The accuracy of reserve measurement in PJM can be evaluated using historical data on performance during spinning events. The level of tier 1 biasing also reflects PJM dispatchers' estimate of the error in the measurement of tier 1 synchronized reserve. Both of these data sources provide insight into the accuracy of reserve measurement based on actual historical data.

Historical Performance During Spinning Events

Historical data on response from synchronized reserves during spinning events shows the accuracy of PJM reserve estimates. Synchronized reserves consist of tier 1 and tier 2 synchronized reserves that are procured to meet the RTO and Mid-Atlantic reserve requirements. Tier 1 synchronized reserve is comprised of all online resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event.[97]

All resources that respond to spinning events are paid for their response. Table 3-87 shows the performance of tier 1 and tier 2 synchronized reserves during spinning events, declared in 2015 and 2016, that lasted at least 10 minutes. In 2015, tier 1 response MW shown in Table 3-87 were measured as the increase in MW from all resources as a response to the spinning event declaration, regardless of whether the units were part of the tier 1 MW estimate. Since the tier 1 response MW to spinning events included resources that were not part of the tier 1 MW estimate, the 2015 estimates for tier 1 response were greater than 100 percent. In 2016, PJM reports tier 1 response only from the units that were part of the estimated tier 1 MW.

Beginning in 2016, PJM started reporting the response to spinning events only from the units that were part of its tier 1 estimate MW. Table 3-87 shows that, in 2016, the tier 1 MW response percent was never greater than 85 percent, with an average tier 1 response of 75 percent.

If PJM is going to trigger shortage pricing based on shortage of synchronized reserves that is calculated based on current estimates, system operators will be relying on estimates of synchronized reserve MW that have historically been inaccurate.

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

96 155 FERC ¶ 61,276 at P 177 (June 16, 2016).

97 See *2016 State of the Market Report for PJM*, Section 10: Ancillary Service Markets at "Tier 1 Synchronized Reserve" for details on Tier 1 synchronized reserves.

Table 3-87 Performance of synchronized reserves during spinning events: 2015 and 2016[98]

Spin Event (Date, Hour)	Duration (Minutes)	Tier 1 Estimate MW (Adjusted by DGP)	Tier 1 Response MW	Tier 2 Scheduled MW	Tier 2 Response MW	Tier 1 Response Percent	Tier 2 Response Percent
Mar 3, 2015 12	11	1,079.0	1,365.1	484.4	272.3	126.5%	56.2%
Mar 16, 2015 06	24	541.5	576.4	248.0	180.2	106.4%	72.7%
Mar 17, 2015 19	17	1,428.9	1,693.1	247.2	232.8	118.5%	94.2%
Mar 23, 2015 19	15	851.3	1,420.0	273.5	205.8	166.8%	75.2%
Jul 30, 2015 10	10	1,458.4	2,145.7	79.7	24.0	147.1%	30.1%
Jan 18, 2016 17	12	861.0	733.5	616.7	508.8	85.2%	82.5%
Feb 8, 2016 15	10	1,750.2	1,338.2	228.4	200.1	76.5%	87.6%
Apr 14, 2016 20	10	1,182.8	1,000.6	346.3	304.8	84.6%	88.0%
Jul 28, 2016 13	15	649.4	500.4	822.9	655.8	77.1%	79.7%
Nov 4, 2016 17	11	744.5	497.1	758.0	709.2	66.8%	93.6%
Dec 31, 2016 05	12	971.2	585.0	594.4	485.7	60.2%	81.7%

Tier 1 Synchronized Reserve Estimate Bias

The tier 1 synchronized reserve for a unit is measured as the lower of the available 10 minute ramp and the difference between the economic dispatch point and the economic maximum output. The total supply of tier 1 synchronized reserve MW available to the market solution is calculated as the sum of the individual units' tier 1 MW, with further adjustments. These adjustments include eliminating tier 1 MW from nuclear, wind, solar, energy storage, and hydro units, adjusting the available tier 1 MW from remaining units using a metric called Degree of Generator Performance (DGP) and using tier 1 estimate bias.[99] Tier 1 biasing occurs when PJM market operations manually modifies (increasing or decreasing) the tier 1 synchronized reserve estimate of the market solution. This forces the market clearing engine to clear more or less tier 2 synchronized reserve and nonsynchronized reserve to satisfy the synchronized reserve and primary reserve requirements. Tier 1 biasing reflects the operators' view on the available tier 1 MW in the system and a lack of confidence on the calculated estimates of tier 1 MW, thus forcing the market clearing engine to procure more or less synchronized reserves. Table 10-14 shows the average monthly biasing of tier 1 estimates in the Ancillary Service Optimizer (ASO), the tool used to procure reserves on an hourly basis, in 2015 and 2016.

The existence of tier MW biasing raises the possibility that under a five minute shortage pricing construct, shortage pricing penalty factors may be triggered or avoided not due to actual reserve levels, but by operators' discretionary decisions on the amount of available reserves. It is possible that the market engine's estimate of tier 1 MW, even after unit level adjustments such as DGP, may be enough to satisfy the reserve requirement, but an operator's biasing of the market engine's estimate may lead to triggering shortage pricing penalty factors. There are no rules in the PJM tariff or manuals regarding the use of tier 1 MW biasing. In a five minute shortage pricing construct, the need for explicit rules governing operator discretion regarding reserve estimates becomes critical. The IMM has recommended since 2012 that PJM explicitly define the rules for using tier 1 biasing and identify which rule permits it every time tier 1 synchronized reserve estimate biasing is used.

Generator Data used for Reserve Estimates

A potential source for the error in tier 1 MW is the use of economic dispatch point to calculate the available ramp limited MW in 10 minutes as opposed to the actual metered output from the generator for any 5 minute interval. The amount of tier 1 MW available from a resource may differ due to using the metered output from a unit versus the market clearing engine's estimate of the resource's output. PJM addressed this issue partially in 2015 by adjusting a resource's available 10 minute ramp with its DGP. The available tier 1 MW estimated by the market solution for each resource is adjusted by its DGP percent. 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 resource specific DGP.

98 Beginning January 2015, Degree of Generator Performance (DGP) was introduced as a metric to improve the accuracy of the tier 1 MW estimate used by the market solution.

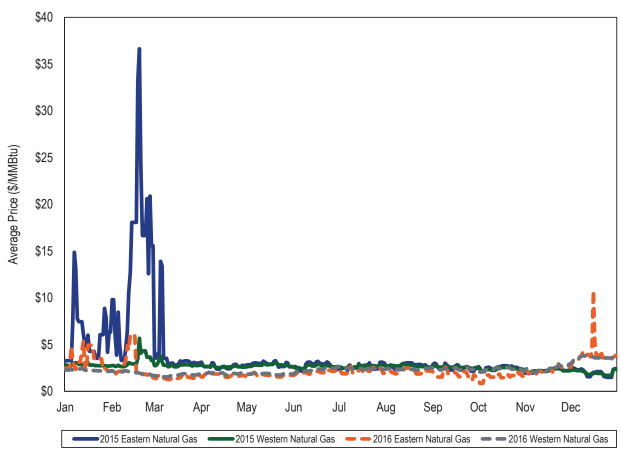
99 DGP measures how closely the unit has been following economic dispatch for the past 30 minutes.

PJM Cold Weather Operations 2016

Natural Gas Supply and Prices

As of January 1, 2017, gas fired generation was 35.7 percent (65,110.3 MW) of the total installed PJM capacity (182,449.1 MW).[100] The extreme cold weather conditions and the associated high demand for natural gas led to supply constraints on the gas transmission system which resulted in natural gas price volatility and interruptions to customers without firm transportation. Figure 3-53 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2016 and 2015.[101]

Figure 3-53 Average daily delivered price for natural gas: 2015 and 2016 ($/MMBtu)



During the first three months of 2015 and 2016, 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. OFOs may, depending on the nature of the transportation service purchased, permit the pipelines to restrict the provision of gas to 24 hour ratable takes which means that hourly nominations must be the same for each of the 24 hours in the gas day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users, depending on the nature of the transportation service purchased, to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during extreme operating conditions. The independent operations of geographically overlapping pipelines during extreme conditions highlights the potential shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of supply and demand. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions suggests there may be potential benefits to creating an ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs, or the creation of a gas supply coordination framework under existing electric ISO/RTOs.

100 *2016 State of the Market Report for PJM*, Section 5: Capacity Market, at Installed Capacity.

101 Eastern natural gas consists of the average of Texas Eastern M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago City gate daily fuel price indices.

Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required 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 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 at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges.

In PJM all energy payments to demand response resources are also 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.

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $175.4 million, or 56.1 percent, in 2016 compared to 2015, from $312.5 million to $137.1 million.
- **Energy Uplift Charges Categories.** The decrease of $175.4 million in 2016 is comprised of a $41.4 million decrease in day-ahead operating reserve charges, a $121.1 million decrease in balancing operating reserve charges, a $8.1 million decrease in reactive services charges, and a $4.9 million decrease in black start services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.071 per MWh, real-time load paid $0.031 per MWh, a DEC paid $0.418 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.347 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.071 per MWh, real-time load paid $0.023 per MWh, a DEC paid $0.372 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.302 per MWh.
- **Reactive Services Rates.** The DPL, PENELEC and EKPC control zones had the three highest local voltage support rates: $0.043, $0.015 and $0.013 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 13.0 percent of all day-ahead generator credits and 10.1 percent of all balancing generator credits. Combustion turbines and diesels received 76.8 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 36.0 percent of all credits. The top 10 organizations received 76.8 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 6102, balancing operating reserves HHI was 3231 and lost opportunity cost HHI was 5356.
- **Economic and Noneconomic Generation.** In 2016, 85.9 percent of the day-ahead generation eligible for operating reserve credits was economic and 78.3 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2016, 1.5 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 47.4 percent received energy uplift payments.

Geography of Charges and Credits

- In 2016, 89.9 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions (at control zones or buses within a control zone), demand and generation, 4.4 percent by transactions at hubs and aggregates and 5.7 percent by interchange transactions at interfaces.

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.

- Generators in the Eastern Region received 50.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 48.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Energy Uplift Issues

- **Lost Opportunity Cost Credits.** In 2016, lost opportunity cost credits decreased by $64.6 million compared to 2015. In 2016, resources in three control zones, AECO, AEP and ComEd, accounted for 59.1 percent of all lost opportunity cost credits, 35.5 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 51.3 percent of all day-ahead generation not committed in real time by PJM from those unit types and 50.7 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Closed Loop Interfaces.** PJM implemented closed loop interfaces to allow reactive constraints and emergency DR to set price when they would not otherwise set price under the LMP logic. This use of closed loop interfaces permits subjective price setting by PJM.
- **Price Setting Logic.** In November 2014, PJM implemented a software change to its day ahead and real time market solution tools that would enable PJM to reduce energy uplift by artificially selecting the marginal unit for any constraint. The goal is to make marginal any unit committed by PJM to provide reactive services, black start or transmission constraint relief if such unit would otherwise run with an incremental offer greater than the correctly calculated LMP. PJM calls this approach price setting logic. Price setting logic is a form of subjective pricing because it varies from fundamental LMP logic based on an administrative decision to reduce energy uplift.
- **Con Edison – PJM Transmission Service Agreements Support.** Certain units located near the boundary between New Jersey and New York City have been operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts. These units are often run out of merit and received substantial operating reserves credits.

Energy Uplift Recommendations

- **Impact of Quantifiable Recommendations.** The impact of implementing the recommendations related to energy uplift proposed by the MMU on the rates paid by participants would be significant. For example, in 2016, the average rate paid by a DEC in the Eastern Region would have been $0.027 per MWh under the MMU proposal, which is $0.391 per MWh, or 93.5 percent, lower than the actual average rate paid.

Recommendations

The MMU recognizes that many of the issues addressed in the recommendations are being discussed in PJM stakeholder processes. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing market rules.

- The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to modify the LMP price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff. (Priority: Medium. First Reported Q3, 2016. Status: Not adopted.)

- The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Not adopted.)
- The MMU recommends the elimination of the day-ahead operating reserve category 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. Stakeholder process.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted. Stakeholder process.)
- The MMU recommends not compensating self scheduled units 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 four additional modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours 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 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. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Not adopted. Stakeholder process.)
- 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: Not adopted. Stakeholder process.)
- 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 reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. 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 operating reserve credits 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, which is currently allocated solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment

reasons. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)

- 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). In addition, the MMU recommends that PJM allow and wind units submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants should 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. New recommendation. 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 2014.)
- 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.)
- 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 2012. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)

Conclusion

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Loss is defined to be receiving revenue less than the short run marginal costs incurred in order to generate energy. Referred to in PJM as day-ahead operating reserves, balancing operating reserves, energy lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at short run marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start charges.

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.

From the perspective of those participants paying energy uplift charges, these costs are an unpredictable and unhedgeable component of participants' costs in PJM. 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 that the allocation of these charges reflects the reasons that the costs are incurred to the extent possible.

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market energy uplift payments. When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted for more than ten years.

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.

The level of energy uplift paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters, the details of the rules which define payments and the decisions of PJM operators. Energy uplift payments result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, no load and startup costs. Energy uplift payments also result from units' operational parameters that may require PJM to schedule or commit resources during noneconomic hours. The balance of these costs not covered by energy revenues are collected as energy uplift rather than reflected in price as a result of the rules governing the determination of LMP.

PJM's goal should be to minimize the total level of energy uplift paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. For example, up to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated. Some uplift payments are the result of inflexible operating parameters included in offers by generating units. Operating parameters should reflect the flexibility of the benchmark new entrant unit in the PJM capacity market if the unit is to receive uplift payments from other market participants. 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.

But it is also important that the reduction of uplift payments not be a goal to be achieved at the expense of the fundamental logic of an 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 price setting logic.

Energy Uplift

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 hourly LMP is less than the offer price including incremental, no load and startup costs.

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 4-1 and Table 4-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 4-1 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits		→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	in RTO, Eastern or Western Region
			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 4-2 Reactive services, synchronous condensing and black start services credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:
		Reactive		
Resources Providing Reactive Service	Day-Ahead Operating Reserve Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Charge	Zonal Real-Time Load
			Reactive Services Local Constraint	Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges decreased by $175.4 million or 56.1 percent in 2016 compared to 2015. Table 4-3 shows total energy uplift charges in 2001 through 2016.[2]

Table 4-3 Total energy uplift charges: 2001 through 2016

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.1	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.5%	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	($151.5)	(31.9%)	1.2%
2010	$623.2	$300.4	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.5	7.7%	2.2%
2013	$843.0	$193.1	29.7%	2.5%
2014	$960.7	$117.7	14.0%	1.9%
2015	$312.5	($648.2)	(67.5%)	0.7%
2016	$137.1	($175.4)	(56.1%)	0.4%

Table 4-4 compares energy uplift charges by category for 2015 and 2016. The decrease of $175.5 million in 2016 is comprised of a decrease of $41.4 million in day-ahead operating reserve charges, a decrease of $121.2 million in balancing operating reserve charges, a decrease of $8.1 million in reactive services charges, a decrease of $0.02 million in synchronous condensing charges and a decrease of $4.9 million in black start services charges.

The decrease in total energy uplift charges was mainly a result of lower lost opportunity cost credits to combustion turbines and diesels scheduled in the Day-Ahead Energy Market and not committed in real time ($56.4 million), lower balancing operating reserve credits to units in the Pepco and PSEG control zone ($39.5 million) and lower day-ahead operating reserve credits to units in the BGE, Pepco and PSEG control zones ($34.4 million).

Table 4-4 Energy uplift charges by category: 2015 and 2016

Category	2015 Charges (Millions)	2016 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$98.7	$57.3	($41.4)	(41.9%)
Balancing Operating Reserves	$198.1	$77.0	($121.1)	(61.1%)
Reactive Services	$10.5	$2.5	($8.1)	(76.4%)
Synchronous Condensing	$0.0	$0.0	($0.0)	(99.8%)
Black Start Services	$5.2	$0.3	($4.9)	(94.6%)
Total	$312.5	$137.1	($175.4)	(56.1%)

The decrease in energy uplift charges in 2016 was greatest for February. Total energy uplift charges decreased by $91.8 million in February 2016 from February 2015. Uplift charges in February 2015 were a result of high natural gas prices which increased the cost of units in the PSEG and Pepco control zones committed for relief of transmission constraints. Table 4-5 compares monthly energy uplift charges by category for 2015 and 2016.

2 Table 4-3 includes all categories of charges as defined in Table 4-1 and Table 4-2 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 27, 2017.

Table 4-5 Monthly energy uplift charges: 2015 and 2016

	2015 Charges (Millions)						2016 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	$16.8	$24.7	$1.8	$0.0	$1.7	$45.0	$7.4	$7.5	$0.00	$0.0	$0.0	$14.9
Feb	$31.4	$71.1	$2.4	$0.0	$1.1	$106.0	$7.6	$6.5	$0.0	$0.0	$0.0	$14.2
Mar	$7.0	$24.8	$2.1	$0.0	$1.9	$35.8	$6.4	$3.9	$0.2	$0.0	$0.0	$10.5
Apr	$3.1	$8.5	$1.7	$0.0	$0.1	$13.4	$3.0	$4.7	$0.2	$0.0	$0.0	$8.0
May	$5.7	$15.4	$0.7	$0.0	$0.2	$22.0	$2.8	$3.3	$0.1	$0.0	$0.0	$6.3
Jun	$9.1	$8.6	$0.5	$0.0	$0.0	$18.2	$4.6	$5.3	$0.1	$0.0	$0.1	$10.1
Jul	$5.1	$11.9	$0.1	$0.0	$0.0	$17.1	$3.6	$11.4	$0.1	$0.0	$0.0	$15.2
Aug	$4.5	$9.1	$0.1	$0.0	$0.0	$13.6	$2.4	$11.5	$0.0	$0.0	$0.0	$13.9
Sep	$4.1	$8.7	$0.6	$0.0	$0.0	$13.5	$2.9	$6.9	$0.1	$0.0	$0.0	$9.9
Oct	$3.0	$5.3	$0.4	$0.0	$0.1	$8.8	$3.6	$8.7	$0.3	$0.0	$0.0	$12.5
Nov	$4.3	$6.0	$0.1	$0.0	$0.0	$10.4	$5.7	$2.8	$1.0	$0.0	$0.1	$9.5
Dec	$4.6	$4.2	$0.1	$0.0	$0.0	$8.8	$7.3	$4.5	$0.4	$0.0	$0.0	$12.2
Total	$98.7	$198.1	$10.5	$0.0	$5.2	$312.5	$57.3	$77.0	$2.5	$0.0	$0.3	$137.1
Share	31.6%	63.4%	3.4%	0.0%	1.7%	100.0%	41.8%	56.2%	1.8%	0.0%	0.2%	100.0%

Table 4-6 shows the composition of the 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.[3] Day-ahead operating reserve charges decreased by $41.4 million or 41.9 percent in 2016 compared to 2015. Day-ahead operating reserve charges remain high primarily because of uplift payments to units scheduled as must run by PJM. Units are typically scheduled as must run by PJM in the Day-Ahead Energy Market when the day-ahead model does not reflect certain real-time conditions or requirements (for example, reactive or ALR black start) or when units have parameters that extend beyond the 24 hour day-ahead model.

Table 4-6 Day-ahead operating reserve charges: 2015 and 2016

Type	2015 Charges (Millions)	2016 Charges (Millions)	Change (Millions)	2015 Share	2016 Share
Day-Ahead Operating Reserve Charges	$98.5	$57.3	($41.2)	99.8%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.2	$0.0	($0.2)	0.2%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$98.7	$57.3	($41.4)	100.0%	100.0%

Table 4-7 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by $121.1 million in 2016 compared to 2015.

Table 4-7 Balancing operating reserve charges: 2015 and 2016

Type	2015 Charges (Millions)	2016 Charges (Millions)	Change (Millions)	2015 Share	2016 Share
Balancing Operating Reserve Reliability Charges	$41.1	$23.0	($18.1)	20.7%	29.9%
Balancing Operating Reserve Deviation Charges	$156.0	$53.5	($102.5)	78.7%	69.5%
Balancing Operating Reserve Charges for Load Response	$0.2	$0.1	($0.1)	0.1%	0.1%
Balancing Local Constraint Charges	$0.9	$0.4	($0.4)	0.4%	0.6%
Total	$198.1	$77.0	($121.1)	100.0%	100.0%

3 See PJM. OATT Attachment K-Appendix § 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 ten times, totaling $26.9 million.

Table 4-8 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges equal make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In 2016, 64.9 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, an increase of 18.4 percentage points compared to the share in 2015.

Table 4-8 Balancing operating reserve deviation charges: 2015 and 2016

Charge Attributable To	2015 Charges (Millions)	2016 Charges (Millions)	Change (Millions)	2015 Share	2016 Share
Make Whole Payments to Generators and Imports	$72.5	$34.7	($37.8)	46.5%	64.9%
Energy Lost Opportunity Cost	$83.3	$18.7	($64.6)	53.4%	35.0%
Canceled Resources	$0.2	$0.1	($0.1)	0.1%	0.2%
Total	$156.0	$53.5	($102.5)	100.0%	100.0%

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $8.1 million in 2016 compared to 2015. Black start services charges decreased by $4.9 million in 2016 compared to 2015 as a result of the replacement of black start units under the automatic load rejection (ALR) option in the second quarter of 2015.

Table 4-9 Additional energy uplift charges: 2015 and 2016

Type	2015 Charges (Millions)	2016 Charges (Millions)	Change (Millions)	2015 Share	2016 Share
Reactive Services Charges	$10.5	$2.5	($8.1)	67.0%	89.9%
Synchronous Condensing Charges	$0.0	$0.0	($0.0)	0.2%	0.0%
Black Start Services Charges	$5.2	$0.3	($4.9)	32.9%	10.1%
Total	$15.7	$2.8	($13.0)	100.0%	100.0%

Table 4-10 and Table 4-11 show the amount and percent shares of regional balancing charges in 2015 and 2016. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by demand deviations. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In 2016, regional balancing operating reserve charges decreased by $120.6 million compared to 2015. Balancing operating reserve reliability charges decreased by $18.1 million or 44.0 percent and balancing operating reserve deviation charges decreased by $102.5 million or 65.7 percent.

Table 4-10 Regional balancing charges allocation (Millions): 2015

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$35.1	17.8%	$4.0	2.0%	$1.1	0.5%	$40.2	20.4%
	Real-Time Exports	$0.7	0.4%	$0.1	0.1%	$0.0	0.0%	$0.9	0.4%
	Total	$35.9	18.2%	$4.1	2.1%	$1.1	0.5%	$41.1	20.8%
Deviation Charges	Demand	$86.0	43.6%	$2.8	1.4%	$1.2	0.6%	$89.9	45.6%
	Supply	$25.3	12.9%	$0.8	0.4%	$0.4	0.2%	$26.6	13.5%
	Generator	$38.0	19.3%	$1.2	0.6%	$0.4	0.2%	$39.5	20.1%
	Total	$149.3	75.7%	$4.8	2.4%	$1.9	1.0%	$156.0	79.2%
Total Regional Balancing Charges		$185.2	93.9%	$8.9	4.5%	$3.0	1.5%	$197.1	100%

Table 4-11 Regional balancing charges allocation (Millions): 2016

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$18.3	23.9%	$3.5	4.6%	$0.4	0.6%	$22.2	29.0%
	Real-Time Exports	$0.7	0.9%	$0.1	0.1%	$0.0	0.0%	$0.8	1.0%
	Total	$18.9	24.8%	$3.6	4.7%	$0.5	0.6%	$23.0	30.1%
Deviation Charges	Demand	$28.3	37.1%	$3.0	3.9%	$0.5	0.7%	$31.8	41.6%
	Supply	$9.2	12.0%	$0.8	1.1%	$0.1	0.2%	$10.1	13.3%
	Generator	$10.1	13.2%	$1.2	1.5%	$0.2	0.3%	$11.5	15.0%
	Total	$47.6	62.3%	$5.0	6.5%	$0.9	1.1%	$53.5	69.9%
Total Regional Balancing Charges		$66.6	87.0%	$8.6	11.3%	$1.3	1.7%	$76.5	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 4-1 shows how these charges are allocated.[4]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2015 and 2016. The average rate in 2016 was $0.069 per MWh, $0.051 per MWh lower than the average in 2015. The highest rate in 2016 occurred on December 15, when the rate reached $0.730 per MWh, $0.870 per MWh lower than the $1.600 per MWh reached in 2015, on February 16. The increase on December 15 was a result of high natural gas prices which increased the cost of units in the PSEG control zone committed for relief of transmission constraints. Figure 4-1 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 2015 or 2016.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2015 and 2016

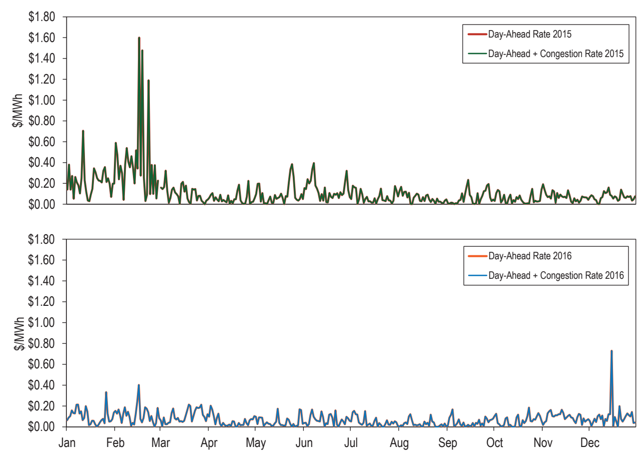


Figure 4-2 shows the RTO and the regional reliability rates for 2015 and 2016. The average daily RTO reliability rate was $0.024 per MWh. The highest RTO reliability rate in 2016 occurred on August 11, when the rate reached $0.234 per MWh, $0.538 per MWh lower than the $0.772 per MWh rate reached in 2015, on February 19.

4 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 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2015 and 2016

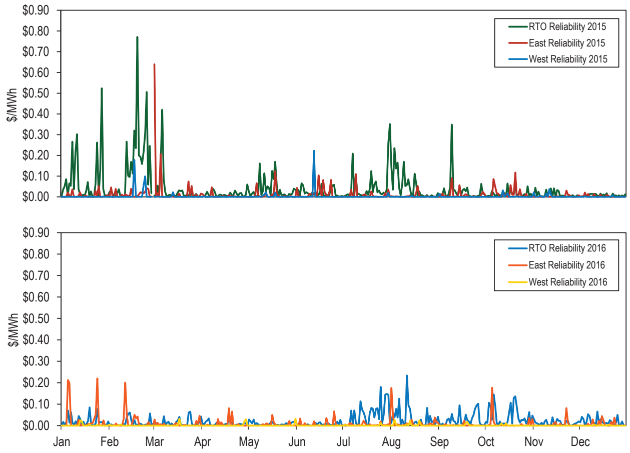


Figure 4-3 shows the RTO and regional deviation rates for 2015 and 2016. The average daily RTO deviation rate was $0.184 per MWh. The highest daily rate in 2016 occurred on October 19, when the RTO deviation rate reached $2.042 per MWh, $10.465 per MWh lower than the $12.507 per MWh rate reached in 2015, on February 17.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2015 and 2016

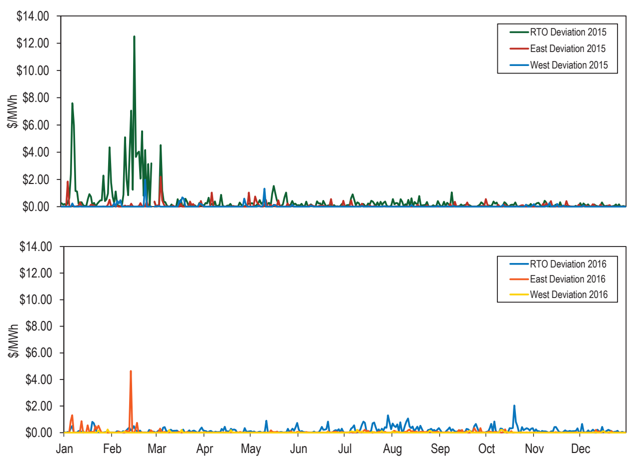


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2015 and 2016. The lost opportunity cost rate averaged $0.119 per MWh. The highest lost opportunity cost rate occurred on April 14, when it reached $1.294 per MWh, $12.110 per MWh lower than the $13.404 per MWh rate reached in 2015, February 19.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2015 and 2016

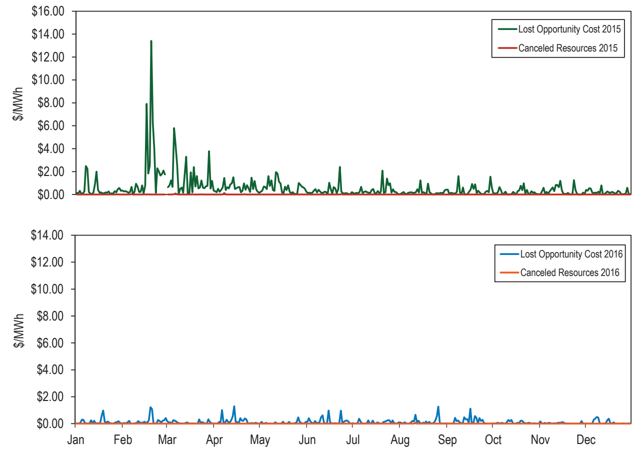


Table 4-12 shows the average rates for each region in each category in 2015 and 2016.

Table 4-12 Operating reserve rates ($/MWh): 2015 and 2016

Rate	2015 ($/MWh)	2016 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.120	0.069	(0.051)	(42.6%)
Day-Ahead with Unallocated Congestion	0.120	0.069	(0.051)	(42.6%)
RTO Reliability	0.045	0.024	(0.022)	(48.0%)
East Reliability	0.011	0.010	(0.001)	(12.2%)
West Reliability	0.003	0.001	(0.002)	(59.0%)
RTO Deviation	0.479	0.184	(0.295)	(61.6%)
East Deviation	0.068	0.061	(0.007)	(9.8%)
West Deviation	0.030	0.012	(0.018)	(61.2%)
Lost Opportunity Cost	0.606	0.119	(0.487)	(80.3%)
Canceled Resources	0.001	0.001	(0.001)	(65.2%)

Table 4-13 shows the operating reserve cost of a one MW transaction in 2016. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.418 per MWh with a maximum rate of $4.904 per MWh, a minimum rate of $0.021 per MWh and a standard deviation of $0.420 per MWh. The rates in Table 4-13 include all operating reserve charges including RTO deviation charges. Table 4-13 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-13 Operating reserve rates statistics ($/MWh): 2016

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	4.883	0.347	0.001	0.428
	DEC	4.904	0.418	0.021	0.420
	DA Load	0.730	0.071	0.000	0.067
	RT Load	0.297	0.031	0.000	0.043
	Deviation	4.883	0.347	0.001	0.428
West	INC	2.276	0.302	0.000	0.329
	DEC	2.340	0.372	0.021	0.322
	DA Load	0.730	0.071	0.000	0.067
	RT Load	0.241	0.023	0.000	0.032
	Deviation	2.276	0.302	0.000	0.329

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 revenue requirement charges which are a fixed annual charge based on approved FERC filings. 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.

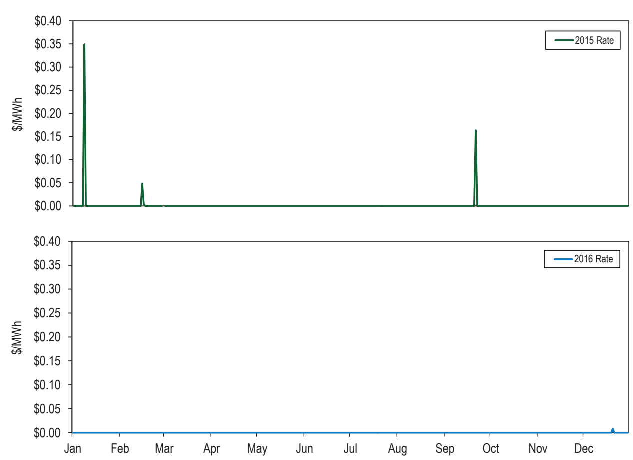
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support in 2015 and 2016. Table 4-14 shows that in 2016 the DPL Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $0.043 per MWh for reactive services associated with local voltage support, $0.081 or 65.5 percent lower than the average rate paid in 2015.

Table 4-14 Local voltage support rates: 2015 and 2016

Control Zone	2015 ($/MWh)	2016 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	(0.000)	(100%)
AEP	0.002	0.001	(0.001)	(64.6%)
AP	0.000	0.000	(0.000)	(100%)
ATSI	0.056	0.000	(0.056)	(100%)
BGE	0.000	0.000	0.000	0.0%
ComEd	0.000	0.010	0.010	12,563.0%
DAY	0.000	0.000	(0.000)	(100%)
DEOK	0.000	0.000	(0.000)	(100%)
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.026	0.000	(0.026)	(99.3%)
DPL	0.124	0.043	(0.081)	(65.5%)
EKPC	0.000	0.013	0.013	NA
JCPL	0.000	0.000	0.000	0.0%
Met-Ed	0.002	0.001	(0.001)	(56.2%)
PECO	0.000	0.000	0.000	0.0%
PENELEC	0.016	0.015	(0.002)	(9.9%)
Pepco	0.000	0.004	0.004	1,335.5%
PPL	0.000	0.000	0.000	795.0%
PSEG	0.000	0.000	0.000	0.0%
RECO	0.000	0.000	0.000	0.0%

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in 2015 and 2016. The average rate in 2016 was virtually zero, compared to the $0.002 per MWh average rate in the 2015 because PJM committed only one generation resource on one day to provide voltage support to the 500 kV system.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2015 and 2016



Balancing Operating Reserve Determinants

Table 4-15 shows the determinants used to allocate the regional balancing operating reserve charges in 2015 and 2016. Total real-time load and real-time exports were 10,945,104 MWh or 1.4 percent higher in 2016 compared to 2015. Total deviations summed across the demand, supply, and generator categories were 19,354,858 MWh or 14.1 percent higher in 2016 compared to 2015.

Table 4-15 Balancing operating reserve determinants (MWh): 2015 and 2016

		Reliability Charge Determinants (MWh)			Deviation Charge Determinants (MWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
2015	RTO	776,092,889	18,143,333	794,236,222	82,142,280	23,096,525	32,160,875	137,399,680
	East	368,942,885	9,859,610	378,802,495	41,990,810	12,258,089	16,603,269	70,852,168
	West	407,150,004	8,283,723	415,433,727	39,361,077	10,521,281	15,557,606	65,439,964
2016	RTO	778,268,661	26,912,664	805,181,325	91,963,877	31,071,933	33,718,729	156,754,538
	East	367,239,524	11,097,604	378,337,128	46,050,068	17,766,995	18,122,772	81,939,834
	West	411,029,137	15,815,060	426,844,197	45,379,231	12,971,056	15,595,957	73,946,243
Difference	RTO	2,175,772	8,769,331	10,945,104	9,821,597	7,975,407	1,557,854	19,354,858
	East	(1,703,361)	1,237,994	(465,367)	4,059,258	5,508,906	1,519,502	11,087,666
	West	3,879,133	7,531,337	11,410,470	6,018,154	2,449,774	38,351	8,506,279

Deviations fall into three categories, demand, supply and generator deviations. Table 4-16 shows the different categories by the type of transactions that incurred deviations. In 2016, 29.2 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 70.8 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-16 Deviations by transaction type: 2016

Deviation Category		Deviation (MWh)			Share		
	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	999,381	875,851	123,530	0.6%	1.1%	0.2%
	DECs Only	14,666,398	6,416,144	7,715,676	9.4%	7.8%	10.4%
	Exports Only	5,671,844	2,888,815	2,783,030	3.6%	3.5%	3.8%
	Load Only	62,107,823	30,135,763	31,972,059	39.6%	36.8%	43.2%
	Combination with DECs	6,700,851	4,785,193	1,915,658	4.3%	5.8%	2.6%
	Combination without DECs	1,817,579	948,302	869,277	1.2%	1.2%	1.2%
Supply	Bilateral Purchases Only	607,031	483,499	123,532	0.4%	0.6%	0.2%
	Imports Only	6,053,645	3,257,096	2,796,549	3.9%	4.0%	3.8%
	INCs Only	21,087,513	11,871,521	8,882,110	13.5%	14.5%	12.0%
	Combination with INCs	3,251,752	2,095,007	1,156,745	2.1%	2.6%	1.6%
	Combination without INCs	71,991	59,872	12,119	0.0%	0.1%	0.0%
Generators		33,718,729	18,122,772	15,595,957	21.5%	22.1%	21.1%
Total		156,754,538	81,939,834	73,946,243	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-17 shows the totals for each credit category in 2015 and 2016. During 2016, 56.1 percent of total energy uplift credits were in the balancing operating reserve category, a decrease of 7.2 percentage points from 63.3 in 2015.

Table 4-17 Energy uplift credits by category: 2015 and 2016

Category	Type	2015 Credits (Millions)	2016 Credits (Millions)	Change	Percent Change	2015 Share	2016 Share
Day-Ahead	Generators	$98.5	$57.3	($41.2)	(41.8%)	31.6%	41.8%
	Imports	$0.0	$0.0	($0.0)	(22.4%)	0.0%	0.0%
	Load Response	$0.2	$0.0	($0.2)	(99.9%)	0.1%	0.0%
Balancing	Canceled Resources	$0.2	$0.1	($0.1)	(60.3%)	0.1%	0.1%
	Generators	$113.4	$57.7	($55.7)	(49.1%)	36.3%	42.1%
	Imports	$0.2	$0.0	($0.2)	(91.6%)	0.1%	0.0%
	Load Response	$0.1	$0.1	($0.0)	(39.3%)	0.0%	0.1%
	Local Constraints Control	$0.9	$0.4	($0.4)	(49.6%)	0.3%	0.3%
	Lost Opportunity Cost	$83.0	$18.6	($64.4)	(77.6%)	26.6%	13.6%
Reactive Services	Day-Ahead	$7.7	$1.4	($6.3)	(81.6%)	2.5%	1.0%
	Local Constraints Control	$0.0	$0.0	($0.0)	(100%)	0.0%	0.0%
	Lost Opportunity Cost	$0.1	$0.0	($0.1)	(70.0%)	0.0%	0.0%
	Reactive Services	$2.6	$1.0	($1.6)	(61.9%)	0.8%	0.7%
	Synchronous Condensing	$0.2	$0.1	($0.1)	(65.1%)	0.1%	0.0%
Synchronous Condensing		$0.0	$0.0	($0.0)	(99.8%)	0.0%	0.0%
Black Start Services	Day-Ahead	$4.3	$0.0	($4.3)	(100%)	1.4%	0.0%
	Balancing	$0.5	$0.0	($0.5)	(99.4%)	0.1%	0.0%
	Testing	$0.4	$0.3	($0.1)	(28.9%)	0.1%	0.2%
Total		$312.2	$137.0	($175.2)	(56.1%)	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-18 shows the distribution of total energy uplift credits by unit type in 2015 and 2016. The decrease in energy uplift in 2016 compared to 2015 was primarily a result of lower credits paid to combined cycles, combustion turbines and steam turbines (not fired by coal) in the 2016 winter compared to the 2015 winter as a result of lower natural gas costs. Credits to these units decreased by $139.1 million or 64.4 percent.

Table 4-18 Energy uplift credits by unit type: 2015 and 2016

Unit Type	2015 Credits (Millions)	2016 Credits (Millions)	Change	Percent Change	2015 Share	2016 Share
Combined Cycle	$72.4	$14.7	($57.8)	(79.8%)	23.2%	10.7%
Combustion Turbine	$112.3	$58.8	($53.5)	(47.7%)	36.0%	42.9%
Diesel	$1.8	$0.6	($1.2)	(65.8%)	0.6%	0.5%
Hydro	$1.1	$0.1	($1.1)	(95.5%)	0.4%	0.0%
Nuclear	$0.4	$1.2	$0.8	180.8%	0.1%	0.9%
Steam - Coal	$87.6	$56.4	($31.2)	(35.6%)	28.1%	41.2%
Steam - Other	$31.3	$3.5	($27.8)	(88.8%)	10.0%	2.6%
Wind	$4.7	$1.7	($3.0)	(63.3%)	1.5%	1.3%
Total	$311.8	$136.9	($174.9)	(56.1%)	100.0%	100.0%

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in 2016. Coal fired steam turbines received 80.9 percent of the day-ahead generator credits in 2016, 19.1 percentage points higher than the share received in 2015. Combustion turbines received 72.5 percent of the balancing generator credits in 2016, 39.6 percentage points higher than the share received in 2015. Combustion turbines and diesels received 76.8 percent of the lost opportunity cost credits in 2015, 8.6 percentage points lower than the share received in 2015.

Table 4-19 Energy uplift credits by unit type: 2016

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	13.0%	10.1%	0.0%	0.0%	3.4%	29.3%	0.0%	11.8%
Combustion Turbine	3.5%	72.5%	35.7%	71.1%	75.6%	11.2%	100.0%	88.2%
Diesel	0.0%	0.6%	0.0%	0.0%	1.2%	1.0%	0.0%	0.0%
Hydro	0.0%	0.0%	64.3%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	6.3%	0.0%	0.0%	0.0%
Steam - Coal	80.9%	13.3%	0.0%	27.0%	4.3%	56.1%	0.0%	0.0%
Steam - Others	2.6%	3.4%	0.0%	0.0%	0.2%	2.4%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	1.9%	9.0%	0.0%	0.0%	0.0%
Total (Millions)	$57.3	$57.7	$0.1	$0.4	$18.6	$2.5	$0.0	$0.3

Table 4-19 also shows the distribution of reactive service credits and black start services credits by unit type. In 2016, coal units received 56.1 percent of all reactive services credits, compared to 19.1 percent in 2015.

Concentration of Energy Uplift Credits

There continues to be a high level of concentration in the units and companies receiving energy uplift credits. This concentration results from a combination of unit operating parameters, PJM's persistent need to commit specific units out of merit in particular locations and the fact that the lack of transparency makes it almost impossible for competition to affect these payments.

Figure 4-6 shows the concentration of energy uplift credits. The top 10 units received 36.0 percent of total energy uplift credits in 2016, compared to 34.4 percent in 2015. In 2016, 274 units received 90 percent of all energy uplift credits, compared to 247 units in 2015.

Figure 4-6 Cumulative share of energy uplift credits in 2015 and 2016 by unit

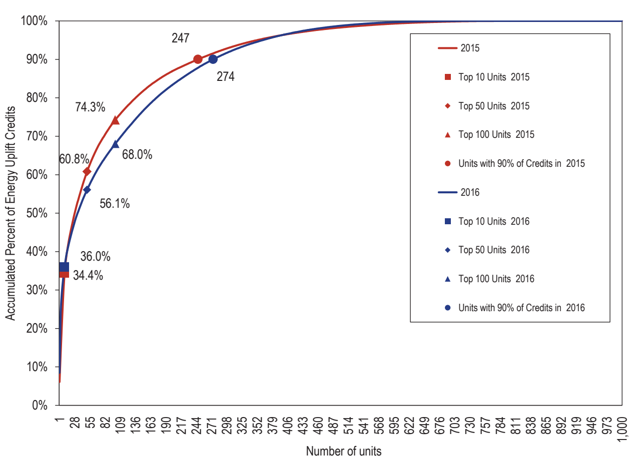


Table 4-20 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-20 Top 10 units and organizations energy uplift credits: 2016

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$42.0	73.2%	$55.7	97.2%
Balancing	Canceled Resources	$0.1	100.0%	$0.1	100.0%
	Generators	$9.8	17.0%	$40.6	70.4%
	Local Constraints Control	$0.4	91.2%	$0.4	100.0%
	Lost Opportunity Cost	$4.9	26.5%	$13.0	69.8%
Reactive Services		$2.3	92.0%	$2.5	99.9%
Synchronous Condensing		$0.0	100.0%	$0.0	100.0%
Black Start Services		$0.1	47.3%	$0.3	92.9%
Total		$49.3	36.0%	$105.1	76.8%

Table 4-21 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2016, 85.3 percent of all credits paid to these units were allocated to deviations while the remaining 14.7 percent were paid for reliability reasons.

Table 4-21 Identification of balancing operating reserve credits received by the top 10 units by category and region: 2016

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$1.2	$0.2	$0.0	$7.2	$1.2	$0.0	$9.8
Share	12.2%	2.5%	0.0%	73.1%	12.2%	0.0%	100.0%

In 2016, concentration in all energy uplift credit categories was high.[5] [6] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-22 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 6102, for balancing operating reserve credits to generators was 3231, for lost opportunity cost credits was 5356 and for reactive services credits was 9845.

Table 4-22 Daily energy uplift credits HHI: 2016

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	6102	1589	10000	100.0%	39.9%
	Imports	10000	10000	10000	100.0%	63.2%
	Load Response	10000	10000	10000	100.0%	100.0%
Balancing	Canceled Resources	10000	10000	10000	100.0%	64.3%
	Generators	3231	864	9554	97.7%	12.8%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9837	5138	10000	100.0%	47.8%
	Lost Opportunity Cost	5356	1068	10000	100.0%	10.0%
Reactive Services		9845	5058	10000	100.0%	47.7%
Synchronous Condensing		10000	10000	10000	100.0%	100.0%
Black Start Services		9457	5042	10000	100.0%	53.5%
Total		2904	751	8954	94.6%	21.1%

Pool Scheduled and Self Scheduled Generation

In PJM, units can have either a pool scheduled or self scheduled commitment status. Pool scheduled units are committed by PJM while self scheduled units are committed by the generation owners. Self scheduled units specify an output level (MW) at which they must run. A self scheduled unit can specify to PJM that the economic minimum is must run or that the entire output of the unit is must run. Pool scheduled units can also specify to PJM that if committed, PJM must take the entire output of the unit. Table 4-23 shows the categories of PJM day-ahead and real-time generation commitment status:

- **Self Scheduled (Must Run):** MWh from self scheduled units that PJM must run.
- **Self Scheduled (Dispatchable):** MWh from self scheduled units that offer a dispatchable range to PJM.
- **Pool Scheduled (Block Loaded):** MWh from pool scheduled units that are offered to PJM as a single MWh block which is not dispatchable.
- **Pool Scheduled (Dispatchable):** MWh from pool scheduled units that are offered to PJM with a dispatchable range.
- **Not Defined Status:** MWh from units that did not specify their commitment status in their offer or did not have an offer.

Table 4-23 shows the in 2016, 61.8 percent in day ahead and 60.6 percent in real time of the total generation was self scheduled. In the Day-Ahead Energy Market, 32.5 percent was must run while 29.3 percent was dispatchable. In the Real-Time Energy Market 35.7 percent was must run while 24.9 percent was dispatchable.

Table 4-23 Day-ahead and real-time generation commitment status percent: 2016

Energy Market	Self Scheduled (Must Run)	Self Scheduled (Dispatchable)	Pool Scheduled (Block Loaded)	Pool Scheduled (Dispatchable)	No Defined Status
Day Ahead	32.5%	29.3%	3.4%	34.8%	0.0%
Real Time	35.7%	24.9%	4.9%	34.2%	0.3%

Economic and Noneconomic Generation[7]

Economic generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled or producing energy at an incremental offer higher than the LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator 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. Table 4-24 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating reserve credits. In the Day-Ahead Energy Market only pool-

5 See *2016 State of the Market Report for PJM*, Volume II: Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

6 Table 4-22 excludes local constraints control categories.

7 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.

scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that follow PJM's dispatch instructions are eligible for balancing operating reserve credits.

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 cost 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 costs and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits whenever the total energy revenues covered the total offer (including no load and startup costs) for the entire day or segment. In 2016, 38.2 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 36.1 percent of the real-time generation was eligible for balancing operating reserve credits.[8]

Table 4-24 Day-ahead and real-time generation (GWh): 2016

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percent
Day-Ahead	814,803	311,123	38.2%
Real-Time	816,633	294,798	36.1%

Table 4-25 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In 2016, 85.9 percent of the day-ahead generation eligible for operating reserve credits was economic and 78.3 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 4-25 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

Table 4-25 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): 2016

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	267,400	43,723	85.9%	14.1%
Real-Time	230,695	64,103	78.3%	21.7%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment, scheduled or committed, is noneconomic, including no load and startup costs. Table 4-26 shows the generation receiving day-ahead and balancing operating reserve credits. In 2016, 3.4 percent of the day-ahead generation eligible for operating reserve credits received credits and 2.5 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-26 Day-ahead and real-time generation receiving operating reserve credits (GWh): 2016

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	311,123	10,498	3.4%
Real-Time	294,798	7,289	2.5%

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. PJM puts such reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection (ALR) units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[9] 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.[10] Units scheduled as must run by PJM may set LMP if raised above economic minimum and following the dispatch signal and are eligible for day-ahead operating reserve credits. Table 4-27 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In 2016, 1.5 percent of the total

8 In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that operate as requested by PJM are eligible for balancing operating reserve credits.

9 See PJM. "Item 12 - October 2012 MIC DAM Cost Allocation," PJM Presentation to the Market Implementation Committee (October 12, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-minutes.ashx>.

10 See PJM. "PJM eMkt Users Guide," Section Managing Unit Data (version July 9, 2015) p. 42, <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

day-ahead generation was scheduled as must run by PJM, 0.5 percentage points lower than 2015.

Table 4-27 Day-ahead generation scheduled as must run by PJM (GWh): 2015 and 2016

	2015			2016		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	77,937	2,143	2.7%	73,821	935	1.3%
Feb	74,224	2,904	3.9%	66,367	979	1.5%
Mar	68,201	1,857	2.7%	60,431	1,047	1.7%
Apr	55,957	1,138	2.0%	56,338	514	0.9%
May	61,955	1,523	2.5%	59,078	429	0.7%
Jun	68,558	1,447	2.1%	70,573	772	1.1%
Jul	75,490	1,201	1.6%	81,801	981	1.2%
Aug	73,934	922	1.2%	83,021	1,694	2.0%
Sep	66,927	616	0.9%	69,962	1,682	2.4%
Oct	58,731	763	1.3%	60,950	1,066	1.7%
Nov	58,517	486	0.8%	59,983	819	1.4%
Dec	62,976	551	0.9%	72,478	1,112	1.5%
Total	803,408	15,552	1.9%	814,803	12,031	1.5%

Pool-scheduled units 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. Pool-scheduled units scheduled as must run by PJM are only paid day-ahead operating reserve credits when their total offer is greater than the revenues from the Day-Ahead Energy Market.

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 4-28 shows the total day-ahead generation scheduled as must run by PJM by category. In 2016, 47.4 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, almost all paid day-ahead operating reserve credits, a small amount (2.7 percent) paid as reactive services, and none paid for black start services. The remaining 52.6 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-28 Day-ahead generation scheduled as must run by PJM by category (GWh): 2016

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	0	0	375	560	935
Feb	0	0	584	395	979
Mar	0	0	712	335	1,047
Apr	0	0	263	251	514
May	0	0	289	140	429
Jun	0	0	534	238	772
Jul	0	0	419	562	981
Aug	0	0	410	1,284	1,694
Sep	0	2	422	1,258	1,682
Oct	0	7	464	595	1,066
Nov	0	211	458	151	819
Dec	0	103	456	553	1,112
Total	0	323	5,385	6,323	12,031
Share	0.0%	2.7%	44.8%	52.6%	100.0%

Total day-ahead operating reserve credits in 2016 were $57.3 million, of which $44.6 million or 77.8 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

Geography of Charges and Credits

Table 4-29 shows the geography of charges and credits in 2016. Table 4-29 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the AEP Control Zone paid 13.2 percent of all operating reserve charges allocated regionally, and resources in the AEP Control Zone were paid 8.2 percent of the corresponding credits. The AEP Control Zone received less operating reserve credits than operating reserve charges paid and had 12.9 percent of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the BGE Control Zone paid 4.5 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 22.8 percent of the corresponding credits.

The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 47.2 percent of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-29 also shows that 89.9 percent of all charges were allocated in control zones, 4.4 percent in hubs and aggregates and 5.7 percent in interfaces.

Table 4-29 Geography of regional charges and credits: 2016

Location		Charges (Millions)	Credits (Millions)	Balance	Shares: Total Charges	Shares: Total Credits	Shares: Deficit	Shares: Surplus
Zones	AECO	$1.8	$3.0	$1.2	1.4%	2.3%	0.0%	2.3%
	AEP	$17.7	$10.9	($6.7)	13.2%	8.2%	12.9%	0.0%
	AP	$7.3	$2.1	($5.2)	5.4%	1.5%	10.0%	0.0%
	ATSI	$9.6	$3.0	($6.6)	7.2%	2.2%	12.8%	0.0%
	BGE	$6.0	$30.5	$24.5	4.5%	22.8%	0.0%	47.2%
	ComEd	$14.8	$16.5	$1.7	11.0%	12.3%	0.0%	3.3%
	DAY	$2.5	$2.9	$0.4	1.9%	2.1%	0.0%	0.7%
	DEOK	$3.8	$1.8	($2.0)	2.8%	1.3%	3.9%	0.0%
	DLCO	$1.9	$0.5	($1.3)	1.4%	0.4%	2.5%	0.0%
	Dominion	$13.4	$13.8	$0.3	10.0%	10.3%	0.0%	0.7%
	DPL	$3.3	$8.0	$4.8	2.4%	6.0%	0.0%	9.2%
	EKPC	$2.0	$2.8	$0.7	1.5%	2.1%	0.0%	1.4%
	External	$0.0	$1.3	$1.3	0.0%	1.0%	0.0%	2.5%
	JCPL	$3.6	$2.6	($1.1)	2.7%	1.9%	2.1%	0.0%
	Met-Ed	$2.7	$1.1	($1.6)	2.0%	0.8%	3.1%	0.0%
	PECO	$6.7	$0.7	($5.9)	5.0%	0.5%	11.4%	0.0%
	PENELEC	$3.9	$0.8	($3.1)	2.9%	0.6%	6.0%	0.0%
	Pepco	$5.2	$17.1	$11.9	3.9%	12.8%	0.0%	23.0%
	PPL	$6.6	$2.0	($4.6)	4.9%	1.5%	8.8%	0.0%
	PSEG	$7.3	$12.4	$5.1	5.5%	9.3%	0.0%	9.7%
	RECO	$0.3	$0.0	($0.3)	0.2%	0.0%	0.5%	0.0%
	All Zones	$120.3	$133.7	$13.4	89.9%	100.0%	74.1%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.4	$0.0	($0.4)	0.3%	0.0%	0.7%	0.0%
	Dominion	$0.2	$0.0	($0.2)	0.2%	0.0%	0.4%	0.0%
	Eastern	$0.2	$0.0	($0.2)	0.2%	0.0%	0.4%	0.0%
	New Jersey	$0.2	$0.0	($0.2)	0.1%	0.0%	0.3%	0.0%
	Ohio	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Western	$4.8	$0.0	($4.8)	3.6%	0.0%	9.2%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$5.8	$0.0	($5.8)	4.4%	0.0%	11.2%	0.0%
Interfaces	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	IMO	$0.4	$0.0	($0.4)	0.3%	0.0%	0.9%	0.0%
	Linden	$0.3	$0.0	($0.3)	0.3%	0.0%	0.7%	0.0%
	MISO	$3.0	$0.0	($3.0)	2.2%	0.0%	5.7%	0.0%
	Neptune	$0.6	$0.0	($0.6)	0.4%	0.0%	1.1%	0.0%
	NIPSCO	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.1	$0.0	($0.1)	0.1%	0.0%	0.3%	0.0%
	NYIS	$0.9	$0.0	($0.9)	0.7%	0.0%	1.8%	0.0%
	OVEC	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	South Exp	$0.6	$0.0	($0.6)	0.5%	0.0%	1.2%	0.0%
	South Imp	$1.5	$0.0	($1.5)	1.1%	0.0%	2.8%	0.0%
	All Interfaces	$7.6	$0.0	($7.6)	5.7%	0.0%	14.7%	0.0%
	Total	$133.7	$133.7	$0.0	100.0%	100.0%	100.0%	100.0%

Energy Uplift Issues

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are paid to units under two scenarios. If a combustion turbine or a diesel is scheduled to operate in the Day-Ahead Energy Market, but is not requested by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus balancing spot energy market charges that the unit has to pay. For purposes of this report, this LOC will be referred to as day-ahead LOC.[11] If a unit generating in real time with an offer price lower than the real-time LMP at the unit's bus is reduced or suspended by PJM due to a transmission constraint or other reliability issue, the unit will receive a credit for LOC based on the desired output. For purposes of this report, this LOC will be referred to as real-time LOC.

In 2016, LOC credits decreased by $64.4 million, 77.6 percent, compared 2015. The decrease of $64.4 million is comprised of a decrease of $56.4 million in day-ahead LOC and a decrease of $8.0 million in real-time LOC. Table 4-30 shows the monthly composition of LOC credits in 2015 and 2016. In 2016, 5.2 percent of the day-ahead scheduled generation from combustion turbines and diesels was not committed in real time and paid LOC credits, 12.5 percentage points lower than in 2015. The reduction in

11 A unit's day-ahead financial position equals the revenues from the Day-Ahead Energy Market minus the expected costs (valued at the unit's offer curve cleared in day ahead). A unit scheduled in the Day-Ahead Energy Market and not committed in real time incurs balancing spot energy charges since it has to cover its day-ahead scheduled energy position in real time.

lost opportunity cost is attributable to several factors. In September 2015, PJM adopted three recommendations proposed by the MMU to improve the calculation of LOC payments. In 2016, compared to 2015, more generation from combustion turbines and diesels that cleared the Day-Ahead Energy Market was committed in real time as shown in Table 4-31.[12]

Table 4-30 Monthly lost opportunity cost credits (Millions): 2015 and 2016

	2015			2016		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$4.4	$0.9	$5.2	$1.5	$0.2	$1.7
Feb	$23.0	$3.0	$25.9	$2.0	$0.1	$2.1
Mar	$13.9	$1.5	$15.4	$0.7	$0.3	$0.9
Apr	$5.2	$0.5	$5.7	$1.8	$0.6	$2.4
May	$5.6	$1.8	$7.4	$0.5	$0.1	$0.7
Jun	$3.8	$0.4	$4.2	$1.7	$0.9	$2.6
Jul	$4.1	$0.4	$4.5	$0.8	$0.5	$1.4
Aug	$2.1	$0.4	$2.5	$1.6	$0.4	$2.0
Sep	$3.0	$1.2	$4.2	$2.2	$0.2	$2.4
Oct	$1.5	$0.6	$2.1	$0.8	$0.1	$0.9
Nov	$1.8	$1.6	$3.3	$0.3	$0.1	$0.4
Dec	$2.4	$0.0	$2.4	$0.3	$0.8	$1.1
Total	$70.7	$12.3	$83.0	$14.3	$4.3	$18.6
Share	85.2%	14.8%	100.0%	76.7%	23.3%	100.0%

Table 4-31 Day-ahead generation from combustion turbines and diesels (GWh): 2015 and 2016

	2015			2016		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits
Jan	827	347	244	705	211	115
Feb	1,593	838	499	746	192	92
Mar	1,368	688	505	1,090	162	66
Apr	1,392	536	408	1,531	276	95
May	1,898	556	365	1,349	115	48
Jun	1,736	406	242	1,433	231	80
Jul	2,651	432	273	2,697	227	76
Aug	1,881	331	202	2,402	143	58
Sep	1,714	291	183	1,774	239	97
Oct	1,375	204	108	1,360	155	60
Nov	1,258	185	94	512	68	25
Dec	1,041	314	180	462	48	21
Total	18,734	5,128	3,304	16,062	2,068	831
Share	100.0%	27.4%	17.6%	100.0%	12.9%	5.2%

Table 4-31 shows, for combustion turbines and diesels scheduled day ahead, the total day-ahead generation, the day-ahead generation from units that were not requested by PJM in real time and the subset of that generation that received lost opportunity costs credits.

Table 4-31 shows that day-ahead scheduled generation from CTs and diesels decreased by 2,672 GWh, 14.3 percent, from 18,734 GWh in 2015 to 16,062 GWh in 2016 and that the generation that received LOC credits decreased by 2,473 GWh or 74.8 percent.

In 2016, the top three control zones in which generation received LOC credits, AECO, AEP and ComEd, accounted for 59.1 percent of all LOC credits, 35.5 percent of all the day-ahead generation from combustion turbines and diesels, 51.3 percent of all day-ahead generation not committed in real time by PJM from those unit types and 51.3 percent of all day-ahead generation not committed in real time by PJM and receiving LOC credits from those unit types.

Combustion turbines and diesels receive LOC credits on an hourly basis. For example, if a combustion turbine is scheduled day ahead to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for LOC credits for hours 10, 11, 17 and 18. Table 4-32 shows the LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market for units that did not run in real time and units that ran in real time for at least one hour of their day-ahead schedule. Table 4-32 shows that in 2016, $7.7 million or 54.1 percent of all LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 8.3 percentage points lower than 2015.

12 See *2015 State of the Market Report for PJM*, Volume II Section 4: "Energy Uplift," at "Lost Opportunity Cost Calculation" for an explanation of these recommendations and the impact.

Table 4-32 Lost opportunity cost credits paid to combustion turbines and diesels by scenario (Millions): 2015 and 2016

	2015			2016		
	Units that did not run in real time	Units that ran in real time for at least one hour of their day-ahead schedule	Total	Units that did not run in real time	Units that ran in real time for at least one hour of their day-ahead schedule	Total
Jan	$2.4	$2.0	$4.4	$0.9	$0.7	$1.5
Feb	$15.4	$7.5	$23.0	$0.8	$1.2	$2.0
Mar	$9.1	$4.8	$13.9	$0.2	$0.5	$0.7
Apr	$3.0	$2.2	$5.2	$0.9	$0.9	$1.8
May	$3.0	$2.6	$5.6	$0.4	$0.2	$0.5
Jun	$2.2	$1.6	$3.8	$1.2	$0.4	$1.7
Jul	$2.5	$1.6	$4.1	$0.4	$0.4	$0.8
Aug	$1.3	$0.8	$2.1	$0.8	$0.8	$1.6
Sep	$1.6	$1.4	$3.0	$1.5	$0.7	$2.2
Oct	$0.9	$0.6	$1.5	$0.3	$0.4	$0.8
Nov	$1.0	$0.8	$1.8	$0.2	$0.1	$0.3
Dec	$1.8	$0.6	$2.4	$0.2	$0.2	$0.3
Total	$44.2	$26.5	$70.7	$7.7	$6.5	$14.3
Share	62.5%	37.5%	100.0%	54.1%	45.9%	100.0%

Table 4-33 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2015 and 2016[13]

	2015			2016		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	246	102	348	142	43	185
Feb	497	335	832	104	63	167
Mar	543	140	682	72	71	143
Apr	366	168	534	124	110	234
May	280	258	538	58	41	99
Jun	240	125	365	100	63	163
Jul	259	124	383	79	50	129
Aug	163	123	286	67	31	97
Sep	211	73	284	99	85	184
Oct	141	53	194	69	52	121
Nov	113	51	164	20	35	55
Dec	212	75	287	21	24	44
Total	3,269	1,626	4,896	954	667	1,621
Share	66.8%	33.2%	100.0%	58.9%	41.1%	100.0%

PJM may not run units in real time if the real-time value of the energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 4-33 shows the total day-ahead generation from combustion turbines and diesels that were not committed in real time by PJM and received LOC credits. Table 4-33 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP), defined here as economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In 2016, 58.9 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 41.1 percent was noneconomic.

The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not committed by PJM in real time when they are economic.

Closed Loop Interfaces

PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[14] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR resources would not otherwise set price under the fundamental LMP logic. Of the 17 closed loop interface definitions, 11 (65 percent) were created for the purpose of allowing emergency DR to set price.

Closed loop interfaces are used to model the transfer capability into a specific area. Areas or regions are defined in PJM by hubs, aggregates or control zones, all comprised of buses. Closed loop interfaces are not defined by buses, but defined by the transmission facilities that connect the buses inside the loop with the rest of PJM. When PJM wants a closed loop interface to bind, PJM reduces the capacity of the transmission

13 The total generation in Table 4-33 is lower than the day-ahead generation not requested in real time in Table 4-31 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-33 includes all generation, including generation from units that were not committed in real time and did not receive LOC credits.

14 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

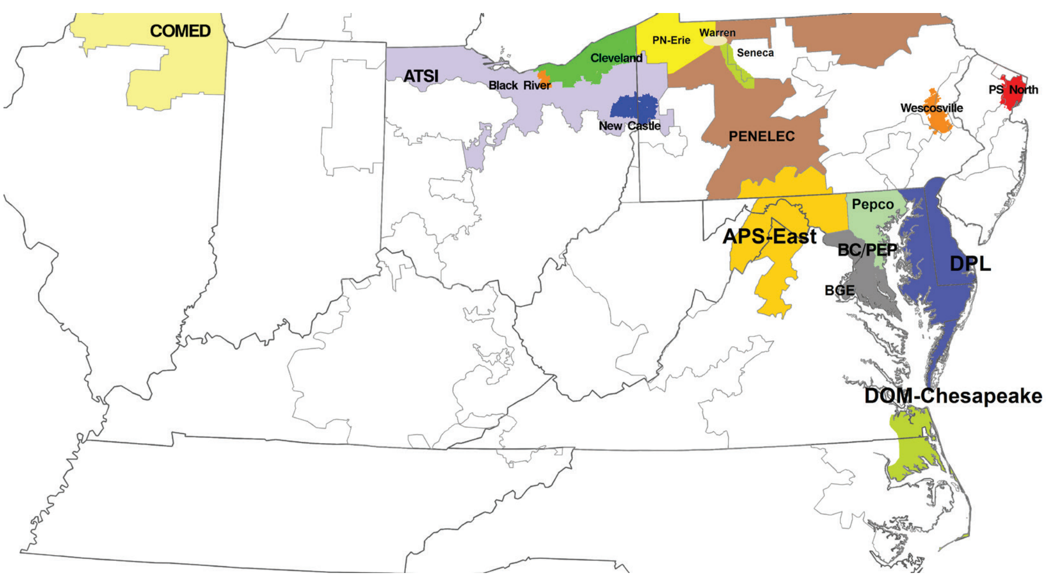
facilities to a level that will artificially make marginal the resource selected by PJM. Table 4-34 shows the closed loop interfaces that PJM has defined and PJM's objective in defining each closed loop interface.

Table 4-34 PJM closed loop interfaces[15 16 17]

Interface	Control Zone(s)	Objective	Effective Date	Limit Calculation
APS-East	AP	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
ATSI	ATSI	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 17, 2013	Limit equal to actual flow
BC	BGE	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
BC/PEP	BGE and Pepco	Reactive Interface (not an IROL). Used to model import capability into the BGE/PEPCO/Doubs/Northern Virginia area	NA	PJM Transfer Limit Calculator
Black River	ATSI	Allow emergency DR resources set real-time LMP	September 1, 2014	Limit equal to actual flow
Cleveland	ATSI	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
COMED	ComEd	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
DOM-Chesapeake	Dominion	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	August 14, 2015	Limit equal to actual flow
DPL	DPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
New Castle	ATSI	Allow emergency DR resources set real-time LMP	July 1, 2014	Limit equal to actual flow
PENELEC	PENELEC	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	April 22, 2015	Limit equal to actual flow
Pepco	Pepco	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
PL-Wescosville	PPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 24, 2014	Limit equal to actual flow
PN-Erie	PENELEC	Allow emergency DR resources set real-time LMP	April 22, 2015	Limit equal to actual flow
PS North	PSEG	Objective not identified. Interface was modeled in 2014/2015 Annual FTR auction	NA	NA
Seneca	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	February 1, 2014	Limit equal to actual flow
Warren	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	September 26, 2014	Limit equal to actual flow

Figure 4-7 shows the approximate geographic location of PJM's closed loop interfaces.

Figure 4-7 PJM Closed loop interfaces map



15 See PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)," for a description of reactive interfaces.
16 See closed loop interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.
17 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

PJM's uses closed loop interfaces to artificially allow the strike price of emergency DR to set LMP. This use of closed loop interfaces permits subjective price setting by PJM. PJM has not explained why the economic fundamentals require that DR strike prices set LMP when the resource is not marginal. Although DR should be nodal, DR is not nodal and cannot routinely set price in an LMP model. The MMU has recommended that DR be nodal so that it can set price when appropriate. The current PJM rules permit emergency DR to set a strike price as high as $1,849. There are no incentives for DR to set strike prices at an economically rational level because emergency DR is guaranteed the payment of its strike price whenever called. The MMU has recommended that emergency DR have an offer cap no higher than generation resources, that emergency DR be required to make offers in the Day-Ahead Energy Market like other capacity resources and the emergency DR be paid LMP rather than a guaranteed strike price when called on. PJM's use of closed loop interfaces is a result of significant deficiencies in the rules governing DR. PJM's use of closed loop interfaces is also result of significant issues with PJM's scarcity pricing model which is not adequately locational. PJM uses closed loop interfaces and emergency DR strike prices as a substitute for improved, more locational scarcity pricing.

In a DC power flow model, such as the one used by PJM for dispatch and pricing, units scheduled for reactive support are only marginal when they are needed to supply energy above their economic minimum. With the use of closed loop interface, these units are forced to be marginal in the model even when not needed for energy, by adjusting the limit of the closed loop interface. This artificially creates congestion in the area that can only be relieved by the units providing reactive support inside the loop. The goal is to reduce energy uplift from the noneconomic operation of units needed for reactive support by forcing these units to be marginal when they are not, raising energy prices and thereby reducing uplift.[18]

The MMU has recommended and supports PJM's goal of having dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of energy uplift charges. But part of that goal is to avoid distortion of the way in which the transmission network is modeled. The use of closed loop interfaces is a distortion of the model.

The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason.

Market prices should be a function of market fundamentals and energy market prices should be a function of energy market fundamentals. PJM has not explained why the other consequences of deviating from market fundamentals do not outweigh any benefits of artificially creating constraints in order to let reactive resources set price when they are not in fact marginal. PJM has not explained why the use of closed loop interfaces to permit emergency DR to set price is not simply a crude workaround to a viable solution, consistent with the LMP model, which would be to make DR nodal. The need for closed loop interfaces to let emergency DR set price is primarily a result of the fact that DR is zonal, or subzonal with one day's notice, and therefore cannot be dispatched nodally or set price nodally. The reduction of uplift is a reasonable goal in general, but the reduction of uplift is not a goal that justifies creating distortions in the price setting mechanism.

Price Setting Logic

In November 2014, PJM implemented a software change to its day ahead and real time market solution tools that would enable PJM to reduce energy uplift by artificially selecting the marginal unit for any constraint. The goal is to make marginal any unit committed by PJM to provide reactive services, black start or transmission constraint relief if such unit would otherwise run with an incremental offer greater than the correctly calculated LMP. PJM calls this approach price setting logic.

The application of the price setting logic reduces energy uplift payments by artificially increasing the LMP. The price setting logic is a form of subjective pricing

18 See "PJM Price-Setting Changes," presented to the EMUSTF at <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02c-price-setting-option.ashx>

because it varies from fundamental LMP logic based on an administrative decision to reduce energy uplift.

PJM and Alstom presented examples of this approach at the FERC Technical Conference, "Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software."[19] The presentation shows a two bus model connected by one transmission line, three generators (A, B and C) and load at one of the buses. Solution 1: In the solution based on the fundamental LMP logic that PJM has used since the inception of markets, two of the generators are committed (A at 50 MW and B at 50 MW) to serve load (100 MW). The LMP is set at $50 per MWh (the offer of generator A) at both buses. Generator B has to be made whole (paid energy uplift) because the LMP ($50 per MWh) does not cover the generator's offer ($100 per MWh). Generator B does not set the LMP because its economic minimum is higher than the relief needed to relieve the constraint. This solution is not acceptable for PJM because the most expensive generator would have to be made whole. In order to reduce energy uplift, PJM shows two alternatives. Solution 2: Artificially redefine the economic minimum of generator B to zero MW. Solution 3: Artificially redefine the limit of the transmission line to a level that would make the LMP higher at the bus where the most expensive generator is connected.

In solution 2, generator B is dispatched at 10 MW, despite the fact that this is physically impossible. This allows generator A to increase its output to 80 MW, which makes the transmission constraint binding and causes price separation between the two buses. This is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

In solution 3, the line limit is reduced from 80 MW to 40 MW, despite the fact that this is not the actual limit. As a result, generator A is dispatched to 40 MW (10 MW less than the original solution), the transmission line constraint is binding and congestion occurs. The goal is met and energy uplift is reduced to zero because the LMPs at both buses are increased so that they equal or exceed the generators' offers. Again, this is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

Attempting to reduce uplift at the expense of fundamental LMP logic is not consistent with the objective of clearing the market using a least cost approach. The result of PJM's price setting logic in this example is to increase total production costs.

The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift.

The MMU supports efforts to ensure that LMP reflects the appropriate marginal resource. The MMU recommends that if PJM believes it appropriate to modify the price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff.

Confidentiality of Energy Uplift Information

All data posted publicly by PJM or the MMU must comply with confidentiality rules. Prior to March 31, 2016, confidentiality rules did not allow posting data for three or fewer PJM participants and did not permit aggregation for a geographic area smaller than a control zone.[20]

Energy uplift charges are out of market, nontransparent payments made to resources operating at PJM's direction. Energy uplift charges are highly concentrated in a small number of zones and paid to a small number of PJM participants. These costs are not reflected in PJM market prices. Current confidentiality rules prevent the publication of detailed data concerning the reasons and locations of these payments, making it difficult for other participants to compete with the resources receiving energy uplift payments. Uplift charges are not included in the transmission planning process meaning that transmission solutions are not considered. The confidentiality rules were implemented in order to protect competition. The application of confidentiality rules in the case of energy uplift information does exactly the opposite. Energy uplift is not a market and

19 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: "Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software," in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

20 See PJM. Manual 33: Administrative Services for the PJM Interconnection Operating Agreement, Revision 12 (March 31, 2016) at "Market Data Postings".

the absence of relevant information creates a barrier to entry. The MMU recommends that PJM revise the current energy uplift confidentiality rules in order to allow the disclosure of energy uplift credits by zone, by owner and by resource. PJM partially adopted the MMU recommendation at the March 31, 2016, Markets and Reliability Committee (MRC).[21] PJM adopted a rule permitting the posting of energy uplift information by control zone, regardless of the number of PJM participants receiving energy uplift payments in that control zone.

Energy Uplift Recommendations

Recommendations for Calculation of Credits

Day-Ahead Operating Reserve Elimination

The only reason to pay energy uplift in the Day-Ahead Energy Market is that a day-ahead schedule could cause a unit to incur losses as a result of differences between the Day-Ahead and Balancing Markets. Units cannot incur losses in the Day-Ahead Energy Market. Units do not incur costs in the Day-Ahead Energy Market. There is no reason to pay energy uplift in the Day-Ahead Energy Market. All energy uplift should be paid in real time including energy uplift that results from differences between day-ahead and real-time schedules. Paying energy uplift in the Day-Ahead Energy Market results in overpayments.

Day-ahead operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not scheduled in the Day-Ahead Energy Market by PJM to operate at a loss in real time. Balancing operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not operated by PJM at a loss in real time. Units are paid day-ahead operating reserve credits whenever their total offer (including no load and startup costs and based on their day-ahead scheduled output) is not covered by the day-ahead energy revenues (day-ahead LMP times day-ahead scheduled output). Units are paid balancing operating reserve credits whenever their total offer (including no load and startup costs and based on their real-time output) are not covered by their day-ahead energy revenues, balancing energy revenues and a subset of net ancillary services revenues.[22]

Units scheduled in the Day-Ahead Energy Market do not operate until committed or dispatched in real time. Therefore, it cannot be determined if a unit was operated at a loss until the unit actually operates or does not operate. The current operating reserve rules governing the day-ahead operating reserve credits assume that units are going to operate exactly as scheduled because they are made whole based on their day-ahead scheduled output. A unit's real-time output may be greater or lower than their day-ahead scheduled output. Units dispatched in real time by PJM above their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by increasing their output they operate at a loss because their offers are greater than the real-time LMP. Units dispatched in real time by PJM below their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by decreasing their output the units operate at a loss or incur opportunity costs because real-time LMP is greater than the day-ahead LMP. The balancing operating reserve credits and lost opportunity costs credits ensure that units recover their total offers or keep their net revenues in real time.

Units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in additional losses, are paid energy uplift in the form of balancing operating reserve or lost opportunity cost credits to ensure that they do not operate at a loss. This determination is not symmetrical because units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in reduced losses or not loss do not have a reduction in energy uplift payments.

Units that follow PJM dispatch instructions are made whole through operating reserve credits to ensure that they do not operate at a loss. In order to determine if a unit operated at a loss, it needs to be committed or dispatched. The day-ahead scheduled output is one of PJM's dispatch instructions, but it does not determine if a unit actually operated at a loss. In order to determine

21 See the Markets and Reliability Committee (March 31, 2016) minutes <http://www.pjm.com/~/media/committees-groups/committees/mrc/20160418-special/20160418-item-01-draft-minutes-mrc.ashx>.

22 The balancing operating reserve credit calculation includes net DASR revenues, net synchronized reserve revenues, net nonsynchronized reserve revenues and reactive services revenues.

if a unit operated at a loss it is necessary to take into account the unit's real-time output and both the day-ahead and balancing energy revenues and ancillary services net revenues.

In order to properly compensate units, the MMU recommended enhancing the day-ahead operating reserve credits calculation to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their real time operation results in a lower loss or no loss at all. The MMU also recommended including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.[23] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[24] The elimination of day-ahead operating reserve payments also ensures that units are always made whole based on their actual operation and actual revenues.

The MMU calculated the impact of this recommendation for 2015 and 2016. In 2015 and 2016, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $38.1 million or 17.3 percent ($2.8 million paid to units providing reactive support, $0.9 million paid to units providing black start support and $34.5 million paid to units as day-ahead and balancing operating reserves).

The elimination of the day-ahead operating reserve category would change the allocation of such charges under the current energy uplift rules. If the day-ahead operating reserve category were eliminated but the MMU's uplift allocation recommendations were not implemented, units that clear the Day-Ahead Energy Market would be made whole through balancing operating reserve credits, which under the current rules are allocated to deviations or real-time load plus real-time exports. Therefore, this recommendation should be implemented concurrently with the MMU's allocation recommendations.

23 See *2013 State of the Market Report for PJM*, Volume II Section 4: "Energy Uplift," at "Day-Operating Reserve Credits," and at "Net DASR Revenues Offset" for an explanation of these recommendations.

24 PJM agrees with this recommendation. See "Explanation of PJM Proposals," from the Energy Market Uplift Senior Task Force (April 30, 2014). <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20140417/20140417-explanation-of-pjm-proposals.ashx>.

Net Regulation Revenues Offset

On October 1, 2008, PJM filed revisions to the Operating Agreement and Tariff with FERC related to the PJM Regulation Market. The filing included four elements: implement the TPS test in the PJM Regulation Market; increase the regulation offer adder from $7.50 per MW to $12.00 per MW; eliminate the use of net regulation revenues as an offset in the balancing operating reserve calculation; and calculate the lost opportunity cost on the lower of a unit's price-based or cost-based offer. The four elements were based on a settlement rather than a rational evaluation of an efficient market design.

The elimination of the use of net regulation revenues as an offset in the balancing operating reserve calculation had a direct impact on the level of energy uplift paid to participants that regulate while operating noneconomic. The result of not using the net regulation revenues as an offset in the balancing operating reserve credit calculation is that PJM does not accurately calculate whether a unit is running at a loss. PJM procures energy, regulation, synchronized and nonsynchronized reserves in a jointly optimized manner. PJM determines the mix of resources that could provide all of those services in a least-cost manner. Excluding the net regulation revenues from the balancing operating reserve credit calculation is inconsistent with the process used by PJM to procure these services and inconsistent with the basic PJM uplift logic. Whether a unit is running for PJM at a loss defined by marginal costs cannot be determined if some of the revenues are arbitrarily excluded.

Another issue related to this exclusion is the treatment of pool-scheduled units that elect to self-schedule a portion of their capacity for regulation. A unit can be pool-scheduled for energy, which means PJM may commit or dispatch the unit based on economics, but it can also self-schedule some of its capacity for regulation. When this happens the capacity self-scheduled for regulation is treated as a price taker, but in the energy market any increase in MW to provide regulation are treated as additional costs, which can result in increased balancing operating reserve credits whenever the real-time LMP is lower than the unit's offer. For example, if a unit raises its economic minimum in order to provide regulation and the additional costs resulting from operating at a higher economic minimum are not covered by the real-time LMP, the unit will be made whole for the additional costs through balancing operating reserve credits.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2015 and 2016, using net regulation revenues as an offset in the balancing operating reserve calculation would have resulted in a net decrease of balancing operating reserve charges of $8.4 million, of which $6.2 million or 74.3 percent was a result of generators that elected to self-schedule for regulation while being noneconomic in the energy market and receiving balancing operating reserve credits.[25]

Self Scheduled Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[26] Units offered as pool-scheduled clear the Day-Ahead Energy Market based on their offers and operate in real time following PJM dispatch instructions. Units offered as self-scheduled clear the Day-Ahead Energy Market regardless of their offers and may operate in real time following PJM dispatch instructions. Units offered as self-scheduled follow PJM dispatch instructions when they are offered with a minimum must run output from which the units may be dispatched up but not down. Self-scheduled units are not eligible to receive day-ahead or balancing operating reserve credits. The current rules determine if a unit is pool-scheduled or self-scheduled for operating reserve credits purposes separately for each hour using the hourly commitment status flag. If the flag is set as economic the unit is assumed to be pool-scheduled, if the flag is set as must run the unit is assumed to be self-scheduled. When a unit submits different flags within a day, the day-ahead operating reserve credit calculation treats each group of hours separately. The day-ahead operating reserve credit calculation only uses the hours flagged as economic and excludes any hours flagged as must run.

Units offered as self-scheduled for some hours of the day and pool-scheduled for the remaining hours are made whole for startup costs when they should not be. For example, if a unit is offered as self-scheduled for hours 10 through 24 and as pool-scheduled for the balance of the day and PJM selects the unit to start for hour nine, the unit will be made whole for its startup cost if the hourly revenues do not cover the costs. The only hour used in the day-ahead or balancing operating reserve credit calculation is hour nine because the unit is not eligible for operating reserve credits for hours 10 through 24. The result is that any net revenue from hours 10 through 24 will not be used to offset the unit's startup cost despite the fact that the unit would have started and incurred those costs regardless of PJM dispatch instructions.

The MMU recommends that self-scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.

Lost Opportunity Cost Calculation

The current energy LOC calculations are inaccurate and create unreasonable compensation. The MMU recommended four modifications, of which three were adopted on September 1, 2015.[27] [28] The one outstanding modification not adopted by PJM is the calculation of LOC using segments of hours. Current rules calculate LOC on an hourly basis; each hour is treated as a standalone calculation. This means that units receive an LOC payment during hours in which it is economic for them to run and receive the benefit of not being called on during hours in which it is not economic for them to run. PJM dispatchers might make the right decision to not call a unit in real time because the operation of the unit during all the hours in which the unit cleared the Day-Ahead Energy Market would not be economic, but the unit could still receive an LOC payment.

This is inconsistent with the basic PJM energy uplift logic. If a unit does not run in real time, it loses net revenues if the real-time LMP is greater than the unit's offer but it gains net revenues if the real-time LMP is lower than the unit's offer. The correct lost opportunity costs for units that clear the Day-Ahead Energy Market and are not committed in real time cannot be determined if profitable hours are arbitrarily excluded. In the case of separate hourly calculations, units are overcompensated

25 These estimates take into account the elimination of the day-ahead operating reserve category.
26 See "PJM eMkt Users Guide," Section Managing Unit Data (version July 9, 2015) p. 42. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

27 See *2015 State of the Market Report for PJM*, Volume II Section 4, "Energy Uplift," at "Lost Opportunity Cost Calculation" for an explanation of the adopted recommendations.
28 152 FERC ¶ 61,165 (2015)

compared to the net revenues they would have received had they run.

The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours for combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. This recommendation has not been adopted. The MMU calculated the impact of this recommendation 2016. In 2016, lost opportunity cost payments would have had been reduced by $2.7 million or 14.4 percent.

In addition to the initial four recommendations, the MMU recommends three additional steps to address issues with the current LOC calculations:

- **Achievable Output:** CTs and diesels are compensated for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. This LOC calculation uses the day-ahead scheduled output as the achievable output for which units are entitled to receive LOC compensation. Units are paid LOC based on the difference between the real-time energy price (RT LMP) and the unit's offer times the day-ahead scheduled output.

  The actual LOC is a function of the real-time desired and achievable output rather than the day-ahead scheduled output. If a unit is capable of profitably producing more or fewer MWh in real time than the day-ahead scheduled MWh, it is the actual foregone MWh in real time that define actual LOC. Also, if a unit is not capable of producing at the day-ahead scheduled output level in real time it should not be compensated based on an output that cannot be achieved.

  The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output.

- **Intra-Hour Calculations:** CTs and diesels scheduled in the Day-Ahead Energy Market and not committed in real time are compensated for LOC based on their real-time hourly integrated output. In order to compensate a unit for LOC, PJM must determine if the unit was scheduled in the Day-Ahead Energy Market and if the unit was not committed in real time. Units clear the Day-Ahead Energy Market for full hours. That means that if a unit cleared the Day-Ahead Energy Market in an hour it is expected to produce energy in real time for the entire hour. The determination by PJM of whether a unit is committed or not committed in real time is based on the unit's hourly integrated output. If the hourly integrated output is greater than zero that means the unit was committed during that hour. But in real time a unit may be committed for part of an hour. The calculation of LOC does not reflect the exact time at which the unit was turned on.

  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.

- **LOC Unit Type Eligibility:** The current rules compensate only CTs and diesels for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. The reason for this difference is that other unit types have a commitment obligation when scheduled in the Day-Ahead Energy Market. For example, steam turbines and combined cycle units commitment instructions are their day-ahead schedule. Units of these types that clear the Day-Ahead Energy Market are automatically committed to be on or remain on in real time. These units are eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment for reliability purposes. CT and diesel commitment instructions occur in real time even if these units were committed in the Day-Ahead Energy Market. CTs and diesels are committed in real time, after PJM dispatch has a more complete knowledge of real-time conditions. The goal is to permit the dispatch of flexible units in real time based on real-time conditions as they evolve. The reason for this special treatment of CTs and diesels is that historically, such units were usually more flexible to commit than other unit types. But that is no longer correct and should not be assumed to be correct.

  The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time.

Actual Cost Reimbursement

PJM Manual 11 (Energy and Ancillary Services Market Operations) Attachment C describes an after the fact cost recovery procedure that is not consistent with the PJM tariff. The MMU recommends that PJM revise Manual 11 Attachment C Procedure for Cost Reimbursement to be consistent with the PJM tariff. Manual 11 incorrectly states that the purpose of this procedure is to address "differences between cost-based offers and actually incurred costs for resettlement." The PJM tariff rules for compensation greater than LMP payments are covered by the OA Schedule 1 Section 3.2.3, which specifies that compensation shall be made based on the "applicable offer" or "offered price" and not based actually incurred costs which can be known only after the fact.

The MMU recommends that PJM revise Manual 11 consistent with the tariff to limit compensation to offered costs. The Manual 11 procedure should describe the steps market participants can take to change the availability of cost-based energy offers that have been submitted day ahead. This procedure only applies for units that have not been committed by PJM in the Day-Ahead Energy Market or in real time. This enables PJM dispatchers to select the most appropriate cost-based energy offer to set the LMP and possible uplift payments. The MMU recommends that PJM eliminate this procedure when hourly offers (ER16-372-000) are implemented as this rule was a short term solution for the absence of hourly offers.

Recommendations for Allocation of Charges

Up to Congestion Transactions

Up to congestion transactions do not pay energy uplift charges. An up to congestion transaction affects unit commitment and dispatch in the same way that increment offers and decrement bids affect unit commitment and dispatch in the Day-Ahead Energy Market. All such virtual transactions affect the results of the Day-Ahead Energy Market and contribute to energy uplift costs. Up to congestion transactions are currently receiving preferential treatment, relative to increment offers and decrement bids and other transactions because they are not charged energy uplift.

The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC.

The MMU calculated the impact on energy uplift rates if up to congestion transactions had paid energy uplift charges based on deviations in the same way that increment offers and decrement bids do along with other recommendations that impact the total costs of energy uplift and its allocation.

Up to congestion transactions would have paid an average rate between \$0.290 and \$0.295 per MWh in 2015 and between \$0.044 and \$0.055 per MWh in 2016 if the MMU's recommendations regarding energy uplift had been in place.[29] [30]

Internal Bilateral Transactions

Market participants are allocated a portion of the costs of balancing operating reserves based on their deviations. Deviations are calculated in three categories, demand, supply and generation. Generators deviate when their real-time output is different than the desired output or their day-ahead scheduled output.[31] Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids also incur deviations.

Generators are allowed to offset their deviations with other generators at the same bus if the generators have the same electrical impact on the transmission system For example, a generator with a negative deviation (generation below the desired level) can offset such deviation if a generator at the same bus has a positive deviation (generation above the desired level) if this occurs in the same hour.

Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids are also allowed to offset their deviations. These transactions are grouped by demand and supply,

29 The range of operating reserve rates paid by up to congestion transactions depends on the location of the transactions' source and sink.

30 This analysis assumes that not all costs associated with units providing support to the Con Edison – PJM Transmission Service Agreements would be reallocated under the MMU's proposal. The *2013 State of the Market Report for PJM* analysis assumed that all such costs would be reallocated. This analysis also assumes that only 50 percent of all cleared up to congestion transactions would have cleared had this recommendation been in place prior to September 8, 2014 and all cleared up to congestion transactions would have cleared after September 8, 2014. The *2013 State of the Market Report for PJM* analysis showed that more than 66.7 percent of up to congestion transactions would have remained under the MMU proposal.

31 See PJM. OATT 3.2.3 (o) for a complete description of how generators deviate.

and then aggregated by location. A negative deviation from one transaction can offset a positive deviation from another transaction in the same category, as long as both transactions are at the same location at the same hour.[32] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset. The same applies to supply transactions such as imports, internal bilateral purchases and increment offers. Unlike all other transaction types, internal bilateral sales and purchases do not impact dispatch or market prices. Internal bilateral transactions (IBTs) are used by participants to transfer the financial responsibility or right of the energy withdrawn or injected into the system in the Day-Ahead and Real-Time Energy Markets.

IBTs should not pay for balancing operating reserves and should not be used to offset other transactions that deviate. IBTs shift the responsibility for an injection or withdrawal in PJM from one participant to another but IBTs are not part of the day-ahead unit commitment process, do not set energy prices and do not impact the energy flows in either the Day-Ahead or the Real-Time Energy Market, and thus IBTs should not be considered in the allocation of balancing operating reserve charges. The use of IBTs has been extended to offset deviations from other transactions that do impact the energy market. The elimination of the use of IBTs in the deviation calculation would eliminate the balancing operating reserve charges to participants that use IBTs only in real time. Such elimination would increase the balancing operating reserve charges to participants that use IBTs to offset deviations from day-ahead transactions.

The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.

Day-Ahead Reliability Energy Uplift Allocation

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[33] The energy uplift paid to units scheduled for voltage is allocated to real-time load. The energy uplift associated with units scheduled for black start is allocated to real-time load and interchange reservations. The energy uplift paid to units scheduled because of local contingencies not modeled in the Day-Ahead Energy Market and scheduled because of their long lead times is allocated to day-ahead demand, day-ahead exports and decrement bids.

The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels.

Con Edison – PJM Transmission Service Agreements Support

It appears that certain units located near the boundary between New Jersey and New York City are frequently operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts.[34] These units are often run out of merit and receive substantial day-ahead and balancing operating reserve credits.

The MMU recommends that this issue be addressed by PJM in order to determine if the cost of running these units is being allocated properly.

Reactive Services Credits and Balancing Operating Reserve Credits

Energy uplift credits to resources providing reactive services are separate from balancing operating reserve credits.[35] Under the current rules regarding energy uplift credits for reactive services, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service

32 Locations can be control zones, hubs, aggregates and interfaces. See "Determinants and Deviation Categories" in this section for a description of balancing operating reserve locations.

33 See PJM. "Item 12 - October 2012 MIC DAM Cost Allocation," PJM presentation to the Market Implementation Committee (October 12, 2012).

34 See the *2016 State of the Market Report for PJM*, Volume II, Section 9, "Interchange Transactions" at " Consolidated Edison Company of New York, Inc. (Con Edison) Wheeling Contracts" for a description of the contracts and the PJM-NYISO proposed protocol after Con Edison announced its intent to terminate the contracts on April 28, 2016..

35 PJM. OATT Attachment K - Appendix § 3.2.3B (f).

credits. But when the reactive services credits do not cover a unit's entire offer, the unit is made whole for the balance through balancing operating reserves. The result is a misallocation of the costs of providing reactive services. Reactive services credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve charges are paid by deviations from day-ahead or real-time load plus exports in the RTO, Eastern or Western Region depending on the allocation process rather than by zone.

In 2016, units providing reactive services were paid $0.3 million in balancing operating reserve credits in order to cover their total energy offer. In 2015, this misallocation was $0.8 million.

The MMU recommends that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load.[36]

Allocation Proposal

The elimination of the day-ahead operating reserve category and other MMU recommendations require enhancements to the current method of energy uplift allocation.

The current method allocates day-ahead operating reserve charges to day-ahead load, day-ahead exports and decrement bids. The elimination of the day-ahead operating reserve category would shift these costs to the balancing operating reserve category which would be paid by deviations or by real-time load plus real-time exports depending on the balancing operating reserve allocation rules.

The MMU recommends creating a new category for energy uplift payments to units scheduled in the Day-Ahead Energy Market (for reasons other than reactive or black start services), which would be allocated to all day-ahead transactions and resources. All these transaction types have an impact on the outcome of the day-ahead scheduling process, so allocating these costs to all day-ahead transactions ensures that all transactions that affect the way the Day-Ahead Energy Market clears are responsible for any energy uplift credits paid to the units scheduled in the Day-Ahead Energy Market. Energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market (for reasons related to expected conditions in the real-time market not including reactive or black start services) should be allocated to real-time load, real-time exports and real-time wheels.

The MMU recommends allocating energy uplift payments to units not scheduled in the Day-Ahead Energy Market and committed in real time, but before the operating day, to the current deviation categories with the addition of up to congestion, wheels and units that clear the Day-Ahead Scheduling Reserve Market but do not perform.

The MMU recommends the exclusion of offsets based on internal bilateral transactions. These costs should be allocated to the current deviation categories whenever the units receiving energy uplift payments are committed before the operating day.

The MMU recommends allocating energy uplift payments to units committed during the operating day to a new deviation category which would include physical transactions or resources (day-ahead minus real-time load, day-ahead minus real-time interchange transactions, generators and DR not following dispatch). This allocation would ensure that commitment changes that occur during the operating day and that result in energy uplift payments are paid by transactions or resources affecting the commitment of units during the operating day. For example, real-time load or interchange transactions that do not bid in the Day-Ahead Energy Market, generators and DR resources that do not follow dispatch would be allocated these costs. Any reliability commitment should be allocated to real-time load, real-time exports and real-time wheels independently of the timing of the commitment.

The MMU recommends changing the allocation of lost opportunity cost and canceled resources. LOC paid to units scheduled in the Day-Ahead Energy Market and not committed in real time should be allocated to deviations based on the proposed definition of deviations. LOC paid

36 See the Day-Ahead Reliability and Reactive Cost Allocation Final Report (December 13, 2013) for a complete description of the issues discussed in that group. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02b-darrca-final-report.ashx>.

to units reduced for reliability in real time and payments to canceled resources should be allocated to real-time load, real-time exports and real-time wheels.

Table 4-35 shows the current allocation by energy uplift reason. For example, energy uplift payments to units scheduled in the Day-Ahead Energy Market are called day-ahead operating reserves, these costs are paid by day-ahead load, day-ahead exports and decrement bids. Any additional payment resulting from the real-time operation of these units are called balancing operating reserves, these costs are paid by either deviations or real-time load and real-time exports depending on the amount of intervals the units are economic.

Table 4-35 Current energy uplift allocation

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market	Day-Ahead Operating Reserve	NA	Day-Ahead Load, Day-Ahead Exports and Decrement Bids
Units scheduled in the Day-Ahead Energy Market	Balancing Operating Reserve	LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		LMP > Offer for at least four intervals	Deviations
Unit not scheduled in the Day-Ahead Energy Market and committed in real time	Balancing Operating Reserve	Committed before the operating day for reliability	Real-Time Load and Real-Time Exports
		Committed before the operating day to meet forecasted load and reserves	Deviations
		Committed during the operating day and LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		Committed during the operating day and LMP > Offer for at least four intervals	Deviations
Units scheduled in the Day-Ahead Energy Market not committed in real time	LOC Credit	NA	Deviations
Units reduced for reliability in real time	LOC Credit	NA	Deviations
Units canceled before coming online	Cancellation Credit	NA	Deviations

Table 4-36 shows the MMU allocation proposal by energy uplift reason. The proposal eliminates the day-ahead operating reserve category and creates a new category for any energy uplift payments to units scheduled in the Day-Ahead Energy Market and committed in real time. This new category would be allocated to day-ahead transactions and resources. The proposal also eliminates the need to determine the number of intervals that units are economic to determine if the energy uplift charge should be allocated to deviations or to real-time load and real-time exports. In the proposal, any commitment instruction before the operating day would be allocated based on the proposed definition of deviations; any commitment instruction during the operating day would be allocated to physical deviations.

Table 4-36 MMU energy uplift allocation proposal

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market and committed in real time	Day-Ahead Segment Make Whole Credit	Scheduled by the day ahead model (not must run)	Day-Ahead Transactions and Day-Ahead Resources
		Scheduled as must run in the day ahead model	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
Units not scheduled in the Day-Ahead Energy Market and committed in real time	Real Time Segment Make Whole Credit	Committed before the operating day	Deviations
		Committed during the operating day	Physical Deviations
		Any commitment for reliability	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
Units scheduled in the Day-Ahead Energy Market not committed in real time	Day-Ahead LOC	NA	Deviations
Units reduced for reliability in real time	Real-Time LOC	NA	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
Units canceled before coming online	Cancellation Credit	NA	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels

Quantifiable Recommendations Impact

Table 4-37 shows energy uplift charges based on the current allocation and energy uplift charges based on the MMU allocation proposal including the MMU recommendations regarding energy uplift credit calculations. Total charges (excluding black start and reactive services charges) would have been reduced by $67.8 million or 15.8 percent in 2015 and 2016 if three recommendations regarding energy uplift credit calculations proposed by the MMU had been implemented. The elimination of the day-ahead operating reserve credit would have resulted in a decrease of $34.5 million, the proposed changes to lost opportunity cost calculations would have resulted in a decrease of $23.9 million and the use of net regulation revenues offset would have resulted in a decrease of $8.4 million.[37] Table 4-37 shows that deviations charges would have been reduced by $126.0 million or 60.0 percent. The reason for this change is that, besides the reduction in the overall charges, under the MMU proposal, a subset of charges is reallocated to a new physical deviation category (based on the timing of the commitment of the resource being paid energy uplift) and another subset of charges is allocated to real-time load, real-time exports and real-time wheels (based on reliability actions).

Table 4-37 Current and proposed energy uplift charges by allocation (Millions): 2015 and 2016[38]

Allocation	2015	2016	Total
Current			
Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	$98.5	$57.3	$155.9
Real-Time Load and Real-Time Exports	$41.1	$23.0	$64.1
Deviations	$156.5	$53.6	$210.1
Total	$296.2	$133.9	$430.1
Proposal			
Day-Ahead Transactions and Day-Ahead Resources	$27.5	$10.7	$38.2
Real-Time Load and Real-Time Exports	$99.8	$44.5	$144.3
Deviations	$68.1	$16.0	$84.1
Physical Deviations	$51.0	$44.7	$95.7
Total	$246.5	$115.8	$362.3
Impact			
Impact ($)	($49.7)	($18.1)	($67.8)
Impact (%)	(16.8%)	(13.5%)	(15.8%)

The MMU calculated the rates that participants would have paid in 2015 and 2016 if all the MMU's recommendations on energy uplift had been in place. These recommendations have been included in the analysis: day-ahead operating reserve elimination; net regulation revenues offset; implementation of the proposed changes to lost opportunity cost calculations; reallocation of operating reserve credits paid to units scheduled as must run in the Day-Ahead Energy Market (for reasons other than reactive or black start services); reallocation of operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements; elimination of internal bilateral transactions from the deviations calculation; allocation of energy uplift charges to up to congestion transactions and the MMU energy uplift allocation proposal.

Table 4-38 shows the energy uplift cost of a 1 MW transaction if these recommendations had been implemented in 2015 and 2016. Table 4-38 assumes two scenarios under the MMU proposal. The first scenario assumes all the up to congestion transactions volume cleared. The second scenario assumes zero volume of up to congestion transactions in 2015 and 2016, in this scenario, the cost reflects the expected cost for the first 1 MWh cleared up to congestion transaction. Table 4-38 shows for example that a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.147 and $0.027 per MWh in the 2015 and 2016, under the first scenario, $1.026 and $0.391 per MWh less than the actual average rate paid. Up to congestion transactions sourced in the Eastern Region and sinking in the Western Region would have paid an average rate of $0.292 and $0.049 per MWh in 2015 and 2016 under the first scenario. Table 4-38 shows the current and proposed averages energy uplift rates for all transactions.

37 The total impact of the elimination of the day-ahead operating reserve credit and the impact of net regulation revenues offset is greater because they also impact black start and reactive services charges.

38 These energy uplift charges do not include black start and reactive services charges.

Table 4-38 Current and proposed average energy uplift rate by transaction: 2015 and 2016[39]

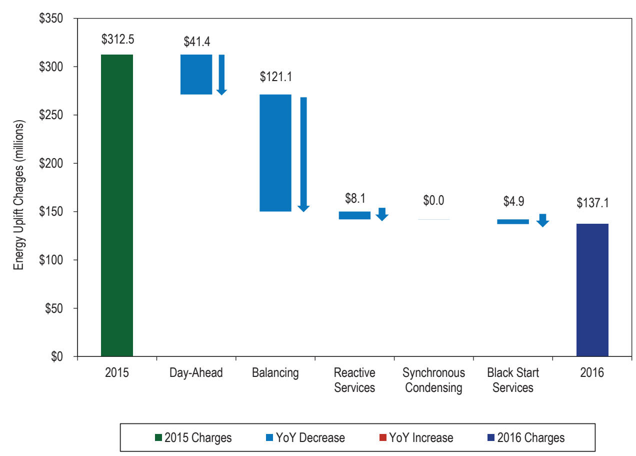
		2015			2016		
Transaction		Current Rates ($/MWh)	Proposed Rates - 100% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)	Current Rates ($/MWh)	Proposed Rates - 100% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)
East	INC	1.058	0.147	0.376	0.347	0.027	0.093
	DEC	1.174	0.147	0.376	0.418	0.027	0.093
	DA Load	0.115	0.013	0.015	0.071	0.004	0.006
	RT Load	0.050	0.118	0.118	0.031	0.058	0.058
	Deviation	1.058	0.497	0.723	0.347	0.387	0.451
West	INC	1.023	0.145	0.376	0.302	0.022	0.078
	DEC	1.138	0.145	0.376	0.372	0.022	0.078
	DA Load	0.115	0.013	0.015	0.071	0.004	0.006
	RT Load	0.042	0.118	0.118	0.023	0.058	0.058
	Deviation	1.023	0.429	0.659	0.302	0.312	0.366
UTC	East to East	NA	0.295	0.751	NA	0.055	0.186
	West to West	NA	0.290	0.752	NA	0.044	0.156
	East to/from West	NA	0.292	0.752	NA	0.049	0.171

Year over Year Energy Uplift Charges Analysis

Energy uplift charges decreased by $175.4 million (56.1 percent), from $312.5 million in 2015 to $137.1 million in 2016. This change resulted mainly from a decrease of $121.1 million in balancing operating reserve charges and $41.4 million in day-ahead operating reserve charges. Other categories had smaller changes. Reactive services charges decreased by $8.1 million. Synchronous condensing and black start services charges together decreased by $4.9 million.

Figure 4-8 shows the net impact of each category on the change in total energy uplift charges from the 2015 level to the 2016 level. The outside bars show the total energy uplift charges in 2015 (left side) and total energy uplift charges in 2016 (right side). The other bars show the change in each energy uplift category. For example, the second bar from the left shows the change in day-ahead operating reserve charges in 2015 compared to 2016 (a decrease of $41.4 million).

Figure 4-8 Energy uplift charges change from 2015 to 2016 by category



39 The deviation transaction means load, interchange transactions, generators and DR deviations.

Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for 2016, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

Table 5-1 The capacity market results were competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2]
- 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 competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters and the inclusion of imports which are not substitutes for internal capacity resources.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[6] Also effective for the 2012/2013 Delivery Year, a Conditional

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.

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.

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

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

6 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[7]

The 2017/2018 RPM Second Incremental Auction and the 2018/2019 RPM First Incremental Auction were conducted in the third quarter of 2016.

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[8] For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for the 2016/2017 and 2017/2018 Delivery Years. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[9] Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant Delivery Year, the existing commitment was converted to a CP commitment which is subject to the CP performance requirements and Non-Performance Charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.

RPM prices are locational and may vary depending on transmission constraints.[10] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit 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. Demand Resources and Energy Efficiency Resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During 2016, PJM installed capacity increased 4,766.3 MW or 2.7 percent, from 177,682.8 MW on January 1 to 182,449.1 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2016, 36.5 percent was coal; 35.7 percent was gas; 18.1 percent was nuclear; 3.7 percent was oil; 4.9 percent was hydroelectric; 0.6 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Supply.** Total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year decreased 3,709.2 MW from 204,557.3 MW on June 1, 2015, to 200,848.1 MW on June 1, 2016. This decrease was the result of the integration of the East

7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 See Docket No. ER15-623-000 (December 12, 2014) and 151 FERC ¶ 61,208 (2015).
9 See "PJM Manual 18: PJM Capacity Market," Revision 36 (December 22, 2017) at 8.
10 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

Kentucky Power Cooperative (EKPC) Zone resources (2,735.7 MW), new generation (5,517.4 MW), reactivated generation (751.8 MW), net generation capacity modifications (cap mods) (-3,373.3 MW), Demand Resource (DR) modifications (-10,690.1 MW), Energy Efficiency (EE) modifications (262.5 MW), the EFORd effect due to lower sell offer EFORds (1,039.0 MW), and higher load management UCAP conversion factor (47.8 MW).

- **Demand.** There was a 3,148.1 MW increase in the RPM reliability requirement from 177,184.1 MW on June 1, 2015, to 180,332.2 MW on June 1, 2016. The 3,148.1 MW increase in the RTO Reliability Requirement was a result of a 2,436.8 MW increase in the forecast peak load in UCAP terms holding the Forecast Pool Requirement (FPR) constant at the 2015/2016 level and a 711.3 MW increase attributable to the change in FPR. On June 1, 2016, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 67.8 percent, up from 65.1 percent on June 1, 2015.
- **Market Concentration.** In the 2016/2017 RPM Base Residual Auction, 2016/2017 RPM First Incremental Auction, 2016/2017 RPM Second Incremental Auction, 2016/2017 RPM Third Incremental Auction, 2017/2018 RPM Base Residual Auction, 2017/2018 RPM First Incremental Auction, 2017/2018 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2018/2019 RPM First Incremental Auction, and the 2019/2020 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[11] The TPS test was not applied in the 2016/2017 Capacity Performance (CP) Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. All offers in the CP Transition Auctions were subject to overall offer caps. Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[12 13 14]
- **Imports and Exports.** Of the 4,343.4 MW of imports in the 2019/2020 RPM Base Residual Auction, 3,875.9 MW cleared. Of the cleared imports, 1,828.6 MW (47.2 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,248.9 MW for June 1, 2016, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2016/2017 Delivery Year (14,988.5 MW) less replacement capacity from sources other than Demand Resources and Energy Efficiency (4,739.6 MW).

Market Conduct

- **2016/2017 RPM Base Residual Auction.** Of the 1,199 generation resources which submitted offers, unit-specific offer caps were calculated for 152 generation resources (12.7 percent). The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM First Incremental Auction.** Of the 115 generation resources which submitted offers, unit-specific offer caps were calculated for 37 generation resources (32.2 percent). The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM Second Incremental Auction.** Of the 101 generation resources that submitted offers, the MMU calculated offer caps for 45 generation resources (44.6 percent), of which 21 were based on the technology specific default (proxy) ACR values and 24 were unit-specific offer caps (23.8 percent).
- **2016/2017 Capacity Performance Transition Incremental Auction.** All 709 generation resources which submitted offers in the 2016/2017 CP

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

12 See PJM. OATT Attachment DD § 6.5.

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

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

Transition Incremental Auction were subject to an offer cap of $165.27 per MW-day, which is 50 percent of the Net Cost of New Entry (CONE) used in the 2016/2017 RPM Base Residual Auction.

- **2016/2017 RPM Third Incremental Auction.** Of the 296 generation resources that submitted offers, the MMU calculated offer caps for 52 generation resources (17.6 percent), of which 35 were based on the technology specific default (proxy) ACR values and 17 were unit-specific offer caps (5.7 percent).
- **2017/2018 RPM Base Residual Auction.** Of the 1,202 generation resources which submitted offers, unit-specific offer caps were calculated for 131 generation resources (10.9 percent). The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values.
- **2017/2018 Capacity Performance Transition Incremental Auction.** All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is 60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.
- **2017/2018 RPM First Incremental Auction.** Of the 118 generation resources that submitted offers, the MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 were based on the technology specific default (proxy) ACR values and 17 were unit-specific offer caps (14.4 percent).
- **2017/2018 RPM Second Incremental Auction.** Of the 95 generation resources that submitted offers, the MMU calculated offer caps for 35 generation resources (36.8 percent), of which 15 (15.8 percent) were based on the technology specific default (proxy) ACR values and 20 (21.1 percent) were unit-specific offer caps.
- **2018/2019 RPM Base Residual Auction.** Of the 473 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 (35.1 percent) were based on the technology specific default (proxy) ACR values and 53 were unit-specific offer caps (11.2 percent). Of the 992 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 35 generation resources (3.5 percent).
- **2018/2019 RPM First Incremental Auction.** Of the 80 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 (22.5 percent) were based on the technology specific default (proxy) ACR values and 12 (15.0 percent) were unit-specific offer caps. Of the 293 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for nine generation resources (3.1 percent).
- **2019/2020 RPM Base Residual Auction.** Of the 505 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 (33.9 percent) were based on the technology specific default (proxy) ACR values and 41 were unit-specific offer caps (8.1 percent). Of the 1,003 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 25 generation resources (2.5 percent).

Market Performance

- The 2016/2017 RPM Third Incremental Auction, 2019/2020 RPM Base Residual Auction, the 2017/2018 RPM Second Incremental Auction, and 2018/2019 RPM First Incremental Auction were conducted in 2016. The weighted average capacity price for the 2017/2018 Delivery Year is $141.93 per MW-day, including all RPM Auctions for the 2017/2018 Delivery Year held through 2016. The weighted average capacity price for the 2018/2019 Delivery Year is $177.38, including all RPM Auctions for the 2018/2019 Delivery Year held through 2016. The weighted average capacity price for the 2019/2020 Delivery Year is $114.30, including all RPM Auctions for the 2019/2020 Delivery Year held through 2016. RPM net excess increased 1,329.5 MW from 5,855.9 MW on June 1, 2015, to 7,185.4 MW on June 1, 2016.
- For the 2016/2017 Delivery Year, RPM annual charges to load are $7.7 billion.
- The delivery year weighted average capacity price was $160.01 per MW-day in 2015/2016 and $121.84 per MW-day in 2016/2017.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2016 was 6.3 percent, a decrease from 7.0 percent for 2015.[15]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2016 was 83.4 percent, a decrease from 83.6 percent for 2015.
- **Outages Deemed Outside Management Control (OMC).** In 2016, 4.0 percent of forced outages were classified as OMC outages, a decrease from 4.2 percent in 2015.

Recommendations[16]

The MMU recognizes that PJM has implemented the Capacity Performance Construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance Construct addresses many of the MMU's recommendations. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[17]

- The MMU recommends the extension of minimum offer price rule (MOPR) to all existing and proposed units in order to protect competition in the capacity market from external subsidies. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[18] [19] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- 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 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 the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[20] [21] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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, 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

15 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data was downloaded from the PJM GADS database on January 28, 2016. 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 *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (June 9, 2015).

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

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

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

21 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

of modeling assumptions.[22] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends two changes to the RPM solution methodology related to make whole payments and the iterative reconfiguration of the VRR curve:
  - The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends the following changes with respect to capacity imports into PJM:
  - 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 as close to full substitutes for internal, physical capacity resources as possible. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported Q1, 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 improvements to the performance incentive requirements of RPM:
- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted. Pending before FERC.)
- The MMU recommends that retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported Q3, 2016. Status: Not adopted.)
- The MMU recommends that treatment of costs in RMR filings be emphasized. Customers should bear all 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. Generation owners should bear all other costs. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. (Priority: Medium. First reported 2016. 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 but did not when EE was first added to the capacity market. 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 if PJM releases capacity in Incremental Auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sale price is not the BRA clearing price, PJM should not reveal its proposed sale price. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the requirement for First and Second Incremental Auctions and hold such auctions only if required based on increases in the Reliability Requirement above defined thresholds. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the notification requirement for deactivations be extended from 90

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).

days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)

- The MMU recommends 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 they need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)
- 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 2013. Status: Adopted 2015.)
- The MMU recommends that the definition of demand side resources be modified in order 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. Status: Adopted 2015.)
- The MMU recommends that all capacity imports have firm transmission to the PJM border acquired prior to offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- 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. Status: Adopted 2015.)
- 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.[23] (Priority: Medium. First reported 2013. Status: Adopted 2015.)

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.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in 2016. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM capacity market results were competitive in 2016.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations

23 See OATT Attachment DD § 10(e). For more on this issue and related incentive issues, see the MMU's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "Capacity in the PJM Market," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

to address those issues.[24 25 26 27 28] In 2015 and 2016, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2. The capacity performance modifications to the RPM construct have significantly improved the capacity market and addressed many of the issues identified by the MMU. The MMU will publish more detailed reports on the CP Transition Incremental Auctions which include more specific issues and suggestions for improvements.

The issue of external subsidies emerged more fully in 2016. The subsidies are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings and the Illinois ZEC subsidy proceeding all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market based mechanisms available to all market participants on a competitive basis and without discrimination.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies. Fortunately, this can be accomplished quickly by expanding the coverage of an existing rule that already reflects stakeholder compromises.

PJM markets have no protection against this emergent threat. Accurate signals for entry and exit are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions. The current MOPR only addresses subsidies for new entry. The current subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources. The MOPR should be expanded to address subsidies for existing units, and this should be done expeditiously. This issue will not become moot unless and until the MOPR is reformed. Action is needed to correct the MOPR immediately. An existing unit MOPR is the best means to defend the PJM markets from the threat posed by subsidies intended to forestall retirement of financially distressed assets. The role of subsidies to renewables should also be clearly defined and be incorporated in this rule.

While the existing unit MOPR would protect markets in the short run, the underlying issues that have resulted in the pressure on markets should also be examined. Unit owners are seeking subsidies because gas prices are low resulting in low energy market margins and because flaws in the PJM capacity design have led to very substantial price suppression over the past 10 years.

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

24 See "Analysis of the 2016/2017 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_20162017_RPM_Base_Residual_Auction_20140418.pdf> (April 18, 2014).

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

26 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).

27 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).

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

should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

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

Table 5-2 RPM related MMU reports, 2015 through 2016

Date	Name
January 14, 2015	IMM Comments re Capacity Performance Docket Nos. EL15-738-000 and EL15-739-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_EL15-738-000_EL15-739-000_20150114.pdf
January 20, 2015	IMM Comments re Capacity Performance Docket No. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_ER15-623-000_EL15-29-000_20150120.pdf
January 29, 2015	IMM Protest re IMEA Waiver Docket No. ER15-834-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Protest_Docket_No_ER15-834-000_20150129.pdf
January 30, 2015	IMM Answer and Motion for Leave to Answer re Calpine Waiver Docket No. ER15-376-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Docket_No_ER15-376-000_20150130.pdf
February 13, 2015	Comments of the Independent Market Monitor for PJM re DR in RPM Docket No. ER15-852-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_ER15-852-000_20150213.pdf
February 22, 2015	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2015/2016, 2016/2017 and 2017/2018 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20150222.pdf
February 25, 2015	IMM Answer and Motion for Leave to Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000, Not Consolidated http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Docket_Nos_ER15-623-000_EL15-29-000_20150225.pdf
February 27, 2015	IMM Answer and Motion for Leave to Answer Errata re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000, Not Consolidated http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Errata_Docket_Nos_ER15-623-000_EL15-29-000_20150227.pdf
March 6, 2015	IMM Comments re Champion Energy Complaint Docket No. EL15-46-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_EL15-46-000_20150306.pdf
March 20, 2015	IMM Answer and Motion for Leave to Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_ER15-623-000_EL15-29-000_20150320.pdf
March 25, 2015	IMM Protest re IMEA Waiver Docket No. ER15-1232-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Protest_Docket_No_ER15-1232-000_20150325.pdf
March 26, 2015	IMM Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_to_Answer_Docket_Nos_ER15-623-000_EL15-29-000_20150326.pdf
April 15, 2015	IMM Comments re Capacity Performance Docket Nos. ER15-623-001 and ER15-1470-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_Nos_ER15-623-001_ER15-1470-000_20150415.pdf
June 30, 2015	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2016/2017, 2017/2018 and 2018/2019 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20150630.pdf
July 6, 2015	IMM Limited Request for Rehearing re Capacity Performance Docket Nos. ER15-623-000, -001 and El15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Limited_Request_for_Rehearing_Docket_Nos_ER15-623-000_001_and_20EL15-29-000_20150706.pdf
July 8, 2015	Intermittent Resources Capacity Performance Value Methodology http://www.monitoringanalytics.com/reports/Market_Messages/Messages/Intermittent_Resources_Capacity_Performance_Value_Methodology_20150708.pdf
July 20, 2015	IMM Comments re Capacity Performance Docket Nos. ER15-623-004 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_Nos_ER15-623-004_EL15-29-000_20150720.pdf
July 31,2015	IMM Answer and Motion for Leave to Answer Request for Rehearing re Capacity Performance Docket Nos. ER15-623-000, -001 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Request_for_Rehearing_Docket_No_ER15-623-000_001_EL15-29-000_20150731.pdf
September 11, 2015	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2016/2017, 2017/2018 and 2018/2019 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20150911.pdf
November 4, 2015	IMM Comments re MISO Resources Docket Nos. EL15-70-000, EL15-71-000, EL15-72-000 and EL15-82-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_Nos_EL15-70-000_EL15-71-000_EL15-72-000_EL15-82-000_20151104.pdf
November 18, 2015	External Capacity: Pseudo Ties http://www.monitoringanalytics.com/reports/Presentations/2015/IMM_PJM_MISO_JCM_External_Capacity_Pseudo_Ties_20151118.pdf
November 30, 2015	IMM Comments re AEP Waiver Request Docket No. ER16-298-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_ER16-298-000_20151130.pdf
December 2, 2015	IMM Answer re AMEA Protest Docket No. ER15-623-000,-008 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_Docket_No_ER15-623-000_008_201512-2.pdf
December 23, 2015	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2016/2017, 2017/2018 and 2018/2019 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20151223.pdf
December 28, 2015	IMM First Supplemental Testimony of Joseph E. Bowring on Behalf of the Independent Market Monitor for PJM re AEP Ohio Case Nos. 14-1693 EL-RDR and 14-1694 EL-AAM http://www.monitoringanalytics.com/reports/Reports/2015/IMM_First_Supplemental_Testimony_AEP_Case_Nos_14-1693_14-1694_20151228.pdf
December 30, 2015	IMM First Supplemental Testimony of Joseph E. Bowring on Behalf of the Independent Market Monitor for PJM re FE Case No. 14-1297 EL-SSO http://www.monitoringanalytics.com/reports/Reports/2015/IMM_First_Supplemental_Testimony_of_Joseph_E_Bowring_14-1297_20151230.pdf
January 13, 2016	IMM Response re Capacity Performance Docket No. ER15-623-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Response_ER15-623-000_20160113.pdf
February 1, 2016	IMM Post-Hearing Brief re AEP Ohio Case Nos. 14-1693 EL-RDR and 14-1694 EL-AAM http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Brief_Case_No_14-1693_and_14-1694_20160201.pdf
February 8, 2016	IMM Post-Hearing Reply Brief re AEP Ohio Case Nos. 14-1693-EL-RDR and 14-1694-EL-AAM http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Reply_Brief_Case_No_14-1693-14-1694_20160208.pdf
February 11, 2016	PJM IMM Joint Statement re Capacity Performance Docket Nos. ER15-623-000, -004 and EL15-29-000, and -003 http://www.monitoringanalytics.com/reports/Reports/2016/PJM_IMM_Joint_Statement_Docket_Nos_ER15-623-000_004_EL15-29-000_003_20160211.pdf
February 16, 2016	IMM Post-Hearing Brief re FE Ohio Case No. 14-1297-EL-SSO http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Brief_Case_No_14-1297_20160216.pdf

Table 5-2 RPM related MMU reports, 2015 through 2016 (continued)

Date	Name
February 24, 2016	IMM Comments re DR CBL Testing http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_Nos_ER16-873_20160223.pdf
February 25, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2016/2017, 2017/2018 and 2018/2019 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20160225.pdf
February 26, 2016	IMM Post-Hearing Reply Brief re FE Ohio Case No. 14-1297-EL-SSO http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Reply_Brief_Case_No_14-1297-EL-SSO_20160226.pdf
March 22, 2016	IMM Answer re DR CBL Docket No. ER16-873-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_ER16-873-000_20160322.pdf
March 28, 2016	IMM Motion for Clarification or Rehearing re Net Revenue Docket No. EL14-94-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Request_for_Rehearing_EL14-94-000_20160328.pdf
April 11, 2016	IMM Comments re Calpine MOPR Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_No_EL16-49-000_20160411.pdf
April 22, 2016	IMM Comments re Ramp Rate Capacity Performance Docket No. ER16-1336-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_No_ER16-1336_20160422.pdf
April 28, 2016	IMM Answer re Calpine Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_EL16-49-000_20160428.pdf
May 4, 2016	New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019 http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf
May 9, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20160509.pdf
May 11, 2016	IMM Answer re Capacity Performance PAH Ramp Rate Docket No. ER16-1336-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_ER16-1336-000_20160511.pdf
June 13, 2016	IMM Answer and Motion for Leave to Answer re Calpine MOPR Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_EL16-49-000_20160613.pdf
June 24, 2016	IMM Answer to IMEA RFR Docket No. ER15-623-010, EL15-29-006 and EL15-41-002 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_Nos_ER15-623-010_EL15-29-006_EL15-41-002_20160624.pdf
July 6, 2016	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 7, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20160707.pdf
July 13, 2016	New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019 ppt http://www.monitoringanalytics.com/reports/Presentations/2016/IMM_MIC_New_Generation_in_the_PJM_Capacity_Market_for_Delivery_Years_20072008_through_20182019_PPT_20160706.pdf
July 13, 2016	New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019 http://www.monitoringanalytics.com/reports/Presentations/2016/IMM_MIC_New_Generation_in_the_PJM_Capacity_Market_for_Delivery_Years_20072008_through_20182019_20160706.pdf
August 26, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20160826.pdf
August 31, 2016	Analysis of the 2019/2020 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf
September 14, 2016	Capacity Release Proposal http://www.monitoringanalytics.com/reports/Presentations/2016/IMM_MIC_Capacity_Release_Proposal_20160914.pdf
November 22, 2016	IMM Complaint re Manual 18 Revisions Docket No. EL17-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Complaint_Docket_No_EL17-_20161122.pdf
December 8, 2016	IMM Comments re CP Aggregate Rules Docket No. ER17-367-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_No_ER17-367-000_20161208.pdf
December 22, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20161222.pdf
December 22, 2016	IMM Notice of Withdrawal re PJM Manual 18 Complaint Docket No. EL17-23-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Notice_of_Withdrawal_Docket_No_EL17-23_20161222.pdf
December 27, 2016	IMM Analysis of Replacement Capacity for RPM Commitments: June 01, 2007 to June 01, 2016 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf
December 30, 2016	IMM Motion to Lodge and for Commencement of Compliance Process re RPM Revisions Docket No. ER14-1461-000, -001 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Motion_to_Lodge_Docket_No_ER14-1461_20161230.pdf

Installed Capacity

On January 1, 2016, PJM installed capacity was 177,682.8 MW (Table 5-3).[29] Over the next twelve months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 182,449.1 MW on December 31, 2016, an increase of 4,766.3 MW or 2.7 percent from the January 1 level.[30 31] The 4,766.3 MW increase was the result of capacity modifications (421.2 MW), new or reactivated generation (5,421.4 MW), and an increase in imports (518.6 MW), offset by deactivations (706.0 MW), derates (197.7 MW), and an increase in exports (691.2 MW).

29 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.

30 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM Auctions.

31 Wind resources accounted for 1,019.1 MW, and solar resources accounted for 262.3 MW of installed capacity in PJM on December 31, 2016. PJM administratively reduces the capabilities of all wind generators to 13 percent and solar generators to 38 percent 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," Revision 12 (January 1, 2017) at 19.

At the beginning of the new delivery year on June 1, 2016, PJM installed capacity was 182,061.4 MW, an increase of 2,194.4 MW or 1.2 percent from the May 31 level.

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2016, as well as the expected installed capacity for the next three delivery years, based on the results of all auctions held through December 31, 2016.[32] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 36.6 percent on June 1, 2016 and is projected to decrease to 29.0 percent by June 1, 2019. The share of gas increased from 29.1 percent in 2007 to 35.6 percent in 2016, and is projected to increase to 45.8 percent in 2019.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2016

	1-Jan-16		31-May-16		1-Jun-16		31-Dec-16	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,674.8	37.5%	66,429.7	36.9%	66,619.9	36.6%	66,622.2	36.5%
Gas	60,487.4	34.0%	62,805.9	34.9%	64,721.7	35.5%	65,110.3	35.7%
Hydroelectric	8,787.5	4.9%	8,854.8	4.9%	8,850.4	4.9%	8,850.4	4.9%
Nuclear	33,071.5	18.6%	33,175.5	18.4%	33,050.6	18.2%	33,043.4	18.1%
Oil	6,851.8	3.9%	6,787.2	3.8%	6,779.8	3.7%	6,772.0	3.7%
Solar	128.0	0.1%	128.0	0.1%	252.4	0.1%	262.3	0.1%
Solid waste	769.4	0.4%	767.5	0.4%	767.5	0.4%	769.4	0.4%
Wind	912.4	0.5%	918.4	0.5%	1,019.1	0.6%	1,019.1	0.6%
Total	177,682.8	100.0%	179,867.0	100.0%	182,061.4	100.0%	182,449.1	100.0%

Figure 5-1 Percent of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2019

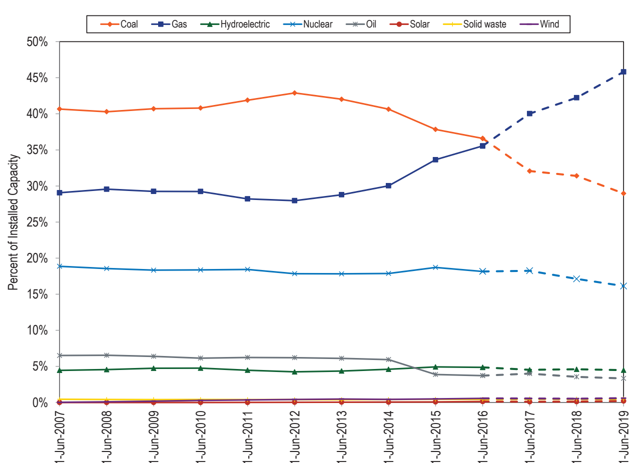


Figure 5-2 shows the fuel diversity index (FDI_c) for PJM installed capacity.[33]

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.[34] 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.[35] The FDI_c increased on average 0.1 percent from 2015 to 2016.

The FDI_c was used to measure the impact of potential retirements of coal and nuclear generators. The dotted line in Figure 5-2 shows the FDI_c calculated assuming that 3,000 MW of coal capacity and 3,000 MW of nuclear capacity were replaced by gas capacity in 2016. The FDI_c under the coal and nuclear retirement assumptions would have decreased the 2016 FDI_c by 0.9 percent.

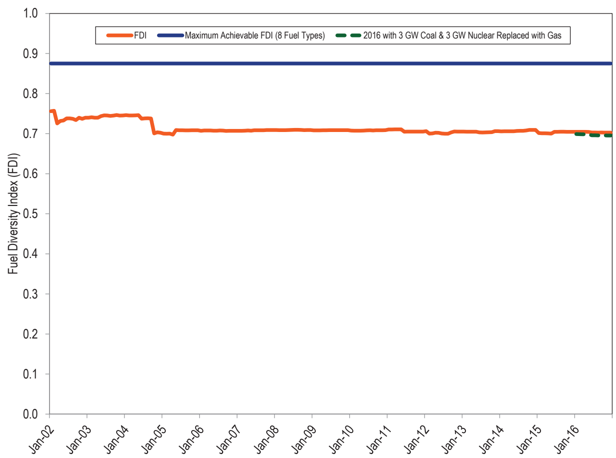
32 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

33 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.

34 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.

35 See the *2016 State of the Market Report for PJM*, Volume II, 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.

Figure 5-2 Fuel Diversity Index for PJM installed capacity (January 1, 2002 – January 1, 2017)



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.[36] In 2016, the 2016/2017 RPM Third Incremental Auction, 2019/2020 RPM Base Residual Auction, 2017/2018 RPM Second Incremental Auction, and 2018/2019 RPM First Incremental Auction were conducted.

Market Structure

Supply

Table 5-4 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2015/2016 Delivery Year. The 18,402.0 MW increase was the result of new generation capacity resources (15,284.9 MW), reactivated generation capacity resources (430.0 MW), uprates (5,510.3 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (5,998.3 MW), a net decrease in capacity exports (2,261.9 MW), offset by deactivations (26,122.3 MW) and derates (3,070.1 MW).

As shown in Table 5-5, total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year decreased 3,709.2 MW from 204,557.3 MW on June 1, 2015, to 200,848.1 MW on June 1, 2016. This increase was the result of the integration of the East Kentucky Power Cooperative (EKPC) Zone resources (2,735.7 MW), new generation (5,517.4 MW), reactivated generation (751.8 MW), net generation capacity modifications (cap mods) (-3,373.3 MW), Demand Resource (DR) modifications (-10,690.1 MW), Energy Efficiency (EE) modifications (262.5 MW), the EFORd effect due to lower sell offer EFORds (1,039.0 MW), and higher load management UCAP conversion factor (47.8 MW). The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2017/2018, 2018/2019, and 2019/2020 auctions, new generation were 15,353.3 MW; reactivated generation were 1,025.7 MW and net generation cap mods were -12,179.0 MW. DR and Energy Efficiency (EE) modifications totaled -2,698.7 MW through June 1, 2019. A decrease of 2,967.0 MW was due to lower EFORds, and an increase of 683.1 MW was due to a higher Load Management UCAP conversion factor. The net effect from June 1, 2016, through June 1, 2019, was a decrease in total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year of 782.6 MW (0.4 percent) from 200,848.1 MW to 200,065.5 MW.

As shown in Table 5-5 and Table 5-13, in the 2016/2017 auction, the 99 additional generation resources offered consisted of 36 new resources (4,900.8 MW), 29 additional resources imported (3,026.3 MW), 18 East Kentucky Power Cooperative (EKPC) integration resources not offered in the 2015/2016 BRA (2,537.3 MW), nine resources that were excused and not offered in the 2015/2016 BRA (1,033.9 MW), three repowered resources (920.2 MW), two resources that were previously entirely FRR committed (168.3 MW), one reactivated resource (17.6 MW), and one additional resource resulting from the disaggregation of an RPM resource. The 36 new Generation Capacity Resources consisted of 11 diesel resources (36.1 MW), nine solar resources (32.1

36 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

MW), eight combined cycle resources (4,597.2 MW), five wind resources (54.3 MW), two CT resources (159.3 MW), and one steam unit (21.8 MW). In addition, there were new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2016/2017 Delivery Year: one wind resource (12.8 MW) and one diesel resource (5.3 MW). The 68 fewer generation resources offered consisted of 33 additional resources excused from offering (1,706.0 MW), 28 deactivated resources (1,389.6 MW), three fewer resources resulting from aggregation of RPM resources, two additional resources committed fully to FRR (28.7 MW), and two Planned Generation Capacity Resources not offered (934.8 MW). In addition, there were the following retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2015/2016 BRA: 25 steam units (2,207.1 MW) and 13 CT resources (245.0 MW).

As shown in Table 5-5 and Table 5-14, in the 2017/2018 auction the 51 additional generation resources offered consisted of 32 new resources (5,103.3 MW), six repowered resources (941.6 MW), four resources that were excused and not offered in the 2016/2017 BRA (384.6 MW), three additional resources imported (714.1 MW), three resources that were previously entirely FRR committed (164.0 MW), two additional resources resulting from the disaggregation of RPM resources, and one reactivated resource (84.1 MW). The 32 new Generation Capacity Resources consisted of 15 solar resources (27.0 MW), nine diesel resources (122.5 MW), six combined cycle resources (4,825.4 MW), one CT resource (122.7 MW), and one hydro resource (5.7 MW). In addition, there were new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2017/2018 Delivery Year: one wind resource (26.0 MW). The 48 fewer generation resources offered consisted of 21 external resources not offered (2,630.4 MW), 18 deactivated resources (3,018.7 MW), three Planned Generation Capacity Resources not offered (1,171.7 MW), three resources excused from offering for reasons other than retirement (554.9 MW), two additional resources committed fully to FRR (168.3MW), and one resource that is no longer a PJM capacity resource (1.7 MW). In addition, there were retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2016/2017 BRA: 24 CT resources (964.4 MW) and 21 steam resources (2,716.2 MW).

As shown in Table 5-5 and Table 5-15, in the 2018/2019 auction the 36 additional generation resources offered consisted of 28 new resources (3,447.4 MW), six additional resources imported (483.2 MW), and two resources that were previously entirely FRR committed (2.9 MW). The 28 new Generation Capacity Resources consisted of 11 solar resources (82.8 MW), six wind resources (127.1 MW), four combined cycle resources (2,257.8 MW), four CT resources (912.3 MW), and three diesel resources (67.4 MW). The 49 fewer generation resources offered consisted of 22 fewer resources resulting from aggregation of RPM resources, 17 deactivated resources (1,083.2 MW), four Planned Generation Capacity Resources not offered (874.4 MW), three external resources not offered (446.1 MW), one resource excused from offering for reasons other than retirement (1.4 MW), one additional resource committed fully to FRR (173.0 MW), and one resource that is no longer a PJM capacity resource (2.3 MW). In addition, there were retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2017/2018 BRA: 16 steam resources (1,947.8 MW).

As shown in Table 5-5 and Table 5-16, in the 2019/2020 auction the 43 additional generation resources offered consisted of 39 new resources (6,685.5 MW), three additional resources imported (162.5 MW), and one resource that was unoffered in the 2018/2019 BRA (2.9 MW). The 39 new Generation Capacity Resources consisted of 18 solar resources (152.3 MW), seven combined cycle resources (5,925.6 MW), five diesel resources (83.2 MW), five wind resources (73.0 MW), and four CT resources (451.4 MW). The 32 fewer generation resources offered consisted of 15 fewer resources resulting from aggregation of RPM resources, six deactivated resources (772.8 MW), five external resources not offered (956.6 MW), resources excused from offering for reasons other than retirement, and Planned Generation Capacity Resources not offered. In addition, there were retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2018/2019 BRA: two steam resources (148.9 MW) and one combustion turbine (0.8 MW).

Table 5-4 Generation capacity changes: 2007/2008 to 2016/2017

	ICAP (MW)									
	Total at June 1	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	163,659.4	372.8	156.8	1,238.1	0.0	(96.7)	143.9	389.5	617.8	519.8
2008/2009	164,179.2	812.9	6.3	1,108.9	0.0	871.1	(1,702.9)	615.0	612.4	3,274.7
2009/2010	167,453.9	188.1	13.0	370.4	0.0	68.6	735.9	472.4	171.2	(739.4)
2010/2011	166,714.5	1,751.2	16.0	587.3	11,821.6	187.2	(427.0)	1,439.2	286.9	13,064.2
2011/2012	179,778.7	3,095.0	138.0	553.8	3,607.4	262.7	(1,374.5)	2,758.5	313.0	5,959.9
2012/2013	185,738.6	266.4	79.0	364.5	2,680.0	841.8	(17.3)	4,152.1	267.6	(170.7)
2013/2014	185,567.9	264.7	20.9	397.9	0.0	2,217.2	21.6	4,027.7	421.9	(1,570.5)
2014/2015	183,997.4	3,036.0	0.0	480.4	0.0	859.1	73.3	11,442.9	221.0	(7,361.7)
2015/2016	176,635.7	5,497.8	0.0	409.0	0.0	787.3	285.1	825.0	158.3	5,425.7
2016/2017	182,061.4									
Total		15,284.9	430.0	5,510.3	18,109.0	5,998.3	(2,261.9)	26,122.3	3,070.1	18,402.0

Table 5-5 Internal capacity: June 1, 2015 to June 1, 2019[37]

	UCAP (MW)												
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
Total internal capacity @ 01-Jun-15	204,557.3	79,793.1	40,055.1	13,227.1	1,900.4	9,518.6	5,227.8	6,466.3	14,407.5	3,484.3			
Integration of existing EKPC resources	2,735.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
New generation	5,517.4	2,291.3	606.5	3.6	0.0	30.2	0.0	0.0	767.1	0.0			
Reactivated generation	751.8	751.8	751.8	0.0	0.0	17.6	0.0	0.0	0.0	0.0			
Generation cap mods	(3,373.3)	(2,385.3)	(1,320.6)	(70.4)	(2.8)	(241.3)	(108.7)	0.0	(92.3)	0.0			
DR mods	(10,690.1)	(6,472.2)	(3,268.1)	(1,030.2)	(139.0)	(986.6)	(428.4)	(428.7)	(791.4)	564.7			
EE mods	262.5	145.6	28.7	85.6	0.7	3.2	0.7	50.4	131.0	55.7			
EFORd effect	1,039.0	575.2	160.5	325.3	6.8	(0.6)	(0.6)	146.4	(101.8)	(69.6)			
DR and EE effect	47.8	18.4	7.0	6.8	0.2	2.1	0.8	3.0	5.1	0.0			
Total internal capacity @ 01-Jun-16	200,848.1	74,717.9	37,020.9	12,547.8	1,766.3	8,343.2	4,691.6	6,237.4	14,325.2	4,035.1	26,091.2	3,717.0	10,570.7
Correction in resource modeling	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adjusted internal capacity @ 01-Jun-16	200,848.1	74,718.7	37,020.9	12,547.8	1,766.3	8,343.2	4,691.6	6,237.4	14,325.2	4,035.1	26,091.2	3,717.0	10,570.7
New generation	5,179.3	3,599.6	1,663.2	856.3	0.0	2.8	0.0	0.0	770.2	0.0	3.4	122.7	959.9
Reactivated generation	1,025.7	1,025.7	84.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Generation cap mods	(7,943.1)	(2,286.3)	(2,190.5)	(57.9)	5.7	(1,135.3)	(509.9)	15.7	(751.7)	(818.0)	85.1	0.0	(49.9)
DR mods	(3,472.4)	(941.6)	(407.6)	(198.9)	(33.0)	(167.9)	(50.2)	(54.4)	(889.9)	(208.7)	497.8	635.1	(171.2)
EE mods	158.9	91.4	26.9	61.5	0.9	4.4	0.1	77.2	(58.4)	(14.6)	583.3	50.9	
EFORd effect	(2,167.1)	(987.4)	(267.1)	(329.7)	(19.8)	(122.1)	(62.0)	35.1	(529.7)	(77.2)	33.6	(361.9)	(236.1)
DR and EE effect	(7.1)	(2.5)	(1.4)	(0.4)	(0.2)	(0.4)	(0.2)	(0.3)	(1.3)	(0.4)		(0.1)	(0.3)
Total internal capacity @ 01-Jun-17	193,622.3	75,217.6	35,928.5	12,878.7	1,719.9	6,924.7	4,069.4	6,310.7	12,864.4	2,916.2	27,293.4	4,163.7	11,072.1
Correction in resource modeling	0.0	0.0	0.0	0.0	0.0	0.0	(19.9)	0.0	0.0	0.0	0.0	0.0	0.0
Adjusted internal capacity @ 01-Jun-17	193,622.3	75,217.6	35,928.5	12,878.7	1,719.9	6,924.7	4,049.5	6,310.7	12,864.4	2,916.2	27,293.4	4,163.7	11,072.1
New generation	3,988.3	1,054.8	1,036.1	0.0	50.0	981.2	0.0	0.0	0.0	0.0	245.6	0.0	0.0
Reactivated 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
Generation cap mods	(1,852.4)	399.2	(101.3)	(34.9)	(31.2)	(18.3)	(12.8)	0.0	(633.7)	(296.7)	(216.3)	(35.1)	89.5
DR mods	746.6	198.4	67.6	28.7	30.5	(53.7)	(13.4)	23.9	(119.1)	(18.4)	589.6	5.0	69.1
EE mods	(9.3)	(4.9)	(8.2)	3.2	(1.6)	4.7	2.2	(56.6)	(109.4)	(35.5)	136.1	59.8	4.4
EFORd effect	(1,858.8)	(417.7)	(623.1)	(20.4)	12.3	(357.7)	(170.6)	(153.1)	39.2	89.7	(708.1)	131.9	24.6
DR and EE effect	626.1	239.9	85.4	79.7	5.1	19.5	7.9	36.1	44.8	14.3	117.8	43.6	41.4
Total internal capacity @ 01-Jun-18	195,262.8	76,687.3	36,385.0	12,935.0	1,785.0	7,500.4	3,862.8	6,161.0	12,086.2	2,669.6	27,458.1	4,368.9	11,301.1
Correction in resource modeling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adjusted internal capacity @ 01-Jun-18	195,262.8	76,687.3	36,385.0	12,935.0	1,785.0	7,500.4	3,862.8	6,161.0	12,086.2	2,669.6	27,458.1	4,368.9	11,301.1
New generation	6,185.7	2,341.6	35.6	912.2	7.0	12.0	0.0	912.2	766.5	0.0	43.5	0.0	939.0
Reactivated 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
Generation cap mods	(2,383.5)	(1,421.4)	(1,003.8)	(48.5)	(16.4)	(450.7)	12.5	0.0	(850.9)	(79.9)	1.5	(48.5)	11.5
DR mods	(326.8)	(409.7)	(71.3)	(266.8)	(15.3)	(9.1)	14.8	(157.4)	282.3	79.0	(236.4)	(109.4)	(71.7)
EE mods	204.3	66.1	118.3	(91.6)	1.3	33.8	1.4	(1.1)	10.1	(5.4)	(27.5)	(90.5)	15.1
EFORd effect	1,058.9	(8.6)	28.3	78.9	(29.5)	(135.0)	(1.2)	29.1	(70.1)	(52.0)	560.4	42.3	24.2
DR and EE effect	64.1	22.0	8.0	6.8	0.6	1.8	0.8	3.2	5.5	1.8	11.5	3.6	3.9
Total internal capacity @ 01-Jun-19	200,065.5	77,277.3	35,500.1	13,526.0	1,732.7	6,953.2	3,891.1	6,947.0	12,229.6	2,613.1	27,811.1	4,166.4	12,223.1

37 The RTO includes MAAC, EMAAC, SWMAAC, and ATSI. MAAC includes EMAAC, SWMAAC, and PPL. EMAAC includes DPL South, PSEG and PSEG North. PSEG includes PSEG North. SWMAAC includes Pepco and BGE. ATSI includes ATSI Cleveland.

Demand

As shown in Table 5-8, there was a 3,148.1 MW increase in the RPM reliability requirement from 177,184.1 MW on June 1, 2015, to 180,332.2 MW on June 1, 2016. The 3,148.1 MW increase in the RTO Reliability Requirement was a result of a 2,436.8 MW increase in the forecast peak load in UCAP terms holding the FPR constant at the 2015/2016 level and a 711.3 MW increase attributable to the change in FPR.

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, 2016, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 67.8 percent (Table 5-6), up from 65.1 percent on June 1, 2015. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 32.2 percent, down from 34.9 percent on June 1, 2015. 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, 2016 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 67.8 percent on June 1, 2016. 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 32.2 percent on June 1, 2016. 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.

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2016

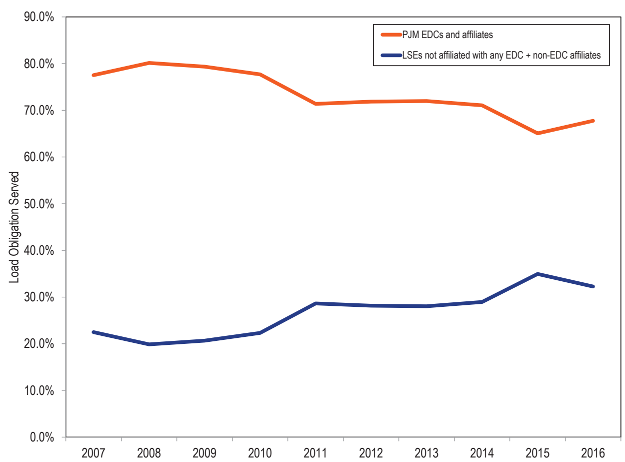


Table 5-6 Capacity market load obligations served: June 1, 2016

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	53,042.9	23,917.9	5,835.4	4,624.2	5,560.2	1,820.9	27,401.2	122,202.6
Percent of total obligation	43.4%	19.6%	4.8%	3.8%	4.5%	1.5%	22.4%	100.0%

Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays for the transmission system through firm transmission charges and pays for congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA is equal to the Unforced Capacity imported into the LDA, based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

For LDAs in which the RPM Auctions for a Delivery Year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs.

In the 2019/2020 RPM Base Residual Auction, EMAAC had 4,242.2 MW of CTRs with a total value of $30,695,796, ComEd had 2,355.1 MW of CTRs with a total value of $88,584,307, and BGE had 4,720.3 MW of CTRs with a total value of $518,289. Additionally, EMAAC had 898.0 MW of ICTRs with a total annualized value of $6,497,766, and BGE had 371.7 MW with a total annualized value of $33,599.

Market Concentration

Auction Market Structure

As shown in Table 5-7, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test in the 2016/2017 RPM Base Residual Auction, 2016/2017 RPM First Incremental Auction, 2016/2017 RPM Second Incremental Auction, 2016/2017 RPM Third Incremental Auction, 2017/2018 RPM Base Residual Auction, 2017/2018 RPM First Incremental Auction, 2017/2018 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2018/2019 RPM First Incremental Auction, and the 2019/2020 RPM Base Residual Auction.[38] The TPS test was not applied in the 2016/2017 CP Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. 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.[39] [40] [41] An overall offer cap was applied to all offers in the CP Transition Auctions.

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-7 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSIx). The RSIx is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSIx is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSIx is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

38 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.

39 See PJM. OATT Attachment DD § 6.5.

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

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

Table 5-7 RSI results: 2016/2017 through 2019/2020 RPM Auctions[42]

RPM Markets	$RSI_{1,\,1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2016/2017 Base Residual Auction				
RTO	0.78	0.59	110	110
MAAC	0.56	0.38	6	6
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 First Incremental Auction				
RTO	0.58	0.16	29	29
MAAC	0.26	0.00	3	3
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 Second Incremental Auction				
RTO	0.63	0.37	32	32
PSEG North	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 Third Incremental Auction				
RTO	0.54	0.35	64	64
MAAC	0.00	0.00	0	0
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
2017/2018 Base Residual Auction				
RTO	0.80	0.61	119	119
PSEG	0.00	0.00	1	1
2017/2018 First Incremental Auction				
RTO	0.47	0.40	38	38
PSEG	0.00	0.00	1	1
2017/2018 Second Incremental Auction				
RTO	0.65	0.32	30	30
PSEG	0.00	0.00	0	0
PSEG North	0.00	0.00	0	0
2018/2019 Base Residual Auction				
RTO	0.81	0.65	125	125
EMAAC	0.59	0.16	12	12
ComEd	1.11	0.02	4	4
2018/2019 First Incremental Auction				
RTO	0.51	0.23	32	32
EMAAC	0.00	0.00	2	2
ComEd	0.00	0.00	1	1
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

42 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.[43] 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."[44] 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.[45] Effective for the 2018/2019 through the 2019/2020 Delivery Years, Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 5-4, Figure 5-5 and Figure 5-6.

43 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.

44 PJM. OATT Attachment DD § 5.10 (a) (ii).

45 146 FERC ¶ 61,052 (2014).

Figure 5-4 Map of PJM Locational Deliverability Areas

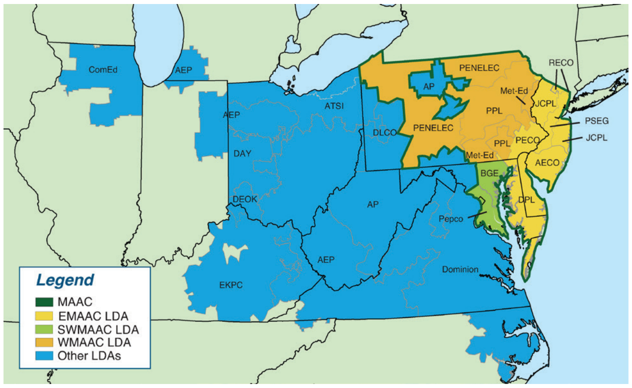


Figure 5-5 Map of PJM RPM EMAAC subzonal LDAs

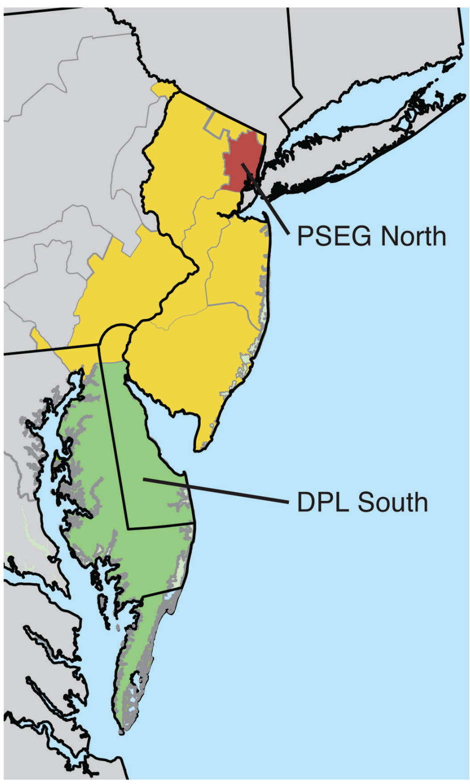
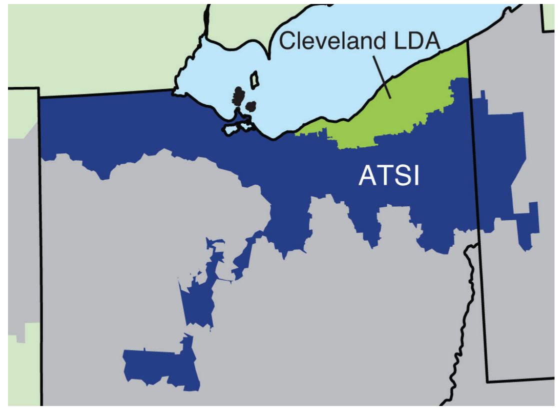


Figure 5-6 Map of PJM RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM Auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[46]

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. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. While pseudo ties were a step toward this goal, pseudo ties alone are not adequate to ensure deliverability. Pseudo ties create potential issues in the exporting area and do not ensure deliverability into the importing area. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the Day-Ahead Energy

46 PJM. OATT Attachment DD § 5.6.6(b).

Market should be clarified for both internal and external resources.

Effective with the 2017/2018 Delivery Year, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant delivery year due to the curtailment of firm transmission by third parties.[47] 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.[48]

As shown in Table 5-8, net exchange increased 3,548.6 MW from June 1, 2016 to June 1, 2016. Net exchange, which is imports less exports, increased due to an increase in imports of 3,546.0 MW and a decrease in exports of 2.6 MW.

As shown in Table 5-9, of the 4,343.4 MW of imports in the 2019/2020 RPM Base Residual Auction, 3,875.9 MW cleared. Of the cleared imports, 1,828.6 MW (47.2 percent) were from MISO.

Importing Capacity

Existing External Generation Capacity Resource

Generation external to the PJM region is eligible to be offered into an RPM Auction if it meets specific requirements.[49] [50] Firm transmission service from the unit to the border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point-to-point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of nonrecallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market.[51]

To avoid balancing market deviations, any offer accepted in the Day-Ahead Energy Market must be scheduled to physically flow in the Real-Time Energy Market. When submitting the real-time energy market transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Additionally, external capacity transactions must designate the transaction as such when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits. If the offer is not accepted in the Day-Ahead Energy Market, but the unit is requested during the operating day, the PJM dispatch operator will notify the participant. The market participant will then submit a tag to match the request. This tag will also be subject to all scheduling timing requirements and PJM interchange ramp limits.

Planned External Generation Capacity Resource

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[52] [53] Planned External Generation

47 147 FERC ¶ 61,060 (2014).
48 151 FERC ¶ 61,208 (2015).
49 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
50 See "PJM Manual 18: PJM Capacity Market," Revision 36 (December 22, 2016) at 54-55 & 78-79.
51 OATT, Schedule 1, Section 1.10.1A.
52 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Section 1.69A.
53 See "PJM Manual 18: PJM Capacity Market," Revision 36 (December 22, 2016) at 57-58.

Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[54] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction.[55]

Exporting Capacity

Nonfirm transmission can be used to export capacity from the PJM region. A Generation Capacity Resource located in the PJM region not committed to service of PJM loads may be removed from PJM Capacity Resource status if the Capacity Market Seller shows that the resource has a financially and physically firm commitment to an external sale of its capacity.[56] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[57]

The MMU evaluates requests submitted by Capacity Market Sellers to export Generation Capacity Resources, makes a determination as to whether the resource meets the applicable criteria to export, and must inform both the Capacity Market Seller and PJM of such determination.[58]

When submitting a real-time market export capacity transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Capacity transactions must designate the transaction as capacity when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits.

Table 5-8 PJM capacity summary (MW): June 1, 2007 to June 1, 2019[59] [60]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13	01-Jun-14	01-Jun-15	01-Jun-16	01-Jun-17	01-Jun-18	01-Jun-19
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0	210,812.4	217,829.1	216,671.5	208,605.9	210,712.9	213,519.5
Unforced capacity (UCAP)	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0	199,063.2	207,738.6	207,578.0	198,282.6	199,583.9	203,539.2
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7	164,561.2	169,159.7	167,003.7	166,836.9	167,305.9
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0	112.6	2.7	0.0	65.2	38.6	23.6
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5	173,549.0	178,086.5	177,184.1	180,332.2	179,545.1	174,896.8	171,036.8
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4	149,988.7	148,323.1	162,777.4	166,127.5	165,007.1	160,607.4	157,092.4
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	10,638.4	5,976.5	6,518.3	5,472.3	5,855.9	7,185.4	6,187.0	6,268.1	8,722.0
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2	4,055.5	4,395.5	7,941.5	5,854.8	5,603.4	4,762.3
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)	(1,228.1)	(1,214.2)	(1,211.6)	(1,194.5)	(1,282.3)	(1,288.6)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8	2,827.4	3,181.3	6,729.9	4,660.3	4,321.1	3,473.7
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4	14,832.8	12,408.1	10,974.8	11,084.4	10,348.0
EE cleared						568.9	679.4	822.1	922.5	1,117.3	1,338.9	1,246.5	1,515.1
ILR	1,636.3	3,608.1	6,481.5	8,236.4	9,032.6								
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6	518.1	356.8	501.9	556.2	650.2	642.1
Short-Term Resource Procurement Target						3,343.3	3,749.7	3,708.1	4,069.4	4,153.2	4,125.2		

54 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).

55 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

56 OATT Attachment DD § 6.6(g).

57 *Id.*

58 OATT Attachment M-Appendix § II.C.2.

59 Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity plus make-whole MW less the reliability requirement plus ILR. For 2007/2008 through 2011/2012, certified ILR was used in the calculation, because the certified ILR data are now available. For the 2012/2013 Delivery Year and beyond, net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement plus the Short-Term Resource Procurement Target. For the 2018/2019 and subsequent Delivery Years, the net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement. For the 2019/2020 and subsequent Delivery Years, the net excess under RPM is calculated as cleared generation and DR capacity plus make whole MW less the reliability requirement.

60 The results for RPM Incremental Auctions are not included in this table.

Table 5-9 RPM imports: 2007/2008 through 2019/2020 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9

Demand Resources

There are three basic demand products incorporated in the RPM market design:[61]

- **Demand Resources (DR).** Interruptible load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Interruptible Load for Reliability (ILR).** Interruptible load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the second incremental auction. The ILR product was eliminated after the 2011/2012 Delivery Year.
- **Energy Efficiency (EE) Resources.** Load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. The EE resource type was eligible to be offered in RPM Auctions starting with the 2012/2013 Delivery Year and in incremental auctions in the 2011/2012 Delivery Year.[62]

Effective for the 2014/2015 through the 2017/2018 Delivery Year, there are three types of Demand Resource products included in the RPM market design:[63 64]

- **Annual DR.** A Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
- **Extended Summer DR.** A Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended Summer DR is required to be capable of maintaining each interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Limited DR.** A Demand Resource that is required to be available on weekdays not including NERC holidays during the period of June through September in the relevant delivery year for up to 10 interruptions. Limited DR is required to be capable of maintaining each interruption for only six hours only during the hours of 12:00 p.m. to 8:00 p.m. EPT.

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of Demand Resource and Energy Efficiency Resource products included in the RPM market design:[65 66]

- **Base Capacity Demand Resource.** 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 ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Base Capacity Energy Efficiency Resource.** 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

61 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.
62 Letter Order in Docket No. ER10-366-000 (January 22, 2010).
63 134 FERC ¶ 61,066 (2011).
64 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.
65 151 FERC ¶ 61,208.
66 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

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 Resource**
  - **Annual Demand Resource.** 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 ten 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 Resource.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Annual Energy Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and the period from the hour ending 8:00 EPT and the hour ending 9:00 EPT and the period from the hour ending 19:00 EPT and the hour ending 20:00 EPT from January through February, excluding weekends and federal holidays.

Effective with the 2020/2021 Delivery Year, the Capacity Performance Product will be the only capacity product type.

As shown in Table 5-10 and Table 5-12, capacity in the RPM load management programs was 10,248.9 MW for June 1, 2016, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2016/2017 Delivery Year (14,988.5 MW) less replacement capacity (4,739.6 MW). Table 5-11 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

Table 5-10 RPM load management statistics by LDA: June 1, 2015 to June 1, 2019[67 68 69 70]

		UCAP (MW)												
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
01-Jun-15	DR cleared	15,453.7	6,675.4	2,624.0	2,022.4	86.3	787.3	263.5	867.7	2,167.9				
01-Jun-15	EE cleared	1,189.6	279.0	73.1	164.8	3.1	26.4	11.5	59.3	142.0				
01-Jun-15	DR net replacements	(4,829.7)	(2,393.0)	(1,078.7)	(672.5)	(10.4)	(363.6)	(128.4)	(310.7)	(1,082.2)				
01-Jun-15	EE net replacements	335.9	230.4	48.5	149.2	0.0	12.4	2.7	61.1	15.2				
01-Jun-15	RPM load management	12,149.5	4,791.8	1,666.9	1,663.9	79.0	462.5	149.3	677.4	1,242.9				
01-Jun-16	DR cleared	13,265.3	5,398.0	2,017.5	1,622.6	105.7	622.6	227.1	683.9	1,841.4	470.8			
01-Jun-16	EE cleared	1,723.2	418.0	86.4	262.6	2.0	27.9	10.8	136.5	226.9	58.6			
01-Jun-16	DR net replacements	(4,800.7)	(1,908.8)	(802.5)	(407.4)	(43.1)	(287.8)	(92.8)	(150.1)	(1,290.5)	(342.3)			
01-Jun-16	EE net replacements	61.1	111.0	27.1	94.5	(0.6)	6.3	3.3	17.9	(79.0)	(15.4)			
01-Jun-16	RPM load management	10,248.9	4,018.2	1,328.5	1,572.3	64.0	369.0	148.4	688.2	698.8	171.7			
01-Jun-17	DR cleared	11,735.2	4,577.2	1,623.6	1,464.1	86.3	402.8	157.1	658.3	1,127.8	309.0	1,602.9	805.8	811.9
01-Jun-17	EE cleared	1,844.1	509.6	154.0	280.3	4.9	36.4	10.3	150.8	176.0	41.3	736.8	129.5	42.6
01-Jun-17	DR net replacements	(322.0)	(215.0)	(113.0)	(18.0)	0.0	(2.0)	(2.0)	(6.0)	(48.0)	0.0	(28.0)	(12.0)	(39.0)
01-Jun-17	EE net replacements	(62.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(62.9)	(12.3)	0.0	0.0	0.0
01-Jun-17	RPM load management	13,194.4	4,871.8	1,664.6	1,726.4	91.2	437.2	165.4	803.1	1,192.9	338.0	2,311.7	923.3	815.5
01-Jun-18	DR cleared	11,200.6	4,302.1	1,690.7	1,183.1	86.8	389.9	139.2	523.1	958.6	287.2	1,895.2	660.0	716.2
01-Jun-18	EE cleared	1,579.8	443.3	170.7	225.2	3.5	44.4	10.9	125.1	67.6	13.9	753.8	100.1	28.9
01-Jun-18	DR net replacements	(232.4)	(81.4)	(68.9)	0.0	0.0	(10.9)	0.0	0.0	(16.0)	0.0	(95.0)	0.0	0.0
01-Jun-18	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
01-Jun-18	RPM load management	12,548.0	4,664.0	1,792.5	1,408.3	90.3	423.4	150.1	648.2	1,010.2	301.1	2,554.0	760.1	745.1
01-Jun-19	DR cleared	10,348.0	3,777.1	1,636.5	739.7	91.3	380.7	176.5	483.3	897.6	289.9	1,757.4	256.4	739.8
01-Jun-19	EE cleared	1,515.1	426.9	160.8	179.7	1.0	49.3	8.4	79.0	41.0	0.2	724.8	100.7	50.9
01-Jun-19	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
01-Jun-19	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
01-Jun-19	RPM load management	11,863.1	4,204.0	1,797.3	919.4	92.3	430.0	184.9	562.3	938.6	290.1	2,482.2	357.1	790.7

Table 5-11 RPM load management cleared capacity and ILR: 2007/2008 through 2019/2020[71 72 73 74]

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,730.7	9,032.6
2012/2013	8,429.7	8,740.9	643.4	666.1	0.0	0.0
2013/2014	10,345.6	10,779.6	871.0	904.2	0.0	0.0
2014/2015	14,337.6	14,943.0	1,035.4	1,077.7	0.0	0.0
2015/2016	14,891.6	15,453.7	1,147.7	1,189.6	0.0	0.0
2016/2017	12,737.6	13,265.3	1,656.9	1,723.2	0.0	0.0
2017/2018	11,299.9	11,735.2	1,777.2	1,844.1	0.0	0.0
2018/2019	10,292.1	11,200.6	1,452.2	1,579.8	0.0	0.0
2019/2020	9,510.3	10,348.0	1,393.7	1,515.1	0.0	0.0

67 See PJM. 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. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

68 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year include transactions associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

69 See PJM. OATT. Attachment DD § 5.14C. The reported DR cleared MW for the 2015/2016 and 2016/2017 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

70 See PJM. 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.

71 For Delivery Years through 2011/2012, certified ILR data is shown, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for Incremental Auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

72 See PJM. 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. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

73 See PJM. OATT. Attachment DD § 5.14C. The reported DR cleared MW for the 2015/2016 and 2016/2017 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

74 See PJM. 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 load management statistics: June 1, 2007 to June 1, 2019[75] [76]

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,570.7	10,935.6	(1,017.3)	(1,052.4)	0.2	0.2	9,553.6	9,883.4
01-Jun-12	9,073.1	9,407.0	(2,173.4)	(2,253.6)	(33.7)	(34.9)	6,866.0	7,118.5
01-Jun-13	11,216.6	11,683.8	(3,184.8)	(3,318.8)	120.0	125.0	8,151.8	8,490.0
01-Jun-14	15,373.0	16,020.7	(6,458.4)	(6,731.8)	196.4	204.7	9,111.0	9,493.6
01-Jun-15	16,039.3	16,643.3	(4,653.7)	(4,829.7)	323.7	335.9	11,709.3	12,149.5
01-Jun-16	14,394.5	14,988.5	(4,609.3)	(4,800.7)	58.7	61.1	9,843.9	10,248.9
01-Jun-17	13,077.1	13,579.3	(310.0)	(322.0)	(60.6)	(62.9)	12,706.5	13,194.4
01-Jun-18	11,744.3	12,780.4	(213.5)	(232.4)	0.0	0.0	11,530.8	12,548.0
01-Jun-19	10,904.0	11,863.1	0.0	0.0	0.0	0.0	10,904.0	11,863.1

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.[77] [78] [79] For Base Capacity, offer caps are defined 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 as the applicable zonal net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market. For RPM Third Incremental Auctions, capacity market sellers may elect, for Base Capacity offers, an offer cap equal to 1.1 times the BRA clearing price for the relevant LDA and delivery year or, for Capacity Performance offers, an offer cap equal to the greater of the net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year.

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[80] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. For Capacity Performance Resources, avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/non-performance charges.[81] 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.[82]

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).[83] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for

75 For Delivery Years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for Incremental Auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

76 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

77 See OATT Attachment DD § 6.5.

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

79 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).

80 OATT Attachment DD § 6.8 (b).

81 For details on the competitive offer of a capacity performance resource, 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).

82 OATT Attachment DD § 6.8 (a).

83 151 FERC ¶ 61,208.

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.

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[84] 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.[85]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[86] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exemption 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 constrained LDAs only.

2016/2017 RPM Base Residual Auction

As shown in Table 5-13, 1,199 generation resources submitted offers in the 2016/2017 RPM Base Residual Auction. Unit-specific offer caps were calculated for 152 generation resources (12.7 percent), including 138 generation resources (11.5 percent) with an Avoidable Project Investment Recovery Rate (APIR) and one generation resource (0.1 percent) without an APIR component. The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 (41.0 percent) were based on the technology specific default (proxy) ACR values. Of the 1,199 generation resources, 31 Planned Generation Capacity Resources had uncapped offers (2.6 percent), 15 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.3 percent), and 11 generation resources had uncapped planned uprates along with price taker status for the existing portion (0.9 percent), while the remaining 519 generation resources were price takers (43.3 percent). Market power mitigation was applied to the sell offers for 50 generation resources.

Of the 1,199 generation resources which submitted offers, 138 (11.5 percent) included an APIR component. As shown in Table 5-17, the weighted average gross ACR for units with APIR ($352.84 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($180.23 per MW-day) decreased from the 2015/2016 BRA values of $401.95 per MW-day and $246.63 per MW-day, due primarily to lower weighted average gross ACRs for combined cycle, combustion turbine, oil and gas steam units, and subcritical/supercritical coal units. The APIR component added an average of $191.19 per MW-day to the ACR value of the APIR units compared to $238.79 per MW-day in the 2015/2016 BRA. The highest APIR for a technology ($236.99 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($773.08 per MW-

84 135 FERC ¶ 61,022 (2011).
85 135 FERC ¶ 61,022 (2011), order on reh'g, 137 FERC ¶ 61,145 (2011).
86 143 FERC ¶ 61,090 (2013).

day) is the maximum amount by which an offer cap was increased by APIR.

2016/2017 RPM First Incremental Auction

As shown in Table 5-13, 115 generation resources submitted offers in the 2016/2017 RPM First Incremental Auction. Unit-specific offer caps were calculated for 37 generation resources (32.2 percent of all generation resources), of which 32 generation resources (27.8 percent) included an APIR component. The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values (21.7 percent). Of the 115 generation resources, one Planned Generation Capacity Resources had uncapped offers (0.9 percent), while the remaining 52 generation resources were price takers (45.2 percent). Market power mitigation was applied to the sell offers for four generation resources.

2016/2017 RPM Second Incremental Auction

As shown in Table 5-13, 101 generation resources submitted offers in the 2016/2017 RPM Second Incremental Auction. The MMU calculated offer caps for 45 generation resources (44.6 percent), of which 21 were based on the technology specific default (proxy) ACR values and 24 were unit-specific offer caps (23.8 percent of all generation resources), of which 23 offer caps included an APIR component. Of the 101 generation resources, one Planned Generation Capacity Resource had an uncapped offer (1.0 percent), while the remaining 52 generation resources were price takers (51.5 percent). Market power mitigation was applied to the sell offers for two generation resources.

2016/2017 CP Transition Incremental Auction

All 709 generation resources which submitted offers in the 2016/2017 CP Transition Incremental Auction were subject to an offer cap of $165.27 per MW-day, which is 50 percent of the Net Cost of New Entry (CONE) used in the 2016/2017 RPM Base Residual Auction.

2016/2017 RPM Third Incremental Auction

As shown in Table 5-13, 296 generation resources submitted offers in the 2016/2017 RPM Third Incremental Auction. The MMU calculated offer caps for 52 generation resources (17.6 percent), of which 35 were based on the technology specific default (proxy) ACR values and 17 were unit-specific offer caps (5.7 percent of all generation resources), of which 17 offer caps included an APIR component. Of the 296 generation resources, 244 did not request unit specific offer caps, of which 145 generation resources elected the offer cap option of 1.1 times the BRA clearing price, 11 Planned Generation Capacity Resources had uncapped offers (3.7 percent), and 88 generation resources were price takers (29.7 percent). Market power mitigation was applied to the sell offers of zero generation resources.

2017/2018 RPM Base Residual Auction

As shown in Table 5-14, 1,202 generation resources submitted offers in the 2017/2018 RPM Base Residual Auction. Unit-specific offer caps were calculated for 131 generation resources (10.9 percent of all generation resources), of which 122 generation resources (10.1 percent) included an APIR component. The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values (33.3 percent). Of the 1,202 generation resources, 28 Planned Generation Capacity Resources had uncapped offers (2.3 percent), while the remaining 637 generation resources were price takers (53.0 percent). Market power mitigation was applied to the sell offers for 39 generation resources.

Of the 1,202 generation resources which submitted offers, 122 (10.1 percent) included an APIR component. As shown in Table 5-18, the weighted average gross ACR for units with APIR ($413.87 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($256.02 per MW-day) increased from the 2016/2017 BRA values of $352.84 per MW-day and $180.23 per MW-day, due to higher weighted average gross ACRs for combined cycle, combustion turbine, subcritical/supercritical coal, and other units. The APIR component added an average of $217.84 per MW-day to the ACR value of the APIR units compared to $191.19 per MW-day in the 2016/2017 BRA. The highest APIR for a technology ($281.82 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($863.76 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2017/2018 CP Transition Incremental Auction

All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is

60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.

2017/2018 RPM First Incremental Auction

As shown in Table 5-14, 118 generation resources submitted offers in the 2017/2018 RPM First Incremental Auction. The MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 were based on the technology specific default (proxy) ACR values, 17 were unit-specific offer caps with an APIR component (14.4 percent of all generation resources), six Planned Generation Capacity Resources had uncapped offers (5.1 percent), and the remaining 57 generation resources were price takers (48.3 percent). Market power mitigation was applied to the sell offers for six generation resources.

2017/2018 RPM Second Incremental Auction

As shown in Table 5-14, 505 generation resources submitted offers in the 2017/2018 RPM Second Incremental Auction. The MMU calculated offer caps for 35 generation resources (36.8 percent), of which 15 were based on the technology specific default (proxy) ACR values and 20 were unit-specific offer caps (21.1 percent of all generation resources), of which 18 included an APIR component. Of the 95 generation resources, seven Planned Generation Capacity Resources had uncapped offers (7.4 percent), and the remaining 53 generation resources were price takers (55.8 percent). Market power mitigation was applied to the sell offers of four generation resources, including 157.0 MW.

2018/2019 RPM Base Residual Auction

As shown in Table 5-15, 473 generation resources submitted Base Capacity offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 were based on the technology specific default (proxy) ACR values, 53 were unit-specific offer caps (11.2 percent of all generation resources), of which 45 included an APIR component, eight Planned Generation Capacity Resources had uncapped offers (1.7 percent), and the remaining 246 generation resources were price takers (52.0 percent).

As shown in Table 5-15, 992 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 35 generation resources (3.5 percent), all of which were unit-specific with an APIR component, 15 Planned Generation Capacity Resources had uncapped offers (1.5 percent), and the remaining 54 generation resources were price takers (5.4 percent). All offers were below the offer caps.

Of the 473 generation resources which submitted Base Capacity offers, 45 (9.5 percent) included an APIR component. Of the 992 generation resources which submitted Capacity Performance offers, 35 (3.5 percent) included an APIR component. As shown in Table 5-19, the weighted average gross ACR for units with APIR was \$406.58 per MW-day for Base Capacity Resources and \$496.37 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was \$321.80 per MW-day for Base Capacity Resources and \$356.54 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of \$281.13 per MW-day for Base Capacity Resources and \$344.93 for Capacity Performance Resources. The maximum APIR effect (\$1,051.98 per MW-day for Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of \$0.00 per MW-day for Base Capacity Resources and \$10.08 per MW-day for Capacity Performance Resources.

2018/2019 RPM First Incremental Auction

As shown in Table 5-15, 80 generation resources submitted Base Capacity offers in the 2018/2019 RPM First Incremental Auction. The MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 were based on the technology specific default (proxy) ACR values and 12 were unit-specific offer caps (15.0 percent of all generation resources), of which all of which included an APIR component. Of the 30 generation resources with Base Capacity offers, four Planned Generation Capacity Resources had uncapped offers (5.0 percent), and the remaining 46 generation resources were price takers (57.5 percent). Market power mitigation was applied to the Base Capacity sell offers of three generation resources, including 8.2 MW.

As shown in Table 5-15, 293 generation resources submitted Capacity Performance offers in the 2018/2019 RPM First Incremental Auction. The MMU calculated offer caps for nine generation resources (3.1 percent), all of which were unit-specific with an APIR component. Of the 293 generation resources, 261 generation resources had the B times net CONE offer cap (89.1 percent), seven Planned Generation Capacity Resources had uncapped offers (2.4 percent), one generation resource had an uncapped planned uprate plus B times net CONE offer cap for the existing portion of the unit (0.3 percent), and the remaining 15 generation resources were price takers (5.1 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2019/2020 RPM Base Residual Auction

As shown in Table 5-16, 505 generation resources submitted Base Capacity offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 were based on the technology specific default (proxy) ACR values and 41 were unit-specific offer caps (8.1 percent of all generation resources), of which 34 included an APIR component. Of the 505 generation resources, nine Planned Generation Capacity Resources had uncapped offers (1.8 percent), and the remaining 284 generation resources were price takers (56.2 percent). Market power mitigation was applied to the Base Capacity sell offers of 34 generation resources, including 3,116.5 MW.

As shown in Table 5-16, 1,003 generation resources submitted Capacity Performance offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 25 generation resources (2.5 percent), all of which were unit-specific with an APIR component. Of the 1,003 generation resources, 888 generation resources had the B times net CONE offer cap (88.5 percent), 14 Planned Generation Capacity Resources had uncapped offers (1.4 percent), two generation resources had uncapped planned uprates plus B times net CONE offer cap for the existing portion of the units (0.2 percent), and the remaining 74 generation resources were price takers (5.4 percent). Market power mitigation was applied to the Capacity Performance sell offers of three generation resources, including 50.8 MW.

Of the 505 generation resources which submitted Base Capacity offers, 34 (6.7 percent) included an APIR component. Of the 1,003 generation resources which submitted Capacity Performance offers, 25 (2.5 percent) included an APIR component. As shown in Table 5-20, the weighted average gross ACR for units with APIR was $341.40 per MW-day for Base Capacity Resources and $499.18 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $271.22 per MW-day for Base Capacity Resources and $323.27 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $230.67 per MW-day for Base Capacity Resources and $375.38 for Capacity Performance Resources. The maximum APIR effect ($1,104.93 per MW-day for Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.00 per MW-day for Base Capacity Resources and $1.53 per MW-day for Capacity Performance Resources.

Table 5-13 ACR statistics: 2016/2017 RPM Auctions

	2016/2017 Base Residual Auction		2016/2017 First Incremental Auction		2016/2017 Second Incremental Auction		2016/2017 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	471	39.3%	24	20.9%	17	16.8%	35	11.8%
Unit specific ACR (APIR)	138	11.5%	32	27.8%	23	22.8%	17	5.7%
Unit specific ACR (APIR and CPQR)	NA	NA	NA	NA	NA	NA	NA	NA
Unit specific ACR (non-APIR)	1	0.1%	4	3.5%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	NA	NA	NA	NA	NA	NA	NA	NA
Opportunity cost input	8	0.7%	1	0.9%	1	1.0%	0	0.0%
Default ACR and opportunity cost	5	0.4%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	NA	NA	NA	NA	NA	NA
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	145	49.0%
Uncapped planned uprate and default ACR	15	1.3%	1	0.9%	4	4.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and price taker	11	0.9%	0	0.0%	3	3.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	0	0.0%
Uncapped planned generation resources	31	2.6%	1	0.9%	1	1.0%	11	3.7%
Existing generation resources as price takers	519	43.3%	52	45.2%	52	51.5%	88	29.7%
Total Generation Capacity Resources offered	1,199	100.0%	115	100.0%	101	100.0%	296	100.0%

Table 5-14 ACR Statistics: 2017/2018 RPM Auctions

	2017/2018 Base Residual Auction		2017/2018 First Incremental Auction		2017/2018 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	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	369	30.7%	36	30.5%	15	15.8%
Unit specific ACR (APIR)	122	10.1%	17	14.4%	18	18.9%
Unit specific ACR (APIR and CPQR)	NA	NA	NA	NA	NA	NA
Unit specific ACR (non-APIR)	4	0.3%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	NA	NA	NA	NA	NA	NA
Opportunity cost input	5	0.4%	0	0.0%	2	2.1%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	NA	NA	NA	NA
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and default ACR	31	2.6%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and price taker	6	0.5%	2	1.7%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	28	2.3%	6	5.1%	7	7.4%
Existing generation resources as price takers	637	53.0%	57	48.3%	53	55.8%
Total Generation Capacity Resources offered	1,202	100.0%	118	100.0%	95	100.0%

Table 5-15 ACR Statistics: 2018/2019 RPM Auctions

	2018/2019 Base Residual Auction				2018/2019 First Incremental Auction			
	Base Capacity		Capacity Performance		Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	164	34.7%	0	0.0%	18	22.5%	0	0.0%
Unit specific ACR (APIR)	45	9.5%	9	0.9%	12	15.0%	8	2.7%
Unit specific ACR (APIR and CPQR)	0	0	26	2.6%	0	0	1	0.3%
Unit specific ACR (non-APIR)	1	0.2%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%	0	0	0	0.0%
Opportunity cost input	7	1.5%	0	0.0%	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	881	88.8%	NA	NA	261	89.1%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and default ACR	2	0.4%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	6	0.6%	NA	NA	1	0.3%
Uncapped planned uprate and price taker	0	0.0%	1	0.1%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	8	1.7%	15	1.5%	4	5.0%	7	2.4%
Existing generation resources as price takers	246	52.0%	54	5.4%	46	57.5%	15	5.1%
Total Generation Capacity Resources offered	473	100.0%	992	100.0%	80	100.0%	293	100.0%

Table 5-16 ACR Statistics: 2019/2020 RPM Auctions

	2019/2020 Base Residual Auction			
	Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	171	33.9%	0	0.0%
Unit specific ACR (APIR)	34	6.7%	8	0.8%
Unit specific ACR (APIR and CPQR)	0	0	17	1.7%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%
Opportunity cost input	7	1.4%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%
Net CONE times B	NA	NA	888	88.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	2	0.2%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	9	1.8%	14	1.4%
Existing generation resources as price takers	284	56.2%	74	7.4%
Total Generation Capacity Resources offered	505	100.0%	1,003	100.0%

Table 5-17 APIR Statistics: 2016/2017 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$42.11	$33.46	$78.32	$215.57	$75.69	$102.23
Net revenues	$194.19	$56.23	$42.33	$208.04	$228.59	$150.24
Offer caps	$4.80	$7.64	$36.43	$29.03	$4.63	$16.07
APIR units						
ACR	$52.48	$93.23	$188.80	$432.72	$53.20	$352.84
Net revenues	$72.50	$17.49	$16.68	$222.52	$62.15	$177.14
Offer caps	$13.92	$79.12	$167.29	$213.88	$5.91	$180.23
APIR	$14.45	$57.71	$64.90	$236.99	$23.01	$191.19
Maximum APIR effect						$773.08

Table 5-18 APIR Statistics: 2017/2018 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$36.92	$31.52	$84.84	$182.60	$47.54	$94.78
Net revenues	$121.99	$51.56	$13.98	$116.61	$158.64	$92.26
Offer caps	$2.17	$9.90	$71.43	$70.61	$8.28	$36.87
APIR units						
ACR	$136.06	$97.45	$180.36	$440.80	$554.65	$413.87
Net revenues	$0.00	$1.84	$42.70	$92.18	$382.31	$137.71
Offer caps	$136.06	$95.61	$137.66	$319.61	$163.77	$256.02
APIR	$95.80	$55.48	$92.23	$281.82	$128.37	$217.84
Maximum APIR effect						$863.76

Table 5-19 APIR Statistics: 2018/2019 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)	
	Base Capacity	Capacity Performance
Non-APIR units		
ACR	$85.36	$197.45
Net revenues	$117.38	$131.61
Offer caps	$30.74	$65.83
APIR units		
ACR	$406.58	$496.37
Net revenues	$83.43	$139.25
Offer caps	$321.80	$356.54
APIR	$281.13	$344.93
CPQR	$0.00	$10.08
Maximum APIR effect	$1,051.98	$1,051.98

Table 5-20 APIR Statistics: 2019/2020 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)	
	Base Capacity	Capacity Performance
Non-APIR units		
ACR	$89.05	
Net revenues	$150.86	
Offer caps	$33.97	
APIR units		
ACR	$341.40	$499.18
Net revenues	$65.48	$167.61
Offer caps	$271.22	$323.27
APIR	$230.67	$375.38
CPQR	$0.00	$1.53
Maximum APIR effect	$1,104.93	$1,104.93

Market Performance

Figure 5-7 shows cleared MW weighted average capacity market prices on a Delivery Year basis for the entire history of the PJM capacity markets. Table 5-21 shows RPM clearing prices for all RPM Auctions held through 2016.

Figure 5-8 shows the RPM cleared MW weighted average prices for each LDA for the current Delivery Year and all results for auctions for future Delivery Years that have been held through 2016. A summary of these weighted average prices is given in Table 5-22.

Table 5-23 shows RPM revenue by resource type for all RPM Auctions held through 2016 with $6.3 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices. A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

Table 5-24 shows RPM revenue by calendar year for all RPM Auctions held through 2016. In 2015, RPM revenue was $9.0 billion. In 2016, RPM revenue was $8.9 billion.

Table 5-25 shows the RPM annual charges to load. For the 2015/2016 Delivery Year, RPM annual charges to load are $9.6 billion. For the 2016/2017 Delivery Year, annual charges to load are $7.7 billion.

Table 5-21 Capacity prices: 2007/2008 through 2019/2020 RPM Auctions

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2007/2008 BRA		$40.80	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$197.67	$188.54		$40.80	$188.54
2008/2009 BRA		$111.92	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$148.80	$210.11		$111.92	$210.11
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$10.00	$223.85		$10.00	$223.85
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$191.32	$237.33		$102.04	$237.33
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00		$40.00	$86.00
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	$174.29		$174.29	$174.29
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00		$50.00	$50.00
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00		$110.00	$110.00
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00		$55.00	$55.00
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	$133.37		$16.46	$133.37
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	$16.46	$16.46	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	$13.01	$13.01	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	$27.73	$27.73	$226.15
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	$20.00	$20.00	$54.82
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$10.00	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	$7.01	$7.01	$10.00
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$30.00	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	$4.05	$4.05	$30.00
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03	$0.03	$5.23
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 Second Incremental Auction	Limited	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Second Incremental Auction	Extended Summer	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Second Incremental Auction	Annual	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Third Incremental Auction	Limited	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2014/2015 Third Incremental Auction	Extended Summer	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2014/2015 Third Incremental Auction	Annual	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62	$118.54	$150.00
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08	$136.00	$167.46
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00	$136.00	$167.46
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 First Incremental Auction	Extended Summer	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 First Incremental Auction	Annual	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 Second Incremental Auction	Limited	$123.56	$141.12	$123.56	$141.12	$141.12	$141.12	$141.12	$155.02	$155.02	$141.12	$204.10	$123.56	$141.12
2015/2016 Second Incremental Auction	Extended Summer	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Second Incremental Auction	Annual	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Third Incremental Auction	Limited	$100.76	$122.33	$100.76	$122.33	$122.33	$122.33	$122.33	$122.56	$122.56	$122.33	$100.76	$100.76	$122.33
2015/2016 Third Incremental Auction	Extended Summer	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2015/2016 Third Incremental Auction	Annual	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$94.45	$59.37	$119.13
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 First Incremental Auction	Limited	$53.93	$89.35	$53.93	$89.35	$89.35	$89.35	$89.35	$214.44	$214.44	$89.35	$94.45	$53.93	$89.35
2016/2017 First Incremental Auction	Extended Summer	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 First Incremental Auction	Annual	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 Second Incremental Auction	Limited	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Extended Summer	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Annual	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Capacity Performance Transition Auction	Capacity Performance	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00
2016/2017 Third Incremental Auction	Limited	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Extended Summer	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Annual	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2017/2018 BRA	Limited	$106.02	$106.02	$106.02	$40.00	$106.02	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02	$106.02	$106.02
2017/2018 BRA	Extended Summer	$120.00	$120.00	$120.00	$53.98	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 BRA	Annual	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 Capacity Performance Transition Auction	Capacity Performance	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50
2017/2018 First Incremental Auction	Limited	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Extended Summer	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Annual	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 Second Incremental Auction	Limited	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Extended Summer	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Annual	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2018/2019 BRA	Base Capacity	$149.98	$149.98	$149.98	$75.00	$210.63	$149.98	$210.63	$210.63	$210.63	$149.98	$149.98	$200.21	$149.98
2018/2019 BRA	Base Capacity DR/EE	$149.98	$149.98	$149.98	$75.00	$210.63	$59.95	$210.63	$210.63	$210.63	$41.09	$149.98	$200.21	$59.95

Table 5-21 Capacity prices: 2007/2008 through 2019/2020 RPM Auctions (continued)

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2018/2019 BRA	Capacity Performance	$164.77	$164.77	$164.77	$164.77	$225.42	$164.77	$225.42	$225.42	$225.42	$164.77	$164.77	$215.00	$164.77
2018/2019 First Incremental Auction	Base Capacity	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Base Capacity DR/EE	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Capacity Performance	$27.15	$27.15	$27.15	$27.15	$84.68	$27.15	$84.68	$84.68	$84.68	$27.15	$27.15	$30.00	$27.15
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

Table 5-22 Weighted average clearing prices by zone: 2016/2017 through 2019/2020

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2016/2017	2017/2018	2018/2019	2019/2020
RTO				
AEP	$115.27	$140.42	$162.19	$96.60
AP	$115.27	$140.42	$162.19	$96.60
ATSI	$122.15	$139.84	$152.87	$97.03
Cleveland	$112.13	$139.01	$161.42	$97.44
ComEd	$115.27	$140.97	$209.55	$200.02
DAY	$115.27	$140.42	$162.19	$96.60
DEOK	$115.27	$140.42	$162.19	$96.60
DLCO	$115.27	$140.42	$162.19	$96.60
Dominion	$115.27	$140.42	$162.19	$96.60
EKPC	$115.27	$140.42	$162.19	$96.60
MAAC				
EMAAC				
AECO	$123.01	$138.01	$219.98	$114.57
DPL	$123.01	$138.01	$219.98	$114.57
DPL South	$119.87	$136.06	$219.21	$118.10
JCPL	$123.01	$138.01	$219.98	$114.57
PECO	$123.01	$138.01	$219.98	$114.57
PSEG	$220.70	$208.66	$220.71	$117.49
PSEG North	$218.25	$214.38	$223.42	$118.46
RECO	$123.01	$138.01	$219.98	$114.57
SWMAAC				
BGE	$120.96	$130.11	$143.38	$95.92
Pepco	$118.60	$134.81	$151.84	$92.25
WMAAC				
Met-Ed	$122.13	$140.03	$155.64	$98.04
PENELEC	$122.13	$140.03	$155.64	$98.04
PPL	$122.13	$136.45	$153.51	$97.03

Table 5-23 RPM revenue by type: 2007/2008 through 2019/2020[87] [88]

				Coal		Gas		Hydroelectric	
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$5,537,085	$0	$22,225,980	$1,019,060,206	$0	$1,624,111,360	$3,472,667	$209,490,444	$0
2008/2009	$35,349,116	$0	$60,918,903	$1,835,059,769	$0	$2,112,913,366	$9,751,112	$287,850,403	$0
2009/2010	$65,762,003	$0	$56,517,793	$2,409,315,953	$1,854,781	$2,548,801,710	$30,168,831	$364,742,517	$0
2010/2011	$60,235,796	$0	$106,046,871	$2,648,278,766	$3,168,069	$2,823,632,390	$58,065,964	$442,429,815	$0
2011/2012	$55,795,785	$139,812	$185,421,273	$1,586,775,249	$28,330,047	$1,717,850,463	$98,448,693	$278,529,660	$0
2012/2013	$264,387,898	$11,408,552	$13,260,822	$1,014,858,378	$7,568,127	$1,256,096,304	$76,633,409	$179,117,975	$11,397
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,741,613,525	$12,950,135	$2,153,560,721	$167,844,235	$308,853,673	$25,708
2014/2015	$681,315,139	$42,308,549	$135,573,409	$1,935,468,356	$57,078,818	$2,172,570,169	$205,555,569	$333,941,614	$6,649,774
2015/2016	$903,496,003	$66,652,986	$260,806,674	$2,902,870,267	$63,682,708	$2,672,530,801	$535,039,154	$389,540,948	$15,478,144
2016/2017	$466,952,356	$68,709,670	$244,091,507	$2,137,545,515	$72,217,195	$2,212,974,257	$667,098,133	$283,613,426	$13,927,638
2017/2018	$513,340,753	$84,562,120	$218,558,934	$2,447,293,628	$62,716,892	$2,538,564,397	$983,815,482	$346,315,522	$15,183,161
2018/2019	$635,787,176	$92,912,038	$262,439,441	$2,622,702,914	$76,339,006	$2,966,354,301	$1,440,327,407	$414,573,552	$15,344,022
2019/2020	$372,297,036	$79,809,657	$124,354,356	$1,589,569,993	$47,528,002	$1,942,148,285	$1,056,052,247	$247,708,445	$6,208,824

	Nuclear		Oil		Solar		Solid waste	
	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$996,085,233	$0	$340,362,114	$0	$0	$0	$31,512,230	$0
2008/2009	$1,322,601,837	$0	$378,756,365	$4,837,523	$0	$0	$35,011,991	$0
2009/2010	$1,517,723,628	$0	$450,523,876	$5,676,582	$0	$0	$42,758,762	$523,739
2010/2011	$1,799,258,125	$0	$446,000,462	$4,339,539	$0	$0	$40,731,606	$413,503
2011/2012	$1,079,386,338	$0	$266,483,502	$967,887	$0	$66,978	$25,636,836	$261,690
2012/2013	$762,719,551	$0	$248,611,128	$2,772,987	$0	$1,246,337	$26,840,670	$316,420
2013/2014	$1,346,223,419	$0	$386,561,718	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705
2014/2015	$1,464,950,862	$0	$323,630,668	$4,106,697	$0	$3,836,582	$34,281,137	$1,709,533
2015/2016	$1,850,033,226	$0	$401,718,239	$5,947,275	$0	$7,064,983	$35,862,368	$6,179,607
2016/2017	$1,483,759,630	$0	$265,547,984	$4,030,823	$0	$7,057,256	$32,648,789	$6,380,604
2017/2018	$1,692,710,933	$0	$279,435,824	$3,888,126	$0	$9,531,809	$34,350,458	$9,009,006
2018/2019	$1,979,780,844	$0	$342,162,298	$2,922,855	$0	$14,933,887	$37,917,294	$9,645,386
2019/2020	$1,262,041,327	$0	$187,212,812	$1,723,692	$0	$11,167,534	$21,032,486	$5,299,864

	Wind		
	Existing	New/repower/ reactivated	Total revenue
2007/2008	$430,065	$0	$4,252,287,381
2008/2009	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$812,644	$5,052,036	$3,871,714,635
2013/2014	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$1,524,551	$32,766,219	$7,437,267,646
2015/2016	$1,829,269	$42,994,253	$10,161,726,902
2016/2017	$1,144,873	$26,189,042	$7,993,888,695
2017/2018	$1,300,167	$39,886,653	$9,280,463,863
2018/2019	$1,166,553	$53,365,379	$10,968,674,353
2019/2020	$752,496	$44,986,052	$6,999,893,108

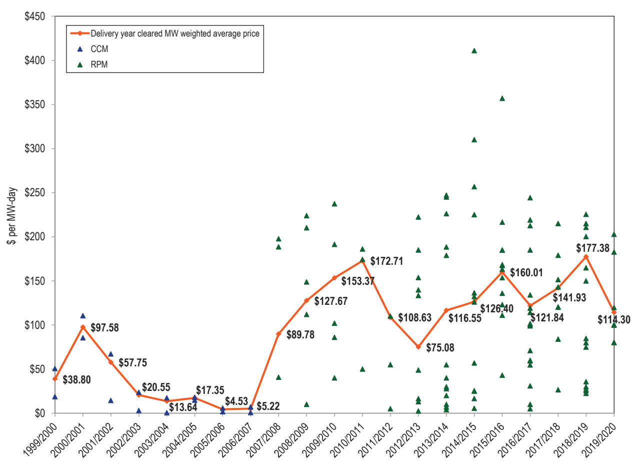
87 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

88 The results for the ATSI Integration Auctions are not included in this table.

Table 5-24 RPM revenue by calendar year: 2007 through 2020[89]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$99.39	154,044.3	365	$5,588,442,225
2014	$122.32	160,668.7	365	$7,173,539,072
2015	$146.10	169,112.0	365	$9,018,343,604
2016	$137.69	176,742.6	366	$8,906,998,628
2017	$133.62	179,368.7	365	$8,748,209,479
2018	$162.71	172,927.6	365	$10,270,263,986
2019	$140.39	168,422.6	365	$8,630,559,230
2020	$114.30	167,329.5	152	$2,907,059,433

Figure 5-7 History of PJM capacity prices: 1999/2000 through 2019/2020[90]



89 The results for the ATSI Integration Auctions are not included in this table.

90 The 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2019/2020 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by Delivery Year. The RPM data points plotted are RPM resource clearing prices. For the 2014/2015 and subsequent Delivery Years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-8 Map of RPM capacity prices: 2016/2017 through 2019/2020

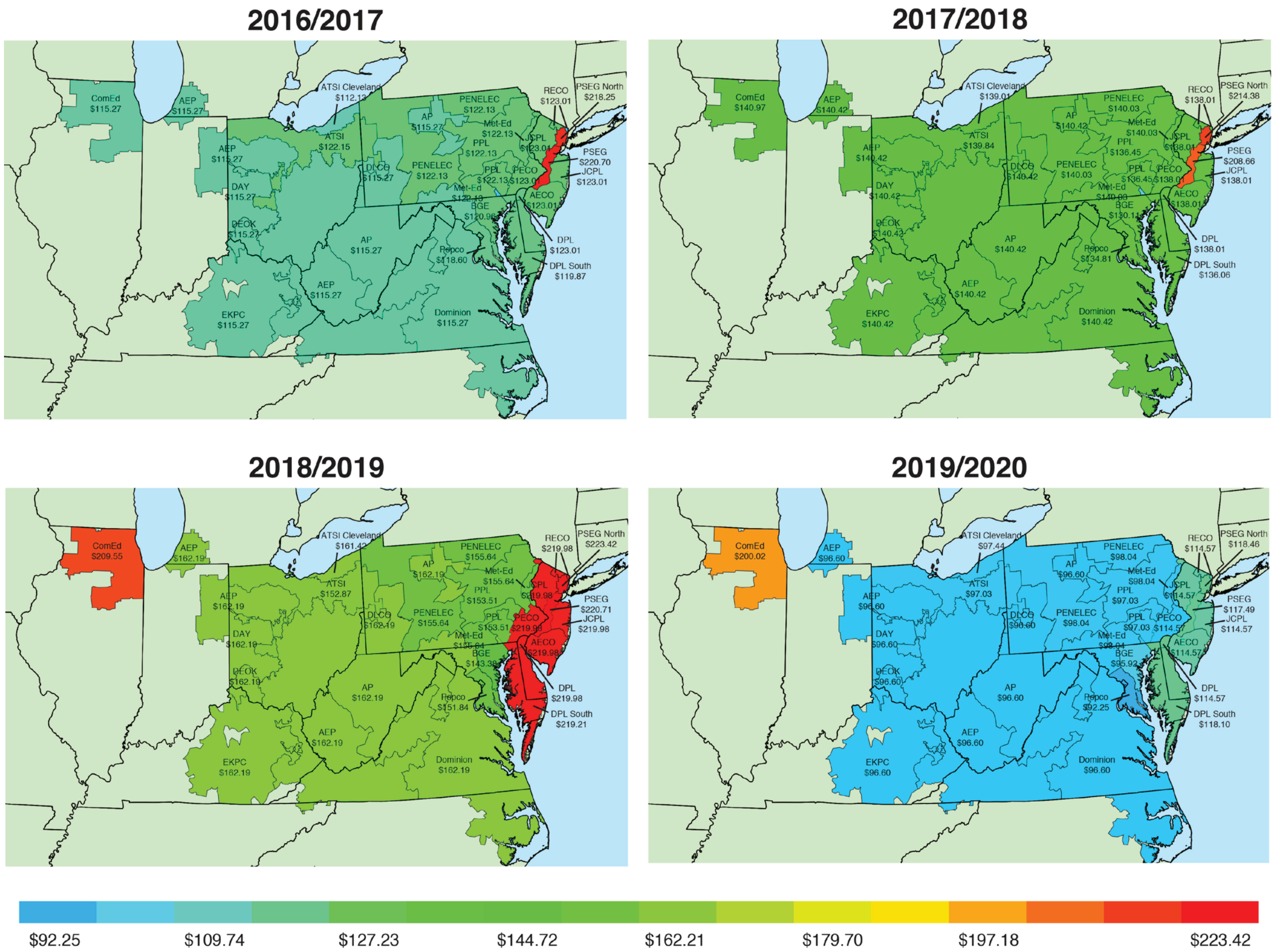


Table 5-25 RPM cost to load: 2015/2016 through 2019/2020 RPM Auctions[91 92 93]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2015/2016			
Rest of RTO	$135.81	81,984.4	$4,075,305,460
Rest of MAAC	$166.53	53,819.9	$3,280,332,235
PSEG	$166.29	11,398.1	$693,698,017
ATSI	$293.00	14,631.7	$1,569,095,567
Total		161,834.1	$9,618,431,279
2016/2017			
Rest of RTO	$101.62	81,169.7	$3,010,600,585
Rest of MAAC	$163.27	52,594.4	$3,134,361,252
PSEG	$224.70	11,042.7	$905,665,239
ATSI	$133.23	14,084.2	$684,910,081
Total		158,891.0	$7,735,537,157
2017/2018			
Rest of RTO	$151.26	97,894.4	$5,404,664,473
Rest of MAAC	$151.38	45,679.7	$2,523,928,434
PSEG	$206.31	11,295.9	$850,620,887
PPL	$149.58	8,266.1	$451,307,271
Total		163,136.1	$9,230,521,064
2018/2019			
Rest of RTO	$162.30	75,583.6	$4,477,496,562
Rest of MAAC	$216.11	42,763.4	$3,373,215,391
BGE	$155.91	7,897.7	$449,426,120
ComEd	$209.32	24,909.7	$1,903,172,638
Pepco	$154.63	7,416.8	$418,613,355
PPL	$152.87	8,445.3	$471,233,226
Total		167,016.4	$11,093,157,292
2019/2020			
Rest of RTO	$96.77	90,810.6	$3,216,399,297
Rest of EMAAC	$114.21	24,500.3	$1,024,120,622
BGE	$96.89	7,831.5	$277,722,332
ComEd	$189.99	25,326.5	$1,761,076,090
Pepco	$91.64	7,401.5	$248,261,480
PSEG	$114.46	11,435.5	$479,041,445
		167,305.9	$7,006,621,266

91 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.

92 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.

93 Prior to the 2009/2010 Delivery Year, the final UCAP obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 Delivery Years, the final UCAP obligations are determined after the clearing of the Third Incremental Auction. Effective with the 2012/2013 Delivery Year, the final UCAP obligation is determined after the clearing of the final Incremental Auction. Prior to the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after the final Incremental Auction. The 2017/2018, 2018/2019, and 2019/2020 Net Load Prices are not finalized. The 2017/2018, 2018/2019, and 2019/2020 obligation MW are not finalized.

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. In 2016, nuclear units had a capacity factor of 93.0 percent, compared to 94.5 percent in 2015; combined cycle units had a capacity factor of 62.0 percent in 2016, compared to a capacity factor of 62.5 percent in 2015; and steam units, which are primarily coal fired, had a capacity factor of 32.5 percent in 2016, compared to 43.8 percent in 2015. The decline in the capacity factor for coal units is the result of its higher operating costs compared to combined cycle and combustion turbine units in 2016.

Table 5-26 PJM capacity factor (By unit type (GWh)): January through December, 2015 and 2016[94]

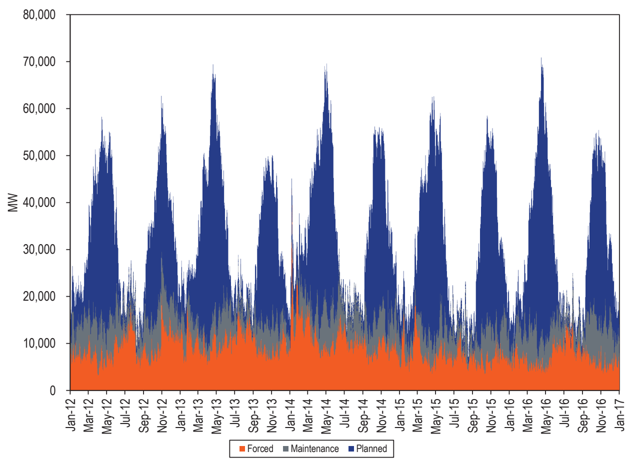
	2015		2016		Change in
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	2016 from 2015
Battery	7.6	0.5%	15.7	0.6%	0.1%
Combined Cycle	159,420.8	62.5%	187,368.5	62.0%	(0.5%)
Combustion Turbine	14,213.8	5.6%	17,980.5	6.8%	1.2%
Diesel	578.9	15.2%	662.7	16.9%	1.7%
Diesel (Landfill gas)	1,508.6	45.6%	1,501.9	45.1%	(0.4%)
Fuel Cell	227.1	86.4%	227.6	86.4%	(0.0%)
Nuclear	279,106.5	94.5%	279,546.4	93.0%	(1.4%)
Pumped Storage Hydro	6,038.4	12.8%	6,074.3	13.9%	1.1%
Run of River Hydro	7,000.9	30.5%	7,609.6	31.3%	0.8%
Solar	531.8	16.0%	970.3	17.7%	1.7%
Steam	388,709.8	43.8%	375,485.9	32.5%	(11.3%)
Wind	16,609.7	28.4%	17,696.2	28.0%	(0.3%)
Total	873,954.0	47.6%	895,139.6	41.2%	(6.4%)

94 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The MW on outage vary throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-9, due to restrictions on planned outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-12.

Figure 5-9 PJM outages (MW): 2012 through December 2016



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 5-10. Metrics by unit type are shown in Table 5-27.

Figure 5-10 PJM equivalent outage and availability factors: 2007 to 2016

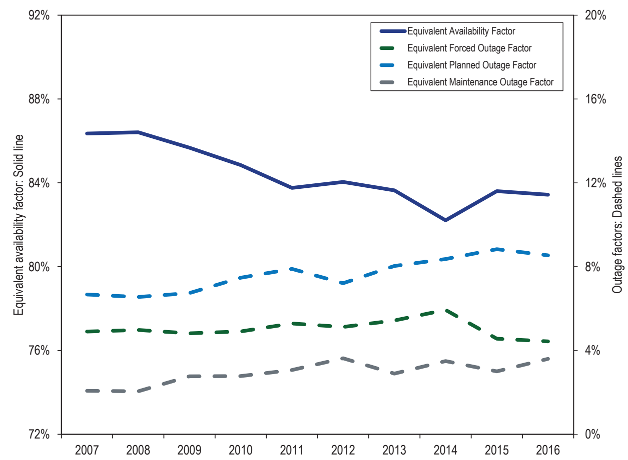


Table 5-27 EFOF, EPOF, EMOF and EAF by unit type: 2007 through 2016

	Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Steam			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	2.3%	6.1%	1.8%	89.8%	4.4%	2.4%	2.5%	90.6%	10.2%	0.6%	1.6%	87.6%	1.3%	7.2%	1.4%	90.1%	1.3%	5.3%	0.3%	93.1%	7.3%	8.6%	2.7%	81.4%
2008	2.1%	5.9%	1.7%	90.4%	2.7%	4.0%	2.2%	91.1%	9.1%	1.0%	1.2%	88.7%	1.3%	7.8%	2.1%	88.8%	1.8%	5.1%	0.8%	92.3%	7.9%	8.0%	2.6%	81.6%
2009	2.7%	6.3%	3.1%	87.9%	1.5%	2.8%	2.3%	93.4%	6.6%	0.6%	1.1%	91.7%	2.3%	8.7%	2.3%	86.8%	4.1%	5.2%	0.6%	90.1%	6.8%	8.5%	3.7%	81.0%
2010	2.6%	8.5%	3.0%	86.0%	1.9%	3.0%	2.0%	93.1%	4.4%	0.4%	1.5%	93.6%	0.7%	8.6%	1.9%	88.8%	2.3%	5.4%	0.5%	91.8%	7.7%	9.3%	3.9%	79.0%
2011	2.4%	9.6%	2.4%	85.5%	2.0%	3.8%	2.4%	91.8%	3.3%	0.1%	1.8%	94.8%	1.7%	11.7%	1.9%	84.7%	2.6%	6.1%	1.2%	90.1%	8.3%	9.2%	4.2%	78.3%
2012	3.6%	8.1%	2.6%	85.7%	2.8%	3.2%	1.7%	92.4%	3.9%	0.7%	2.4%	93.1%	2.8%	6.3%	2.1%	88.8%	1.5%	6.4%	1.1%	91.1%	7.8%	8.7%	5.6%	77.9%
2013	2.4%	8.6%	2.4%	86.5%	5.0%	4.0%	1.9%	89.1%	6.0%	0.3%	1.4%	92.4%	2.3%	7.8%	1.9%	87.9%	1.1%	5.9%	0.7%	92.2%	8.3%	10.2%	4.3%	77.2%
2014	2.6%	10.6%	2.5%	84.4%	6.0%	3.8%	1.9%	88.3%	13.8%	0.4%	2.2%	83.5%	2.5%	9.3%	3.0%	85.2%	1.8%	5.8%	0.9%	91.5%	8.8%	10.3%	5.5%	75.4%
2015	2.1%	10.6%	2.1%	85.2%	2.8%	4.5%	2.5%	90.2%	7.6%	0.3%	2.7%	89.4%	3.7%	9.6%	1.5%	85.2%	1.3%	5.5%	1.2%	91.9%	7.4%	11.3%	4.4%	77.0%
2016	2.6%	10.5%	1.7%	85.1%	2.1%	5.7%	2.7%	89.6%	5.4%	0.2%	2.6%	91.8%	2.4%	7.7%	3.3%	86.6%	1.7%	5.5%	1.2%	91.7%	7.4%	10.4%	5.8%	76.3%

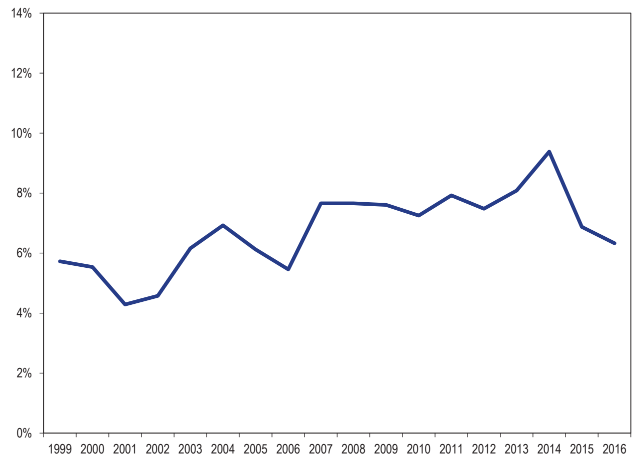
Generator Forced Outage Rates

There are three primary forced outage rate metrics. The most fundamental forced outage rate metric is EFORd. The other forced outage rate metrics either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp. The other outage rate metrics will no longer be used under the capacity performance capacity market design.

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[95] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for 2016 was 6.3 percent, a decrease from 7.0 percent for 2015. Figure 5-11 shows the average EFORd since 1999 for all units in PJM.[96]

Figure 5-11 Trends in the PJM equivalent demand forced outage rate (EFORd): 1999 through 2016



95 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.

96 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2016 State of the Market Report for PJM*, Appendix A: "PJM Geography" for details.

Table 5-28 shows the class average EFORd by unit type.

Table 5-28 PJM EFORd data for different unit types: 2007 through 2016

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Combined Cycle	3.7%	3.7%	4.1%	3.8%	3.4%	4.3%	3.1%	4.3%	2.8%	3.3%
Combustion Turbine	11.0%	11.1%	9.7%	9.0%	8.0%	8.2%	10.7%	15.8%	8.8%	5.8%
Diesel	11.7%	10.3%	9.3%	6.4%	9.3%	5.1%	6.6%	14.8%	9.1%	7.1%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	3.7%	3.8%	5.2%	3.5%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	1.2%	1.9%	1.4%	1.9%
Steam	9.1%	10.1%	9.3%	9.8%	11.2%	10.6%	11.6%	12.1%	10.2%	10.0%
Total	7.0%	7.7%	7.6%	7.3%	7.9%	7.5%	8.1%	9.4%	7.0%	6.3%

Other Forced Outage Rate Metrics

There are a number of performance incentives in the current capacity market design, but they fall short of the incentives that a unit would face if it earned all its revenue in an energy market. These incentives will change when the capacity performance capacity market design is implemented beginning with 2018/2019 Delivery Year but remain essential reasons why the incentive components of capacity performance design were necessary.

Currently, there are two additional forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. Under the capacity performance modifications to RPM, neither XEFORd nor EFORp will be relevant.

The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). Under the capacity performance modifications to RPM, all outages will be included in the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market, including the outages previously designated as OMC. OMC outages will no longer be excluded from the EFORd calculations.

The EFORp metric is the EFORd metric adjusted to remove OMC outages and to reflect unit availability only during the approximately 500 hours defined in the PJM RPM tariff to be the critical load hours. Under the capacity performance modifications to RPM, EFORp will no longer be used to calculate performance penalties.

Current PJM capacity market rules use XEFORd to determine the UCAP for generating units. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the XEFORd multiplied by the unit ICAP.

The current PJM Capacity Market rules create an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define capacity available for sale, the current PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC. That incentive is removed in the capacity performance design.

Outages Deemed Outside Management Control

OMC outages will continue to be excluded from outage rate calculations through the end of the 2017/2018 Delivery Year. Under the capacity performance modifications to RPM, effective with the 2018/2019 Delivery Year, OMC outages will no longer be excluded from the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. All forced outages will be included.[97]

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).[98] For NERC, an outage can be classified as an OMC outage only if the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions," also lists specific cause codes (codes that are standardized for specific outage causes) that would be considered OMC outages.[99] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, according to the NERC

97 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 5.B.

98 Generator Availability Data System Data Reporting Instructions states, "The electric industry in Europe and other parts of the world has made a change to examine losses of generation caused by problems with and outside plant management control… There are a number of outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. The standard sets a boundary on the generator side of the power station for the determination of equipment outside management control." The Generator Availability Data System Data Reporting Instructions can be found on the NERC website: <http://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_K_Outside_Plant_Management_Control.pdf>.

99 For a list of these cause codes, see the *Technical Reference for PJM Markets*, at "Generator Performance: NERC OMC Outage Cause Codes," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

specifications, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered separately per NERC.

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metrics used in the capacity market.[100] That choice was made by PJM and can be modified without violating any NERC requirements.[101] It is possible to have an OMC outage under the NERC definition, which PJM does not define as an OMC outage for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM chose to exclude only some of the OMC outages from the XEFORd metric.

PJM does not have a clear, documented, public set of criteria for designating outages as OMC, although PJM's actual practice appears to be improving.

All outages, including OMC outages, are included in the EFORd that is used for PJM planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd.

Table 5-29 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 4.0 percent of all forced outages in 2016. The largest contributor to OMC outages, flood, was the cause of 37.5 percent of OMC outages and 1.5 percent of all forced outages.

Table 5-29 OMC outages: 2016

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Flood	37.5%	1.5%
Lack of fuel	17.8%	0.7%
Transmission line	11.9%	0.5%
Transmission system problems other than catastrophes	11.5%	0.5%
Other switchyard equipment	8.0%	0.3%
Transmission equipment beyond the 1st substation	6.1%	0.2%
Lack of water (hydro)	2.8%	0.1%
Switchyard circuit breakers	1.5%	0.1%
Lightning	1.0%	0.0%
Other miscellaneous external problems	0.6%	0.0%
Transmission equipment	0.6%	0.0%
Wet coal	0.5%	0.0%
Other catastrophe	0.1%	0.0%
Switchyard system protection devices	0.1%	0.0%
Switchyard transformers and associated cooling systems	0.1%	0.0%
Other fuel quality problems	0.0%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Storms	0.0%	0.0%
Fire	0.0%	0.0%
Total	100.0%	4.0%

An outage is an outage, regardless of the cause. It is inappropriate that units on outage do not have to reflect that outage in their outage statistics, which affect their performance incentives and the level of unforced capacity and therefore capacity sold. No outages should be treated as OMC because when a unit is not available it is not available, regardless of the reason, and the data and payments to units should reflect that fact.[102]

Lack of fuel is an example of why, even if the OMC concept were accepted, many types of OMC outages are not actually outside the control of management. Virtually any issue with fuel supply can be addressed by additional expenditures. These are economic issues within the control of management and the resultant tradeoffs should be reflected in actual forced outage rates rather than ignored by designation as OMC. It is significant that some OMC outages are classified as economic. Firm gas contracts, including contracts with intermediaries, could be used in place of interruptible gas contracts. Alternative fuels could be used as a supplement to primary fuels. Improved fuel management practices including additional investment could eliminate wet coal as a reason. Better diversification in supplies could

100 For example, the NYISO does not classify any fuel related outages or derates as OMC under its capacity market rules. See New York Independent System Operator, "Manual 4: Installed Capacity Manual," Version 6.20. (January, 24 2012) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_mnl.pdf>. When a generator, energy/capacity limited resource, system resource, intermittent power resource or control area system resource is forced into an outage by an equipment failure that involves equipment located on the electric network beyond the step-up transformer, and including such step-up transformer, the NYISO shall not treat the outage as a forced outage for purposes of calculating the amount of unforced capacity such installed capacity suppliers are qualified to supply in the NYCA. This exception is limited to an equipment failure that involves equipment located on the electric network beyond the generator step-up transformer, and including such step-up transformer on the output side of the generator, energy/capacity limited resource, system resource, intermittent power resource or control area system resource. This exception does not apply to fuel related outages or derates or other cause codes that might be classified as outside management control in the NERC Data reporting Instructions. NYISO only accepts OMC outages for outages at or beyond the step-up transformer.

101 It is unclear whether there were member votes taken on this issue prior to PJM's implementation of its approach to OMC outages. It does not appear that PJM has consulted with members for the subsequent changes to its application of OMC outages.

102 For more on this issue, see the MMU's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market,*" <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

eliminate interruptions from individual suppliers. But regardless of the reason, an outage is an outage.

If a particular unit or set of units have outages for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.

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 after appropriate notice. OMC outages should not be reflected in forced outage metrics which affect market payments to generating units. OMC outages will be eliminated under the capacity performance rules.

Performance Incentives

There are a number of performance incentives in the current (pre capacity performance) capacity market design, but they fall short of the incentives that a unit would face if it earned all its revenue in an energy market. These incentives will change when the capacity performance market design is implemented beginning with 2018/2019 Delivery Year, but remain essential reasons why the incentive components of capacity performance design are necessary.

The most basic incentive is that associated with the reduction of payments for a failure to perform. In any market, sellers are not paid when they do not provide a product. That is only partly true in the PJM Capacity Market. Under the current RPM design, in place in 2016, in addition to the exclusion of OMC outages, which reduces forced outage rates resulting in payments to capacity resources not consistent with actual forced outage rates, other performance incentives were not designed to ensure that capacity resources are paid when they perform and not paid when they do not perform.

Until the capacity performance market design is fully implemented for the 2020/2021 Delivery Year, EFORp will continue be used in the calculation of nonperformance charges for units that are not capacity performance capacity resources.

In concept, units do not receive RPM revenues to the extent that they do not perform during defined peak hours, but there are significant limitations on this incentive in the current rules.

The maximum level of RPM revenues at risk are based on the difference between a unit's actual Peak Period Capacity Available (PCAP) and the unit's expected Target Unforced Capacity (TCAP). PCAP is based on EFORp while TCAP is based on XEFORd- 5. PCAP is the resource position, while TCAP is the resource commitment. In other words, if the forced outage rate during the peak hours (EFORp) is greater than the forced outage rate calculated over a five year period (XEFORd-5), the unit owner may have a capacity shortfall of up to 50 percent of the unit's capacity commitment in the first year.

(PCAP) Peak Period Capacity = ICAP * (1 - EFORp)

(TCAP) Target Unforced Capacity = ICAP *
(1 – XEFORd-5)

Peak Period Capacity Shortfall = TCAP – PCAP

The peak-hour period availability charge is equal to the seller's weighted average resource clearing price for the delivery year for the LDA.[103]

The peak hour availability charge understates the appropriate revenues at risk for underperformance because it is based on EFORp and because it is compared to a five year XEFORd. Both outage measures exclude OMC outages. The use of a five year average XEFORd measure is questionable as the measure of expected performance during the delivery year because it covers a period which is so long that it is unlikely to be representative of the current outage performance of the unit. The UCAP sold during a delivery year is a function of ICAP and the final effective EFORd, which is defined

103 PJM. OATT Attachment DD § 10 (j).

to be the XEFORd calculated for the 12 months ending in September in the year prior to the delivery year.[104]

This maximum level of RPM revenues at risk is reduced by several additional factors including the ability to net any shortfalls against over performance across all units owned by the same participant within an LDA and the ability to use performance by resources that were offered into RPM but did not clear as an offset.[105]

Excess available capacity (EAC) may also be used to offset peak hour availability shortfalls. EAC is capacity which was offered into RPM Auctions, did not clear but was offered into all PJM markets consistent with the obligations of a capacity resource. EAC must be part of a participant's total portfolio, but does not have to be in the same LDA as the shortfall being offset, unlike the netting provision.[106]

There is a separate exception to the performance related incentives related to lack of gas during the winter period. Single-fuel, natural gas-fired units do not face the peak-hour period availability charge during the winter if the capacity shortfall was due to nonavailability of gas to supply the unit.[107] The result is an exception, analogous to the lack of fuel exception, except much broader, which appears to have no logical basis.

There is a separate exception to the performance related incentives related to a unit that runs less than 50 hours during the RPM peak period. If a unit runs for less than 50 peak period service hours, then the EFORp used in the calculation of the peak hour availability charges is based on PCAP calculated using the lower of the delivery year XEFORd or the EFORp.[108]

There is a separate exception for wind and solar capacity resources which are exempt from this performance incentive.[109]

The peak hour availability charge does not apply if the unit unavailability resulted in another performance related charge or penalty.[110]

104 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 4.2.5
105 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 8.4.5.
106 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 8.4.5.1.
107 PJM. OATT Attachment DD § 7.10 (e).
108 *Id.*
109 *Id.*
110 *Id.*

Under the peak hour availability charge, the maximum exposure to loss of capacity market revenues is 50 percent in the first year of higher than 50 percent EFORp. That percent increases to 75 percent in year two of sub 50 percent performance and to 100 percent in year three, but returns to a maximum of 50 percent after three years of better performance.

This limitation on maximum exposure is in addition to limitations that result from the way in which PJM applies the OMC rules in the calculation of EFORp and XEFORd, is in addition to the exclusion for gas availability in the winter, which is over and above the OMC exclusion, and is in addition to the case where a unit has less than 50 service hours in a delivery year and can use the lower of the delivery year XEFORd or EFORp.

Not all unit types are subject to RPM performance incentives. In addition to the exceptions which apply to conventional generation as a result of EFORp and XEFORd calculations, wind, solar and hydro generation capacity resources are exempt from key performance incentives. Wind and solar generation capacity resources are not subject to peak hour availability incentives, to summer or winter capability testing or to peak season maintenance compliance rules. Hydro generation capacity resources are not subject to peak season maintenance compliance rules.[111]

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.[112] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).[113]

PJM EFOF was 4.4 percent in 2016. This means there was 4.4 percent lost availability because of forced outages. Table 5-30 shows that forced outages for boiler tube leaks, at 21.2 percent of the systemwide EFOF, were the largest single contributor to EFOF.

111 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015).
112 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.
113 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-30 Contribution to EFOF by unit type by cause: 2016

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	2.2%	0.0%	0.0%	0.0%	0.0%	29.1%	21.2%
Wet Scrubbers	0.0%	0.0%	0.0%	0.0%	0.0%	10.2%	7.4%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	9.0%	6.5%
Miscellaneous (Generator)	1.9%	8.0%	8.6%	10.2%	0.8%	4.3%	4.3%
Feedwater System	2.4%	0.0%	0.0%	0.0%	1.2%	5.3%	4.2%
Electrical	8.1%	7.8%	3.7%	19.5%	1.6%	2.9%	4.1%
Reserve Shutdown	1.4%	13.4%	15.7%	21.1%	4.1%	2.8%	4.1%
Boiler Fuel Supply from Bunkers to Boiler	0.3%	0.0%	0.0%	0.0%	0.0%	4.2%	3.1%
Miscellaneous (Balance of Plant)	6.1%	1.8%	0.0%	4.3%	1.0%	2.9%	3.0%
Controls	2.9%	0.4%	2.0%	0.8%	25.7%	0.9%	2.9%
Generator	3.2%	0.5%	12.4%	4.3%	0.0%	3.1%	2.7%
Economic	1.0%	20.8%	5.5%	9.3%	0.0%	1.0%	2.7%
Boiler Piping System	3.6%	0.0%	0.0%	0.0%	0.0%	2.3%	2.0%
Condensing System	0.5%	0.0%	0.0%	0.0%	1.6%	2.0%	1.7%
Reactor Vessel and Internals	0.0%	0.0%	0.0%	0.0%	22.1%	0.0%	1.6%
Circulating Water Systems	1.4%	0.0%	0.0%	0.0%	0.6%	2.0%	1.6%
Miscellaneous (Steam Turbine)	7.9%	0.0%	0.0%	0.0%	4.1%	0.7%	1.6%
Miscellaneous (Gas Turbine)	7.5%	10.6%	0.0%	0.0%	0.0%	0.0%	1.6%
Catastrophe	15.4%	0.4%	0.1%	1.1%	0.0%	0.0%	1.6%
All Other Causes	34.1%	36.5%	52.0%	29.4%	36.9%	17.2%	22.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-31 shows the categories which are included in the economic category.[114] Lack of fuel that is considered outside management control accounted for 26.3 percent of all economic reasons.

OMC lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."[115] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 5-31 Contributions to Economic Outages: 2016

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	62.7%
Lack of fuel (OMC)	26.3%
Other economic problems	5.4%
Lack of water (hydro)	4.2%
Fuel conservation	1.2%
Wet fuel (biomass)	0.2%
Ground water or other water supply problems	0.1%
Problems with primary fuel for units with secondary fuel operation	0.0%
Total	100.0%

EFORd, XEFORd and EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

Until the capacity performance market design is fully implemented for the 2020/2021 Delivery Year, EFORp will be used in the calculation of nonperformance charges for units that are not capacity performance capacity resources. Under capacity performance, EFORp will not be used.

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[116] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than XEFORd, suggesting that units elect to take non OMC forced outages during off-peak hours, as much as it is within their ability to do so.

114 The definitions of these outages are defined by NERC GADS.
115 The definitions of these outages are defined by NERC GADS.
116 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.

That is consistent with the incentives created by the PJM Capacity Market but it does not directly address the question of the incentive effect of omitting OMC outages from the EFORP metric.

Table 5-32 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

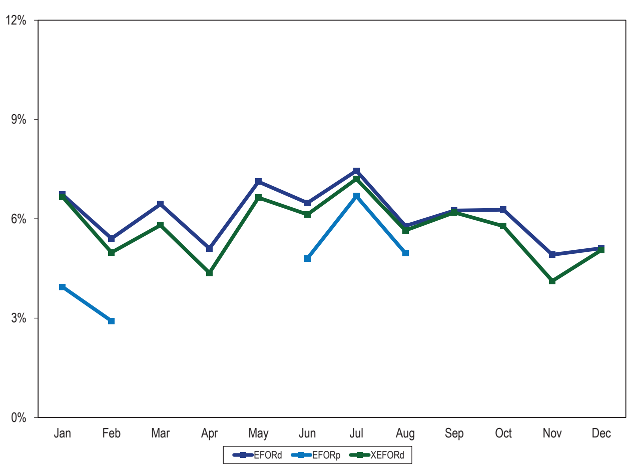
Table 5-32 PJM EFORd, XEFORd and EFORp data by unit type: 2016[117]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.3%	2.6%	1.5%	0.7%	1.8%
Combustion Turbine	5.8%	5.3%	3.3%	0.4%	2.5%
Diesel	7.1%	6.4%	4.1%	0.8%	3.0%
Hydroelectric	3.5%	3.1%	2.3%	0.4%	1.2%
Nuclear	1.9%	1.8%	3.3%	0.1%	(1.4%)
Steam	10.0%	9.8%	8.1%	0.2%	1.9%
Total	6.3%	6.0%	5.0%	0.3%	1.3%

Performance by Month

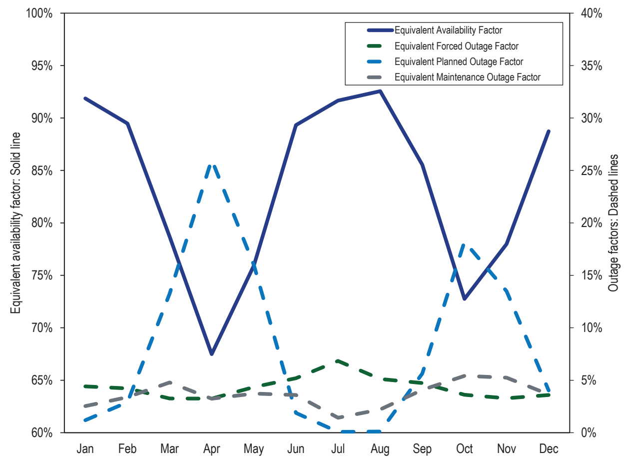
On a monthly basis, EFORp values were less than EFORd and XEFORd values as shown in Figure 5-12, demonstrating that units had fewer non-OMC outages during peak hours than would have been expected based on EFORd.

Figure 5-12 PJM EFORd, XEFORd and EFORp: 2016



On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-13.

Figure 5-13 PJM monthly generator performance factors: 2016



117 EFORp is only calculated for the peak months of January, February, June, July and August.

Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation.

Overview

- **Demand Response Jurisdiction.** In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated Order No. 745, which provided for payment of demand-side resources at full LMP.[1] The court found that the FERC lacked jurisdiction to issue Order No. 745 because the "rule entails direct regulation of the retail market - a matter exclusively within state control."[2] On January 25, 2016, the U.S. Supreme Court voted 6-2 to reverse the decision of the lower court.[3] The result is that FERC retains jurisdiction over demand-side programs.

- **Demand Response Activity.** Demand response includes the economic program and the emergency program. The economic program includes the response to energy prices in the energy market. The emergency and pre-emergency program are part of the capacity market program which includes both capacity payments and associated energy revenues when the capacity is called on to respond.[4] In 2016, the emergency program accounted for 99.0 percent of all revenue received by demand response providers, the economic program for 0.5 percent and synchronized reserve for 0.5 percent. Total emergency revenue decreased by $163.2 million, or 20.1 percent, from $812.2 million in 2015 to $649.0 million in 2016. Capacity market revenue, which comprised 100.0 percent of the emergency demand response program in 2016, decreased by $162.7 million, or 20.0 percent, from $811.7 million in 2015 to $649.0 million in 2016.5

  Economic program revenue decreased by $4.7 million, from $8.0 million in 2015 to $3.3 million in 2016, a 58.8 percent decrease.[6] Synchronized reserve revenue decreased by $1.6 million, from $5.0 million in 2015 to $3.4 million in 2016, a 32.0 percent decrease.

  Total demand response revenue decreased by 169.5 million, from $825.2 million in 2015 to $655.7 million in 2016, a 20.5 percent decrease. Not all DR activities in 2016 had been reported to PJM at the time of this report.

  All demand response energy payments are uplift. LMP does not cover demand response energy payments although emergency demand response can and does set LMP. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Economic demand response energy costs are paid by 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 single system price determined under the net benefits test for that month.[7]

- **Demand Response Market Concentration.** The ownership of economic demand response was highly concentrated in 2015 and 2016. The HHI for economic demand response reductions decreased from 7834 in 2015 to 7729 in 2016. The ownership of emergency demand response was moderately concentrated in 2016. The HHI for emergency demand response registrations was 1497 for the 2015/2016 Delivery Year and 1469 for the 2015/2016 Delivery Year. In the 2016/2017 Delivery Year, the four largest companies contributed 66.6 percent of all registered emergency demand response resources.

- **Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes, only

1 Electric Power Supply Association v. FERC, No. 11-1486, *petition for en banc review denied*; *see Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011); *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011); *order on reh'g*, Order No. 745-B, 138 FERC 61,148 (2012).

2 *Id.*

3 FERC v. Electric Power Supply Association, Slip Op. No. 14-840.

4 Throughout this document, emergency demand response refers to both emergency and pre-emergency demand response.

5 The total credits and MWh numbers for demand resources were calculated as of January 10, 2017 and may change as a result of continued PJM billing updates.

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

7 PJM: "Manual 28: Operating Agreement Accounting," Revision 75 (November 18, 2016), p 77.

if the subzone is defined at least one day before it is dispatched and only until PJM removes the definition of the subzone. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation resources.

Recommendations

The MMU recognizes that PJM incorporated some of the recommendations related to Demand Response in the Capacity Performance filing. The status of each recommendation reflects the status at December 31, 2016.

- The MMU recommends, as a preferred alternative to having PJM demand side programs, that demand response be on the demand side of the markets and that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion and that customer payments be determined only by metered load. (Priority: High. First reported 2014. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the emergency load response program be treated as an economic resource, responding to economic price signals like other capacity resources and not an emergency program responding only after an emergency is called, and not triggering the definition of a PJM emergency and not triggering a Performance Assessment Hour under the new PJM Capacity Market rules. (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 a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[8] (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 eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[9] (Priority: Medium. First reported 2013. Status: Not adopted.)

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

9 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 June 29, 2016) ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Not 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 to terminate registrations that are no longer capable of responding to PJM dispatch directives because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzone and maintain a public record of all created and removed subzones. (Priority: Low. First reported Q3, 2016. Status: Not adopted.)
- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year. (Priority: High. First reported 2011. Status: Partially adopted.[10])
- 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 capping 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 capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted, 2014.)

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 the value of the uses of 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

10 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

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.

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 and not be limited to a small number of hours.

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

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

In order to be a substitute for generation, compliance by demand resources to 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 Hours (PAH) will be measured on an hourly 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 registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative, demand response should be on the demand side of the capacity market rather than on the supply side. Rather than complex 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.

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

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

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

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

This approach would work under the current RPM design and this approach would work under the CP design. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side. This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

PJM Demand Response Programs

All demand response programs in PJM can be grouped into economic, emergency and pre-emergency programs. Pre-emergency demand response is defined to be dispatchable before an emergency event is declared.[11] Table 6-1 provides an overview of the key features of PJM demand response programs. Demand response program is used here to refer to pre-emergency, emergency and economic programs. Demand Resources is used here to refer to emergency and pre-emergency load response, which participate in the capacity market, and Economic Resources refer to economic load response, which participates solely in the energy market. All Demand Resources must register as pre-emergency unless the participant relies on behind the meter generation or the resource has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[12] In all demand response programs, CSPs are companies that seek to sign up end-use customers, participants, that have the ability to reduce load. After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response program, but a participant can register as a PJM special member and become a CSP without any additional cost.

11 147 FERC ¶ 61,103 (2014).

12 OATT Attachment K Appendix Section 8.5

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Load Response Program			Economic Load Response Program
	Load Management (LM)			
Market	Capacity Only	Capacity and Energy	Energy Only	Energy Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment
Penalties	RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	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.

In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated Order No. 745, which provided for payment of demand-side resources at full LMP.[13] The court found that the FERC lacked jurisdiction to issue Order No. 745 because the "rule entails direct regulation of the retail market - a matter exclusively within state control."[14] On January 25, 2016, the Supreme Court voted 6-2 to reverse the decision of the lower court.[15] The result is that FERC retains jurisdiction over demand-side programs.

Participation in Demand Response Programs

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefits test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission already included in customers' tariff rates.

Figure 6-1 shows all revenue from PJM demand response programs by market for each year for 2008 through 2016. Since the implementation of the RPM Capacity Market on June 1, 2007, demand response that participated through the capacity market, which includes emergency energy revenue, has been the primary source of revenue to demand response participants.[16]

In 2016, emergency and pre-emergency revenue, which includes capacity and emergency energy revenue, accounted for 99.0 percent of all revenue received by demand response providers, credits from the economic program were 0.5 percent and revenue from synchronized reserve was 0.5 percent.

Total emergency and pre-emergency revenue decreased by $163.2 million, or 20.1 percent, from $812.1 million in 2015 to $649.0 in 2016. Of the total emergency revenue, capacity market revenue decreased by $162.6 million, or 20.0 percent, from $811.7 million in 2015 to $649.0 million in 2016. This was in part a result of lower capacity market prices in 2016. The capacity revenue in 2016 include five months of the 2015/2016 RPM auction clearing price and seven months of the 2016/2017 RPM auction clearing price. Capacity market prices decreased $6,078 per MW-year from $54,646 in 2015 to $48,568, an 11.1 percent decrease.[17] Total demand response revenue in 2016 decreased by 20.5 percent from $812.2 million in 2015 to $655.7 million in 2016. Total demand response revenue includes economic, pre-emergency, emergency and synchronized reserve revenue.

Total revenue under the economic program decreased by $4.7 million from $8.0 million in 2015 to $3.3 million in 2016, a 58.8 percent decrease.

13 Electric Power Supply Association v. FERC, No. 11-1486, *petition for en banc review denied*; *see Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011); *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011); *order on reh'g*, Order No. 745-B, 138 FERC 61,148 (2012).

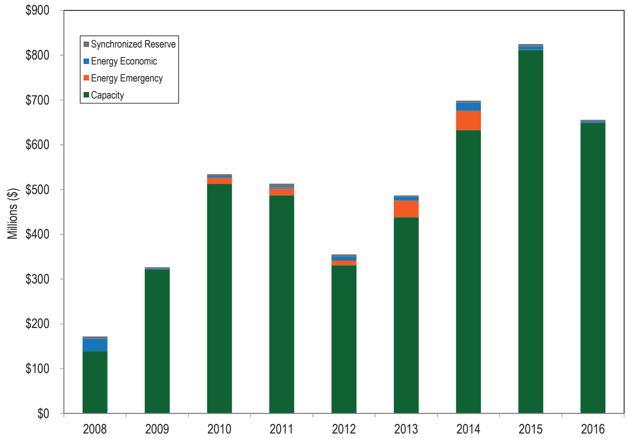
14 *Id.*

15 FERC v. Electric Power Supply Association, Slip Op. No. 14-840.

16 This includes both capacity market revenue and emergency energy revenue for capacity resources.

17 *2016 State of the Market Report for PJM*, Section 7: Net Revenues, Table 7-6.

Figure 6-1 Demand response revenue by market: 2008 through 2016



Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period January 2010 through December 2016. Registration is a prerequisite for CSPs to participate in the economic program. Both the average number of registrations for economic demand response and the average registered MW decreased in 2016 compared to 2015. The average number of monthly registrations decreased by 199 from 974 in 2015 to 774 in 2016. The average monthly registered MW decreased by 241 MW, or 8.7 percent, from 2,788 MW in 2015 to 2,547 MW in 2016.

Table 6-2 Economic program registrations on the last day of the month: January 2010 through December 2016

	2010		2011		2012		2013		2014		2015		2016	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,841	2,623	1,609	2,432	1,993	2,385	841	2,314	1,180	2,325	1,078	2,960	838	2,557
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,327	1,174	2,330	1,076	2,956	835	2,557
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,284	1,185	2,692	1,075	2,949	834	2,556
Apr	1,849	2,587	1,611	2,534	189	1,318	970	2,346	1,194	2,827	1,076	2,938	832	2,556
May	1,875	2,819	1,687	3,166	371	1,669	1,375	2,414	745	2,511	980	2,846	829	2,545
Jun	813	1,608	1,143	1,912	803	2,347	1,302	2,144	928	2,943	871	2,614	518	2,500
Jul	1,192	2,159	1,228	2,062	942	2,323	1,315	2,443	1,036	3,006	870	2,609	519	2,421
Aug	1,616	2,398	1,987	2,194	1,013	2,373	1,299	2,527	1,080	3,033	869	2,609	805	2,569
Sep	1,609	2,447	1,962	2,183	1,052	2,421	1,280	2,475	1,077	2,919	867	2,608	831	2,608
Oct	1,606	2,444	1,954	2,179	828	2,269	1,210	2,335	1,060	2,943	858	2,568	822	2,564
Nov	1,605	2,444	1,988	2,255	824	2,267	1,192	2,307	1,063	2,995	851	2,566	820	2,564
Dec	1,598	2,439	1,992	2,259	846	2,283	1,192	2,311	1,071	2,923	850	2,566	807	2,561
Avg.	1,609	2,432	1,606	2,382	1,150	2,175	1,113	2,364	1,067	2,732	974	2,788	774	2,547

Several demand response resources are registered for both the economic and emergency demand response programs. There were 539 registrations and 2,104 nominated MW in the emergency program that were also registered in the economic program during 2016.

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 more, less or the same amount of MW as registered in the program. Table 6-3 shows the sum of peak economic MW dispatched by registration each month for 2010 through 2016. The monthly peak is the sum of each registration's monthly noncoincident peak dispatched MW and annual peak is the sum of each registration's noncoincident peak dispatched MW each year. The annual peak dispatched MW for all economic demand response registered resources decreased by 423 MW, from 1,848 MW in 2015 to 1,425 MW in 2016.[18]

Table 6-3 Sum of peak MW reductions for all registrations per month: 2010 through 2016

Sum of Peak MW Reductions for all Registrations per Month							
Month	2010	2011	2012	2013	2014	2015	2016
Jan	183	132	110	193	450	169	139
Feb	121	89	101	119	307	336	128
Mar	115	81	72	127	369	198	119
Apr	111	80	108	133	146	143	118
May	172	98	143	192	151	161	131
Jun	209	561	954	433	483	833	121
Jul	999	561	1,631	1,091	665	1,362	1,303
Aug	794	161	952	497	357	272	249
Sep	276	84	451	548	795	816	259
Oct	118	81	242	168	214	136	150
Nov	111	86	165	155	166	127	93
Dec	114	88	98	168	155	122	79
Annual	1,202	840	1,942	1,467	1,532	1,848	1,425

18 As a result of the 60 day data lag from event date to settlement, not all settlements for November and December 2016 are incorporated in this report.

All demand response energy payments are uplift rather than market payments. 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.[19] The zonal allocation is shown in Table 6-13.

Table 6-4 shows the total MW reductions made by participants in the economic program and the total credits paid for these reductions every year from 2010 to 2016. The average credits per MWh paid decreased by $21.77 per MWh, or 33.0 percent, from $65.91 per MWh in 2015 to $44.14 per MWh dispatched in 2016. The average real-time load weighted PJM LMP decreased by $2.50 per MWh, or 19.2 percent, from $36.16 per MWh in 2015 to $29.23 per MWh in 2016. Curtailed energy for the economic program was 74,490 MWh in 2016 and the total payments were $3,287,731.[20] Total credits paid for economic DR in 2016 decreased by $4.7 million or 58.8 percent, compared to 2015.

Table 6-4 Credits paid to the PJM economic program participants: 2010 through 2016

Year	Total MWh	Total Credits	$/MWh
2010	72,757	$4,728,660	$64.99
2011	17,398	$2,052,996	$118.00
2012	145,019	$9,284,118	$64.02
2013	133,963	$8,711,873	$65.03
2014	149,246	$17,704,828	$118.63
2015	121,129	$7,983,488	$65.91
2016	74,490	$3,287,731	$44.14

Economic demand response resources that are dispatched in both the economic and emergency programs at the same time are settled under emergency rules. For example, assume a demand resource has an economic strike 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. All other resources that clear in the day-ahead market are financially firm at the clearing price.

Figure 6-2 shows monthly economic demand response credits and MWh, from January 2010 through December 2016. Higher energy prices and FERC Order No. 745 increased incentives to participate starting in April 2012. Energy prices have continued to trend lower and this has resulted in lower credits paid to economic DR resources in 2016 compared to 2015.

Figure 6-2 Economic program credits and MWh by month: 2010 through 2016

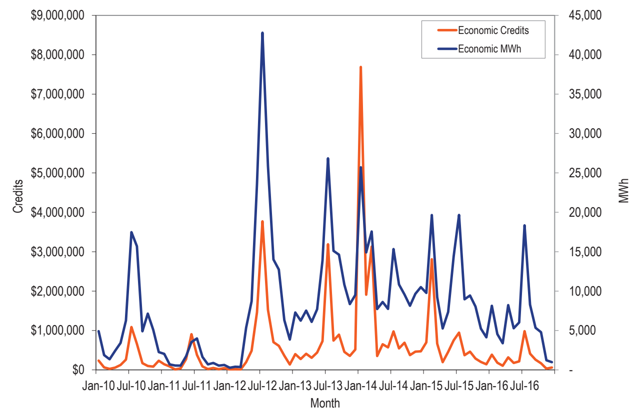


Table 6-5 shows performance for 2015 and 2016 in the economic program by control zone and participation type. Total economic program reductions decreased 15.2 percent from 121,129 MW in 2015 to 74,490 MW in 2016. The economic credits decreased by 58.8 percent from $7,983,488 in 2015, to $3,287,731 in 2016.

19 PJM: "Manual 28: Operating Agreement Accounting," Revision 75 (November 18, 2016), p 78.

20 The total MWh and Total Credits values in this table are the most up to date at the time of this report. Succeeding tables that report on charges paid for economic demand response may vary slightly from these numbers due to the timing of PJM settlement database updates.

Table 6-5 PJM economic program participation by zone: 2015 and 2016[21]

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2015	2016	Percent Change	2015	2016	Percent Change	2015	2016	Percent Change
AECO, JCPL, PECO, Pepco, RECO	$535,542	$262,540	(51.0%)	4,824	4,660	(3.4%)	$111.03	$56.34	(49.3%)
AEP, AP	$140,057	$55,987	(60.0%)	2,121	1,294	(39.0%)	$66.03	$43.28	(34.5%)
ATSI, ComEd, DAY, DEOK, DLCO, EKPC	$788,249	$666,647	(15.4%)	18,607	16,343	(12.2%)	$42.36	$40.79	(3.7%)
BGE, DPL, Met-Ed, PENELEC	$1,016,592	$877,955	(13.6%)	20,527	19,306	(5.9%)	$49.52	$45.47	(8.2%)
Dominion	$4,583,225	$986,080	(78.5%)	59,432	20,984	(64.7%)	$77.12	$46.99	(39.1%)
PPL, PSEG	$919,823	$438,523	(52.3%)	15,617	11,903	(23.8%)	$58.90	$36.84	(37.4%)
Total	$7,983,488	$3,287,731	(58.8%)	121,129	74,490	(15.2%)	$65.91	$44.14	(33.0%)

Table 6-6 shows total settlements submitted for 2010 through 2016. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-6 Settlements submitted by year in the economic program: 2010 through 2016

Year	2010	2011	2012	2013	2014	2015	2016
Number of Settlements	3,781	732	5,835	2,846	3,014	2,173	1,727

Table 6-7 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements by year from 2010 through 2016. There were 55 fewer active participants in 2016 than in 2015. All participants must be included in a CSP.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: 2010 through 2016

	2010		2011		2012		2013		2014		2015		2016	
	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants
Total Distinct Active	16	258	15	203	22	428	20	276	18	165	18	116	15	61

The ownership of economic demand response was highly concentrated in 2015 and 2016.[22] Table 6-8 shows the average hourly HHI for each month and the average hourly HHI for 2015 and 2016. The table also lists the share of reductions provided by, and the share of credits claimed by the four largest parent companies in each year. In 2016, 88.1 percent of all economic DR reductions and 86.6 percent of economic DR revenue were attributable to the four largest parent companies. The HHI for economic demand response decreased 105 points, from 7834 in 2015 to 7729 in 2016.

Table 6-8 HHI and market concentration in the economic program: January 2015 through December 2016[23]

	HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2015	2016	Percent Change	2015	2016	Change in Percent	2015	2016	Change in Percent
Jan	8088	7434	(8.1%)	96.8%	97.5%	0.7%	98.6%	98.0%	(0.6%)
Feb	7385	7696	4.2%	91.4%	99.9%	8.5%	87.8%	99.8%	12.0%
Mar	7548	8587	13.8%	89.1%	98.9%	9.8%	84.4%	99.4%	15.0%
Apr	7207	6753	(6.3%)	97.8%	100.0%	2.2%	97.8%	100.0%	2.2%
May	7780	8155	4.8%	98.9%	97.9%	(1.0%)	99.4%	98.3%	(1.1%)
Jun	8038	7685	(4.4%)	96.8%	100.0%	3.2%	95.6%	100.0%	4.4%
Jul	7755	7324	(5.6%)	91.5%	91.7%	0.2%	84.3%	89.2%	4.9%
Aug	8412	7609	(9.6%)	94.9%	93.5%	(1.4%)	94.0%	89.3%	(4.7%)
Sep	8009	7659	(4.4%)	99.0%	93.9%	(5.1%)	98.9%	92.7%	(6.2%)
Oct	7584	8168	7.7%	99.4%	100.0%	0.6%	99.3%	100.0%	0.7%
Nov	7859	9546	21.5%	96.1%	100.0%	3.9%	97.7%	100.0%	2.3%
Dec	8480	8672	2.3%	97.5%		NA	98.0%		NA
Total	7834	7729	(1.3%)	63.9%	88.1%	24.3%	77.7%	86.6%	9.0%

21 PJM and the MMU cannot publish more detailed information about the Economic Program Zonal Settlements as a result of confidentiality requirements in the PJM Market Rules.

22 Parent companies may own one CSP or multiple CSPs. All HHI calculations in this section are at the parent company level.

23 December 2016 is omitted for the top four companies share of reductions and credits columns due to confidentiality requirements.

Table 6-9 shows average MWh reductions and credits by hour for 2015 and 2016. In 2015, 94 percent of reductions and 92.2 percent of credits occurred in hours ending 0700 to 2100, and in 2016, 97.3 percent of reductions and 98.4 percent of credits occurred in hours ending 0700 to 2100.

Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: 2015 and 2016

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2015	2016	Percent Change	2015	2016	Percent Change
1	344	65	(81%)	$38,514	$857	(98%)
2	332	66	(80%)	$33,948	$743	(98%)
3	360	65	(82%)	$40,805	$427	(99%)
4	431	65	(85%)	$46,066	$362	(99%)
5	424	73	(83%)	$46,863	$600	(99%)
6	864	287	(67%)	$103,844	$12,562	(88%)
7	4,591	2,526	(45%)	$493,613	$156,329	(68%)
8	6,542	4,139	(37%)	$621,492	$213,548	(66%)
9	7,406	4,770	(36%)	$437,719	$175,717	(60%)
10	5,597	3,700	(34%)	$383,584	$123,285	(68%)
11	4,826	3,207	(34%)	$316,502	$103,507	(67%)
12	5,126	3,412	(33%)	$316,743	$115,789	(63%)
13	5,400	3,590	(34%)	$296,866	$128,188	(57%)
14	7,549	5,225	(31%)	$410,419	$252,951	(38%)
15	8,968	6,079	(32%)	$475,906	$320,210	(33%)
16	11,722	7,271	(38%)	$622,273	$370,295	(40%)
17	12,549	7,704	(39%)	$730,570	$392,309	(46%)
18	12,639	7,441	(41%)	$759,306	$373,211	(51%)
19	10,011	5,849	(42%)	$650,681	$246,833	(62%)
20	6,871	4,223	(39%)	$465,489	$147,474	(68%)
21	5,125	3,326	(35%)	$378,924	$116,093	(69%)
22	1,898	820	(57%)	$165,502	$25,445	(85%)
23	816	340	(58%)	$77,661	$6,889	(91%)
24	739	248	(66%)	$70,198	$4,104	(94%)
Total	121,129	74,490	(39%)	$7,983,488	$3,287,731	(59%)

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in 2015 and 2016. In 2016, 0.6 percent of MWh reductions and 1.8 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): 2015 and 2016

	MWh Reductions			Program Credits		
LMP	2015	2016	Percent Change	2015	2016	Percent Change
$0 to $25	34	17	(51%)	$48	$276	472%
$25 to $50	8,024	10,673	33%	$174,984	$226,110	29%
$50 to $75	67,043	48,450	(28%)	$2,586,298	$1,792,300	(31%)
$75 to $100	18,770	8,317	(56%)	$1,184,714	$513,620	(57%)
$100 to $125	9,207	2,459	(73%)	$806,756	$182,093	(77%)
$125 to $150	5,255	2,341	(55%)	$577,613	$237,908	(59%)
$150 to $175	2,891	1,046	(64%)	$390,938	$135,013	(65%)
> $175	1,886	470	(75%)	$285,945	$58,826	(79%)
Total	121,129	74,490	(39%)	$7,983,488	$3,287,731	(59%)

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 2016 was calculated using generation offers from February 2015. 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 1.[24] 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 the real-time or day-ahead prices. In addition, it is a single price used to trigger payments to economic demand response resources throughout the entire RTO, regardless of their location.

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

24 PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p 146.

market impact of that choice does not require a test for appropriateness.

When the LMP is above the NBT threshold price, economic demand response resources that reduce their power consumption are paid the full LMP. When the LMP is below the NBT threshold price, economic demand response resources are not paid for any load reductions. About 0.6 percent of DR dispatch occurred during hours with LMP lower than the NBT threshold price.

Table 6-11 shows the NBT threshold price from April 2012, when FERC Order No. 745 was implemented in PJM, through December of 2016. Significantly lower fuel prices in 2016 led to lower NBT threshold prices.

Table 6-11 Net benefits test threshold prices: April 2012 through December 2016

	Net Benefits Test Threshold Price ($/MWh)				
Month	2012	2013	2014	2015	2016
Jan		$25.72	$29.51	$29.63	$23.67
Feb		$26.27	$30.44	$26.52	$26.71
Mar		$25.60	$34.93	$24.99	$22.10
Apr	$25.89	$26.96	$32.59	$24.92	$19.93
May	$23.46	$27.73	$32.08	$23.79	$20.69
Jun	$23.86	$28.44	$31.62	$23.80	$20.62
Jul	$22.99	$29.42	$31.62	$23.03	$20.73
Aug	$24.47	$28.58	$29.85	$23.17	$23.24
Sep	$24.93	$28.80	$29.83	$21.69	$24.70
Oct	$25.96	$29.13	$30.20	$21.48	$26.50
Nov	$25.63	$31.63	$29.17	$22.28	$29.27
Dec	$25.97	$28.82	$29.01	$22.31	$29.71
Average	$24.80	$28.09	$30.91	$23.97	$23.99

Table 6-12 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price. In 2016, the highest zonal LMP in PJM was higher than the NBT threshold price 7,530 hours out of 8,784 hours, or 85.7 percent of all hours. Reductions occurred in 6,511 hours, or 86.5 percent, of those 7,530 hours in 2016. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices in 2015 and 2016.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: 2015 and 2016

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with DR		
Month	2015	2016	2015	2016	Percent Change	2015	2016	Percent Change
Jan	744	744	669	690	3.1%	48.6%	81.4%	32.9%
Feb	672	696	670	595	(11.2%)	66.1%	66.7%	0.6%
Mar	743	743	719	710	(1.3%)	53.0%	83.9%	31.0%
Apr	720	720	713	692	(2.9%)	48.0%	93.1%	45.1%
May	744	744	692	602	(13.0%)	55.2%	97.3%	42.1%
Jun	720	720	659	576	(12.6%)	60.9%	94.6%	33.8%
Jul	744	744	708	697	(1.6%)	71.2%	97.1%	25.9%
Aug	744	744	665	704	5.9%	72.6%	100.0%	27.4%
Sep	720	720	659	651	(1.2%)	76.9%	97.5%	20.6%
Oct	744	744	708	693	(2.1%)	71.9%	86.3%	14.4%
Nov	721	721	676	401	(40.7%)	49.0%	68.3%	19.4%
Dec	744	744	654	519	(20.6%)	44.6%	56.5%	11.8%
Total	8,760	8,784	8,192	7,530	(8.1%)	59.8%	86.5%	26.7%

Economic DR revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-13 shows the sum of real-time DR charges and day-ahead DR charges for each zone and for exports. Real-time loads in AEP, Dominion, and ComEd paid the highest DR charges in 2016.

Table 6-13 Zonal DR charge: 2016

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$3,909	$2,797	$572	$2,699	$2,006	$2,590	$15,701	$5,781	$2,893	$875	$172	$615	$40,608
AEP	$61,507	$26,701	$19,772	$55,451	$28,377	$33,758	$138,190	$61,304	$39,715	$28,654	$4,529	$9,802	$507,760
AP	$25,411	$12,526	$7,495	$21,191	$10,641	$12,386	$53,344	$23,249	$15,531	$10,823	$1,748	$3,754	$198,099
ATSI	$30,433	$14,082	$10,414	$29,156	$15,424	$18,108	$78,490	$34,379	$20,837	$15,358	$2,472	$5,041	$274,195
BGE	$17,843	$13,378	$4,900	$13,129	$6,937	$8,588	$40,535	$17,640	$11,992	$8,179	$1,878	$2,318	$147,316
ComEd	$35,941	$9,206	$12,101	$33,432	$22,093	$27,308	$122,641	$50,969	$31,707	$22,105	$2,796	$6,662	$376,962
DAY	$8,580	$3,505	$2,662	$7,589	$3,972	$4,887	$19,909	$9,015	$5,800	$4,288	$655	$1,334	$72,196
DEOK	$12,263	$3,982	$3,881	$11,534	$6,103	$7,889	$31,911	$14,246	$9,178	$5,926	$901	$1,857	$109,670
Dominion	$52,633	$27,376	$14,607	$40,297	$21,615	$27,008	$122,961	$52,343	$35,851	$25,360	$5,401	$7,336	$432,788
DPL	$9,111	$4,489	$2,439	$5,439	$3,756	$4,013	$24,867	$9,392	$5,387	$1,701	$417	$1,299	$72,309
DLCO	$5,960	$2,557	$1,998	$5,790	$3,173	$3,984	$17,404	$7,392	$4,610	$3,020	$468	$940	$57,297
EKPC	$6,939	$2,164	$1,809	$5,275	$2,592	$3,415	$12,875	$5,979	$3,773	$2,359	$447	$1,017	$48,644
JCPL	$9,635	$4,081	$1,611	$7,346	$4,909	$5,862	$34,202	$12,963	$6,776	$2,127	$371	$1,169	$91,053

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports in 2016. On a dollar per MWh basis, real-time load and exports in AECO, JCPL, PSEG and RECO paid the highest charges for economic demand response in 2016. The highest average zonal monthly per MWh charges for economic demand response occurred in February, when real-time load and exports paid an average of $0.039/MWh.

Table 6-14 Zonal DR charge per MWh of load and exports: 2016

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Zonal Average
AECO	$0.010	$0.039	$0.001	$0.008	$0.011	$0.004	$0.168	$0.017	$0.012	$0.002	$0.001	$0.002	$0.023
AEP	$0.009	$0.021	$0.002	$0.009	$0.010	$0.004	$0.028	$0.008	$0.015	$0.004	$0.001	$0.002	$0.009
AP	$0.009	$0.023	$0.002	$0.009	$0.010	$0.004	$0.027	$0.008	$0.012	$0.004	$0.001	$0.002	$0.009
ATSI	$0.009	$0.018	$0.002	$0.009	$0.010	$0.004	$0.029	$0.008	$0.014	$0.004	$0.001	$0.002	$0.009
BGE	$0.009	$0.024	$0.002	$0.008	$0.009	$0.003	$0.026	$0.009	$0.009	$0.004	$0.001	$0.001	$0.009
ComEd	$0.011	$0.010	$0.002	$0.007	$0.013	$0.004	$0.042	$0.011	$0.025	$0.004	$0.001	$0.001	$0.011
DAY	$0.009	$0.018	$0.002	$0.009	$0.010	$0.004	$0.028	$0.008	$0.017	$0.004	$0.001	$0.002	$0.009
DEOK	$0.010	$0.016	$0.002	$0.009	$0.012	$0.004	$0.035	$0.009	$0.024	$0.003	$0.001	$0.001	$0.010
Dominion	$0.009	$0.021	$0.002	$0.009	$0.010	$0.003	$0.030	$0.009	$0.012	$0.004	$0.001	$0.001	$0.009
DPL	$0.010	$0.029	$0.002	$0.007	$0.010	$0.003	$0.038	$0.015	$0.011	$0.002	$0.002	$0.002	$0.011
DLCO	$0.010	$0.018	$0.002	$0.009	$0.012	$0.004	$0.035	$0.009	$0.018	$0.003	$0.001	$0.002	$0.010
EKPC	$0.010	$0.018	$0.002	$0.009	$0.009	$0.004	$0.031	$0.008	$0.017	$0.003	$0.001	$0.002	$0.010
JCPL	$0.010	$0.025	$0.001	$0.009	$0.012	$0.004	$0.149	$0.015	$0.015	$0.002	$0.001	$0.002	$0.020
Met-Ed	$0.011	$0.025	$0.001	$0.009	$0.009	$0.004	$0.098	$0.011	$0.012	$0.002	$0.001	$0.002	$0.015
PECO	$0.010	$0.023	$0.001	$0.009	$0.011	$0.004	$0.121	$0.013	$0.013	$0.002	$0.001	$0.003	$0.018
PENELEC	$0.010	$0.025	$0.002	$0.010	$0.011	$0.004	$0.038	$0.007	$0.011	$0.003	$0.001	$0.003	$0.010
Pepco	$0.009	$0.019	$0.002	$0.008	$0.010	$0.003	$0.029	$0.010	$0.010	$0.004	$0.001	$0.001	$0.009
PPL	$0.010	$0.027	$0.001	$0.010	$0.009	$0.004	$0.091	$0.010	$0.011	$0.002	$0.001	$0.003	$0.015
PSEG	$0.010	$0.024	$0.001	$0.009	$0.010	$0.004	$0.131	$0.012	$0.014	$0.002	$0.001	$0.002	$0.018
RECO	$0.011	$0.018	$0.001	$0.008	$0.011	$0.004	$0.129	$0.013	$0.018	$0.003	$0.001	$0.002	$0.018
Exports	$0.010	$0.010	$0.001	$0.006	$0.003	$0.003	$0.026	$0.009	$0.010	$0.003	$0.001	$0.001	$0.007
Monthly Average	$0.010	$0.022	$0.002	$0.009	$0.010	$0.004	$0.063	$0.010	$0.014	$0.003	$0.001	$0.002	$0.012

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges in 2015 and 2016. The day-ahead DR charges decreased by $1.2 million, or 55.2 percent, from $2.2 million in 2015 to $1.0 million in 2016. The real-time DR charges decreased $3.5 million, or 60.2 percent, from $5.8 million in 2015 to $2.3 million in 2016. The per MWh charge paid by all real-time load and exports for economic DR decreased $0.008/MWh, or 39.8 percent, from $0.020/MWh in 2015 to $0.012/MWh in 2016.

Table 6-15 Monthly day-ahead and real-time DR charge: 2015 and 2016

	Day-ahead DR Charge			Real-time DR Charge			Per MWh Charge ($/MWh)		
Month	2015	2016	Percent Change	2015	2016	Percent Change	2015	2016	Percent Change
Jan	$177,389	$163,639	(7.8%)	$520,844	$222,281	(57.3%)	$0.025	$0.010	(60.2%)
Feb	$704,043	$64,230	(90.9%)	$2,105,071	$117,388	(94.4%)	$0.059	$0.022	(63.7%)
Mar	$152,590	$14,620	(90.4%)	$515,178	$90,349	(82.5%)	$0.020	$0.002	(92.5%)
Apr	$55,282	$94,264	70.5%	$138,987	$223,013	60.5%	$0.008	$0.009	6.4%
May	$272,213	$64,456	(76.3%)	$184,413	$111,839	(39.4%)	$0.015	$0.010	(31.8%)
Jun	$311,871	$71,162	(77.2%)	$438,270	$144,731	(67.0%)	$0.021	$0.004	(82.2%)
Jul	$218,885	$310,567	41.9%	$727,286	$670,150	(7.9%)	$0.020	$0.063	217.1%
Aug	$106,600	$98,494	(7.6%)	$265,010	$312,815	18.0%	$0.008	$0.010	29.2%
Sep	$78,310	$58,644	(25.1%)	$383,021	$199,396	(47.9%)	$0.011	$0.014	29.6%
Oct	$71,805	$39,644	(44.8%)	$215,168	$128,325	(40.4%)	$0.014	$0.000	(100%)
Nov	$37,098	$5,836	(84.3%)	$163,313	$23,480	(85.6%)	$0.017	$0.000	(100%)
Dec	$31,055	$7,582	(75.6%)	$109,786	$50,825	(53.7%)	$0.020	$0.000	(100%)
Total	$2,217,142	$993,138	(55.2%)	$5,766,346	$2,294,593	(60.2%)	$0.020	$0.012	(39.8%)

Emergency and Pre-Emergency Programs

The emergency and pre-emergency load response programs consist of the limited, extended summer and annual demand response product in the capacity market during the 2015/2016 and 2016/2017 Delivery Years. To participate as a limited demand resource, the provider must clear MW in an RPM auction. Emergency resources receive capacity revenue from the capacity market and also receive revenue at a predefined strike price from the energy market for reductions during a PJM initiated emergency event. The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions.

The MMU recommends that if demand resources remain on the supply side of the capacity market, a daily must offer requirement in the Day-Ahead Energy Market apply to demand resources, comparable to the rule applicable to generation capacity resources. This will help to ensure comparability and consistency for demand resources.

The MMU recommends that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[25]

The ownership of Demand Resources was moderately concentrated in 2016. The HHI for Demand Resources was 1497 for the 2015/2016 Delivery Year and 1470 for the 2016/2017 Delivery Year. In 2016, the four largest companies contributed 66.6 percent of all registered Demand Resources.

Table 6-16 shows the HHI value for LDAs by delivery year. The HHI values are calculated by the cleared UCAP MW in each delivery year for Demand Resources. The ownership of DR was unconcentrated in one LDA in the 2016/2017 Delivery Year. The ownership of DR in six LDAs was moderately concentrated in the 2015/2016 Delivery Year and the ownership of DR in five LDAs was moderately concentrated in the 2016/2017 Delivery Year. The ownership of DR in three LDAs was highly concentrated in the 2015/2016 Delivery Year and the ownership of DR in four LDAs was highly concentrated in the 2016/2017 Delivery Year.

Table 6-16 HHI value for LDAs by delivery year: 2015/2016 and 2016/2017 Delivery Year

Delivery Year	LDA	UCAP MW	HHI Value
2015/2016	ATSI	2,167.9	2305
	DPL-SOUTH	86.3	2923
	EMAAC	1,750.4	1993
	MAAC	2,029.0	1909
	PEPCO	867.7	2983
	PS-NORTH	263.5	1622
	PSEG	523.8	1707
	RTO	6,610.4	1853
	SWMAAC	1,154.7	3579
2016/2017	ATSI	1,370.6	2757
	ATSI-CLEVELAND	470.8	3735
	DPL-SOUTH	105.7	2338
	EMAAC	1,289.2	2051
	MAAC	1,757.9	1891
	PEPCO	683.9	3735
	PS-NORTH	230.3	1599
	PSEG	404.1	1456
	RTO	6,423.6	1794
	SWMAAC	940.5	5125

25 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 6-17 shows zonal monthly capacity market revenue to demand resources for 2016. Capacity market revenue decreased in 2016 by $162.7 million, or 20.0 percent, compared to 2015, from $811.7 million to $649.0 million, as a result of lower RPM prices and less DR in RPM for the 2016/2017 delivery year.

Table 6-17 Zonal monthly capacity revenue: 2016

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$1,018,226	$952,534	$1,018,226	$985,380	$1,018,226	$618,278	$638,888	$638,888	$618,278	$638,888	$618,278	$638,888	$9,402,978
AEP, EKPC	$6,881,145	$6,437,200	$6,881,145	$6,659,173	$6,881,145	$3,292,264	$3,402,006	$3,402,006	$3,292,264	$3,402,006	$3,292,264	$3,402,006	$57,224,625
AP	$3,279,835	$3,068,232	$3,279,835	$3,174,034	$3,279,835	$1,613,157	$1,666,929	$1,666,929	$1,613,157	$1,666,929	$1,613,157	$1,666,929	$27,588,955
ATSI	$19,097,783	$17,865,668	$19,097,783	$18,481,726	$19,097,783	$5,701,661	$5,891,717	$5,891,717	$5,701,661	$5,891,717	$5,701,661	$5,891,717	$134,312,596
BGE	$5,546,155	$5,188,338	$5,546,155	$5,367,247	$5,546,155	$3,355,267	$3,467,109	$3,467,109	$3,355,267	$3,467,109	$3,355,267	$3,467,109	$51,128,285
ComEd	$6,679,174	$6,248,259	$6,679,174	$6,463,717	$6,679,174	$2,980,466	$3,079,815	$3,079,815	$2,980,466	$3,079,815	$2,980,466	$3,079,815	$54,010,158
DAY	$760,832	$711,746	$760,832	$736,289	$760,832	$448,489	$463,438	$463,438	$448,489	$463,438	$448,489	$463,438	$6,929,752
DEOK	$1,319,812	$1,234,663	$1,319,812	$1,277,237	$1,319,812	$577,029	$596,264	$596,264	$577,029	$596,264	$577,029	$596,264	$10,587,479
DLCO	$5,235,719	$4,897,930	$5,235,719	$5,066,825	$5,235,719	$2,395,261	$2,475,103	$2,475,103	$2,395,261	$2,475,103	$2,395,261	$2,475,103	$42,758,103
Dominion	$2,201,083	$2,059,077	$2,201,083	$2,130,080	$2,201,083	$1,572,292	$1,624,702	$1,624,702	$1,572,292	$1,624,702	$1,572,292	$1,624,702	$22,008,088
DPL	$878,296	$821,632	$878,296	$849,964	$878,296	$388,781	$401,741	$401,741	$388,781	$401,741	$388,781	$401,741	$7,079,793
JCPL	$1,720,510	$1,609,510	$1,720,510	$1,665,010	$1,720,510	$797,470	$824,053	$824,053	$797,471	$824,053	$797,470	$824,053	$14,124,673
Met-Ed	$1,667,231	$1,559,668	$1,667,231	$1,613,449	$1,667,231	$1,120,926	$1,158,290	$1,158,290	$1,120,926	$1,158,290	$1,120,926	$1,158,290	$16,170,748
PECO	$3,824,221	$3,577,497	$3,824,221	$3,700,859	$3,824,221	$1,898,249	$1,961,524	$1,961,524	$1,898,249	$1,961,524	$1,898,249	$1,961,524	$32,291,864
PENELEC	$2,625,490	$2,456,104	$2,625,490	$2,540,797	$2,625,490	$1,545,027	$1,596,528	$1,596,528	$1,545,027	$1,596,528	$1,545,027	$1,596,528	$23,894,563
Pepco	$4,232,745	$3,959,665	$4,232,745	$4,096,205	$4,232,745	$2,379,380	$2,458,692	$2,458,692	$2,379,380	$2,458,692	$2,379,380	$2,458,692	$37,727,013
PPL	$5,591,452	$5,230,713	$5,591,452	$5,411,083	$5,591,452	$3,571,436	$3,690,484	$3,690,484	$3,571,436	$3,690,484	$3,571,436	$3,690,484	$52,892,398
PSEG	$3,862,880	$3,613,662	$3,862,880	$3,738,271	$3,862,880	$4,088,123	$4,224,394	$4,224,394	$4,088,123	$4,224,394	$4,088,123	$4,224,394	$48,102,517
RECO	$103,031	$96,384	$103,031	$99,707	$103,031	$36,097	$37,300	$37,300	$36,097	$37,300	$36,097	$37,300	$762,672
Total	$76,525,621	$71,588,484	$76,525,621	$74,057,052	$76,525,621	$38,379,653	$39,658,975	$39,658,975	$38,379,653	$39,658,975	$38,379,653	$39,658,975	$648,997,257

Table 6-18 shows the amount of energy efficiency (EE) resources in PJM for the 2012/2013 through 2016/2017 delivery years. Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources cleared in the capacity auction increased by 88.4 percent from 1,147.7 MW in the 2015/2016 delivery year to 2,162.5 MW in 2016/2017 Delivery Year.

Table 6-18 Energy efficiency resources by MW: 2012/2013 through 2016/2017 Delivery Year

	EE ICAP (MW)					EE UCAP (MW)				
	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017
Total	643.4	871.0	1,035.4	1,147.7	2,162.5	666.1	904.2	1,077.7	1,189.6	2,249.7

FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014, effective on June 1, 2015.[26] The quick lead time demand response was defined after Demand Resources cleared in the RPM base residual auctions for the 2014/2015, 2015/2016, 2016/2017 and 2017/2018 delivery years. PJM submitted a filing on October 20, 2014, to allow DR that is unable to respond within 30 minutes to exit the market without penalty before the mandatory 30 minute lead time with the 2015/2016 Delivery Year.[27] The quick lead time is the default lead time for the 2015/2016 Delivery Year, unless a CSP submits an exception request for 60 or 120 minute notification time due to a physical constraint.[28] The exception requests must clearly state why the resource is unable to respond within 30 minutes based on the defined reasons for exception listed in Manual 18. Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year. Resources that request longer lead times without a physical constraint are rejected.

Table 6-19 shows the number of customer locations and nominated MW by product type and lead time for the 2015/2016 Delivery Year. PJM approved 3,174 locations, or 17.9 percent of all locations, with 4,334.6 nominated MW capacity, or 37.2 percent of all nominated capacity, for exceptions to the 30 minutes lead time rule for the 2015/2016 Delivery Year.

26 See "Order Rejecting, in part, and Accepting, in part, Proposed Tariff Changes, Subject to Conditions," Docket No. ER14-822-001 (May 9, 2014).
27 See "PJM Interconnection, L.L.C.," Docket No. ER14-135-000 (October 20, 2014).
28 See "Manual 18: Capacity Market," Revision 35 (November 17, 2016), p. 62.

Table 6-19 Lead time by product type: 2015/2016 Delivery Year

Lead Type	Product Type	Locations	Nominated MW
Long Lead (120 Minutes)	Annual and Extended Summer	791	697
	Limited	1,957	3,058
Short Lead (60 Minutes)	Extended Summer and Limited	426	580
Quick Lead (30 Minutes)	Annual	191	174
	Extended Summer	3,723	2,043
	Limited	10,635	5,092
Total		17,723	11,643

Table 6-20 shows the number of customer locations and nominated MW by product type and lead time for the 2016/2017 Delivery Year. PJM approved 2,673 locations, or 16.8 percent of all locations, which have 3,580 nominated MW capacity, or 38.3 percent of all nominated capacity, for exceptions to the 30 minutes lead time rule for the 2015/2016 Delivery Year.

Table 6-20 Lead time by product type: 2016/2017 Delivery Year

Program Type	On-site Generation MW	HVAC MW	Refrigeration and Lighting MW	Manufacturing or Water Heating MW	Other, Batteries or Plug Load MW	Total MW	Percent by Type
Firm Service Level	2,636.7	2,541.3	1,162.8	4,575.0	58.8	10,974.6	94.3%
Guaranteed Load Drop	20.6	106.1	13.5	47.6	0.0	187.8	1.6%
DLC (Non hourly metered sites)	0.0	444.9	0.0	35.3	0.0	480.1	4.1%
Total	2,657.3	3,092.3	1,176.3	4,657.8	58.8	11,642.6	100.0%
Percent by method	22.8%	26.6%	10.1%	40.0%	0.5%	100.0%	

There are three different ways to measure load reductions of Demand Resources. The Firm Service Level (FSL) method measures the difference between a customer's peak load contribution (PLC) and real time load multiplied by the loss factor. The Guaranteed Load Drop (GLD) method calculates the minimum of: the CBL minus real time load multiplied by the loss factor; or the PLC minus the real time load multiplied by the loss factor. The GLD method uses the minimum of the two to avoid the possibility of double counting reductions which could occur if the CBL were used and the CBL were greater than the PLC.[29] The Direct Load Control (DLC) method measures when the CSP turns on and turns off the direct load control switch to remotely control load reductions. DLC customers do not measure metered real-time load for reductions. The direct load control method is no longer an eligible reduction method after May 31, 2016.[30]

Table 6-21 shows the MW registered by measurement and verification method and by load drop method for the 2015/2016 Delivery Year. For the 2015/2016 Delivery Year, 1.6 percent use the guaranteed load drop (GLD) measurement and verification method, 94.3 percent use the firm service level (FSL) method and 4.1 percent use direct load control (DLC).

Table 6-21 Reduction MW by each demand response method: 2015/2016 Delivery Year

Program Type	On-site Generation MW	HVAC MW	Refrigeration and Lighting MW	Manufacturing or Water Heating MW	Other, Batteries or Plug Load MW	Total MW	Percent by Type
Firm Service Level	2,636.7	2,541.3	1,162.8	4,575.0	58.8	10,974.6	94.3%
Guaranteed Load Drop	20.6	106.1	13.5	47.6	0.0	187.8	1.6%
DLC (Non hourly metered sites)	0.0	444.9	0.0	35.3	0.0	480.1	4.1%
Total	2,657.3	3,092.3	1,176.3	4,657.8	58.8	11,642.6	100.0%
Percent by method	22.8%	26.6%	10.1%	40.0%	0.5%	100.0%	

29 135 FERC ¶ 61,212.
30 PJM. "Manual 18: PJM Capacity Market," Revision 36 (December 22, 2016), p. 63.

Table 6-22 shows the MW registered by measurement and verification method and by load drop method for the 2016/2017 Delivery Year. For the 2016/2017 Delivery Year, 0.9 percent use the guaranteed load drop (GLD) measurement and verification method, 99.1 percent use the firm service level (FSL) method and 0.0 percent use direct load control (DLC). FSL registrations increased by 2,437.9 MW while GLD registrations decreased by 38.8 MW and DLC registrations decreased by 111.9 MW from the 2015/2016 delivery year to the 2016/2017 delivery year.

Table 6-22 Reduction MW by each demand response method: 2016/2017 Delivery Year

Program Type	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	1,148.1	2,978.6	224.5	856.0	3,862.0	142.1	50.2	9,261.4	99.1%
Guaranteed Load Drop	16.2	26.4	1.5	9.1	31.2	0.1	0.0	84.4	0.9%
Non hourly metered sites (DLC)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total	1,164.2	3,004.9	226.0	865.1	3,893.2	142.2	50.2	9,345.8	100.0%
Percent by method	12.5%	32.2%	2.4%	9.3%	41.7%	1.5%	0.5%	100.0%	

Table 6-23 shows the fuel type used in the on-site generators identified in Table 6-21 and Table 6-22 for the 2015/2016 and 2016/2017 Delivery Years. Of the 22.8 percent of emergency demand response identified as using on-site generation for the 2015/2016 Delivery Year, 84.7 percent of MW are diesel, 12.0 percent are natural gas and 3.3 percent is coal, gasoline, kerosene, oil, propane or waste products. Of the 12.5 percent of emergency demand response identified as using on-site generation for the 2016/2017 Delivery Year, 75.5 percent of MW are diesel, 19.2 percent are natural gas and 5.3 percent is coal, gasoline, kerosene, oil, propane or waste products.

Table 6-23 On-site generation fuel type by MW: 2015/2016 and 2016/2017 Delivery Years

	2015/2016		2016/2017	
Fuel Type	MW	Percent	MW	Percent
Coal, Gasoline, Kerosene, Oil, Propane, Waste Products	87.9	3.3%	61.7	5.3%
Diesel	2,250.9	84.7%	879.2	75.5%
Natural Gas	318.5	12.0%	223.3	19.2%
Total	2,657.3	100.0%	1,164.2	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Table 6-24 shows the demand response cleared UCAP MW for PJM by Delivery Year. Total demand response cleared in PJM decreased by 11.5 percent from 15,453.7 MW in the 2015/2016 Delivery Year to 13,676.6 MW in the 2016/2017 Delivery Year. The DR Cleared MW UCAP decreased by 1,77.1 MW, from 15,453.7 MW in the 2015/2016 Delivery Year to 13,676.6 MW in the 2016/2017 Delivery Year. The DR percent of capacity decreased by 1.5 percent, from 8.9 percent in the 2015/2016 Delivery Year to 7.4 percent in the 2016/2017 Delivery Year.

Table 6-24 Demand response cleared MW UCAP for PJM: 2011/2012 through 2016/2017 Delivery Year

	2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year		2014/2015 Delivery Year		2015/2016 Delivery Year		2016/2017 Delivery Year	
	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP
Total	1,826.6	1.4%	8,740.9	6.2%	10,779.6	6.7%	14,943.0	9.3%	15,453.7	8.9%	13,676.6	7.4%

Subzonal dispatch of emergency demand resources was mandatory for the 2014/2015 Delivery Year, but only if the subzone was defined by PJM no later than the day before the dispatch. There are ten dispatchable subzones in PJM effective August 11, 2015: AEP_CANTON, ATSI_CLE, DPL_SOUTH, PS_NORTH, ATSI_NEWCASOE, PPL_WESCO, ATSI_BLKRIVER, PENELEC_ERIC, APS_EAST, DOM_CHES.[31] Currently PJM can remove a defined subzone at their discretion. There is no reason to remove a defined subzone, 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

31 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed January 25, 2017).

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 loops 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.[32] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR resources would not otherwise set price under the fundamental LMP logic. Of the 17 closed loop interface definitions, 11 (65 percent) were created for the purpose of allowing emergency DR to set price.[33]

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 demand response events occur for partial hours under 30 minutes or for a subzone dispatch that was not defined one business day before dispatch, the events are not measured for compliance. The category of Minutes not Measured for Compliance is the amount of time during which compliance was not measured when demand resources were dispatched.

Demand Resources are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance no less than hourly to accurately report reductions during demand response events. The current rules use the average reduction for the duration of an event. The average duration 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. The MMU recommends demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.[34]

Under the new capacity performance design of the PJM Capacity Market, compliance for potential penalties will be measured for DR only during performance assessment hours (PAH). When pre-emergency or emergency demand response is dispatched, a PAH is triggered for PJM.[35] As a result, PJM now 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 Hour (PAH) for CP compliance.

PJM allows compliance to be measured across zones within a compliance aggregation area (CAA).[36] 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.[37] The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch

32 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

33 See the *2016 State of the Market Report for PJM*, Volume II, Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.

34 PJM "Manual 18: Capacity Market," Revision 34 (July 28, 2016), p 148.

35 PJM. OATT Definitions 2.23A.

36 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 Attachment DD.2 Definitions 2.6A.

37 See "Manual 18: Capacity Market," Revision 36 (December 22, 2016) p. 166.

of demand resources would be consistent with the nodal dispatch of generation.

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.[38] The compliance values PJM reports for demand response events are different than the actual compliance values accounting for both increases and decreases in load from demand resources that are called on and paid under the program.

The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations.

Demand Resources that are also registered as Economic Resources have a calculated CBL for the emergency event days. Demand Resources that are not registered as Economic Resources use the hour before a dispatched event as the CBL for measuring energy reductions. A 2011 KEMA report stated that the hour before method performs poorly during early winter hours. "The hour before the reduction event is typically prior to the morning peak, therefore this CBL severely underestimates the morning peak and the subsequent hours."[39] The calculated CBL more accurately measures reductions for Demand Resources.

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.[40]

Limiting compliance to positive values only 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.

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.

38 PJM. OATT Attachment K § PJM Emergency Load Response Program at Reporting and Compliance.
39 See "PJM Empirical Analysis of Demand Response Baseline Methods," KEMA, April 2011, <https://www.pjm.com/~/media/markets-ops/dsr/pjm-analysis-of-dr-baseline-methods-full-report.ashx> (Accessed January 25, 2017).
40 OATT Attachment K Section 8.9.

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."[41] Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as DR customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events.

Emergency Energy Payments

For any PJM declared load management event in 2016, participants registered under the full option, which contains 99.6 percent of registrations, that were dispatched and reported a load reduction were eligible to receive emergency energy payments. 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.[42] The dispatch 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. The new scarcity pricing rules increased the maximum DR energy price offer for the 2013/2014 Delivery Year to $1,800 per MWh. The maximum offer decreased to $1,599 per MWh for the 2014/2015 Delivery Year and increased to $1,849 per MWh for the 2015/2016 Delivery Year and the 2016/2017 Delivery Year. The maximum generator offer will remain at $1,000 per MWh.[43] [44]

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.[45]

Table 6-25 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2015/2016 Delivery Year. The majority of participants, 77.0 percent, have a minimum dispatch price between $1,550 and $1,850 per MWh, which is the maximum price allowed for the 2015/2016 Delivery Year, 3.4 percent of participants have a dispatch price between $0 and $1 per MWh, and 95.5 percent of participants have a dispatch price above $1,000 per MWh. Energy offers are further increased by submitted shutdown costs, which, in the 2015/2016 Delivery Year, range from $0 to more than $10,000. Depending on the size of the registration, the shutdown costs can significantly increase the effective energy offer. The shutdown cost of resources with $1,000 to $1,100 per MWh strike prices had the highest average at $183.69 per location and $141.56 per MW.

41 OATT Attachment K Appendix Section 8.2.

42 OATT Attachment K Appendix Section 8.2.

43 139 FERC ¶ 61,057 (2012).

44 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.

45 PJM. "Manual 15: Cost Development Guidelines," Revision 28 (October 18, 2016), p. 59.

Table 6-25 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2015/2016 Delivery Year[46]

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	609	3.4%	562.9	4.8%	$0.00	$0.00
$1-$999	192	1.1%	217.0	1.9%	$136.08	$120.42
$1,000-$1,100	2,850	16.1%	3,698.1	31.8%	$183.69	$141.56
$1,101-$1,275	0	0.0%	0.0	0.0%	$0.00	$0.00
$1,276-$1,549	422	2.4%	514.0	4.4%	$59.11	$48.53
$1,550-$1,850	13,650	77.0%	6,651.3	57.1%	$26.97	$55.35
Total	17,723	100.0%	11,643.2	100.0%	$53.19	$80.97

Table 6-26 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2016/2017 Delivery Year. The majority of participants, 58.7 percent, have a minimum dispatch price between $1,550 and $1,850 per MWh, which is the maximum price allowed for the 2015/2016 Delivery Year, 3.5 percent of participants have a dispatch price between $0 and $1 per MWh, and 94.7 percent of participants have a dispatch price above $1,000 per MWh. Energy offers are further increased by submitted shutdown costs, which, in the 2016/2017 Delivery Year, range from $0 to more than $10,000. Depending on the size of the registration, the shutdown costs can significantly increase the effective energy offer. The shutdown cost of resources with $1,000 to $1,100 per MWh strike prices had the highest average at $182.60 per location and $141.91 per MW.

Table 6-26 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2016/2017 Delivery Year[47]

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	576	3.6%	322.9	3.5%	$1.74	$3.10
$1-$999	261	1.6%	198.7	2.1%	$54.39	$71.43
$1,000-$1,100	2,357	14.8%	3,032.9	32.5%	$182.60	$141.91
$1,101-$1,275	0	0.0%	0.0	0.0%	$0.00	$0.00
$1,276-$1,549	292	1.8%	300.8	3.2%	$55.04	$53.43
$1,550-$1,850	12,416	78.1%	5,490.7	58.7%	$41.75	$94.41
Total	15,902	100.0%	9,346.1	100.0%	$61.63	$104.86

46 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.
47 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.

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 (NU), solar, and wind generating units.

Overview

Net Revenue

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Natural gas prices and energy prices were lower in 2016 than in 2015 which affected energy market revenue for all plant types. Capacity prices for calendar year 2016 were lower than in 2015 in all zones except PSEG which affected capacity market revenues for all plant types.
- In 2016, average energy market net revenues increased by 21 percent for a new CT and 14 percent for a new CC. In 2016, average energy market net revenues decreased 54 percent for a new CP, 86 percent for a new DS, 26 percent for a new nuclear plant, 19 percent for a new wind installation, and 28 percent for a new solar installation.
- The results are very sensitive to the relative prices of fuel. For example, gas prices increased in December. While the marginal cost of the new CC was still below that of the new CP, the marginal cost of the new CT was above that of coal in December. As a result, CT hours dropped significantly and CP hours increased in all zones and substantially in some zones.
- Capacity prices for calendar year 2016 were lower than in 2015 in all zones except PSEG. Capacity revenue accounted for 43 percent of total net revenues for a new CT, 32 percent for a new CC, 55 percent for a new CP, 96 percent for a new DS, and 23 percent for a new nuclear plant.
- In 2016, a new CT would have received sufficient net revenue to cover levelized total costs in 13 of the 20 zones. The zones in which a new CT would not have recovered levelized costs were western zones in which lower capacity prices were not offset by changes in energy net revenues.
- In 2016, a new CC would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional five zones.
- In 2016, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2016, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2016, net revenues covered more than 33 percent of the annual levelized total costs of a new entrant wind installation in ComEd, 49 percent of the annual levelized total costs of a new entrant wind installation in PENELEC and 198 percent of the annual levelized total costs of a new entrant solar installation in PSEG. Renewable energy credits accounted for three percent of the total net revenue of a wind installation in ComEd and 37 percent of the total net revenue of a wind installation in PENELEC. Renewable energy credits accounted for 83 percent of the total net revenue of a solar installation in PSEG.
- In 2016, 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 2016, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for most units and technology types in PJM, with the exception of some coal units.
- The actual net revenue results show that 96 units with 14,500 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire. Of the 96 units, 55 are CTs and account for 1,408 MW and 25 are coal units and account for 11,282 MW.

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through 2016. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.

Conclusion

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

Unlike cost of service regulation, markets do not guarantee that units will cover their costs. New CT and CC units that began operation in 2007 have not covered their total costs from energy market and capacity market revenues through December 2016 in the ComEd Zone, in the PSEG Zone and in the BGE Zone. New CT and CC units that began operation on June 1, 2012, have covered or more than covered their total costs in the PSEG Zone and the BGE Zone through December 2016 and have not covered their total costs in the ComEd Zone through December 2016.

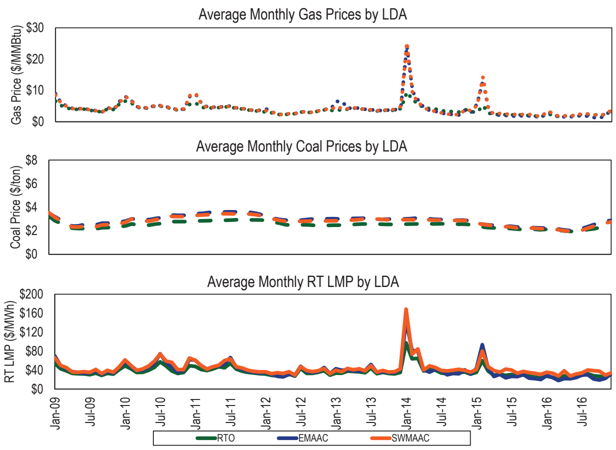
Net Revenue

When compared to annualized fixed costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable 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, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Net revenue is the contribution to total fixed costs received by generators from all PJM markets.

In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover the fixed 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 costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 19.2 percent lower in 2016 than in 2015, $29.23 per MWh versus $36.16 per MWh. Natural gas prices decreased in 2016 and coal prices decreased or remained flat. Comparing fuel prices in 2016 to 2015, the price of Northern Appalachian coal was 10.1 percent lower; the price of Central Appalachian coal was 0.1 percent higher; the price of Powder River Basin coal was 5.1 percent lower; the price of eastern natural gas was 35.6 percent lower; and the price of western natural gas was 4.2 percent lower (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2009 through 2016



Spark Spreads, Dark Spreads, and Quark Spreads

The spark, dark, or quark spread is defined as the difference between the LMP received for selling power and the cost of fuel used to generate power converted to a cost per MWh. The spark spread compares power prices to the cost of gas, the dark spread compares power prices to the cost of coal, and the quark spread compares power prices to the cost of uranium. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{MMBtu}\right) * Heat\ Rate\left(\frac{MMBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

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): 2011 through 2016

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2011	$26.27	$33.76	$48.66	$12.47	$33.68	$30.85	$22.99	$28.15	$47.70	$19.50	$26.15	$41.06
2012	$24.29	$24.21	$36.25	$16.17	$30.87	$27.23	$19.51	$17.57	$33.01	$19.94	$19.86	$31.91
2013	$19.59	$26.45	$40.79	$10.70	$31.64	$30.44	$13.65	$25.09	$42.13	$16.16	$22.34	$36.68
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

Table 7-2 Peak hour spread standard deviation ($/MWh): 2011 through 2016

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2011	$50.7	$51.1	$51.1	$26.3	$26.9	$26.9	$43.6	$45.3	$45.3	$37.2	$37.5	$37.4
2012	$33.7	$33.9	$33.7	$23.6	$23.7	$23.7	$29.6	$29.7	$29.7	$27.6	$28.0	$27.8
2013	$32.6	$33.3	$33.3	$18.2	$18.3	$18.2	$32.4	$30.4	$30.4	$25.3	$25.5	$25.5
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

Figure 7-2 shows the hourly spark spread for peak hours since January 2011 for BGE, ComEd, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2011 through 2016[1]

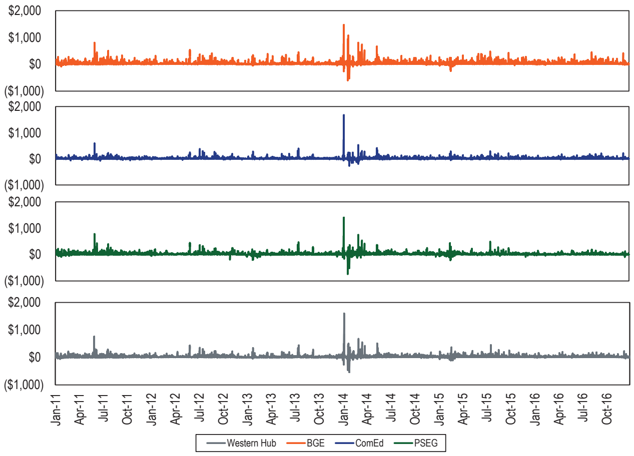


Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2011 through 2016[2]

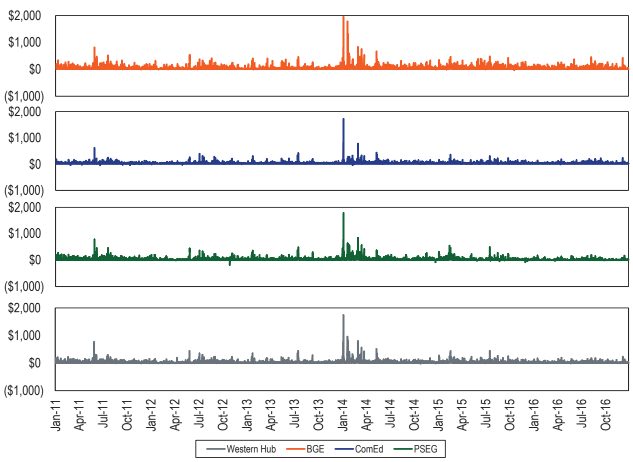
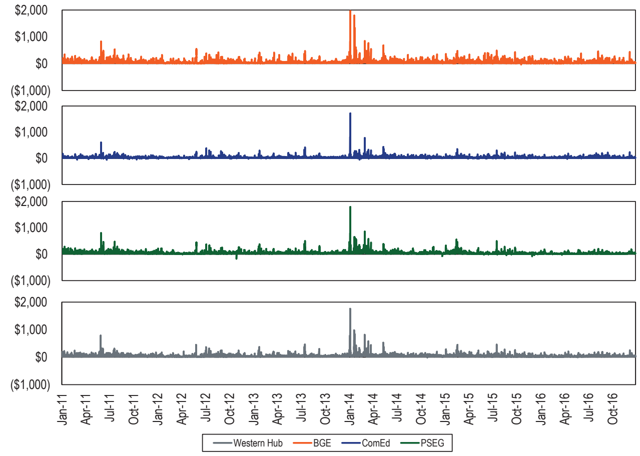


Figure 7-4 Hourly quark spread (uranium) for selected zones ($/MWh): 2011 through 2016[3]



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets.

Analysis of energy market net revenues for a new entrant includes seven power plant configurations:

- The CT plant has an installed capacity of 641.2 MW and consists of two GE Frame 7HA.02 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant has an installed capacity of 971.4 MW and consists of two GE Frame 7HA.02 CTs equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[4]
- The CP has an installed capacity of 600.0 MW and is a sub-critical steam unit, equipped with selective catalytic reduction system (SCR) for NOx control, a flue gas desulphurization (FGD) system with chemical injection for SOx and mercury control, and a bag-house for particulate control.

1 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for ComEd, Zone 6 non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

2 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs and daily coal prices; Powder River Basin coal for ComEd, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

3 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium prices.

4 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.

- The DS plant has an installed capacity of 2.0 MW and consists of one oil fired CAT 2 MW unit using New York Harbor ultra low sulfur diesel.
- The nuclear plant has an installed capacity of 2,200 MW and consists of two units and related facilities using the Westinghouse AP1000 technology.
- The wind installation consists of twenty two Siemens 2.3 MW wind turbines totaling 50.6 MW installed capacity.
- The solar installation consists of a 60 acre ground mounted solar farm totaling 10 MW of AC installed capacity.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[5 6] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost. CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[7]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[8] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day planned annual outage in the fall season.

Ancillary service revenues for the provision of regulation service were calculated for the CP. The regulation clearing price was compared to the day ahead LMP. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour. No black start service capability is assumed for any of the unit types.

CT generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CT generators with 20 or fewer operating years. CC generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CP generators with 60 or fewer operating years. Table 7-3 includes reactive capability revenue of $3,500/MW-Yr.[9]

Table 7-3 New entrant ancillary service revenue (Dollars per MW-year)

	Reactive			Regulation
	CT	CC	CP	CP
2009	$4,273	$4,991	$3,963	$38
2010	$7,765	$4,280	$3,980	$6
2011	$7,025	$4,539	$6,753	$2
2012	$4,261	$6,065	$6,216	$20
2013	$4,708	$3,486	$3,614	$53
2014	$3,712	$4,046	$3,501	$168
2015	$3,673	$4,911	$3,386	$74
2016	$3,436	$4,573	$3,470	$24

Zonal net revenues reflect zonal fuel costs based on locational fuel indices and zone specific delivery charges.[10] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[11] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month prices, adjusted for rail transportation costs.[12]

Short run marginal cost includes fuel costs, emissions costs, and VOM costs.[13 14] Average short run marginal costs are shown in Table 7-4.

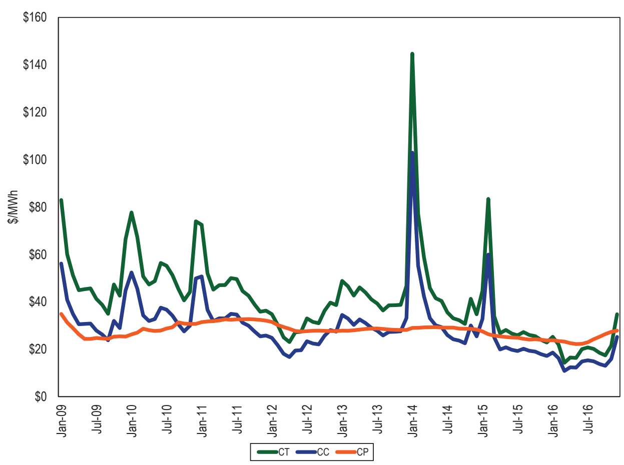
Table 7-4 Average short run marginal costs: 2016

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$20.62	9,437	$0.25
CC	$15.27	6,679	$1.00
CP	$24.29	9,250	$4.00
DS	$126.80	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

5 Hourly ambient conditions supplied by Schneider Electric.
6 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.
7 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
8 Outage figures obtained from the PJM eGADS database.
9 $3,500/MW-Yr is the average of reactive capability payments of selected units obtained from FERC filings.
10 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
11 Gas daily cash prices obtained from Platts.
12 Coal prompt prices obtained from Platts.
13 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
14 VOM rates provided by Pasteris Energy, Inc.

A comparison of the short run marginal cost of the theoretical CT, CC and CP plants since January 2009 shows that the CC plant has been competitive with the CP plant but that 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). For much of 2016, the short run marginal costs of the CT and CC plant were below the short run marginal cost of the coal plant (Figure 7-5).

Figure 7-5 Average short run marginal costs: 2009 through December 2016



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: 2009 through 2016

	CT	CC	CP	DS	Nuclear	Wind	Solar
2009	1,066	5,183	8,760	44	8,760		
2010	1,788	5,641	8,760	117	8,760		
2011	2,744	6,853	8,760	50	8,760		
2012	4,595	7,812	8,784	27	8,784	6,739	3,669
2013	2,243	6,558	8,760	20	8,760	6,873	3,755
2014	3,681	6,732	8,760	176	8,760	6,991	3,641
2015	4,345	7,013	8,760	210	8,760	6,884	3,741
2016	5,976	8,033	5,602	75	8,784	6,729	3,768

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator going forward costs and fixed costs. Capacity revenue for 2016 includes five months of the 2015/2016 RPM auction clearing price and seven months of the 2016/2017 RPM auction clearing price.[15]

Table 7-6 Capacity revenue by PJM zones (Dollars per MW-year): 2009 through 2016[16]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Average
AECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$59,151
AEP	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$35,327
AP	$57,842	$66,187	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$39,401
ATSI	NA	NA	NA	NA	NA	$31,149	$95,422	$78,709	$68,427
BGE	$82,515	$73,135	$49,858	$45,261	$68,535	$63,360	$56,448	$50,948	$61,257
ComEd	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$35,327
DAY	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$35,327
DEOK	NA	NA	NA	NA	$8,420	$31,149	$48,128	$33,377	$30,269
DLCO	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$35,327
Dominion	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$33,377	$35,327
DPL	$63,411	$67,098	$50,501	$52,309	$77,542	$66,206	$56,448	$50,948	$60,558
EKPC	NA	NA	NA	NA	NA	$31,149	$48,128	$33,377	$37,552
JCPL	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$59,151
Met-Ed	$57,842	$66,187	$49,858	$45,261	$68,535	$63,360	$56,448	$50,948	$57,305
PECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$59,151
PENELEC	$57,842	$66,187	$49,858	$45,216	$68,503	$63,360	$56,448	$50,945	$57,295
Pepco	$82,515	$73,135	$49,858	$45,261	$73,027	$66,529	$56,448	$50,948	$62,215
PPL	$57,842	$66,187	$49,858	$45,261	$68,535	$63,360	$56,448	$50,948	$57,305
PSEG	$63,411	$66,187	$49,858	$49,957	$75,882	$72,567	$60,936	$67,224	$63,253
RECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$50,948	$59,151
PJM	$52,370	$60,604	$49,878	$32,806	$36,601	$46,247	$54,646	$48,568	$47,715

Net Revenue Adequacy

When total net revenues exceed the annual, nominal levelized total costs for the technology, that technology is covering all its costs including a return on and of capital and all the expenses of operating the facility.

The extent to which net revenues cover the levelized total costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue. Table 7-7 includes new entrant levelized total costs for selected technologies. The levelized total costs of all the technologies increase in 2016 over 2015 with the exception of the solar installation.

Net revenues include net revenues from the PJM energy market, from the PJM Capacity Market and from any applicable ancillary service plus RECs for wind installations and SRECs for solar installations.

15 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant Base Residual Auctions.
16 See the *2016 State of the Market Report for PJM*, Appendix A: "PJM Geography," for details on the expansion of the PJM footprint.

Levelized Total Costs

Table 7-7 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[17 18]

	20-Year Levelized Total Cost							
	2009	2010	2011	2012	2013	2014	2015	2016
Combustion Turbine	$128,705	$131,044	$110,589	$113,027	$109,731	$108,613	$111,639	$113,821
Combined Cycle	$173,174	$175,250	$153,682	$155,294	$150,654	$146,443	$146,300	$148,327
Coal Plant	$446,550	$465,455	$473,835	$480,662	$491,240	$504,050	$517,017	$523,540
Diesel Plant	$153,143	$153,143	$153,143	$153,143	$153,143	$161,746	$170,500	$173,182
Nuclear Plant	$801,100	$801,100	$801,100	$801,100	$801,100	$880,770	$935,659	$963,107
Wind Installation (with 1603 grant)				$196,186	$196,148	$198,033	$202,874	$231,310
Solar Installation (with 1603 grant)				$394,855	$263,824	$236,289	$234,151	$218,937

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 a capacity factor for the specified new entrant unit type. CCs had a low levelized cost of energy in 2016 because low gas prices resulted in low short run marginal costs which increased dispatch and the capacity factor, which increased the MWh over which costs are spread. Coal units had a relatively high levelized cost of energy in 2016 because coal units ran for fewer hours in 2016, which decreased the coal capacity factor, which decreased the MWh over which costs are spread.

Table 7-8 Levelized cost of energy: 2016

	CT	CC	CP	DS	Nuclear	Wind (ComEd)	Wind (PENELEC)	Solar (PSEG)
Levelized cost ($/MW-Yr)	$113,821	$148,327	$523,540	$173,182	$963,107	$231,310	$231,310	$218,937
Short run marginal costs ($/MWh)	$20.62	$15.27	$24.29	$126.80	$8.50	$0.00	$0.00	$0.00
Capacity factor (%)	68%	91%	64%	1%	98%	77%	77%	43%
Levelized cost of energy ($/MWh)	$40	$34	$118	$2,430	$120	$34	$34	$58

New Entrant Combustion Turbine

Energy market net revenue was calculated for a new CT plant economically dispatched by PJM.[19] 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 applying to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

17 Levelized total costs provided by Pasteris Energy, Inc.

18 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.

19 The 2016 new entrant CT plant is modeled to incorporate the actual flexibility of a new CT. The 2016 CT is modeled with greater flexibility than in prior years.

New entrant CT plant energy market net revenues were higher in all but three zones in 2016 (Table 7-9). The decrease in energy prices was offset by the decrease in gas prices, resulting in higher energy net revenues in 17 of 20 zones. In DEOK, EKPC and PENELEC, the new entrant CT was economic for fewer hours than in 2015, resulting in lower energy net revenues.

Table 7-9 Energy net revenue for a new entrant gas fired CT under economic dispatch (Dollars per installed MW-year)[20]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Change in 2016 from 2015
AECO	$10,270	$41,776	$63,064	$50,716	$31,431	$62,488	$51,404	$48,167	(6%)
AEP	$3,798	$12,246	$29,569	$39,768	$19,169	$58,738	$37,225	$31,391	(16%)
AP	$12,211	$34,656	$49,411	$49,941	$26,767	$78,655	$58,192	$73,765	27%
ATSI	NA	NA	$23,275	$43,763	$25,509	$67,762	$40,147	$28,048	(30%)
BGE	$14,738	$52,514	$63,755	$71,707	$42,986	$89,712	$80,641	$107,070	33%
ComEd	$2,253	$9,555	$18,515	$25,156	$12,992	$26,298	$13,595	$16,106	18%
DAY	$3,011	$11,984	$30,125	$44,423	$19,910	$59,033	$37,710	$26,092	(31%)
DEOK	NA	NA	NA	$36,426	$19,775	$78,150	$84,960	$28,275	(67%)
DLCO	$3,247	$16,803	$33,064	$42,347	$20,903	$52,608	$31,438	$66,431	111%
Dominion	$14,746	$47,122	$49,223	$53,638	$31,175	$43,721	$37,802	$37,027	(2%)
DPL	$11,306	$40,871	$57,501	$62,542	$35,129	$78,702	$41,079	$49,806	21%
EKPC	NA	NA	NA	NA	$15,244	$75,630	$75,433	$24,563	(67%)
JCPL	$9,267	$39,408	$59,820	$49,343	$37,511	$64,876	$49,777	$43,113	(13%)
Met-Ed	$8,092	$38,275	$50,960	$47,325	$29,546	$55,100	$47,292	$46,106	(3%)
PECO	$8,598	$37,178	$59,087	$49,037	$27,857	$56,752	$45,876	$41,989	(8%)
PENELEC	$7,418	$26,960	$47,419	$53,552	$40,971	$120,385	$112,826	$63,471	(44%)
Pepco	$17,071	$49,586	$56,858	$64,640	$39,789	$80,268	$59,478	$48,736	(18%)
PPL	$7,426	$31,826	$52,511	$43,024	$28,268	$61,271	$46,193	$42,792	(7%)
PSEG	$7,067	$35,863	$49,340	$46,919	$30,673	$47,870	$23,810	$30,019	26%
RECO	$5,805	$32,934	$39,366	$42,708	$32,271	$47,536	$25,602	$31,633	24%
PJM	$8,607	$32,915	$46,270	$48,262	$28,394	$65,278	$50,024	$44,230	(12%)

In 2016, a new CT would have received sufficient net revenue to cover levelized total costs in 13 of the 20 zones (Table 7-10). For most zones, net revenue results for a new CT reflected increases in energy market net revenues which offset lower capacity market revenues. Net revenues covered 100 percent or more of levelized total costs for a CT in 13 zones and less than 80 percent in six of the western zones, AEP, ComEd, DAY, DEOK, Dominion, and EKPC.

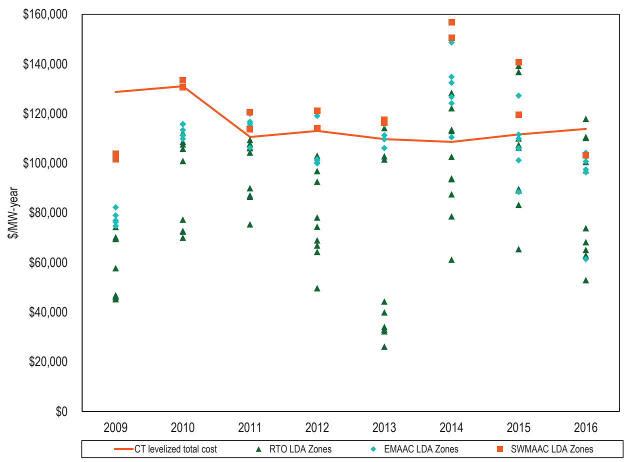
Table 7-10 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015	2016
AECO	64%	88%	108%	90%	100%	122%	100%	106%
AEP	36%	55%	78%	57%	29%	86%	80%	74%
AP	58%	83%	96%	66%	36%	105%	99%	114%
ATSI	NA	NA	NA	NA	NA	94%	125%	110%
BGE	79%	102%	109%	107%	106%	144%	126%	158%
ComEd	35%	53%	68%	44%	24%	56%	59%	56%
DAY	36%	55%	79%	61%	30%	86%	80%	68%
DEOK	NA	NA	NA	NA	NA	104%	123%	70%
DLCO	36%	59%	81%	59%	31%	81%	75%	107%
Dominion	45%	82%	96%	69%	40%	72%	80%	79%
DPL	61%	88%	104%	105%	107%	137%	91%	106%
EKPC	NA	NA	NA	NA	NA	102%	114%	66%
JCPL	60%	87%	106%	89%	105%	124%	98%	101%
Met-Ed	55%	86%	98%	86%	94%	112%	96%	104%
PECO	59%	85%	105%	88%	97%	117%	95%	100%
PENELEC	54%	77%	94%	91%	104%	173%	155%	122%
Pepco	81%	100%	103%	101%	107%	139%	107%	106%
PPL	54%	81%	99%	82%	93%	118%	95%	101%
PSEG	58%	84%	96%	89%	101%	114%	79%	101%
RECO	57%	82%	87%	83%	101%	108%	77%	88%
PJM	55%	79%	95%	80%	77%	110%	98%	97%

20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

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): 2009 through 2016



New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM.[21] 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.[22] If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were higher in all but three zones in 2016 (Table 7-11). The decrease in energy prices was offset by the decrease in gas prices, resulting in higher energy net revenues in 17 of 20 zones. In DEOK, EKPC and PENELEC, the new entrant CC was economic for fewer hours than in 2015, resulting in lower energy net revenues.

21 The 2016 new entrant CC plant is modeled to incorporate the actual flexibility of a new CC. The 2016 CC is modeled with greater flexibility than in prior years.

22 All starts associated with combined cycle units are assumed to be hot starts.

Table 7-11 Energy net revenue for a new entrant CC under economic dispatch (Dollars per installed MW-year)[23]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Change in 2016 from 2015
AECO	$37,852	$79,328	$111,306	$92,466	$70,012	$123,761	$90,646	$78,013	(14%)
AEP	$15,920	$32,720	$70,273	$81,290	$52,898	$94,541	$73,584	$69,313	(6%)
AP	$41,013	$70,232	$101,830	$93,060	$66,602	$121,059	$97,044	$105,413	9%
ATSI	NA	NA	$47,083	$87,078	$64,344	$108,904	$77,638	$64,124	(17%)
BGE	$46,193	$91,219	$111,996	$113,212	$86,520	$160,024	$123,490	$145,186	18%
ComEd	$9,224	$20,318	$31,890	$53,616	$28,188	$38,964	$30,984	$43,630	41%
DAY	$14,063	$30,879	$69,799	$86,887	$56,071	$96,827	$75,212	$63,809	(15%)
DEOK	NA	NA	NA	$75,534	$55,985	$131,815	$126,326	$63,796	(49%)
DLCO	$14,210	$35,028	$69,664	$81,852	$49,647	$80,373	$63,351	$96,607	52%
Dominion	$48,720	$88,838	$98,117	$94,554	$67,136	$87,913	$74,747	$79,224	6%
DPL	$39,572	$76,906	$105,344	$104,125	$73,857	$144,248	$75,044	$82,446	10%
EKPC	NA	NA	NA	NA	$34,714	$127,207	$116,344	$58,759	(49%)
JCPL	$37,944	$77,772	$109,562	$92,010	$77,489	$128,858	$89,489	$72,909	(19%)
Met-Ed	$31,635	$70,703	$95,417	$87,492	$65,530	$112,744	$82,109	$75,696	(8%)
PECO	$33,551	$73,009	$105,795	$89,597	$63,132	$115,652	$83,816	$70,623	(16%)
PENELEC	$31,352	$61,287	$97,938	$98,591	$91,135	$188,435	$149,842	$96,217	(36%)
Pepco	$45,176	$89,540	$103,337	$105,910	$82,294	$144,086	$99,510	$94,523	(5%)
PPL	$29,740	$62,518	$94,143	$83,418	$62,900	$113,566	$82,866	$72,205	(13%)
PSEG	$33,366	$73,323	$94,698	$85,877	$67,412	$103,746	$48,489	$56,283	16%
RECO	$28,128	$67,511	$76,967	$80,214	$68,794	$103,181	$48,869	$58,456	20%
PJM	$31,627	$64,772	$88,620	$88,778	$64,233	$116,295	$85,470	$77,362	(9%)

In 2016, a new CC would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional five zones (Table 7-12). For most zones, net revenue results for a new CC reflected increases in energy market net revenues which offset lower capacity market revenues. Net revenues covered 90 percent or more of levelized total costs for a CC in 14 zones and less than 90 percent in six of the western zones, AEP, ComEd, DAY, DEOK, Dominion, and EKPC and RECO.

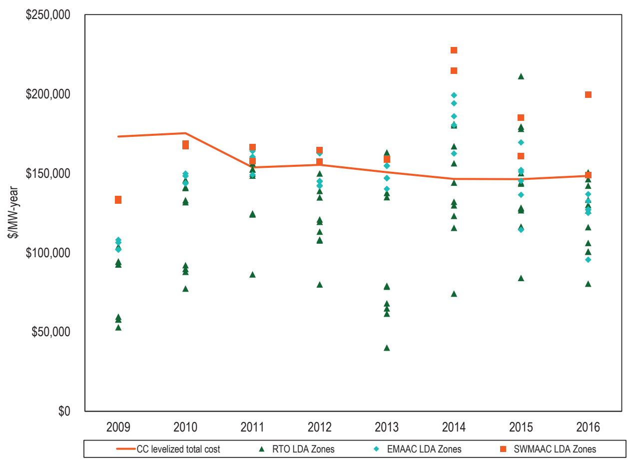
Table 7-12 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015	2016
AECO	61%	85%	108%	93%	98%	132%	104%	103%
AEP	34%	51%	81%	69%	43%	89%	87%	86%
AP	60%	80%	102%	77%	52%	107%	103%	110%
ATSI	NA	NA	NA	NA	NA	98%	122%	113%
BGE	77%	96%	108%	106%	105%	155%	126%	150%
ComEd	31%	44%	56%	51%	27%	51%	57%	68%
DAY	33%	50%	81%	73%	45%	90%	88%	82%
DEOK	NA	NA	NA	NA	NA	114%	123%	82%
DLCO	33%	53%	81%	70%	41%	79%	80%	104%
Dominion	53%	83%	99%	78%	52%	84%	87%	92%
DPL	62%	85%	104%	105%	103%	146%	93%	106%
EKPC	NA	NA	NA	NA	NA	111%	116%	78%
JCPL	61%	85%	107%	93%	103%	136%	103%	99%
Met-Ed	55%	81%	97%	89%	91%	123%	98%	101%
PECO	59%	82%	104%	92%	93%	127%	99%	97%
PENELEC	54%	75%	99%	97%	108%	175%	144%	115%
Pepco	77%	95%	103%	101%	105%	147%	110%	115%
PPL	53%	76%	97%	87%	90%	124%	99%	99%
PSEG	59%	82%	97%	91%	97%	123%	78%	98%
RECO	56%	79%	85%	86%	97%	118%	75%	89%
PJM	54%	75%	95%	86%	79%	116%	100%	99%

23 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

Figure 7-7 shows zonal net revenue and the annual levelized total cost for the new entrant CC by LDA.

Figure 7-7 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2016



New Entrant Coal Plant

Energy market net revenue was calculated for a new CP plant economically dispatched by PJM.[24] 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. The regulation clearing price was compared to the day-ahead LMP. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour.

New entrant CP plant energy market net revenues were lower in all zones in 2016 by an average of 54 percent (Table 7-13). The decrease in energy prices and the decrease in gas prices that exceeded the decrease in coal prices resulted in fewer run hours for the CP and smaller margins.

24 The 2016 new entrant CP plant is modeled to incorporate the actual flexibility of a new CP. The 2016 CP is modeled with greater flexibility than in prior years. In prior reports, the new entrant CP ran for the entire year and received uplift payments for unprofitable days.

Table 7-13 Energy net revenue for a new entrant CP (Dollars per installed MW-year)[25]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Change in 2016 from 2015
AECO	$103,766	$146,624	$92,802	$34,149	$57,755	$177,470	$73,776	$28,825	(61%)
AEP	$46,160	$94,385	$85,512	$34,944	$66,604	$130,312	$60,723	$40,596	(33%)
AP	$99,655	$145,822	$105,988	$47,572	$76,645	$154,779	$79,952	$40,344	(50%)
ATSI	NA	NA	$41,354	$42,673	$74,835	$143,552	$61,397	$37,875	(38%)
BGE	$121,146	$184,563	$121,183	$62,567	$91,820	$228,990	$145,506	$86,749	(40%)
ComEd	$109,938	$135,212	$129,279	$111,542	$130,283	$178,450	$97,010	$33,128	(66%)
DAY	$44,900	$89,635	$81,825	$33,023	$72,665	$135,377	$59,299	$34,873	(41%)
DEOK	NA	NA	NA	$26,451	$62,130	$122,282	$54,717	$32,709	(40%)
DLCO	$43,907	$68,504	$49,251	$27,035	$43,321	$97,572	$47,474	$33,759	(29%)
Dominion	$105,884	$167,920	$101,391	$44,651	$72,880	$180,306	$106,299	$49,031	(54%)
DPL	$114,738	$166,793	$117,229	$57,505	$81,303	$222,872	$103,772	$44,431	(57%)
EKPC	NA	NA	NA	NA	$32,626	$118,063	$45,675	$28,789	(37%)
JCPL	$103,162	$144,597	$90,057	$32,724	$64,305	$181,578	$73,488	$23,852	(68%)
Met-Ed	$104,285	$152,922	$101,258	$43,092	$68,531	$177,954	$74,648	$26,920	(64%)
PECO	$98,600	$139,859	$88,317	$32,534	$52,526	$170,974	$70,211	$24,793	(65%)
PENELEC	$78,821	$113,244	$77,113	$39,044	$67,118	$149,924	$70,797	$29,521	(58%)
Pepco	$111,966	$164,693	$88,212	$38,656	$73,063	$202,767	$114,025	$57,753	(49%)
PPL	$92,013	$125,723	$77,783	$26,866	$52,125	$167,421	$68,996	$22,798	(67%)
PSEG	$96,099	$146,842	$89,665	$31,754	$77,582	$201,663	$83,728	$22,805	(73%)
RECO	$89,060	$137,591	$71,676	$28,196	$83,010	$196,735	$84,679	$22,506	(73%)
PJM	$92,006	$136,761	$89,439	$41,841	$70,056	$166,952	$78,809	$36,103	(54%)

In 2016, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-12). The combination of lower energy market net revenues and lower capacity market net revenues resulted in net revenues covering a smaller share of levelized total costs for the CP.

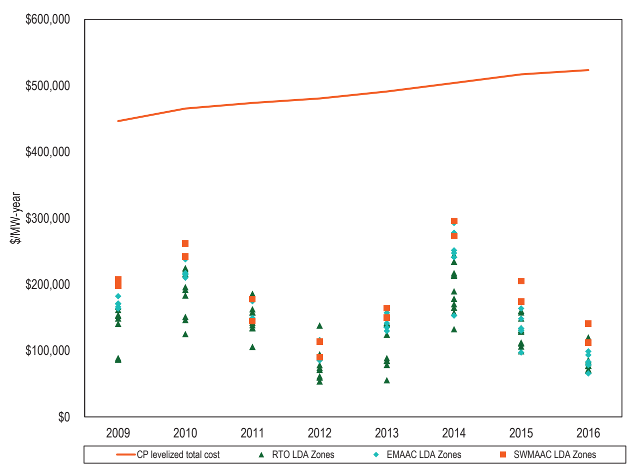
Table 7-14 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015	2016
AECO	38%	47%	32%	18%	27%	49%	26%	16%
AEP	20%	32%	30%	13%	16%	33%	22%	15%
AP	36%	46%	34%	15%	18%	38%	25%	15%
ATSI	NA	NA	NA	NA	NA	35%	31%	23%
BGE	47%	56%	38%	24%	33%	59%	40%	27%
ComEd	34%	41%	39%	29%	29%	42%	29%	13%
DAY	20%	31%	29%	12%	17%	34%	21%	14%
DEOK	NA	NA	NA	NA	NA	31%	21%	13%
DLCO	19%	27%	22%	11%	11%	26%	19%	13%
Dominion	33%	48%	33%	15%	17%	43%	31%	16%
DPL	41%	51%	37%	24%	33%	58%	32%	19%
EKPC	NA	NA	NA	NA	NA	30%	19%	13%
JCPL	38%	46%	31%	18%	29%	50%	26%	15%
Met-Ed	37%	48%	33%	20%	29%	49%	26%	16%
PECO	37%	45%	31%	18%	26%	48%	25%	15%
PENELEC	32%	39%	28%	19%	28%	43%	25%	16%
Pepco	44%	52%	31%	19%	30%	54%	34%	21%
PPL	34%	42%	28%	16%	25%	47%	25%	15%
PSEG	37%	47%	31%	18%	32%	55%	29%	18%
RECO	35%	45%	27%	17%	33%	53%	28%	15%
PJM	34%	44%	31%	18%	26%	44%	27%	16%

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): 2009 through 2016



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 zones in 2016 by an average of 86 percent (Table 7-15). As a result of relatively low energy market prices and the high short run marginal cost of the new entrant DS plant, there were relatively few hours in 2016 with positive margins.

Table 7-15 Energy market net revenue for a new entrant DS (Dollars per installed MW-year)

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Change in 2016 from 2015
AECO	$1,763	$11,217	$6,708	$1,552	$1,082	$37,123	$15,506	$1,894	(88%)
AEP	$112	$499	$1,717	$820	$484	$15,855	$6,002	$885	(85%)
AP	$886	$1,771	$2,007	$1,061	$741	$20,542	$10,490	$1,103	(89%)
ATSI	NA	NA	$308	$1,083	$23,643	$15,553	$5,777	$2,051	(64%)
BGE	$3,712	$14,147	$7,870	$2,577	$2,654	$55,866	$27,241	$8,395	(69%)
ComEd	$11	$480	$811	$909	$384	$12,427	$3,720	$702	(81%)
DAY	$186	$554	$1,894	$946	$517	$15,671	$6,083	$953	(84%)
DEOK	NA	NA	NA	$689	$462	$14,814	$5,829	$1,275	(78%)
DLCO	$674	$2,987	$2,165	$914	$1,231	$14,403	$5,428	$2,356	(57%)
Dominion	$3,639	$10,967	$4,108	$1,664	$1,545	$46,961	$15,836	$2,310	(85%)
DPL	$2,721	$9,892	$5,769	$2,381	$1,083	$43,946	$25,593	$3,912	(85%)
EKPC	NA	NA	NA	NA	$289	$15,816	$4,856	$725	(85%)
JCPL	$1,895	$8,673	$6,610	$1,704	$2,016	$37,086	$15,065	$800	(95%)
Met-Ed	$1,620	$8,711	$5,032	$1,833	$1,254	$35,789	$15,174	$762	(95%)
PECO	$1,558	$8,570	$5,379	$1,936	$1,004	$36,186	$14,033	$754	(95%)
PENELEC	$240	$1,124	$2,642	$2,141	$1,104	$18,141	$8,154	$884	(89%)
Pepco	$4,036	$13,277	$6,077	$2,009	$2,249	$56,830	$18,222	$3,512	(81%)
PPL	$1,428	$7,704	$5,317	$1,747	$1,054	$36,712	$14,906	$692	(95%)
PSEG	$1,394	$7,394	$5,447	$1,695	$1,257	$36,629	$14,566	$891	(94%)
RECO	$1,201	$6,241	$4,255	$1,737	$2,387	$34,756	$16,108	$1,083	(93%)
PJM	$1,593	$6,718	$4,118	$1,547	$2,322	$30,055	$12,429	$1,797	(86%)

In 2015, the new entrant DS would not have received sufficient net revenue to cover levelized total costs in any zone.

Table 7-16 Percent of 20-year levelized total costs recovered by DS energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015	2016
AECO	43%	51%	37%	31%	49%	64%	42%	31%
AEP	25%	35%	34%	14%	6%	29%	32%	20%
AP	38%	44%	34%	14%	6%	32%	34%	20%
ATSI	NA	NA	NA	NA	NA	29%	59%	47%
BGE	56%	57%	38%	31%	46%	74%	49%	34%
ComEd	25%	35%	33%	14%	6%	27%	30%	20%
DAY	25%	35%	34%	14%	6%	29%	32%	20%
DEOK	NA	NA	NA	NA	NA	28%	32%	20%
DLCO	26%	36%	34%	14%	6%	28%	31%	21%
Dominion	28%	42%	35%	14%	7%	48%	38%	21%
DPL	43%	50%	37%	36%	51%	68%	48%	32%
EKPC	NA	NA	NA	NA	NA	29%	31%	20%
JCPL	43%	49%	37%	32%	49%	64%	42%	30%
Met-Ed	39%	49%	36%	31%	46%	61%	42%	30%
PECO	42%	49%	36%	32%	49%	63%	41%	30%
PENELEC	38%	44%	34%	31%	45%	50%	38%	30%
Pepco	57%	56%	37%	31%	49%	76%	44%	31%
PPL	39%	48%	36%	31%	45%	62%	42%	30%
PSEG	42%	48%	36%	34%	50%	68%	44%	39%
RECO	42%	47%	35%	32%	50%	62%	43%	30%
PJM	38%	46%	35%	26%	33%	50%	40%	28%

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 of the year other than forced outage hours.[26]

New entrant nuclear plant energy market net revenues were lower in all zones in 2016 by an average of 26 percent as a result of lower energy prices and constant short run marginal costs (Table 7-17).

26 The class average forced outage rate was applied to total energy market net revenues.

Table 7-17 Energy net revenue for a new entrant nuclear plant (Dollars per installed MW-year)[27]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	Change in 2016 from 2015
AECO	$288,632	$367,483	$335,035	$223,539	$262,810	$387,883	$220,023	$142,053	(35%)
AEP	$218,504	$261,098	$262,335	$198,385	$230,716	$311,569	$204,723	$170,459	(17%)
AP	$256,721	$314,729	$293,355	$210,232	$244,428	$337,998	$228,936	$175,687	(23%)
ATSI	NA	NA	$153,888	$204,058	$242,705	$325,433	$208,372	$171,884	(18%)
BGE	$298,473	$391,960	$341,862	$245,538	$285,910	$444,433	$304,148	$244,794	(20%)
ComEd	$179,104	$217,838	$212,423	$175,450	$206,746	$272,321	$168,496	$155,796	(8%)
DAY	$214,090	$258,210	$262,111	$203,992	$234,102	$314,747	$206,825	$171,657	(17%)
DEOK	NA	NA	NA	$192,158	$221,863	$299,618	$201,391	$166,942	(17%)
DLCO	$208,801	$257,065	$258,686	$199,094	$227,732	$291,888	$193,791	$165,526	(15%)
Dominion	$281,069	$373,737	$319,215	$223,740	$263,891	$388,295	$260,516	$195,475	(25%)
DPL	$291,154	$370,565	$335,597	$236,441	$272,775	$428,044	$250,192	$168,240	(33%)
EKPC	NA	NA	NA	NA	$127,631	$294,606	$190,936	$161,624	(15%)
JCPL	$287,875	$365,408	$332,717	$222,496	$271,028	$392,479	$218,452	$136,807	(37%)
Met-Ed	$279,022	$354,677	$317,652	$217,622	$257,748	$374,408	$211,003	$140,042	(34%)
PECO	$282,937	$359,927	$329,530	$220,535	$256,201	$378,894	$212,675	$134,306	(37%)
PENELEC	$250,469	$310,481	$291,867	$215,338	$256,535	$349,950	$217,124	$158,186	(27%)
Pepco	$298,215	$389,389	$332,675	$238,119	$281,722	$427,666	$279,006	$212,848	(24%)
PPL	$275,067	$343,190	$316,501	$213,393	$255,433	$374,962	$211,595	$136,296	(36%)
PSEG	$292,089	$371,365	$338,912	$226,944	$289,418	$416,439	$230,273	$141,701	(38%)
RECO	$284,023	$360,820	$317,521	$221,087	$295,509	$411,345	$232,025	$142,867	(38%)
PJM	$263,897	$333,408	$297,327	$215,166	$249,245	$361,149	$222,525	$164,660	(26%)

In 2016, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-18). The combination of lower energy market net revenues and lower capacity market net revenues resulted in net revenues covering a smaller share of levelized total costs for the new entrant nuclear plant.

Table 7-18 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue: 2009 through 2016

Zone	2009	2010	2011	2012	2013	2014	2015	2016
AECO	44%	54%	48%	34%	42%	52%	30%	20%
AEP	32%	39%	39%	27%	30%	39%	27%	21%
AP	39%	48%	43%	29%	32%	42%	30%	22%
ATSI	NA	NA	NA	NA	NA	40%	32%	26%
BGE	48%	58%	49%	36%	44%	58%	39%	31%
ComEd	27%	34%	33%	24%	27%	34%	23%	20%
DAY	32%	39%	39%	28%	30%	39%	27%	21%
DEOK	NA	NA	NA	NA	NA	38%	27%	21%
DLCO	31%	39%	39%	27%	29%	37%	26%	21%
Dominion	40%	53%	46%	30%	34%	48%	33%	24%
DPL	44%	55%	48%	36%	44%	56%	33%	23%
EKPC	NA	NA	NA	NA	NA	37%	26%	20%
JCPL	44%	54%	48%	34%	43%	52%	29%	19%
Met-Ed	42%	53%	46%	33%	41%	50%	29%	20%
PECO	43%	53%	47%	33%	41%	51%	29%	19%
PENELEC	38%	47%	43%	33%	41%	47%	29%	22%
Pepco	48%	58%	48%	35%	44%	56%	36%	27%
PPL	42%	51%	46%	32%	40%	50%	29%	19%
PSEG	44%	55%	49%	35%	46%	56%	31%	22%
RECO	43%	53%	46%	33%	46%	54%	31%	20%
PJM	40%	49%	44%	32%	38%	47%	30%	22%

Figure 7-9 New entrant NU net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2016

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly assuming the unit was generating at the average capacity factor of operating wind units in the zone if 75 percent of existing wind units in the zone were generating power in that hour. The unit is credited with wind RECs for its generation and is assumed to have

27 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[28]

Wind energy market net revenues were lower in both zones in 2016 as a result of lower energy prices and lower RECs prices (Table 7-19).

Table 7-19 Net revenue for a wind installation (Dollars per installed MW-year)

	ComEd				PENELEC			
	Energy	RECs	Capacity	Total	Energy	RECs	Capacity	Total
2012	$68,086	-	$2,632	$70,717	$69,632	$56,622	$5,878	$132,132
2013	$83,764	-	$1,095	$84,859	$88,401	$78,900	$8,905	$176,206
2014	$108,420	$75,325	$4,049	$187,795	$127,839	$96,234	$8,237	$232,310
2015	$81,650	$78,533	$6,257	$166,439	$83,937	$95,617	$7,338	$186,892
2016	$69,487	$2,489	$4,339	$76,315	$64,649	$42,003	$6,623	$113,275
Change in 2016 from 2015	(15%)	(97%)	(31%)	(54%)	(23%)	(56%)	(10%)	(39%)

In 2016, a new wind installation would not have received sufficient net revenue to cover levelized total costs in either zone. Renewable energy credits accounted for three percent of the total net revenue of a wind installation in ComEd and 37 percent of the total net revenue of a wind installation in PENELEC.

Table 7-20 Percent of 20-year levelized total costs recovered by wind net revenue (Dollars per installed MW-year): 2012 through 2016

Zone	2012	2013	2014	2015	2016
ComEd	36%	43%	95%	82%	33%
PENELEC	67%	90%	117%	92%	49%

New Entrant Solar Installation

Energy market net revenues for a solar installation located in the PSEG Zone were calculated hourly assuming the unit was generating at the average hourly capacity factor of operating solar units in the zone if 75 percent of existing solar units in the zone were generating power in that hour. The unit is credited with SRECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[29]

Solar energy market net revenues were lower in 2016 (Table 7-21) but total revenue was higher because of SRECs.

Table 7-21 PSEG net revenue for a solar installation (Dollars per installed MW-year)

	PSEG			
	Energy	RECs	Capacity	Total
2012	$48,501	$312,580	$18,984	$380,065
2013	$81,122	$287,853	$28,835	$397,811
2014	$98,182	$281,386	$27,575	$407,144
2015	$67,807	$319,866	$23,156	$410,828
2016	$48,507	$360,487	$25,545	$434,539
Change in 2016 from 2015	(28%)	13%	10%	6%

In 2016, a new solar installation would have received sufficient net revenue to cover levelized total costs in PSEG. Renewable energy credits accounted for 83 percent of the total net revenue of a solar installation.

Table 7-22 Percent of 20-year levelized total costs recovered by solar net revenue (Dollars per installed MW-year)

Zone	2012	2013	2014	2015	2016
PSEG	96%	151%	172%	175%	198%

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through 2016. The analysis also shows that theoretical

28 The 1603 payment is a direct payment of 30 percent of the project cost. REC related net revenues were overstated for the new entrant wind installation in the *2016 Quarterly State of the Market Report for PJM: January through June* and the *2016 Quarterly State of the Market Report for PJM: January through September* and have been updated in this *2016 State of the Market Report for PJM.*

29 The 1603 payment is a direct payment of 30 percent of the project cost. SREC related net revenues were overstated for the new entrant solar installation in the *2016 Quarterly State of the Market Report for PJM: January through June* and the *2016 Quarterly State of the Market Report for PJM: January through September* and have been updated in this *2016 State of the Market Report for PJM.*

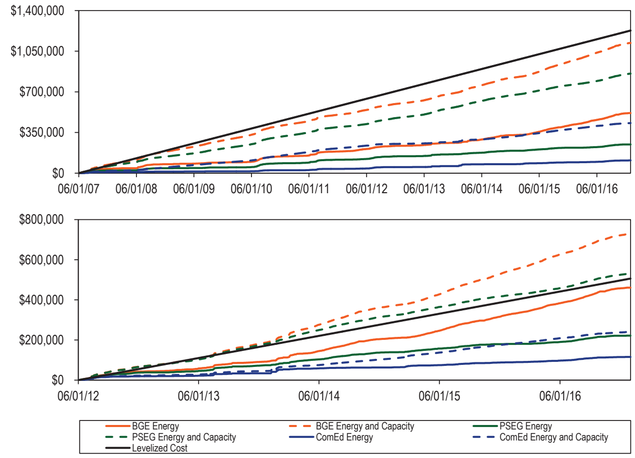
new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.

Under cost of service regulation, units are guaranteed that they will cover their total costs, assuming that the costs were determined to be reasonable. To the extent that units built in the PJM markets did not cover their total costs, investors were worse off and customers were better off than under cost of service regulation.

The summary figures compare net revenues for a new entrant CT and CC that began operation on June 1, 2007, at the start of the RPM capacity market, and new entrant CT and CC that began operation on June 1, 2012. In each figure, the solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

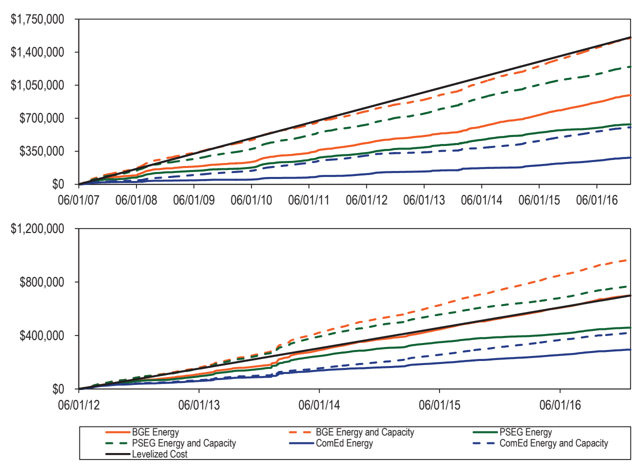
For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-10 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CT that began operation on June 1, 2007 and for a new CT that began operation on June 1, 2012. Cumulative energy market net revenues were less than cumulative total costs in all cases. Cumulative total market net revenues were less than the cumulative total costs of the 2007 new entrant CT unit for each year in each of the three zones. Cumulative total market net revenues were greater than the cumulative total costs of the 2012 new entrant CT unit in BGE and PSEG zones and less than total costs for the ComEd Zone.

Figure 7-10 Historical new entrant CT revenue adequacy: June 2007 through December 2016 and June 2012 through December 2016



For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-11 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CC that began operation on June 1, 2007 and for a new CC that began operation on June 1, 2012. Cumulative total market net revenues were less than the cumulative total costs of the 2007 new entrant CC unit for each year in each of the three zones. Cumulative total market net revenues in 2016 were greater than the cumulative total costs of the 2012 new entrant CC unit in BGE and PSEG zones and less than total costs for the ComEd Zone.

Figure 7-11 Historical new entrant CC revenue adequacy: June 2007 through December 2016



Assumptions used for this analysis are shown in Table 7-23.

Table 7-23 Assumptions for analysis of new entry

	2007 CT	2012 CT	2007 CC	2012 CC
Project Cost CT	$311,737,000	$319,167,000	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$14,475	$14,628	$20,016	$20,126
End of Life Value	$0	$0	$0	$0
Loan Term	20 years	20 years	20 years	20 years
Percent Equity (%)	50%	50%	50%	50%
Percent Debt (%)	50%	50%	50%	50%
Loan Interest Rate (%)	7%	7%	7%	7%
Federal Income Tax Rate (%)	35%	35%	35%	35%
State Income Tax Rate (%)	9%	9%	9%	9%
General Escalation (%)	2.5%	2.5%	2.5%	2.5%
Technology	GE Frame 7FA	GE Frame 7FA.05	GE Frame 7FA	GE Frame 7FA.05
ICAP (MW)	336	410	601	655
Depreciation MACRS 150% declining balance	15 years	15 years	20 years	20 years

Factors in Net Revenue Adequacy

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed and variable costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2016, the average short run marginal cost of the CC was lower than the average short run marginal cost of the CP in every month and the operating cost of the CT was lower than the CP from February through November. (See Figure 7-5.)

The net revenue results illustrate some fundamentals of the PJM wholesale power market. Lower gas prices and relatively flat coal prices in 2016 meant that coal units (CP) ran fewer hours and with smaller margins than in prior years. High demand hours result in less efficient units setting prices, which results in higher net revenues for more efficient units. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, 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. Capacity market prices and revenues have a substantial impact on the profitability of investing in CTs and CCs. In 2016, capacity market prices decreased across all zones.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized total costs from Table 7-7. The results are shown in Table 7-24.[30]

30 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt to equity capital structure with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. An annual rate of cost inflation of 2.5 percent was used in all calculations.

Table 7-24 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$121,321	13.9%	$158,327	13.9%	$553,540	13.5%
Base Case	$113,821	12.0%	$148,327	12.0%	$523,540	12.0%
Sensitivity 2	$106,321	10.0%	$138,327	10.0%	$493,540	10.4%
Sensitivity 3	$98,821	7.9%	$128,327	7.9%	$463,540	8.8%
Sensitivity 4	$91,321	5.5%	$118,327	5.6%	$433,540	7.0%
Sensitivity 5	$83,821	2.8%	$108,327	3.1%	$403,540	5.2%
Sensitivity 6	$76,321	(0.5%)	$98,327	0.1%	$373,540	3.2%

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 7-25 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 7-25 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%	$120,434	$156,726
Sensitivity 2	55%	$117,128	$152,527
Base Case	50%	$113,821	$148,327
Sensitivity 3	45%	$110,515	$144,128
Sensitivity 4	40%	$107,208	$139,929
Sensitivity 5	35%	$103,901	$135,730
Sensitivity 6	30%	$100,594	$131,531

Table 7-26 shows the levelized annual revenue requirement associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

Table 7-26 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	Term of debt in years	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	30	$103,467	$135,181
Sensitivity 2	25	$107,379	$140,149
Base Case	20	$113,821	$148,327
Sensitivity 3	15	$119,247	$155,205
Sensitivity 4	10	$126,446	$164,327

Table 7-27 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant CC has a higher energy output over which to spread the costs than the new entrant CT.

Table 7-27 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%	$110,123	$0	0.0%	$144,329
Sensitivity 2	$8,590	1.8%	$111,972	$13,060	1.4%	$146,328
Base Case	$17,181	3.6%	$113,821	$26,121	2.9%	$148,327
Sensitivity 3	$25,771	5.5%	$115,670	$39,181	4.3%	$150,327
Sensitivity 4	$34,361	7.3%	$117,519	$52,241	5.7%	$152,326
Sensitivity 5	$42,952	9.1%	$119,368	$65,302	7.2%	$154,326
Sensitivity 6	$51,616	10.9%	$120,885	$78,362	8.6%	$156,325
Sensitivity 7	$77,424	16.4%	$126,266	$102,528	11.3%	$159,637
Sensitivity 8	$103,233	21.9%	$131,647	$153,792	16.9%	$167,291

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 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 several technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM Energy and Ancillary Service Markets alone provide sufficient incentive for continued operations in PJM markets. Energy and Ancillary Service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include day-ahead and balancing market energy revenues, less short run marginal costs, plus any applicable day-ahead or balancing operating reserve credits. Ancillary service revenues include actual unit credits for regulation services, synchronized reserves, black start service, and reactive revenues.

The MMU calculated average avoidable costs in dollars per MW-year based on submitted avoidable cost rate (ACR) data for units associated with the most recent 2015/2016 and 2016/2017 RPM Auctions.[31] For units that did not submit ACR data, the default ACR was used.

The PJM capacity market design provides supplemental signals to the market based on the locational and forward looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2015/2016 and 2016/2017 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 2016. Any unit with a significant portion of installed capacity

31 If a unit submitted updated ACR data for an incremental auction, that data was used instead of the ACR data submitted for the Base Residual Auction.

designated as FRR committed was excluded from the analysis.[32] For units exporting capacity, the applicable Base Residual Auction (BRA) clearing price was applied.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the RPM. The analysis was done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Net revenues are calculated using units' price-based offers. A more accurate method would be to use the lower of the unit's price-based or cost-based offers.[33]

Unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 7-28 and Table 7-29 represent 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.

comparable to existing unit CT net revenues, within the range of existing unit CP net revenues and at the low end of existing unit Diesel net revenues.

Table 7-29 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2016, 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. The results do not include nuclear power plants because there is not good public data on nuclear unit avoidable costs.

Table 7-28 Net revenue by quartile for select technologies: 2016

		($/MW-Yr)								
		Energy and ancillary service net revenue			Capacity revenue			Energy, ancillary, and capacity revenue		
Technology	Total Installed Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	55,596	$1,811	$39,944	$65,299	$13,402	$25,360	$51,573	$50,022	$68,280	$100,461
CT - Aero Derivative	6,173	$1,095	$4,505	$8,457	$40,581	$49,364	$52,482	$46,189	$53,111	$59,397
CT - Industrial Frame	21,081	($538)	$1,397	$4,255	$42,786	$48,482	$51,646	$42,465	$50,054	$57,118
Coal Fired	61,317	$6,642	$17,122	$44,554	$40,834	$46,788	$51,273	$46,632	$66,180	$100,127
Diesel	439	($982)	$6,663	$38,870	$42,621	$48,633	$53,510	$47,915	$56,903	$82,162
Hydro	2,750	$40,482	$52,440	$74,257	$6,115	$51,064	$54,056	$56,942	$88,367	$112,738
Oil or Gas Steam	8,199	($2,636)	($467)	$5,710	$46,107	$51,669	$52,872	$44,187	$52,900	$59,616
Pumped Storage	4,721	$39,975	$46,880	$127,140	$6,243	$6,645	$52,917	$46,649	$102,416	$133,334

Table 7-28 shows average energy and ancillary service net revenues by quartile for select technology classes. 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 delivery costs associated with input fuels. The table also includes new entrant net revenue. The results show that the new entrant net revenues are at the high end of existing unit CC net revenues, not

32 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

33 *See* 148 FERC ¶ 61,140 (2014).

Table 7-29 Avoidable cost recovery by quartile: 2016

		Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
Technology	Total Installed Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	55,596	12%	288%	535%	256%	487%	706%
CT - Aero Derivative	6,173	10%	27%	42%	243%	322%	434%
CT - Industrial Frame	21,081	0%	13%	38%	400%	472%	532%
Coal Fired	61,317	6%	21%	52%	61%	85%	131%
Diesel	439	0%	56%	329%	426%	490%	696%
Hydro	2,750	127%	164%	233%	179%	277%	354%
Oil or Gas Steam	8,199	0%	0%	16%	163%	183%	214%
Pumped Storage	4,721	214%	260%	681%	250%	561%	715%

Table 7-30 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. In 2016, RPM 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 units.

Table 7-30 Proportion of units recovering avoidable costs: 2011 through 2016

	Units with full recovery from energy and ancillary net revenue						Units with full recovery from all markets					
Technology	2011	2012	2013	2014	2015	2016	2011	2012	2013	2014	2015	2016
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	85%	79%	79%	95%	88%	93%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	100%	96%	76%	98%	100%	99%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	99%	98%	83%	100%	100%	100%
Coal Fired	31%	17%	27%	80%	16%	15%	82%	36%	54%	85%	64%	41%
Diesel	48%	42%	37%	69%	56%	33%	100%	100%	77%	100%	100%	100%
Hydro	74%	61%	95%	97%	81%	79%	81%	77%	97%	98%	100%	100%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	92%	78%	86%	85%	91%	91%
Pumped Storage	NA	100%	95%	100%	100%	100%	NA	100%	100%	100%	100%	100%

Units At Risk

Units that have either already started the deactivation process or requested deactivation review are excluded from the at risk analysis.

Unit revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover avoidable costs from total market revenues, including capacity market revenues, are at risk of retirement particularly if the results are expected to continue. In addition, units that failed to clear the most recent capacity auction(s) are at increased risk of retirement particularly if this result is expected to continue. The profile of units that have not recovered avoidable costs from total market revenues in two of the last three years or have not cleared either the 2018/2019 or the 2019/2020 capacity auctions is shown in Table 7-31.[34] These units are considered at risk of retirement.[35]

These results mean that 14,500 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire.

Table 7-31 Profile of units at risk of retirement

Technology	No. Units	ICAP (MW)	Avg. 2016 Run Hrs	Avg. Unit Age (Yrs)	Avg. Heat Rate
CC - Combined Cycle	4	915	1,002	28	9,523
CT - Aero Derivative	11	192	26	43	15,076
CT - Industrial Frame	44	1,217	123	39	14,542
Coal Fired	25	11,282	4,179	49	10,363
Diesel	4	30	330	25	10,999
Oil or Gas Steam	8	864	2,918	44	11,778
Total	96	14,500	3,197	34	11,391

34 Avoidable costs are ACR values and exclude APIR.

35 Units expected to continue operations are not considered at risk of retirement.

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets.

At the federal level, the Mercury and Air Toxics Standards Rule (MATS) requires significant investments for some fossil fuel fired power plants in the PJM footprint in order to reduce heavy metal emissions. The Environmental Protection Agency ("EPA") has promulgated intrastate and interstate air quality standards and associated emissions limits for states. The Cross-State Air Pollution Rule (CSAPR) will require investments for some fossil fuel fired power plants in the PJM footprint in order to reduce SO_2 and NO_X emissions.

State regulations and multi-state agreements have an impact on PJM markets. New Jersey's high electric demand day (HEDD) rule limits NO_X emissions on peak energy demand days and requires investments for noncompliant units. CO_2 costs resulting from the Regional Greenhouse Gas Initiative (RGGI) affect some unit offers in the PJM Energy Market.

The investments required for environmental compliance have resulted in higher offers in the Capacity Market, and when units do not clear, in the retirement of units. Federal 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 powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have significant impacts on PJM wholesale markets.

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[1]
- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[2] In January 2016, the EPA began the implementation of the Cross-State Air Pollution Rule (CSAPR) to address this issue through an interstate emissions trading regime.[3]
- **National Emission Standards for Reciprocating Internal Combustion Engines.** On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs.[4] On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. The provisions that allowed RICE participating in emergency demand response programs to operate for additional hours have been eliminated.[5] Zero hours are exempt.[6] As a result, the national emissions standards uniformly apply to all RICE.[7] All RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[8]
- **Greenhouse Gas Emissions Rule.** On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating

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 (February 16, 2012).

2 CAA § 110(a)(2)(D)(i)(I).

3 Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) ("CSAPR").

4 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

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

6 *Id.*

7 *Id.*

8 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations); 0 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

Units (the Clean Power Plan).[9] The rule requires that individual state plans be submitted by September 6, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay of the rule that will prevent its taking effect until judicial review is completed.[10]

- **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.[11] The rule is implemented as National Pollutant Discharge Elimination System (NPDES) permits are issued, with exceptions in certain cases for permits expiring prior to July 14, 2018.
- **Waste Disposal.** On December 19, 2014, the EPA issued its Coal Combustion Residuals rule (CCRR), effective October 19, 2015. The rule sets nonbinding criteria for coal ash disposal facilities.

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** A New Jersey rule that imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on high electric demand days (HEDD).[12] 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.[13]
- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards ("MPS") and Combined Pollutants Standards ("CPS") that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA MATS rule.[14]
- **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. The auction price in the December 7, 2016, auction for the 2015-2017 compliance period was $3.55 per ton. The clearing price is equivalent to a price of $3.91 per metric tonne, the unit used in other carbon markets.

State Renewable Portfolio Standards

Many states in PJM have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of December 31, 2016, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky and Tennessee did not have renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[15]

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On December 31, 2016, 89.4 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 93.4 percent of fossil fuel fired capacity in PJM had NO_X emission control technology.

9 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (August 3, 2015), also known as the "Clean Power Plan."
10 North Dakota v. EPA, et al., Order 15A793.
11 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).
12 N.J.A.C. § 7:27-19.
13 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).
14 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).
15 See Enr. Com. Sub. For H. B. No. 2001.

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.)

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. The extension of the RPS concept to include nuclear power as a zero emissions source in order to provide subsidies to nuclear power will increase this impact. 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.[16]

RECs, federal investment tax credits and federal production tax credits provide out of market payments to qualifying resources, primarily wind and solar, which create an incentive to generate MWh until the LMP is equal to the marginal cost of producing power minus the credit received for each MWh. The same is true for nuclear power credits, ZECs (zero emissions credits). The credits provide an incentive to make negative energy offers and more generally provide an incentive to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. REC markets are not transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. 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 PJM 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 resources by reducing the risks associated with lack of transparent market data. This would be a significant improvement even if some unusual or unique types of RECs remained outside this market.

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 bids 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 ensure 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 for states to comply with the EPA's Clean Power Plan, for example by incorporating a 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 carbon price would be the most efficient way to implement that decision. It would also be an alternative to specific subsidies to individual nuclear power plants 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 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.

16 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.").

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA). The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.[17] [18] The EPA's actions have and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

The EPA also administers the Clean Water Act (CWA), which regulates water pollution. The EPA implements the CWA through a permitting process, which regulates discharges from point sources that impact water quality and temperature in navigable waterways. In 2014, the EPA implemented new regulations for cooling water intakes under section 316(b) of the CWA.

Control of Mercury and Other Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources.

On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the 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.[19] The rule established a compliance deadline of April 16, 2015.

In a related EPA rule also issued on December 16, 2011, regarding utility New Source Performance Standards (NSPS), the EPA required new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter (PM).[20]

On June 29, 2015, the U.S. Supreme Court remanded MATS to the U.S. Court of Appeals for the D.C. Circuit and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[21] The remand did not stay MATS and had no effect on the implementation of MATS. On April 14, 2016, the EPA issued the required finding that "a consideration of cost does not cause us to change our determination that regulation of hazardous air pollutant (HAP) emissions from coal- and oil-fired EGUs is appropriate and necessary."[22] This action supplies the initial cost determination that the U.S. Supreme Court found lacking, and which was the sole basis for remand. The rule has been effective since April 14, 2016, and remains effective.

Air Quality Standards: Control of NO_X, SO_2 and O_3 Emissions Allowances

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).[23] Standards for each pollutant are set and periodically revised, most recently for SO_2 in 2010, and SIPS are filed, approved and revised accordingly.

On April 29, 2014, the U.S. Supreme Court upheld the EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect. On November 21, 2014, the EPA issued a rule requiring compliance with CSAPR's Phase 1 emissions budgets effective January 1, 2015, and CSAPR's Phase 2

17 42 U.S.C. § 7401 et seq. (2000).

18 The EPA defines "major sources" 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.

19 *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 (February 16, 2012); *aff'd*, White Stallion Energy Center, LLC v EPA, No. 12-1100 (D.C. Cir. April 15, 2014).

20 NSPS are promulgated under CAA § 111.

21 Michigan et al. v. EPA, Slip Op. No. 14-46.

22 *Supplemental Finding that it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234; *see also* White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

23 Nitric Oxides (NO_X), Sulfur Dioxide (SO_2), Ozone (O_3), Particulate Matter (PM), Carbon Monoxide (CO) and Lead (Pb).

emissions effective January 1, 2017. The ruling and the EPA rules eliminated CAIR and replaced it with CSAPR.

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.[24] The CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states. The CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.[25] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[26]

CSAPR establishes two groups of states with separate requirements standards. Group 1 includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[27] Group 2 does not include any states in the PJM region.[28] Group 1 states must reduce both annual SO_2 and NO_X emissions to help downwind areas attain the 24-Hour and/or Annual Fine Particulate Matter[29] NAAQS and to reduce ozone season NO_X emissions to help downwind areas attain the 2008 8-Hour Ozone NAAQS.

CSAPR requires reductions of emissions for each state below certain assurance levels, established separately for each emission type. Assurance levels are the state budget for each type of emission, determined by the sum of unit-level allowances assigned to each unit located in such state, plus a variability limit, which is meant to account for the inherent variability in the state's yearly baseline emissions. Because allowances are allocated only up to the state emissions budget, any level of emissions in a state above its budget must be covered by allowances obtained through trading for unused allowances allocated to units located in other states included in the same group.

The rule provides for implementation of a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group.

If state emissions exceed the applicable assurance level, including the variability limit, a penalty is assessed and allocated to resources within the state in proportion to their responsibility for the excess. The penalty requires surrender of two additional allowances for each allowance needed to the cover the excess.

On September 7, 2016, the EPA issued a final rule updating the CSAPR ozone season NO_X emissions program to reflect the decrease to the ozone season NAAQS that occurred in 2008 ("CSAPR Update").[30] The CSAPR had been finalized in 2011 based on the 1997 ozone season NAAQS. The 2008 ozone season NO_X emissions level was lowered to 0.075 ppm from 0.08 in 1997.[31] The CSAPR Update increases the reductions required from upwind states to assist downwind states' ability to meet the lower 2008 standard.

The CSAPR Update also finalizes Federal Implementation Plans (FIPs) for each of the PJM states covered by CSAPR.[32] The EPA approves a FIP for states that fail to timely submit and obtain approval of their own implementation plan (SIPs).

Starting May 1, 2017, the CSAPR Update requires reduced summertime NO_X from power plants in certain PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.[33] The EPA has removed North Carolina from the ozone season NO_X trading

24 CAA § 110(a)(2)(D)(i)(I).

25 *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) ("CSAPR"); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 10342 (February 21, 2012); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 34830 (June 12, 2012).

26 *Id.*

27 Group 1 states include: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.

28 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.

29 The EPA defines Particulate Matter (PM) as "[a] complex mixture of extremely small particles and liquid droplets. It is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles." Fine PM (PM*2.5*) measures less than 2.5 microns across.

30 *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, EPA-HQ-OAR-2015-0500, 81 Fed. Reg. 74504 (–Oct. 26, 2016) ("CSAPR Update").

31 *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, NOPR, EPA-HQ-OAR-2009-0491, 75 Fed. Reg. 45210, 45220 (Aug. 2, 2010).

32 CSAPR Update at 74506 & n.9. PJM states that did not submit SIPs include Illinois, Maryland, Michigan, New Jersey, North Carolina, Pennsylvania, Tennessee, Virginia, and West Virginia; PJM states submitting SIPs but not obtaining approval include Indiana, Kentucky and Ohio. *Id.*

33 *Id.* at 74554.

program.[34] Table 8-1 shows the revised reduced NO_X emissions budgets for each PJM affected state. Table 8-1 also shows the assurance level, which is a hard cap on emissions, meaning that emissions above the assurance cannot be covered by emissions allowances, even if available.

Table 8-1 Current and proposed CSAPR ozone season NO_X budgets for electric generating units (before accounting for variability)[35]

State	2017 CSAPR Ozone Season NO_X Budget for Electric Generating Units (before accounting for variability) (Tons)	Assurance Level (Tons)
Illinois	14,601	17,667
Indiana	23,303	28,197
Kentucky	21,115	25,549
Maryland	3,828	4,632
Michigan	17,023	20,598
New Jersey	2,062	19,094
Ohio	19,522	23,622
Pennsylvania	17,952	21,722
Tennessee	7,736	9,361
Virginia	9,223	11,160
West Virginia	17,815	21,556

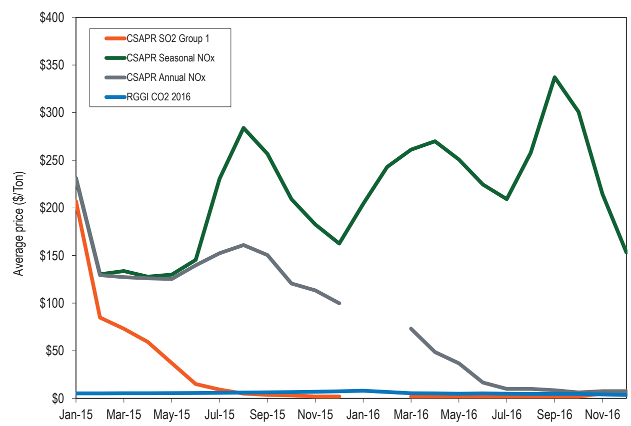
During the delay of CSAPR implementation, the EPA estimates that there "will be approximately 350,000 banked allowances entering the CSAPR NO_X ozone season trading program by the start of the 2017 ozone season control period."[36] The EPA is concerned that "[w]ithout imposing a limit on the transitioned vintage 2015 and 2016 banked allowances, the number of banked allowances would increase the risk of emissions exceeding the CSAPR Update emission budgets or assurance levels and would be large enough to let all affected sources emit up to the CSAPR Update assurance levels for five consecutive ozone seasons."[37] Accordingly, the EPA established a formulaic limit on the use of transitioned vintage 2015 and 2016 banked allowances.[38]

Compliance with CSAPR's Phase 1 emissions budgets is required in 2015 and 2016 and with CSAPR's Phase 2 emissions in 2017 and beyond.[39]

Figure 8-1 shows average, monthly settled prices for NO_X, CO_2 and SO_2 emissions allowances including CSAPR related allowances for 2015 and 2016. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In 2016, CSAPR annual NO_X prices were 83.9 percent lower than in 2015. The CSAPR annual NO_X price was \$230.50 in January 2015, the first month that CSAPR was effective, and has decreased steadily since then. There were not any reported cleared purchases for January or February 2016 for CSAPR Annual NO_X. The CSAPR Seasonal NO_X price hit a peak of \$337.14 in September 2016. The CSAPR Update resulted in fewer CSAPR Seasonal NO_X allowances. The average price of CSAPR SO_2 in 2016 was \$2.70 compared to the average price of \$41.78 for CSAPR SO_2 in 2015.[40]

Figure 8-1 Spot monthly average emission price comparison: 2015 through 2016[41]



34 *Id.* at 74507 n.13.
35 CSAPR Update at 74567.
36 *Id.* at 74588.
37 *Id.*
38 *Id.* at 74560. The EPA states: "The one-time conversion of the 2015 and 2016 banked allowances will be made using a calculated ratio, or equation, to be applied in early 2017 once compliance reconciliation (or 'true-up')s for the 2016 ozone season program is completed." *Id.*
39 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491 (Nov. 21, 2014).

40 There were not any reported cleared purchases for January or February 2016 for CSAPR SO_2 or CSAPR Annual NO_X.
41 Spot monthly average emission price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 20, 2017).

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[42] 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").[43]

The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on whether the engine is an "area source" or "major source," and the starter mechanism for the engine (compression ignition or spark ignition).[44]

On May 22, 2012, the EPA proposed amendments to the 2010 RICE NESHAP Rule.[45] The proposed rule would have allowed owners and operators of emergency stationary internal combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. The rule would have increased the 2010 Rule's 15 hour per year run limit. The exempted emergency demand response programs included RPM demand resources.[46]

On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.[47] As a result, the national emissions standards uniformly apply to all RICE.[48] The Court held that the "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[49] Specifically, the Court found that the EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[50]

On April 15, 2016, the EPA issued a letter explaining how it would implement the vacatur order.[51] The EPA explained upon issuance of the Court's mandate, "an engine may not operate in circumstances described in the vacated [portions of the 2013 NESHAP RICE Rule] for any number of hours power per year."[52] The EPA explained that such engines could, however, continue to operate for specified emergency and nonemergency reasons.[53]

On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. Issuance of the mandate triggered implementation of the policy.

The MMU is currently taking steps to ensure resource portfolios remain in compliance. The MMU contacted all

42 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (January 30, 2013) ("2013 NESHAP RICE Rule"). In 2010, the EPA promulgated two rules with standards for hazardous air pollutant emissions from backup generators. The rules allowed backup generators to operate without emissions controls for fifteen hours each year as part of "demand response programs" during "emergency conditions that could lead to a potential electrical blackout." EPA Docket No. EPA-H-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295, codified at 40 CFR Part 60 Subpart JJJJ ("2010 RICH NESHAP Rule").

43 *Id.*

44 CAA § 112(a) defines "major source" to mean "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants," and "area source" to mean, "any stationary source of hazardous air pollutants that is not a major source."

45 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.

46 If FERC approves PJM's proposal on this issue in Docket No. ER14-822-000, demand resources that use behind the meter generators will maintain emergency status and not have to curtail during pre-emergency events, unlike other demand resources. This matter remains pending.

47 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

48 *Id.*

49 DENREC v. EPA at 3, 20–21.

50 *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012) at 2.

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

52 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations).

53 See 40 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

CSPs with Demand Resources using diesel fuel to ensure compliance is met among all PJM resources.

Regulation of Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[54 55]

The U.S. Court of Appeals for the Seventh Circuit has determined that a government agency can reasonably consider the global benefits of carbon emissions reduction against costs imposed in the U.S. by regulations in analyses known as the "Social Costs of Carbon."[56] 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.[57] Although the decision applies only to the Department of Energy's regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on social cost of carbon analyses.

On September 20, 2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be allowed to emit.[58 59] The proposed rule includes two limits for fossil fuel fired utility boilers and integrated gasification combined cycle (IGCC) units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (seven year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size: 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr).

On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units ("CPE Guidelines" or Clean Power Plan).[60] On February 6, 2016, the U.S. Supreme Court issued a stay on the CPE Guidelines that will prevent them from taking effect until judicial review is completed.[61] An appeal is pending before the U.S. Court of Appeals for the District of Columbia Circuit, and a decision there may be appealed to the U.S. Supreme Court. The status of CPE Guidelines is uncertain with the transition to a new administration.

States would have flexibility to meet the Clean Power Plan's GHG goals, including through participation in multistate CO_2 credit trading programs.

The CPE Guidelines set state by state rate and mass based CO_2 emissions targets.[62] States would be required to develop and obtain EPA approval of plans to achieve the interim goals effective 2022 and the final goals effective 2030.[63] The CPE Guidelines anticipate that meeting these goals would reduce CO_2 emissions from Electric Generating Units (EGUs) by 2030 to a level 32 percent below the level of emissions in 2005.[64]

The EPA has calculated rate and mass-based goals based on EGU emissions rates for each state.[65] The EPA uses three building blocks to calculate state goals.[66] The EPA calculates emissions as of 2005 from EGUs in each state, and then assumes reduced emissions based on implementation of the building blocks.[67]

To calculate state interim and final goals, the EPA assumes the following building blocks: (i) heat rate improvement of 2.1–3.4 percent (depending upon the region) at affected EGUs; (ii) displacement of generation

54 See CAA § 111.

55 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 (December 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.

56 See Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al., Case Nos. 14-2147, et al., Slip Op. (August 8, 2016).

57 *Id.*

58 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1430 (January 8, 2014); The President's Climate Action Plan, Executive Office of the President (June 2013) (Climate Action Plan); Presidential Memorandum–Power Sector Carbon Pollution Standards, Environmental Protection Agency (June 25, 2013); Presidential Memorandum–Power Section Carbon Pollution Standards (June 25, 2013) ("June 25th Presidential Memorandum"). The Climate Action Plan can be accessed at: <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>.

59 79 Fed. Reg. 1352 (January 8, 2014).

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

61 North Dakota v. EPA, 136 S. Ct. 999 (2016).

62 *Id.* at 1560. A rate-based goal is measured in pounds of CO_2 per megawatt hour (lbs/MWh); a mass-based goal is measured in total short tons of CO_2 emissions.

63 *Id.* at 1559.

64 *Id.* at 34839.

65 A mass-based goal is expressed as maximum number of tons of CO_2 that may be emitted over a time period, while a rate-based goal is expressed as a number of pounds of CO_2 per MWh.

66 *Id.* at 1559.

67 *Id.* at 1559–1560.

from lower emitting existing natural gas combined cycle units for reduced generation from higher-emitting affected steam generating units; and (iii) displacement of generation from new zero emitting generating capacity for reduced generation from affected fossil fuel-fired generating units.[68]

The interim and final targets for CO_2 emissions goals for PJM states, in order of highest to lowest, are included in Table 8-2.

Table 8-2 Interim and final targets for CO_2 emissions goals for PJM states (Short Tons of CO_2)[69]

Jurisdiction	2020 Interim New Source Complements (Short Tons of CO_2)	2030 Final New Source Complements (Short Tons of CO_2)	2020 Interim Mass Goal (Short Tons CO_2)	2030 Final Final Goal (Short Tons CO_2)
Delaware	78,842	69,561	5,141,711	4,781,386
District of Columbia	NA	NA	NA	NA
Illinois	818,349	722,018	75,619,224	67,119,174
Indiana	939,343	828,769	86,556,407	76,942,604
Kentucky	752,454	663,880	72,065,256	63,790,001
Maryland	170,930	150,809	16,380,325	14,498,436
Michigan	623,651	550,239	53,680,801	48,094,302
New Jersey	313,526	276,619	17,739,906	16,876,364
North Carolina	692,091	610,623	57,678,116	51,876,856
Ohio	949,997	838,170	83,476,510	74,607,975
Pennsylvania	1,257,336	1,109,330	100,588,162	90,931,637
Tennessee	358,838	316,598	32,143,698	28,664,994
Virginia	450,039	397,063	30,030,110	27,830,174
West Virginia	602,940	531,966	58,686,029	51,857,307
Total	8,008,336	7,065,645	689,786,255	617,871,210

The difference in goals reflects different evaluation of state specific factors, referred to as building blocks, including heat rate improvements, dispatch among affected EGUs, expanded use of less carbon-intensive generating capacity and demand-side energy efficiency.[70] The essence of the approach is that the baseline is set by the current opportunity in a state to achieve additional CO_2 emissions reductions. No credit is given for prior steps that states have taken, some more than others, to achieve CO_2 emissions reductions.

Each state would be required to develop an EPA approved plan to meet its interim and final goals.[71] The CPE Guidelines would not require states to implement the building blocks in their plan, but would require states to meet the goals through an approach included in an EPA-approved plan.

States could implement a state measures approach, which involves a state "adopt[ing] a set of policies and programs, which would not be federally enforceable, except that any standards imposed on affected EGUs would be federally enforceable."[72] States could choose from market-based trading programs, emissions performance standards, renewable portfolio standards (RPS), energy efficiency resource standards (EERS), and other demand-side energy efficiency programs.[73]

The CPE Guidelines recognize that many states have already implemented programs to reduce CO_2 emissions from fossil fuel fired EGUs and specifically highlight the Regional Greenhouse Gas Initiative (RGGI) and California's Global Warming Solutions Act of 2006.[74] Each of these programs would require significant changes in order to comply with the approach in the CPE Guidelines. The trading rules could remain, but new regional goals and compliance deadlines that equal or exceed the state goals and compliance deadlines set in the CPE Guidelines would be needed. The rules would also take into account that the CPE Guidelines rely on reduced emissions from EGUs to reach state goals and does not count non-EGU offsets towards meeting those goals.[75]

The CPE Guidelines permit states to partner and submit multistate plans to reduce CO_2 emissions from EGUs.[76]

Federal Regulation of Environmental Impacts on Water

Water cooling systems at steam electric power generating stations are subject to regulation under the Clean Water Act (CWA).

EPA regulations of discharges from steam electric power generating stations are set forth in the Generating

68 *Id.* 1559.
69 The District of Columbia has no affected EGUs and is not subject to the CPE Guidelines (at 1560).
70 CPE Guidelines 1559–1560.
71 *Id.*
72 *Id.* at 1560.
73 *Id.* at 898.
74 *Id.* at 1560.
75 *Id.* at 34910.
76 *Id.* at 1560.

Effluent Guidelines and Standards in 1974. These standards were amended most recently in 2015.

Section 301(a) of the CWA prohibits the point source discharge of pollutants to a water of the United States, unless authorized by permit.[77] Section 402 of the CWA establishes the required permitting process, known as the National Pollutant Discharge Elimination System (NPDES). NPDES permits limit discharges and include monitoring and reporting requirements. NPDES permits last five years before they must be renewed.

NPDES permits must satisfy the more stringent of a technology based standard, known at Best Technology Available (BTA), or water quality standards. NDPES permits included limits designed to prevent discharges that would cause or contribute to violations of water quality standards. Water quality standards include thermal limits.

PJM states are authorized to issue NPDES permits, with the exception of the District of Columbia. Pennsylvania, Delaware, Indiana and Illinois are partially authorized; the balance of PJM states are fully authorized.

The CWA regulates intakes in addition to discharges.

Section 316(b) of the CWA requires that cooling water intake structures reflect the BTA for minimizing adverse environmental impacts. The EPA's rule implementing Section 316(b) requires an existing facility to use BTA to reduce impingement of aquatic organisms (pinned against intake structures) if the facility withdraws 25 percent or more of its cooling water from waters of the United States and has a design intake flow of greater than two million gallons per day (mgd).[78]

Existing facilities withdrawing 125 mgd must conduct studies that may result in a requirement to install site-specific controls for reducing entrainment of aquatic organisms (drawn into intake structures). If a new generating unit is added to an existing facility, the rule requires addition of BTA that either (i) reduces actual intake flow at the new unit to a level at least commensurate with what can be attained using a closed-cycle recirculating system or (ii) reduces entrainment mortality of all stages of aquatic organisms that pass through a sieve with a maximum opening dimension of 0.56 inches to a prescribed level.

Federal Regulation of Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[79]

Solid waste is regulated under subtitle D, which encourages state management of nonhazardous industrial solid waste and sets nonbinding criteria for solid waste disposal facilities. Subtitle D prohibits open dumping. Subtitle D criteria are not directly enforced by the EPA. However, the owners of solid waste disposal facilities are exposed under the act to civil suits, and criteria set by the EPA under subtitle D can be expected to influence the outcome of such litigation.

Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

The EPA issued a rule under RCRA, the Coal Combustion Residuals rule (CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[80] CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

The CCRR exempts: (i) beneficially used CCRs that are encapsulated (i.e. physically bound into a product); (ii) coal mine filling; (iii) municipal landfills; (iv) landfills receiving CCRs before the effective date; (v) surface impoundments closed by the effective date; and (vi) landfills and surface impoundments on the site of generation facilities that deactivate prior to the effective date. Less restrictive criteria may also apply to some surface impoundments deemed inactive under not yet clarified criteria.

77 The CWA applies to "navigable waters," which are, in turn, defined to include the "waters of the United States, including territorial seas." 33 U.S.C. § 1362(7). An interpretation of this rule has created some uncertainty on the scope of the waters subject to EPA jurisdiction, (see *Rapanos v. U.S., et al.*, 547 U.S. 715 (2006)), which the EPA continues to attempt to resolve.

78 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).

79 42 U.S.C. §§ 6901 *et seq.*

80 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

Table 8-3 describes the criteria and anticipated implementation dates.

Table 8-3 Minimum criteria for existing CCR ponds (surface impoundments) and landfills and date by which implementation is expected

Requirement	Description of requirement to be completed	Implementation Date
Location Restrictions (§ 257.60–§ 257.64)	For Ponds: Complete demonstration for placement above the uppermost aquifer, for wetlands, fault areas, seismic impact zones and unstable areas.	October 17, 2018
	For Landfills: Complete demonstration for unstable areas.	October 17, 2018
Design Criteria (§ 257.71)	For Ponds: Document whether CCR unit is either a lined or unlined CCR surface impoundment.	October 17, 2016
Structural Integrity (§ 257.73)	For Ponds: Install permanent marker.	December 17, 2015
	For Ponds: Compile a history of construction, complete initial hazard potential classification assessment, initial structural stability assessment, and initial safety factor assessment.	October 17, 2016
	Prepare emergency action plan.	April 17, 2017
Air Criteria (§ 257.80)	Ponds and Landfills: Prepare fugitive dust control plan.	October 17, 2015
Run-On and Run-Off Controls (§ 257.81)	For Landfills: Prepare initial run-on and run-off control system plan.	October 17, 2016
Hydrologic and Hydraulic Capacity (§ 257.82)	Prepare initial inflow design flood control system plan.	October 17, 2016
Inspections (§ 257.83)	For Ponds and Landfills: Initiate weekly inspections of the CCR unit.	October 17, 2015
	For Ponds: Initiate monthly monitoring of CCR unit instrumentation.	October 17, 2015
	For Ponds and Landfills: Complete the initial annual inspection of the CCR unit.	January 17, 2016
Groundwater Monitoring and Corrective Action (§ 257.90–§ 257.98)	For Ponds and Landfills: Install the groundwater monitoring system; develop the groundwater sampling and analysis program; initiate the detection monitoring program; and begin evaluating the groundwater monitoring data for statistically significant increases over background levels.	October 17, 2017
Closure and Post-Closure Care (§ 257.103–§ 257.104)	For Ponds and Landfills: Prepare written closure and post-closure care plans.	October 17, 2016
Recordkeeping, Notification, and Internet Requirements (§ 257.105–§ 257.107)	For Ponds and landfills: Conduct required recordkeeping; provide required notifications; establish CCR website.	October 17, 2015

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules apply to total annual and seasonal emissions. 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.[81] 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.[82] NO_X emissions limits for coal units became effective December 15, 2012.[83] NO_X emissions limits for other unit types became effective May 1, 2015.[84] As of December 31, 2016, two Cedar Station units, three Middle Street units, three Missouri units, one Sherman Ave unit, three Burlington units, three Edison units, four Essex units, three Kearny units, one Mercer unit, one National Park unit, one Sewaren unit, eight Glen Gardner units and four Werner units identified as NJ HEDD units have retired.[85] In total 37 NJ HEDD units have retired and the remaining 41 NJ HEDD units are still operating after taking actions to comply with the HEDD regulations.

81 N.J.A.C. § 7:27–19.

82 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).

83 N.J.A.C. § 7:27-19.4.

84 N.J.A.C. § 7:27-19.5.

85 See Current New Jersey Turbines that are HEDD Units, <http://www.nj.gov/dep/workgroups/docs/apcrule_20110909turbinelist.pdf>.

Table 8-4 shows the HEDD emissions limits applicable to each unit type.

Table 8-4 HEDD maximum NO_x emission rates[86]

Fuel and Unit Type	NO_x Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple Cycle Gas CT	1.00
Simple Cycle Oil CT	1.60
Combined Cycle Gas CT	0.75
Combined Cycle Oil CT	1.20
Regenerative Cycle Gas CT	0.75
Regenerative Cycle Oil CT	1.20

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").[87] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

The Illinois Pollution Control Board has granted variances with conditions for compliance with MPS/CPS for Illinois units included in or potentially included in PJM markets.[88] In order to obtain variances, companies in PJM agreed to terms with the Illinois Pollution Control Board that resulted in investments in the installation of environmental pollution control equipment at units and deactivation of Illinois units that differ from what would have occurred had only Federal regulations applied.[89]

State Regulation of Greenhouse Gas Emissions

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[90] RGGI generates revenues for the participating states which have spent approximately 57 percent of revenues to date on energy efficiency, 15 percent on clean and renewable energy, 8 percent on greenhouse gas abatements and 15 percent on direct bill assistance.[91]

Table 8-5 shows the RGGI CO_2 auction clearing prices and quantities for the 2009-2011 compliance period auctions, the 2012-2014 compliance period auctions and 2015-2017 compliance period auctions held as of December 31, 2016, in short tons and metric tonnes. Prices for auctions held December 7, 2016, for the 2015-2017 compliance period were at $3.55 per allowance (equal to one ton of CO_2), above the current price floor of $2.05 for RGGI auctions.[92] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price decreased from the last auction of $4.54 in September 2016. 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 auction to use CRRs.

86 Regenerative cycle CTs are combustion turbines that recover heat from their exhaust gases and use that heat to preheat the inlet combustion air which is fed into the combustion turbine.

87 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_x and SO_2 (CPS)).

88 See, e.g., Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 13-24 (Variance-Air) (April 4, 2013); Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 12-121 (Variance-Air) (August 23, 2012).

89 See *Id.*

90 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>.

91 *Investment of RGGI Proceeds Through 2014*, The Regional Greenhouse Gas Initiative, <http://rggi.org/docs/ProceedsReport/RGGI_Proceeds_FactSheet_2014.pdf> (Accessed January 20, 2017).

92 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).

Table 8-5 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009-2011, 2012-2014 and 2015-2017 Compliance Periods[93]

	Short Tons			Metric Tonnes		
Auction Date	Clearing Price	Quantity Offered	Quantity Sold	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387	$3.38	11,399,131	11,399,131
December 17, 2008	$3.38	31,505,898	31,505,898	$3.73	28,581,678	28,581,678
March 18, 2009	$3.51	31,513,765	31,513,765	$3.87	28,588,815	28,588,815
June 17, 2009	$3.23	30,887,620	30,887,620	$3.56	28,020,786	28,020,786
September 9, 2009	$2.19	28,408,945	28,408,945	$2.41	25,772,169	25,772,169
December 2, 2009	$2.05	28,591,698	28,591,698	$2.26	25,937,960	25,937,960
March 10, 2010	$2.07	40,612,408	40,612,408	$2.28	36,842,967	36,842,967
June 9, 2010	$1.88	40,685,585	40,685,585	$2.07	36,909,352	36,909,352
September 10, 2010	$1.86	45,595,968	34,407,000	$2.05	41,363,978	31,213,514
December 1, 2010	$1.86	43,173,648	24,755,000	$2.05	39,166,486	22,457,365
March 9, 2011	$1.89	41,995,813	41,995,813	$2.08	38,097,972	38,097,972
June 8, 2011	$1.89	42,034,184	12,537,000	$2.08	38,132,781	11,373,378
September 7, 2011	$1.89	42,189,685	7,847,000	$2.08	38,273,849	7,118,681
December 7, 2011	$1.89	42,983,482	27,293,000	$2.08	38,993,970	24,759,800
March 14, 2012	$1.93	34,843,858	21,559,000	$2.13	31,609,825	19,558,001
June 6, 2012	$1.93	36,426,008	20,941,000	$2.13	33,045,128	18,997,361
September 5, 2012	$1.93	37,949,558	24,589,000	$2.13	34,427,270	22,306,772
December 5, 2012	$1.93	37,563,083	19,774,000	$2.13	34,076,665	17,938,676
March 13, 2013	$2.80	37,835,405	37,835,405	$3.09	34,323,712	34,323,712
June 5, 2013	$3.21	38,782,076	38,782,076	$3.54	35,182,518	35,182,518
September 4, 2013	$2.67	38,409,043	38,409,043	$2.94	34,844,108	34,844,108
December 4, 2013	$3.00	38,329,378	38,329,378	$3.31	34,771,837	34,771,837
March 5, 2014	$4.00	23,491,350	23,491,350	$4.41	21,311,000	21,311,000
June 4, 2014	$5.02	18,062,384	18,062,384	$5.53	16,385,924	16,385,924
September 3, 2014	$4.88	17,998,687	17,998,687	$5.38	16,328,139	16,328,139
December 3, 2014	$5.21	18,198,685	18,198,685	$5.74	16,509,574	16,509,574
March 11, 2015	$5.41	15,272,670	15,272,670	$5.96	13,855,137	13,855,137
June 3, 2015	$5.50	15,507,571	15,507,571	$6.06	14,068,236	14,068,236
September 3, 2015	$6.02	25,374,294	25,374,294	$6.64	23,019,179	23,019,179
December 2, 2015	$7.50	15,374,274	15,374,274	$8.27	13,947,311	13,947,311
March 9, 2016	$5.25	14,838,732	14,838,732	$5.79	13,461,475	13,461,475
June 1, 2016	$4.53	15,089,652	15,089,652	$4.99	13,689,106	13,689,106
September 7, 2016	$4.54	14,911,315	14,911,315	$5.00	13,527,321	13,527,321
December 7, 2016	$3.55	14,791,315	14,791,315	$3.91	13,418,459	13,418,459

Zero Emissions Credits (ZEC) Programs

On December 7, 2016, the State of Illinois enacted legislation that, among other things, provides subsidies, known as zero emission credits (ZECs), for certain existing nuclear-powered generation units that indicated they would otherwise retire.[94] The ZEC program provides that starting June 1, 2017, the Illinois Power Agency (IPA) must procure ZECs under ten year contracts with select Illinois nuclear power plants.[95] IPA must procure ZECs equal to 16 percent of 2014 Illinois retail load.[96] The initial base ZEC price equals $16.50/MWh and increases $1.00/MWh annually commencing with the 2023/2024 Delivery Year.[97] The base price is reduced by the amount that "the market price index for the applicable delivery year exceeds the baseline market price index for the consecutive 12-month period ending May 31, 2016."[98]

The revenues provided by the ZEC legislation are expected to forestall the retirement of a specific PJM nuclear unit in Illinois, the Quad Cities Generating Station.[99]

The ZEC legislation creates subsidies for existing units that create the same price suppressive effects as subsidies for new entry that are addressed by the Minimum Offer Price Rule.[100] The MMU has supported modification of the Minimum Offer Price (MOPR) Rules to apply to existing units receiving subsidies.[101] The MMU's proposed modification of the MOPR rules would, if in place, apply to nuclear units receiving subsidies. Such subsidies may otherwise result in noncompetitive offers in PJM markets that would be addressed on a unit specific basis.

A similar issue has arisen in New York, where the New York Public Service Commission ("New York PSC") established a program requiring the purchase of ZEC credits from specific nuclear facilities in upstate New York. The constitutionality of the New York PSC's

93 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 20, 2017).

94 See Illinois 99th Gen. Assemb., S.B. 2814 (Dec. 7, 2016), which can be accessed at: <http://www.ilga.gov/legislation/99/SB/09900SB2814lv.htm>. The Governor of Illinois signed the ZEC legislation, amending the Illinois Power Agency Act ("IPAA"), on December 7, 2016; see also ICC, et al., Potential Nuclear Power Plant Closings in Illinois (Jan. 5, 2015), which can be accessed at: <http://www.ilga.gov/reports/special/report_potential%20nuclear%20power%20plant%20closings%20in%20il.pdf>.

95 See IPAA § 1-75(d-5)(1).

96 See *id.*

97 See IPAA § 1-75(d-5)(1)(B).

98 See *id.*

99 See Ted Caddell, RTO Insider "Exelon's Crane Reports 'Monumental Year,'" (Feb. 8, 2017); Exelon, Press Release, "Exelon Announces Early Retirement of Clinton and Quad Cities Nuclear Plants" (June 2, 2016) (citing "lack of progress on Illinois energy legislation" as a key factor), which can be accessed at: <http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement>; Thomas Overton, Power, "Byron, Three Mile Island Nuclear Plants at Risk, Exelon Says" (June 6, 2016) (reporting Exelon statement that Byron is "economically challenged"), which can be accessed at: <http://www.powermag.com/byron-three-mile-island-nuclear-plants-at-risk-exelon-says/?printmode=1>.

100 OATT Attachment DD § 5.14(h).

101 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EL16-49-000 (April 11, 2016).

program has been challenged in a case pending before the U.S. District Court for the Southern District of New York.[102] On January 9, 2017, the MMU filed an amicus curiae brief supporting plaintiffs on the grounds that the ZEC subsidies interfere with the operation of wholesale power markets in New York and have price suppressive effects in the energy markets in PJM.[103]

State Renewable Portfolio Standards

Nine PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are often required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called "eligible technologies." Load serving entities may generally fulfil 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 by generating power from eligible technologies or purchasing RECs are penalized with alternative compliance payments. As of December 31, 2016, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. had renewable portfolio standards that are mandatory and include penalties in the form of alternative compliance payments for underperformance.

Two PJM jurisdictions have enacted voluntary renewable portfolio standards. Load serving entities in states with voluntary standards are not bound by law to participate and face no alternative compliance payments. Instead, incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. As of December 31, 2016, Virginia and Indiana had renewable portfolio standards that are voluntary and do not include penalties in the form of alternative compliance payments for underperformance.

In this section, voluntary standards will not be directly compared to RPS with enforceable compliance payments. Indiana's voluntary standard illustrates the issue. Although a voluntary standard including target shares was enacted by the Indiana legislature in 2011, no load serving entities have volunteered to participate in the program.[104]

Three PJM states have no renewable portfolio standards. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[105]

Table 8-6 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. In 2014, Ohio delayed a scheduled increase from 2.5 percent to 3.5 percent in its RPS standards from 2015 until 2017 and removed the 12.5 percent alternative energy requirement. Washington, DC will require 35.0 percent of load to be served by renewable resources in 2028, the highest standard of PJM jurisdictions. In October 2016, the Council of the District of Columbia passed legislation that expanded the District's RPS program and increased the percent of retail load in the District that must be served by clean energy resources to 50 percent by 2032.[106]

102 Coalition for Competitive Electricity, et al., v. Audrey Zibelman, et al., Case No. 1:16-cv-08164-VEC (USDC SDNY).

103 Brief of Amicus Curiae of Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM, USDC SDNY Case No. 1:16-cv-08164-VEC (Jan. 9, 2017).

104 See the Indiana Utility Regulatory Commission's "2016 Annual Report." P 34 <http://www.in.gov/iurc/files/Annual%20Report%202016%20WEB%20version.pdf> (Accessed March 7, 2017).

105 See Enr. Com. Sub. For H. B. No. 2001.

106 See B21-0650 – Renewable Portfolio Standard Expansion Amendment Act of 2016. <http://lims.dccouncil.us/Legislation/B21-0650> (Accessed January 18, 2017).

Table 8-6 Renewable standards of PJM jurisdictions: 2016 to 2028[107]

Jurisdiction with RPS		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware		14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%	24.00%	25.00%	25.00%	25.00%	25.00%
Illinois		10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%	22.00%	23.50%	25.00%	25.00%	25.00%
Maryland		15.20%	15.60%	18.30%	17.40%	18.00%	18.70%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Michigan		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey		14.90%	15.99%	18.03%	19.97%	21.91%	23.85%	23.94%	24.03%	24.12%	24.21%	24.30%	24.39%	24.48%
North Carolina		6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio		2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%	12.50%	12.50%
Pennsylvania		13.70%	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Washington, D.C.		13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%
Jurisdiction with Voluntary Standard														
Indiana		4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	10.00%	10.00%	10.00%	10.00%
Virginia		7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%	15.00%	15.00%	15.00%	15.00%
Jurisdiction with No Standard														
Kentucky	No Renewable Portfolio Standard													
Tennessee	No Renewable Portfolio Standard													
West Virginia	No Renewable Portfolio Standard													

Each PJM jurisdiction with an RPS identifies the type of generation resources that may be used for compliance. These resources are often called eligible technologies. Some PJM jurisdictions with RPS group different eligible technologies into tiers based on the magnitude of their environmental impact. Of the nine PJM states with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources. Though there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources.

Delaware, Illinois, Michigan, North Carolina, and Ohio do not classify the resources eligible for their RPS standards by tiers. In Delaware, Illinois, North Carolina, and Ohio, eligible technologies are for the most part identical to Tier I resources. Michigan is the only state with an RPS that does not classify eligible technologies into tiers and also permits technologies that differ markedly from those classified as Tier I resources in states that do classify technologies. Michigan's RPS includes coal gasification, industrial cogeneration, and coal with carbon capture and storage as eligible technologies.

Table 8-7 shows the percent of retail electric load that must be served by Tier II resources under each PJM jurisdictions' RPS by year. Table 8-7 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in are included in the total RPS requirements presented in Table 8-6. Illinois requires that a defined proportion of retail load be served by wind resources, increasing from 7.50 percent of load served in 2016 to 18.75 percent in 2026. Maryland, New Jersey, Pennsylvania and Washington, DC all have Tier II or "Class 2" standards, which allow specific technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. By 2021, North Carolina's RPS requires that 0.2 percent of power be generated using swine waste and that 900 GWh of power be produced by poultry waste.

107 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I, Tier II and Tier III resources.

Table 8-7 Additional renewable standards of PJM jurisdictions: 2016 to 2028

Jurisdiction		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Illinois	Wind Requirement	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%	16.50%	17.63%	18.75%	18.75%	18.75%
Illinois	Distributed Generation	0.10%	0.12%	0.13%	0.15%	0.16%	0.18%	0.19%	0.21%	0.22%	0.24%	0.25%	0.25%	0.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
North Carolina	Swine Waste	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	700	900	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Washington, D.C.	Tier II Standard	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-6 but must be met by solar RECs (SRECs) only. Table 8-8 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdictions' RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC have requirements for the proportion of load to be served by solar. Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are considered Tier II. Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. In 2016, New Jersey had the most stringent solar standard in PJM, requiring that 2.45 percent of retail electricity sales within the state be served by solar resources. As Table 8-8 shows, by 2028, New Jersey will continue to have the most stringent standard, requiring that at least 4.10 percent of load be served by solar.

Figure 8-2 and Figure 8-3 show the percent of retail electric load that must be served by Tier I resources and Tier 2 Resources in each PJM jurisdiction with a mandatory RPS. Figure 8-2 shows the percent of retail load that must be met with Tier I resources only. Because states that do not group eligible technologies into tiers generally classify eligible technologies in their RPS that are identical to Tier I resources, they are included in Figure 8-2. Figure 8-3 shows the percent of retail load that must be met with all eligible technologies, including Tier I, Tier II and alternative energy resources in all PJM jurisdictions with RPS. States with higher percent requirements for renewable and alternative energy resources are shaded darker. Jurisdictions with no standards or with only voluntary renewable standards are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for Tier I and Tier II resources separately. Like all other PJM states with mandatory RPS, the Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind, geothermal, biomass, and low-impact hydropower as Tier I resources. The Pennsylvania RPS identifies waste coal, demand side management, large-scale hydropower, integrated

Table 8-8 Solar renewable standards by percent of electric load for PJM jurisdictions: 2016 to 2028

Jurisdiction with RPS		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware		1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%	3.50%	3.50%	3.50%	3.50%
Illinois		0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%	1.41%	1.50%	1.50%	1.50%
Maryland		0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Michigan	No Minimum Solar Requirement													
New Jersey		2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%	3.74%	3.83%	3.92%	4.01%	4.10%
North Carolina		0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio		0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%	0.50%	0.50%	0.50%
Pennsylvania		0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.		0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%
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													

gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. The 13.7 percent number in Figure 8-3 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-2 Map of retail electric load shares under RPS - Tier I resources only: 2016

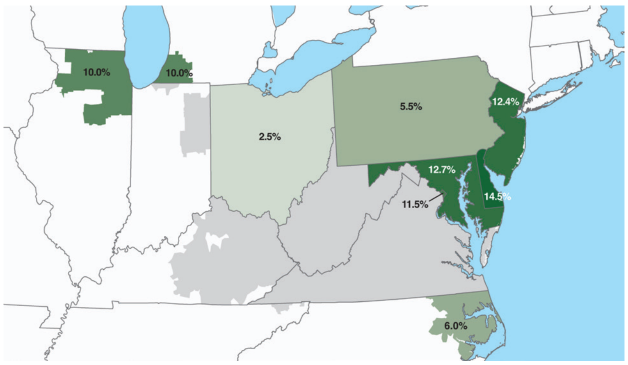
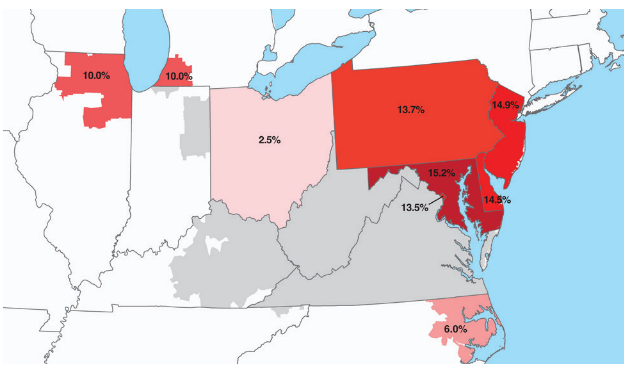


Figure 8-3 Map of retail electric load shares under RPS – Tier I and Tier II resources: 2016



Under the existing state renewable portfolio standards, approximately 7.7 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2016 and, if the proportion of load among states remains constant, 14.4 percent of PJM load must be served by renewable and alternative energy resources in 2028 under defined RPS rules. Approximately 5.6 percent of PJM load must be served by Tier I renewables in 2016 and, if the proportion of load among states remains constant, 9.0 percent of PJM load must be served by Tier I renewables in 2028 under defined RPS rules.

In jurisdictions with RPS, load serving entities must either generate power from eligible technologies identified in their jurisdictions' RPS or purchase RECs from resources classified as eligible technologies. Table 8-9 shows renewable resource generation by jurisdiction and resource type for 2016. Wind output was 15,755.3 GWh of 25,556.9 Tier I GWh, or 61.0 percent, in the PJM footprint. As shown in Table 8-9, 46,412.3 GWh were generated by renewable resources, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 57.1 percent. Total renewable generation was 5.7 percent of total generation in PJM for 2016. Landfill gas, solid waste and waste coal were 19,907.8 GWh of renewable resource generation or 42.9 percent of the total Tier I and Tier II.

Table 8-9 Renewable resource generation by jurisdiction and renewable resource type (GWh): 2016

	Tier I					Tier II				
Jurisdiction	Landfill Gas	Run-of-River Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	40.4	0.0	0.0	0.0	40.4	0.0	0.0	0.0	0.0	40.4
Illinois	113.4	0.0	14.2	6,811.6	6,939.1	0.0	0.0	0.0	0.0	6,939.1
Indiana	57.1	0.0	7.2	4,298.4	4,362.7	0.0	0.0	0.0	0.0	4,362.7
Kentucky	0.0	418.8	0.0	0.0	418.8	0.0	0.0	0.0	0.0	418.8
Maryland	100.2	1,380.4	104.3	525.3	2,110.2	0.0	669.5	0.0	669.5	2,779.7
Michigan	22.1	0.0	0.4	0.0	22.6	0.0	0.0	0.0	0.0	22.6
New Jersey	290.0	8.2	509.7	11.6	819.4	521.4	1,430.4	0.0	1,951.8	2,771.2
North Carolina	0.0	761.6	319.5	7.7	1,088.8	0.0	0.0	0.0	0.0	1,088.8
Ohio	350.9	478.9	1.2	1,172.2	2,003.3	0.0	0.0	0.0	0.0	2,003.3
Pennsylvania	664.4	2,009.4	27.3	3,344.5	6,045.5	1,819.2	1,254.6	7,451.0	10,524.8	16,570.3
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	537.7	915.8	26.0	0.0	1,479.5	2,479.1	785.4	3,497.3	6,761.7	8,241.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	1,174.3	0.0	0.0	1,174.3	0.0	0.0	0.0	0.0	1,174.3
Total	2,176.2	7,147.2	1,009.8	16,171.3	26,504.5	4,819.7	4,139.8	10,948.3	19,907.8	46,412.3
Percent of Renewable Generation	4.7%	15.4%	2.2%	34.8%	57.1%	10.4%	8.9%	23.6%	42.9%	100.0%
Percent of Total Generation	0.3%	0.9%	0.1%	2.0%	3.3%	0.6%	0.5%	1.3%	2.5%	5.7%

Table 8-10 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that have a renewable fuel as an alternative fuel, and thus are able to earn renewable energy credits based on the fuel used to generate energy. For example, a coal generator that can also burn waste coal to generate power could list the alternative fuel as waste coal. A REC is only generated when using the fuel listed as Tier I or Tier II. New Jersey has the largest amount of solar capacity in PJM, 397.2 MW, or 54.9 percent of the total solar capacity. New Jersey's SREC prices were the highest in 2009 at $673 per REC, and in 2016 are at $205 per REC. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 4,448.7 MW, or 61.0 percent of the total wind capacity.

Table 8-10 PJM renewable capacity by jurisdiction (MW): December 31, 2016

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,797.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0	1,818.1
Illinois	0.0	59.3	0.0	0.0	0.0	0.0	9.0	0.0	0.0	2,846.4	2,914.7
Indiana	0.0	8.0	0.0	0.0	0.0	8.2	10.1	0.0	0.0	1,602.4	1,628.7
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	0.0	0.0	0.0	0.0	0.0	166.0	0.0	0.0	0.0	0.0	166.0
Maryland	0.0	25.1	0.0	69.0	0.0	494.4	79.8	128.2	0.0	190.0	986.5
Michigan	0.0	8.0	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	21.9
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	77.7	0.0	0.0	453.0	11.5	397.2	162.0	0.0	4.5	1,105.8
North Carolina	0.0	0.0	0.0	0.0	0.0	352.5	207.1	0.0	0.0	0.0	559.6
Ohio	11,080.0	63.4	0.0	156.0	0.0	119.1	1.1	0.0	0.0	403.0	11,822.6
Pennsylvania	0.0	208.0	2,346.0	0.0	1,269.0	893.3	19.5	345.8	1,611.0	1,337.7	8,030.3
Tennessee	0.0	0.0	0.0	0.0	0.0	52.0	0.0	50.0	0.0	0.0	102.0
Virginia	0.0	222.1	0.0	17.0	5,166.2	350.5	0.0	444.9	585.0	0.0	6,785.7
West Virginia	0.0	2.2	0.0	0.0	0.0	257.9	0.0	0.0	165.0	583.3	1,008.4
PJM Total	11,080.0	681.8	4,143.0	255.0	6,888.2	2,719.2	723.8	1,130.9	2,361.0	7,298.2	37,281.1

Table 8-11 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). This includes solar capacity of 3,047.0 MW of which 1,417.4 MW is in New Jersey. These resources can also earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. Some of this capacity is located in jurisdictions outside PJM, but may qualify for specific renewable energy credits in some PJM jurisdictions. This includes both solar generation located inside PJM but not PJM units, and generation connected to other RTOs outside PJM.

Table 8-11 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on December 31, 2016[108]

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Alabama	0.0	0.0	0.0	0.0	0.0	0.0	0.0	87.5	0.0	87.5
Arkansas	0.0	135.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	153.0
Delaware	0.0	0.0	2.2	0.0	0.0	0.0	77.9	0.0	2.1	82.2
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	38.7	258.9	0.0	297.6
Illinois	0.0	21.4	91.9	0.0	0.6	0.0	39.5	0.0	300.5	453.9
Indiana	0.0	0.0	43.2	0.0	5.2	234.6	22.1	0.0	180.0	485.1
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	476.7	479.8
Kentucky	600.0	86.2	18.6	0.0	0.4	0.0	16.3	93.0	0.0	814.5
Louisiana	0.0	0.0	0.0	0.0	0.0	0.0	0.0	63.0	0.0	63.0
Maryland	65.0	0.0	11.7	129.0	0.0	0.0	592.5	15.0	0.3	813.5
Michigan	55.0	1.3	3.2	0.0	0.0	0.0	3.0	31.0	0.0	93.5
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	451.0	451.2
New Jersey	0.0	0.0	53.1	0.0	8.3	0.0	1,417.4	0.0	5.0	1,483.8
New York	0.0	158.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	159.1
North Carolina	0.0	242.5	12.0	0.0	0.0	0.0	412.7	151.5	0.0	818.7
North Dakota	0.0	0.0	360.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0
Ohio	0.0	1.0	33.6	92.6	16.4	32.4	130.0	109.3	35.1	450.4
Pennsylvania	109.7	31.7	45.2	91.0	13.2	5.0	239.6	68.6	3.3	607.2
Tennessee	0.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.0
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.7	0.0	57.7
Virginia	0.0	18.2	12.1	0.0	0.5	0.0	20.9	287.6	0.0	339.2
West Virginia	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
Wisconsin	0.0	0.0	0.0	0.0	0.0	0.0	3.3	0.0	0.0	3.3
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	28.9	0.0	0.0	28.9
Total	829.7	756.9	686.8	312.6	62.5	272.0	3,047.0	1,267.7	1,454.0	8,689.2

Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. 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. The FERC has found that such costs can be appropriately considered in the rates established through the operation of wholesale organized markets.[109] This decision is an important recognition of the integration of the RECs markets and the other PJM markets.

Delaware, North Carolina, Michigan and Virginia allow various types of renewable 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.[110] This is equivalent to providing a REC price equal to three times its stated value per MWh. PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits.[111]

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

108 See PJM – EIS (Environmental Information Services), "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed January 3, 2017).

109 See 146 FERC ¶ 61,084 at P 32 ("We disagree with Exelon's argument that the Production Tax Credit and Renewable Energy Credits should be considered [out-of-market (OOM)] revenues. The relevant, Commission-approved Tariff provision defines OOM revenues as any revenues that are (i) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (ii) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. [footnote omitted] Neither Production Tax Credit nor Renewable Energy Credits revenues fall within this definition. We also find that ISO-NE's use of an inflation rate in determining the price of Renewable Energy Credits is a reasonable estimate of Renewable Energy Credits for the 2018-2019 Capacity Commitment Period.").

110 See Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed October 19, 2016).

111 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.

ultimately be traded. Table 8-12 shows the REC tracking systems used by each state within the PJM footprint.

Table 8-12 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 8-13 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 states' 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 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.

RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. RECs typically have a shelf life of five years until they cannot be used to satisfy a state's RPS requirement. The REC price figures take the average price for each vintage of REC, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and the District of Columbia, but in the other states REC prices are not publicly available.

Table 8-13 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must first be purchased from resources located within Illinois or resources located in a state directly adjoining Illinois. If there are insufficient RECs from Illinois and adjoining states to fulfill the RPS requirements, utilities may purchase RECs from anywhere.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or resources located in a control area synchronized with PJM.
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 either located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in state contiguous to Ohio has been deemed deliverable into the state of Ohio. If a renewable resource is located outside of this range, then it must demonstrate deliverabilty to the Public Utilities Commission of Ohio.
Pennsylvania	No	RECs must be purchased from resources located anywhere within PJM.
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.

Figure 8-4 shows the average solar REC (SREC) price by jurisdiction for 2009 through 2016. New solar generating units built in New Jersey to satisfy its RPS requirement lowered the SREC price. The average NJ SREC prices dropped from $673 per SREC in 2009 to $205 per SREC in 2016. The limited supply of solar facilities in Washington, DC compared to the RPS requirement resulted in higher SREC prices. The average Washington, D.C. SREC price increased from $197 per SREC in 2011 to $488 per SREC in 2016.[112]

Figure 8-4 Average SREC price by jurisdiction: 2009 through 2016

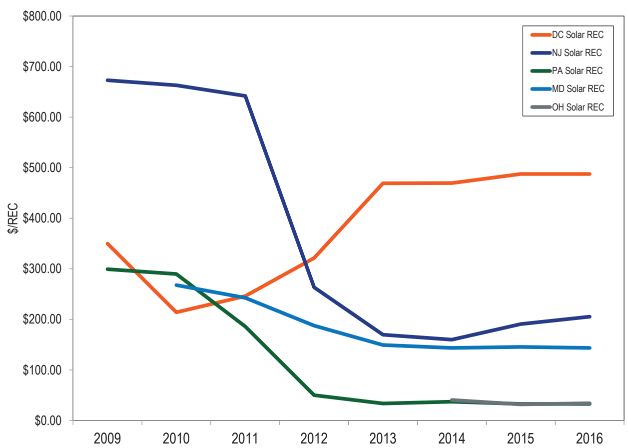
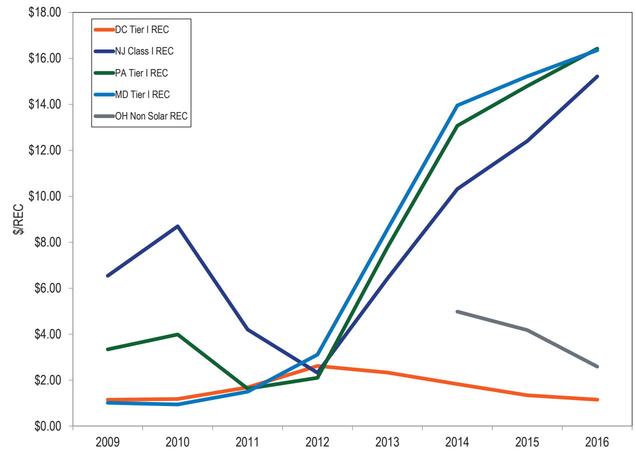


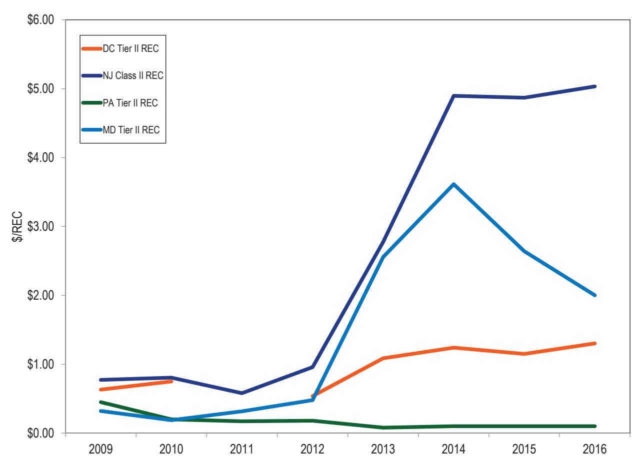
Figure 8-5 shows the average Tier I REC price by jurisdiction from 2009 through 2016. Tier I REC prices are lower than SREC prices. Ohio and Pennsylvania had the lowest SREC prices at $34 per SREC and $33 per SREC in 2016 while Pennsylvania had the highest Tier I REC prices at $16 per REC in 2016.[113]

Figure 8-5 Average Tier I REC price by jurisdiction: 2009 through 2016



Tier II prices are lower than SREC and Tier I REC prices. Figure 8-6 shows the average Tier II REC price by jurisdiction for 2009 through 2016. DC had the lowest Tier II REC prices at $1.15 per REC while New Jersey had the highest Tier II REC prices at $5.03 per REC.[114]

Figure 8-6 Average Tier II REC price by jurisdiction: 2009 through 2016



PJM jurisdictions have various methods for complying with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments, with varying standards, to cover any shortfall between

112 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 20, 2017).
113 Tier I REC price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 20, 2017).
114 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed January 20, 2017).

the RECs required by the state and those the retail supplier actually purchased. In New Jersey, solar alternative compliance payments are $323.00 per MWh.[115] Pennsylvania requires that the alternative compliance payment for solar credits be 200 percent of the average market value of solar RECs sold in the RTO. For all states with an alternative compliance payment, the alternative compliance payment creates a cap on REC prices. Illinois requires that 50 percent of the state's renewable portfolio standard be met through alternative compliance payments. In Michigan and North Carolina, there are no pre-established values for alternative compliance payments. The public utility commissions in Michigan and North Carolina have the discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

Table 8-14 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-14 Renewable alternative compliance payments in PJM jurisdictions: As of December 31, 2016[116 117]

Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$1.89		
Maryland	$40.00	$15.00	$350.00
Michigan	No specific penalties		
New Jersey	$50.00		$323.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$49.75		$300.00
Pennsylvania	$45.00	$45.00	200% market value
Washington, D.C.	$50.00	$10.00	$500.00
Jurisdiction with Voluntary Standard			
Indiana	Voluntary standard - No Penalties		
Virginia	Voluntary standard - No Penalties		
Jurisdiction with No Standard			
Kentucky	No standard		
Tennessee	No standard		
West Virginia	No standard		

Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission. In their submitted compliance reports, load serving entities must indicate the quantity of MWh that they have generated using eligible renewable or alternative energy resources. They must also identify the quantity of RECs they may have purchased to make up for renewable energy generation shortfalls or to comply with RPS provisions requiring that they purchase RECs. The public utility commissions then release RPS compliance reports to the public. The RPS compliance reports are released with a lag of up to three years. It is therefore impossible to know the current level of RPS compliance in PJM jurisdictions. As of December 31, 2016, compliance reports for the year 2015 are available for Delaware, Illinois, Michigan, New Jersey, North Carolina, Pennsylvania, Washington, D.C.[118 119] The RPS compliance report for the year 2014 is available for Ohio. The RPS compliance report for the year 2013 is available for Maryland.[120]

One jurisdiction where RPS compliance costs have raised concerns is the District of Columbia. According to the District of Columbia Public Service Commission's 2015 annual RPS compliance report, electric retailers have been able to meet the allotted standards for Tier I and II resources but have struggled to meet the standard for solar resources. Due to a combination of insufficient supply of eligible solar resources in the District and increasing percentages of load that must be served by solar resources, total solar alternative compliance payments in the District of Columbia have increased from $0.70 million in 2013 to $19.9 million in 2015.[121]

115 See Database of State Incentives for Renewables & Efficiency (DSIRE), New Jersey Incentives/Policies for Renewables & Efficiency, "Solar Renewables Energy Certificates (SRECs)," <http://programs.dsireusa.org/system/program/detail/5687> (Accessed January 20, 2017).

116 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis.com/> (Accessed January 20, 2017).

117 See "Database of State Incentives for Renewables & Efficiency, "Policies & Incentives by State," <http://www.dsireusa.org/> (Accessed February 20, 2017).

118 RPS compliance reports are available on jurisdictions' public utilities commissions' websites.

119 The Lawrence Berkeley National Laboratory, a subsidiary of the US Department of Energy, actively keeps track of compliance reports and data on their website. See the report "U.S. Renewables Portfolio Standards: 2016 Annual Status Report (PDF)" and "RPS Compliance Data (XLSX)" available on their website. <https://emp.lbl.gov/projects/renewables-portfolio> (Accessed January 18, 2017).

120 The Clean Energy States Alliance tracks all completed RPS compliance reports on their website: <http://cesa.org/projects/state-federal-rps-collaborative/state-rps-annual-reports-and-compliance-reports/#MD> (Accessed January 23, 2017).

121 See the Public Service Commission of the District of Columbia's "Report on the Renewable Energy Portfolio Standard for Compliance Year 2015." <http://www.dcpsc.org/getmedia/901b3c18-4859-435d-ae1a-ca296584c26b/aharris_542016_831_1_FC_-_945_-_2016_-_E_-_REPORT.aspx> (Accessed January 20, 2017).

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[122] Many PJM units burning fossil fuels have installed emission control technology.

Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[123] Of the current 64,015.1 MW of coal capacity in PJM, 57,212.0 MW of capacity, 89.4 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-15 shows SO_2 emission controls by fossil fuel fired units in PJM.[124] [125] [126]

Table 8-15 SO_2 emission controls by fuel type (MW): as of December 31, 2016[127]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	57,212.0	6,803.1	64,015.1	89.4%
Diesel Oil	0.0	6,000.6	6,000.6	0.0%
Natural Gas	0.0	52,518.3	52,518.3	0.0%
Other	325.0	4,920.7	5,245.7	6.2%
Total	57,537.0	70,242.7	127,779.7	45.0%

NO_X emission control technology is used by all fossil fuel fired unit types. Of current fossil fuel fired units in PJM, 119,374.0 MW, 93.4 percent, of 127,779.7 MW of capacity in PJM, have emission controls for NO_X. Table 8-16 shows NO_X emission controls by unit type in PJM. While most units in PJM have NO_X emission controls, many of these controls may need to be upgraded in order to meet each state's emission compliance standards based on whether a state is part of CSAPR, CAIR, Acid Rain Program (ARP) or a combination of the three. Future NO_X compliance standards will require select catalytic converters (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[128]

Table 8-16 NO_X emission controls by fuel type (MW), as of December 31, 2016

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	63,075.8	939.3	64,015.1	98.5%
Diesel Oil	2,207.6	3,793.0	6,000.6	36.8%
Natural Gas	51,290.9	1,227.4	52,518.3	97.7%
Other	2,799.7	2,446.0	5,245.7	53.4%
Total	119,374.0	8,405.7	127,779.7	93.4%

Most coal units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[129] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Table 8-17 shows particulate emission controls by unit type in PJM. In PJM, 63,681.1MW, 99.5 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of December 31, 2016. 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 to meet the state and federal emissions limits established by the MATS EPA regulations.[130] Currently, 142 of the 171 coal steam units have baghouse or FGD technology installed, representing 55,683.0 MW out of the 63,681.1 MW total coal capacity, or 87.4 percent.

Table 8-17 Particulate emission controls by fuel type (MW), as of December 31, 2016

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	63,681.1	334.0	64,015.1	99.5%
Diesel Oil	0.0	6,000.6	6,000.6	0.0%
Natural Gas	538.0	51,980.3	52,518.3	1.0%
Other	3,102.0	2,143.7	5,245.7	59.1%
Total	67,321.1	60,458.6	127,779.7	52.7%

Figure 8-7 shows the total CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM, for all CO_2 emitting units, for each year from 1999

122 See EPA. "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 7, 2016).

123 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 March 7, 2016).

124 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed March 7, 2016).

125 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.

126 The total MW for each fuel type are less than the 182,449.1 reported in Section 5: Capacity, 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 March 7, 2016).

127 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.

128 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed March 7, 2016).

129 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed March 7, 2016).

130 On April 14, 2016, the EPA issued a final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants> (Accessed March 7, 2016).

to 2016, as well as the CO_2 short ton emissions per MWh of total generation within PJM from 2004 to 2016.[131] Since 1999 the amount of CO_2 produced per MWh was at a minimum of 0.80 short tons per MWh in 2001, and a maximum of 0.93 short tons per MWh in 2010. In 2016, CO_2 emissions were 0.84 short tons per MWh. Total PJM generation increased from 786,698.5 GWh in 2015 to 812,544.1 GWh in 2016, while CO_2 produced decreased from 484.5 million tons in 2015 to 353.1 million tons in 2016.[132] The reduction in CO_2 emissions was primarily the result of a decrease in the use of coal for generation. Figure 8-8 shows the total on peak hour and off peak hour CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM, for all CO_2 emitting units, for each year from 1999 to 2016. Since 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.80 short tons per MWh in 2016, and a maximum of 0.95 short tons per MWh in 2008. Since 1999 the amount of CO_2 produced per MWh during on peak hours was at a minimum of 0.78 short tons per MWh in 2016, and a maximum of 0.92 short tons per MWh in 2008. In 2016, CO_2 emissions were 0.80 short tons per MWh and 0.78 short tons per MWh for off and on peak hours.

Figure 8-7 CO_2 emissions by year (millions of short tons), by PJM units: 1999 through 2016[133]

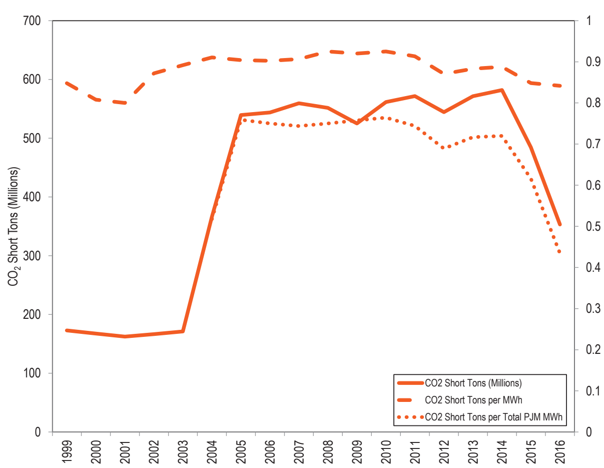


Figure 8-8 CO_2 emissions during on and off peak hours by year (millions of short tons), by PJM units: 1999 through 2016[134]

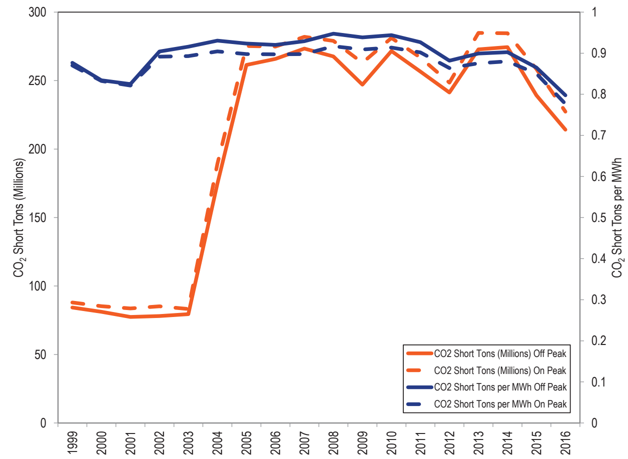


Figure 8-9 shows the total SO_2 and NO_X short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all SO_2 and NO_X emitting units, for each year from 1999 to 2016, as well as the SO_2 and NO_X short ton emissions per MWh of total generation within PJM from 2004 to 2016. Since 1999 the amount of SO_2 produced per MWh was at a minimum of 0.000732 short tons per MWh in 2016, and a maximum of 0.006336 short tons per MWh in 2003. Since 1999, the amount of NO_X produced per MWh was at a minimum of 0.000572 short tons per MWh in 2016, and a maximum of 0.001972 short tons per MWh in 1999. In 2016, SO_2 emissions were 0.000732 short tons per MWh and NO_X emissions were 0.000572 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 from 2006 to 2016.

Figure 8-10 shows the total on peak hour and off peak hour SO_2 and NO_X short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all SO_2 and NO_X emitting units, for each year from 1999 to 2016. Since 1999 the amount of SO_2 produced per MWh during off peak hours was at a minimum of 0.000723 short tons per MWh in 2016, and a maximum of 0.006654 short tons per MWh in 2003. Since 1999 the amount of SO_2 produced per MWh during on peak hours was at a minimum of

131 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.

132 See Table 3-8, Section 3.

133 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

134 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

0.000774 short tons per MWh in 2016, and a maximum of 0.006326 short tons per MWh in 2003. Since 1999, the amount of NO_X produced per MWh during off peak hours was at a minimum of 0.000603 short tons per MWh in 2016, and a maximum of 0.001993 short tons per MWh in 1999. Since 1999, the amount of NO_X produced per MWh during on peak hours was at a minimum of 0.000609 short tons per MWh in 2016, and a maximum of 0.002037 short tons per MWh in 1999. In 2016, SO_2 emissions were 0.000723 short tons per MWh and 0.000774 short tons per MWh for off and on peak hours. In 2016, NO_X emissions were 0.000603 short tons per MWh and 0.000609 short tons per MWh for off and on peak hours.

Figure 8-9 SO_2 and NO_X emissions by year (thousands of short tons), by PJM units: 1999 through 2016[135]

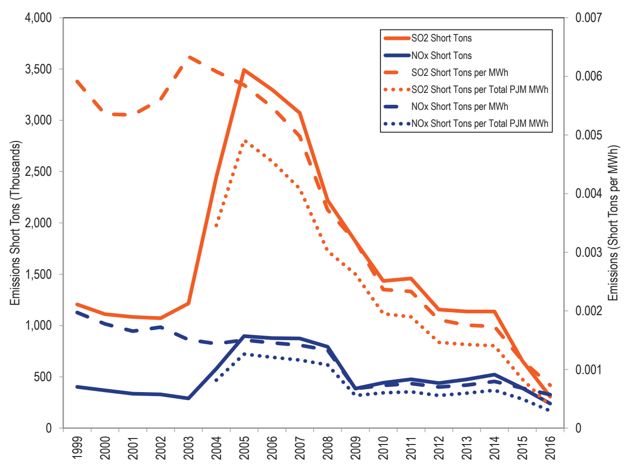
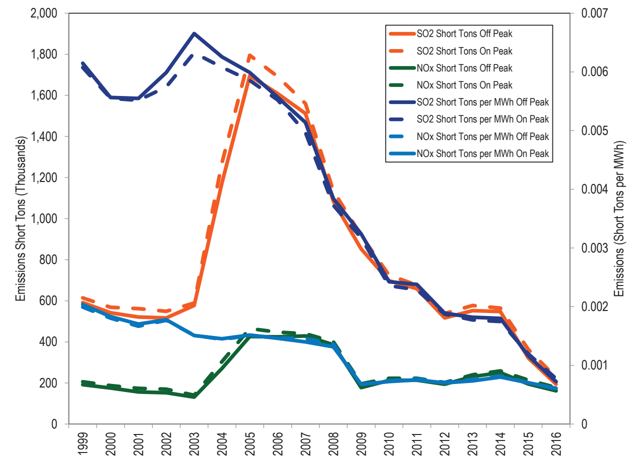


Figure 8-10 SO_2 and NO_X emissions during on and off peak hours by year (thousands of short tons), by PJM units: 1999 through 2016[136]



Wind and Solar Peak Hour Output

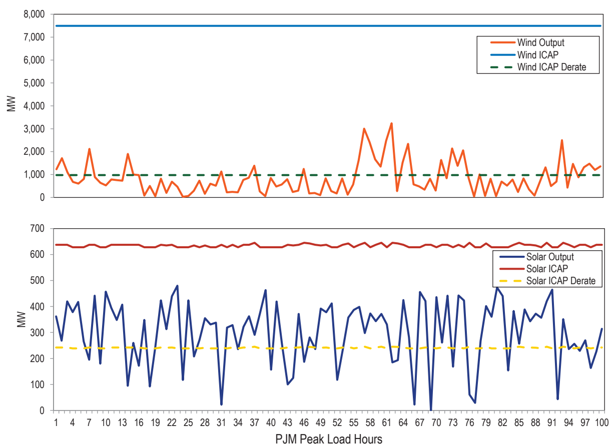
The capacity of solar and wind resources are derated for the PJM capacity market based on expected performance during high load hours. Figure 8-11 shows the wind and solar output during the top 100 load hours in PJM for 2016. The top 100 load hours in PJM during 2016 did not fall entirely within PJM defined peak load periods. There were 89 hours during PJM defined peak periods and 11 hours during PJM defined off peak periods. All top 100 peak load hours in 2016 occurred during the months of July, August and September. The hours are in descending order by load. The solid lines are the total ICAP of wind or solar PJM resources. The dashed lines are the total ICAP of wind and solar PJM resources derated to 13 and 38 percent. The actual output of the wind and solar resources during the top 100 peak load hours are above and below the derated values. Wind output was above the derated ICAP for 31 hours and below the derated ICAP for 69 hours of the top 100 peak load hours of 2016. Wind output was above the derated ICAP 6,288 hours and below the derated ICAP for 2,496 hours for the entire year. The wind capacity factor for the top 100 peak load hours of 2016 is 11.4 percent. Solar output was above the derated ICAP for 71 hours and below the derated ICAP for 29 hours of the top 100 peak load hours of 2016. Solar output was above the derated ICAP 1,940 hours and below the derated ICAP

135 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

136 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

for 6,844 hours for the entire year. The solar capacity factor for the top 100 peak load hours of 2016 is 47.5 percent.

Figure 8-11 Wind and solar output during the top 100 peak load hours in PJM: 2016



Wind Units

Table 8-18 shows the capacity factor of wind units in PJM. In 2016, the capacity factor of wind units in PJM was 28.1 percent. Wind units that were capacity resources had a capacity factor of 28.7 percent and an installed capacity of 6,668 MW. Wind units that were classified as energy only had a capacity factor of 21.5 percent and an installed capacity of 1,111 MW. Wind capacity in RPM is derated to 13 percent of nameplate capacity for the capacity market, and energy only resources are not included in the capacity market.[137]

Table 8-18 Capacity factor of wind units in PJM: 2016[138]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	21.5%	1,111
Capacity Resource	28.7%	6,668
All Units	28.1%	7,779

Figure 8-12 shows the average hourly real-time generation of wind units in PJM, by month for 2016. The hour with the highest average output, 3,322.9 MW, occurred in December, and the hour with the lowest average output, 500.9 MW, occurred in August. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 8-12 Average hourly real-time generation of wind units in PJM: 2016

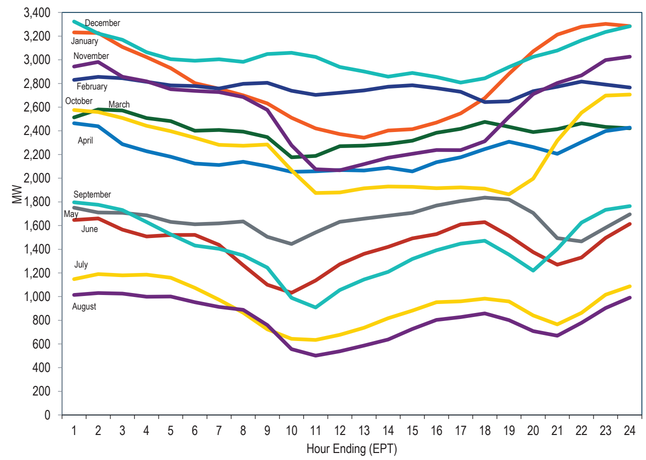


Table 8-19 shows the generation and capacity factor of wind units in each month of 2015 through 2016.

Table 8-19 Capacity factor of wind units in PJM by month: 2015 through 2016

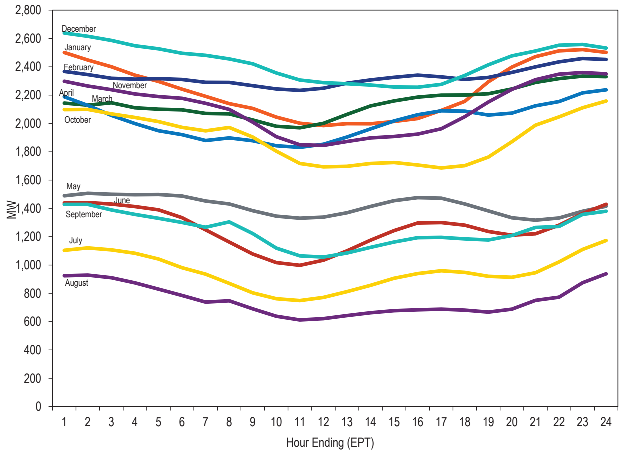
	2015		2016	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	1,664,426.8	33.9%	2,095,618.0	40.5%
February	1,511,093.1	34.1%	1,925,470.3	39.8%
March	1,701,249.6	34.7%	1,781,561.4	34.5%
April	1,641,965.0	34.5%	1,587,976.6	31.7%
May	1,209,088.5	24.6%	1,230,631.9	23.6%
June	955,156.7	20.1%	1,029,071.2	19.7%
July	639,381.7	13.0%	691,689.6	12.8%
August	623,873.6	12.4%	603,498.4	11.2%
September	846,505.6	17.3%	1,017,658.6	19.5%
October	1,756,221.4	34.8%	1,647,392.1	30.5%
November	2,023,340.0	41.3%	1,851,353.3	34.7%
December	2,037,436.4	39.8%	2,254,119.4	39.4%
Annual	16,609,738.2	28.3%	17,716,040.8	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. Wind units may offer noncapacity related wind energy at their discretion. Figure 8-13 shows the average hourly day-ahead generation offers of wind units in PJM, by month. The hourly day-ahead generation offers of wind units in PJM may vary.

137 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.

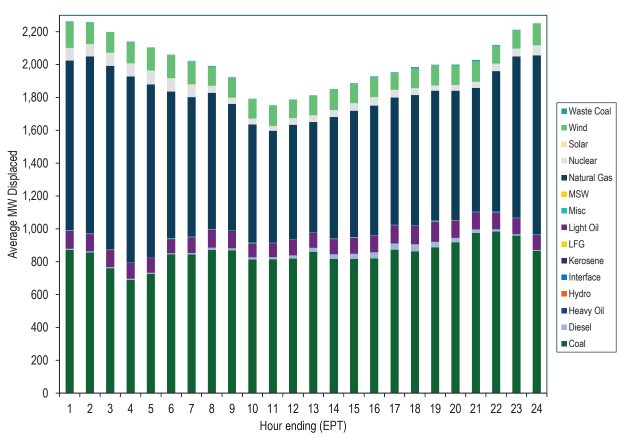
138 Capacity factor is calculated based on online date of the resource.

Figure 8-13 Average hourly day-ahead generation of wind units in PJM: 2016



Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of the wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 8-14 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in 2016. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours.

Figure 8-14 Marginal fuel at time of wind generation in PJM: 2016



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 8-11, there are 3,047.0 MW capacity of solar registered in GATS that are not PJM capacity or energy resources. Some behind the meter generation exists in clusters, such as community solar farms, and serves dedicated customers. Such customers may or may not be located at the same node on the transmission system as the solar farm. When behind the meter generation and its associated load are at separate nodes, loads should pay for the appropriate level of transmission service, and should not be permitted to escape their proper financial responsibility through badly designed rules, such as rules for netting.

Table 8-20 shows the capacity factor of solar units in PJM. In 2016, the capacity factor of solar units in PJM was 18.3 percent. Solar units that were capacity resources had a capacity factor of 18.4 percent and an installed capacity of 552 MW. Solar units that were classified as energy only had a capacity factor of 17.6 percent and an installed capacity of 182 MW. Solar capacity in RPM is derated to 38 percent of nameplate capacity for the capacity market, and energy only resources are not included in the capacity market.[139]

Table 8-20 Capacity factor of wind units in PJM: 2016

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	17.6%	182
Capacity Resource	18.4%	552
All Units	18.3%	734

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-15 shows the average hourly real-time generation of solar units in PJM, by month. Solar generation was highest in June, the month with the highest average hour, 400.6 MW, compared to 645 MW of solar installed capacity in PJM. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

139 Solar resources are derated to 38 percent unless demonstrating higher availability during peak periods.

Figure 8-15 Average hourly real-time generation of solar units in PJM: 2016

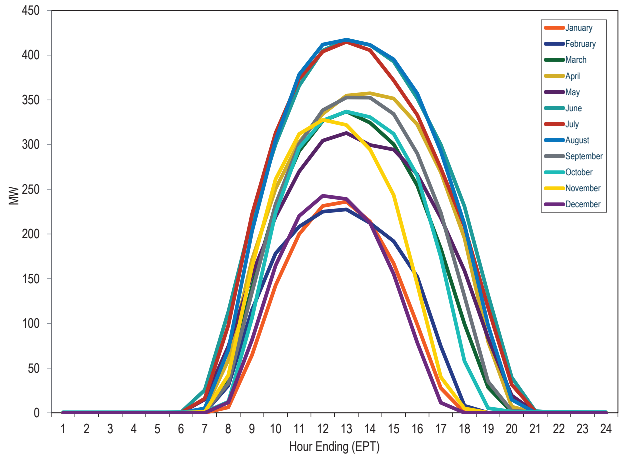


Figure 8-16 Average hourly day-ahead generation of solar units in PJM: 2016

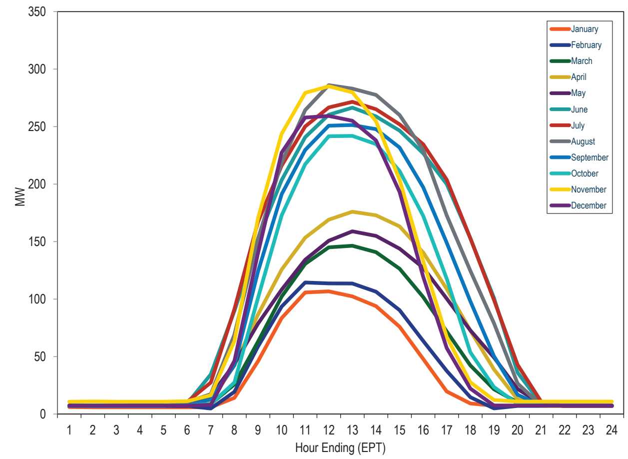


Table 8-21 shows the generation and capacity factor of solar units in each month of 2015 through 2016.

Table 8-21 Capacity factor of solar units in PJM by month: 2015 through 2016

	2015		2016	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	19,969.1	8.6%	38,858.7	10.8%
February	27,836.9	13.1%	43,770.8	12.6%
March	33,353.5	13.6%	73,745.6	19.1%
April	46,307.8	19.5%	85,867.1	22.8%
May	54,641.7	22.2%	77,453.7	19.8%
June	46,659.5	19.3%	101,147.1	26.0%
July	53,800.1	21.5%	101,146.3	25.1%
August	54,975.1	22.0%	99,167.5	24.5%
September	43,878.9	18.1%	74,093.9	18.7%
October	38,640.7	15.4%	67,357.0	16.4%
November	28,899.6	11.9%	57,259.6	14.4%
December	21,570.6	7.4%	38,424.5	9.4%
Annual	470,533.4	16.0%	858,291.9	18.4%

Solar units that are capacity resources are required, like all capacity resources except Demand Resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Solar units may offer non-capacity related solar energy at their discretion. Figure 8-16 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[140]

140 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 2016, PJM was a monthly net importer of energy in the Real-Time Energy Market in January through May and a monthly net exporter of energy in the Real-Time Energy Market in the remaining months.[1] In 2016, the real-time net interchange of -9,153.6 GWh was lower than the net interchange of 15,717.4 GWh in 2015.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2016, PJM was a monthly net importer of energy in the Day-Ahead Energy Market in January, February, March, April and November and a monthly net exporter of energy in the Day-Ahead Energy Market in the remaining months. In 2016, the total day-ahead net interchange of -9,182.4 GWh was lower than net interchange of 1,603.1 GWh in 2015.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2016, gross imports in the Day-Ahead Energy Market were 135.4 percent of gross imports in the Real-Time Energy Market (81.7 percent in 2015). In 2016, gross exports in the Day-Ahead Energy Market were 127.8 percent of the gross exports in the Real-Time Energy Market (114.5 percent in 2015).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2016, there were net scheduled exports at nine of PJM's 20 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2016, there were net scheduled exports at ten of PJM's 18 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[2]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2016, there were net scheduled exports at nine of PJM's 20 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2016, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Up to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2016, up to congestion transactions were net exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Market.
- **Inadvertent Interchange.** In 2016, net scheduled interchange was -9,154 GWh and net actual interchange was -7,967 GWh, a difference of 1,186 GWh. In 2015, the difference was 349 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 2016, the Wisconsin Energy Corporation (WEC) interface had the largest loop flows of any interface with -2,856 GWh of net scheduled interchange and 9,774 GWh of net actual interchange, a difference of 12,630 GWh. In 2016, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 13,849 GWh of net scheduled interchange and 27,584 GWh of net actual interchange, a difference of 13,735 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2016, 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 58.1 percent of the hours.
- **PJM and New York ISO Interface Prices.** In 2016, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/

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

NYIS Interface and the NYISO/PJM proxy bus in 56.3 percent of the hours.

- **Neptune Underwater Transmission Line to Long Island, New York.** In 2016, 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 62.2 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2016, 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 60.5 percent of the hours.
- **Hudson DC Line.** In 2016, 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 11.2 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued nine TLRs of level 3a or higher in 2016, compared to 22 such TLRs issued in 2015.
- **Up to congestion.** There was an increase in up to congestion volume starting in December 2015, coincident with the expiration of the fifteen month limit on the payment of prior uplift charges.[3] The average number of up to congestion bids submitted in the Day-Ahead Energy Market increased by 80.0 percent, from 86,656 bids per day in 2015 to 156,021 bids per day in 2016. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 78.5 percent, from 462,118 MWh per day in 2015, to 824,885 MWh per day in 2016.
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[4] [5] 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.[6]

Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions.

3 148 FERC ¶ 61,144 (2014). *Order Instituting Section 206 Proceeding and Establishing Procedures.* 16 U.S.C. § 824e.

4 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).

5 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).

6 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

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 requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point-to-point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Adopted partially, 2015.)
- 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. Status: Adopted partially, 2013.)

Conclusion

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

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.[7]

Table 9-1 Charges and Credits Applied to Interchange Transactions

Billing Item	Real-Time Transactions: Import (Firm or Non Firm)	Real-Time Transactions: Import (Spot in)	Real-Time Transactions: Export	Real-Time Transactions: Wheel	Day-Ahead Transactions: Import (Firm or Non Firm)	Day-Ahead Transactions: Import (Spot in)	Day-Ahead Transactions: Export	Day-Ahead Transactions: Wheel	Up to Congestion
Firm or Non-Firm Point-to-Point Transmission Service	X		X[1]	X[1]	X		X[1]	X[1]	
Spot Import Service		X[2]				X[2]			
Day-ahead Spot Market Energy					X	X	X		
Balancing Spot Market Energy	X	X	X						
Day-ahead Transmission Congestion					X	X	X	X	X
Balancing Transmission Congestion	X	X	X	X					X
Day-ahead Transmission Losses					X	X	X	X	X
Balancing Transmission Losses	X	X	X	X					X
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	X		X	X	X		X	X	
PJM Scheduling, System Control and Dispatch Service - Market Support	X	X	X		X	X	X		X
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	X	X	X	X	X	X	X	X	X
PJM Scheduling, System Control and Dispatch Service - Market Support Offset	X	X	X		X	X	X		X
PJM Settlement, Inc.	X	X	X		X	X	X		X
Market Monitoring Unit (MMU) Funding	X	X	X		X	X	X		X
FERC Annual Recovery	X		X	X	X		X	X	
Organization of PJM States, Inc. (OPSI) Funding	X		X	X	X		X	X	
Synchronous Condensing			X				X		
Transmission Owner Scheduling, System Control and Dispatch Service	X		X	X	X		X	X	
Reactive Supply and Voltage Control from Generation and Other Sources Service	X		X	X	X		X	X	
Day-ahead Operating Reserve					X	X	X		
Balancing Operating Reserve	X	X	X						
Black Start Service	X		X	X	X		X	X	
Marginal Loss Surplus Allocation (for those paying for transmission service only)			X				X		

1 No charge if Point of Delivery is MISO

2 No charge for spot in transmission

Aggregate Imports and Exports

In 2016, PJM was a monthly net importer of energy in the Real-Time Energy Market in January through May and a monthly net exporter of energy in the Real-Time Energy Market in the remaining months (Figure 9-1).[8] PJM became a monthly net exporter in June primarily as a result of the requirement for external capacity resources to be pseudo tied into PJM. 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 the shift from importing to exporting interchange starting in June, as the previously scheduled imports became internal generation. In 2016, the total real-time net interchange of -9,153.6 GWh was lower than the net interchange of 15,717.4 GWh in 2015. The removal of the pseudo tied units from the interchange totals in 2016 represented 52.6 percent of the real-time net interchange difference between 2015 and 2016. In 2016, the peak month for net importing interchange was January, 2,107.6 GWh; in 2015 it was April, 2,293.9

7 For an explanation and current rate for each billing line item, see "*Customer Guide to PJM Billing*," (January 1, 2017) <http://www.pjm.com/~/media/markets-ops/settlements/custgd.ashx>.

8 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.

GWh. Gross monthly export volumes in 2016 averaged 3,507.3 GWh compared to 2,852.0 GWh in 2015, while gross monthly imports in 2016 averaged 2,744.5 GWh compared to 4,161.7 GWh in 2015.

In 2016, PJM was a monthly net importer of energy in the Day-Ahead Energy Market in January, February, March, April and November and a monthly net exporter of energy in the Day-Ahead Energy Market in the remaining months (Figure 9-1). In 2016, the total day-ahead net interchange of -9,182.4 GWh was lower than the net interchange of 1,603.1 GWh in 2015. The implementation of the pseudo-tied units on June 1, 2016, also impacted the day-ahead interchange totals. Prior to June 1, 2016, some external units were able to meet their day-ahead must offer requirements by submitting day-ahead energy schedules. When those external units became pseudo-tied units in PJM, they were required to offer into the Day-Ahead Energy Market through the Markets Gateway application. These offers replaced the day-ahead energy schedules that those units had submitted in the form of import transactions. The removal of these day-ahead transactions resulted in approximately 57.2 percent of the difference in the day-ahead net interchange totals in 2016 compared to 2015. In 2016, the peak month for net importing interchange was April, 744.2 GWh; in 2015 it was May, 1,433.0 GWh. Gross monthly export volumes in 2016 averaged 4,481.7 GWh compared to 3,265.3 GWh in 2015, while gross monthly imports in 2016 averaged 3,716.5 compared to 3,398.8 GWh in 2015.

Figure 9-1 shows real-time and day-ahead import, export and net interchange volumes. The day-ahead totals include fixed, dispatchable and up to congestion transaction totals. The net interchange of up to congestion transactions are represented by the orange line.

In 2016, gross imports in the Day-Ahead Energy Market were 135.4 percent of gross imports in the Real-Time Energy Market (81.7 percent in 2015). In 2016, gross exports in the Day-Ahead Energy Market were 127.8 percent of gross exports in the Real-Time Energy Market (114.5 percent in 2015). In 2016, net interchange was -9,182.4 GWh in the Day-Ahead Energy Market and -9,153.6 GWh in the Real-Time Energy Market compared to 1,603.1 GWh in the Day-Ahead Energy Market and 15,717.4 GWh in the Real-Time Energy Market in 2015.

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 MW and price differences in the Day-Ahead and Real-Time Energy Markets.[9] In 2016, 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 PJM real-time and day-ahead scheduled imports and exports: 2016

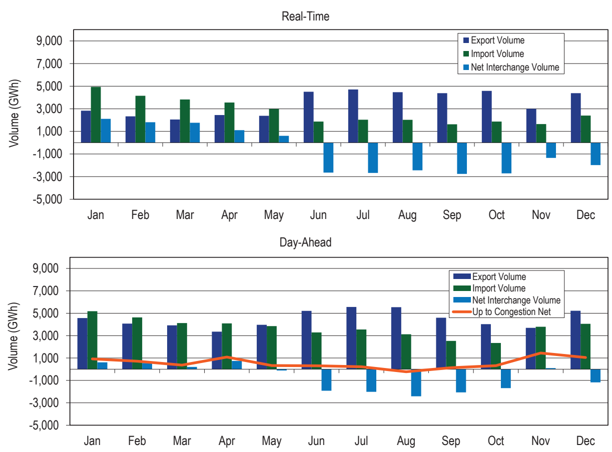
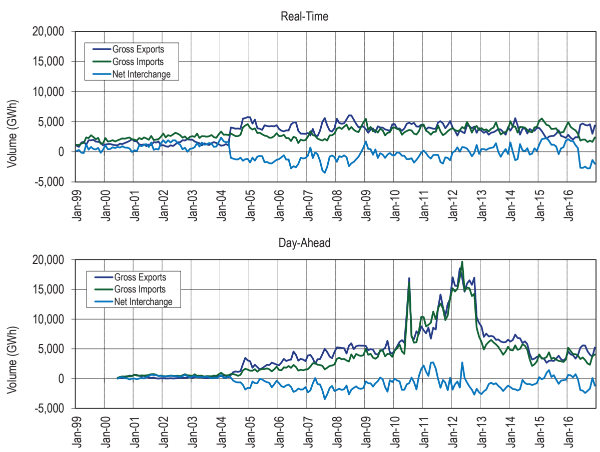


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through 2016. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM 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

9 Up to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

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.

Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 1999 through 2016



Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are defined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. Table 9-17 includes a list of active interfaces in 2016. Figure 9-3 shows the approximate geographic location of the interfaces. In 2016, PJM had 20 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. Similarly, there are ten separate interfaces that make up the MISO Interface between PJM and MISO. Table 9-2 through Table 9-4 show the Real-Time Energy Market scheduled interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the scheduled interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net scheduled interchange in the Real-Time Energy Market is shown by interface for 2016 in Table 9-2, while gross scheduled imports and exports are shown in Table 9-3 and Table 9-4.

In the Real-Time Energy Market, in 2016, there were net scheduled exports at nine of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 55.2 percent of the total net scheduled exports: PJM/MidAmerican Energy Company (MEC) with 21.3 percent, PJM/Neptune (NEPT) with 20.0 percent and PJM/Alliant East (ALTE) with 13.9 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 36.5 percent of the total net PJM scheduled exports in the Real-Time Energy Market. There were net scheduled exports in the Real-Time Energy Market at five of the ten separate interfaces that connect PJM to MISO. Those five exporting interfaces represented 63.5 percent of the total net PJM scheduled exports in the Real-Time Energy Market. Ten PJM interfaces had net scheduled imports, with the top three importing interfaces accounting for 63.7 percent of the total net scheduled imports: PJM/Ameren-Illinois (AMIL) with 25.3 percent, PJM/DUK (DUK) with 22.7 percent and PJM/Tennessee Valley Authority (TVA) with 15.8 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. In 2016, there were net imports in the Real-Time Energy Market at four of the ten separate interfaces that connect PJM to MISO. Those four interfaces represented 34.1 percent of the total net PJM scheduled imports in the Real-Time Energy Market.

On June 1, 2016, 32 new pseudo ties were implemented in the PJM Energy Market to comply with capacity market rules governing capacity imports. These pseudo ties represented 27 units at 11 plants. Prior to June 1, 2016, these units either dynamically scheduled or block scheduled their output into PJM and were part of scheduled interchange. 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

10 In the Real-Time Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

the shift from importing to exporting interchange starting in June, as the previously scheduled imports became internal generation.

The Ohio Valley Electric Corporation (OVEC) consists of two coal fired generating stations. The Clifty Creek plant has a nameplate rating of 1,300 MW and is located in Madison, Indiana. The Kyger Creek plant has a nameplate rating of 1,000 MW and is located in Cheshire, Ohio. Thirteen investor-owned utilities and affiliates of generation and transmission rural electric cooperatives, the Sponsoring Companies, share OVEC's generation output. The Sponsoring Companies purchase power from OVEC according to the terms of the Inter-Company Power Agreement (ICPA), which has a current termination date of June 30, 2040.[11] Approximately 90 percent of OVEC is owned by load serving entities or their affiliates located in the PJM footprint.[12] In June 2016, the Clifty Creek and Kyger Creek units became pseudo tied with PJM. The resulting impact on interchange volumes can be seen starting in June, where interchange shifted from net imports to net exports at the OVEC Interface.

Table 9-2 Real-time scheduled net interchange volume by interface (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(45.7)	(26.0)	121.5	101.5	(1.1)	(20.7)	75.7	63.9	(31.7)	(31.5)	(2.1)	(26.5)	177.4
CPLW	0.0	0.2	6.9	0.0	0.0	(2.8)	(5.0)	4.6	0.0	0.0	0.0	0.0	3.8
DUK	777.9	697.7	215.6	408.5	552.2	133.0	(74.3)	20.9	(65.6)	370.5	223.0	336.9	3,596.6
LGEE	232.1	170.3	129.1	153.6	95.5	125.9	141.5	179.1	169.0	162.2	179.3	235.1	1,972.7
MISO	1,071.8	642.9	960.2	556.1	(341.9)	(2,227.4)	(1,838.0)	(1,584.5)	(2,084.6)	(2,919.9)	(1,290.0)	(1,428.3)	(10,483.5)
ALTE	88.1	(164.2)	74.8	61.0	43.1	(497.6)	(514.5)	(376.4)	(532.0)	(788.4)	(343.0)	(528.8)	(3,477.9)
ALTW	37.2	36.8	30.0	33.3	30.3	19.8	20.6	17.4	34.2	31.4	24.8	7.7	323.6
AMIL	848.5	789.8	685.6	538.0	249.0	84.4	113.8	96.5	36.2	97.4	90.9	378.4	4,008.5
CIN	120.0	119.8	303.1	91.2	(102.8)	(746.3)	(523.1)	(373.4)	(471.6)	(840.7)	(434.4)	(425.4)	(3,283.4)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	53.0	18.6	33.1	(10.4)	(97.5)	(127.4)	(139.8)	(117.0)	(178.0)	(202.8)	(91.7)	(86.1)	(946.0)
MEC	(462.8)	(411.3)	(372.5)	(389.9)	(454.1)	(470.1)	(453.4)	(461.8)	(449.5)	(472.2)	(452.7)	(481.4)	(5,331.7)
MECS	430.1	284.1	259.0	260.3	88.2	(162.3)	78.1	(7.9)	(43.5)	(157.6)	21.1	7.1	1,056.9
NIPS	4.7	17.8	4.6	0.0	0.0	(3.5)	(1.5)	0.7	0.0	0.0	(0.0)	0.0	22.8
WEC	(46.9)	(48.5)	(57.6)	(27.4)	(98.0)	(324.5)	(418.3)	(362.6)	(480.5)	(587.0)	(105.2)	(299.8)	(2,856.2)
NYISO	(1,081.8)	(649.1)	(463.7)	(722.4)	(324.1)	(601.2)	(938.6)	(1,213.7)	(738.5)	(510.3)	(656.3)	(1,231.0)	(9,130.7)
HUDS	(0.2)	0.0	0.0	0.0	(9.0)	(30.4)	0.0	0.0	0.0	(12.3)	(24.1)	0.0	(76.0)
LIND	(189.6)	(160.8)	(56.0)	(1.3)	(36.4)	(37.4)	(56.0)	(139.0)	(129.1)	(101.5)	(110.3)	(218.7)	(1,236.1)
NEPT	(476.1)	(406.8)	(395.1)	(472.5)	(329.6)	(437.0)	(451.8)	(494.9)	(462.1)	(350.5)	(344.7)	(395.5)	(5,016.6)
NYIS	(416.0)	(81.5)	(12.6)	(248.6)	50.9	(96.3)	(430.8)	(579.8)	(147.3)	(45.9)	(177.3)	(616.8)	(2,802.1)
OVEC	607.4	528.6	387.0	360.3	431.1	(14.2)	(14.8)	(14.7)	(14.2)	(16.6)	(16.9)	(20.5)	2,202.4
TVA	546.2	449.2	411.8	252.1	193.9	(35.1)	(17.6)	98.5	7.0	230.7	219.2	151.7	2,507.7
Total	2,107.9	1,813.8	1,768.4	1,109.7	605.4	(2,642.4)	(2,671.2)	(2,445.7)	(2,758.6)	(2,714.8)	(1,343.8)	(1,982.5)	(9,153.6)

11 See OVEC, "Annual Report – 2015: Ohio Valley Electric Corporation and subsidiary Indiana-Kentucky Electric Corporation," <http://ovec.com/FinancialStatements/AnnualReport-2015-Signed.pdf>.

12 See OVEC, "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf>.

Table 9-3 Real-time scheduled gross import volume by interface (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	8.1	7.2	151.3	119.0	30.0	17.3	115.5	102.6	9.5	3.3	5.5	2.3	571.6
CPLW	0.0	0.2	6.9	0.0	0.0	0.0	0.0	4.6	0.0	0.0	0.0	0.0	11.6
DUK	810.3	713.6	231.0	430.3	570.3	283.6	160.6	228.5	182.2	420.2	298.8	393.1	4,722.4
LGEE	232.1	171.9	130.7	153.8	100.0	126.0	144.8	180.0	169.4	167.1	179.3	235.1	1,990.2
MISO	1,975.6	1,551.9	1,644.1	1,385.9	818.6	461.7	552.4	474.8	401.9	353.8	323.2	724.7	10,668.5
ALTE	289.3	79.1	184.4	208.7	243.2	4.2	89.6	133.9	127.1	7.2	0.0	0.0	1,366.8
ALTW	40.8	36.8	30.0	33.3	30.4	19.8	20.6	17.4	34.2	32.0	24.8	7.7	327.9
AMIL	849.0	790.5	686.1	542.4	249.8	95.9	125.5	100.2	37.5	97.4	90.9	379.5	4,044.6
CIN	202.7	222.5	362.1	231.1	138.9	43.1	36.2	62.6	106.2	117.1	103.8	164.9	1,790.9
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	85.3	55.0	56.1	45.4	11.9	9.6	17.7	5.8	3.7	5.8	8.1	12.7	317.0
MEC	21.1	37.9	33.3	36.7	23.3	59.9	55.8	37.0	25.9	31.9	29.6	23.2	415.4
MECS	482.1	311.4	285.3	283.1	121.2	101.2	138.1	95.6	67.4	59.4	66.0	101.2	2,111.8
NIPS	4.7	17.8	4.6	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0	27.8
WEC	0.6	0.9	2.3	5.3	0.0	128.0	68.9	21.7	0.0	3.0	0.0	35.5	266.3
NYISO	727.5	687.1	826.5	837.9	801.6	904.1	954.7	869.8	710.6	639.6	600.4	799.7	9,359.5
HUDS	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.2
LIND	1.2	0.5	7.0	72.2	3.6	23.8	27.3	4.8	5.6	4.2	1.8	0.6	152.6
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.4
NYIS	726.4	686.5	819.4	765.7	798.0	880.1	927.4	864.9	704.8	635.4	598.6	799.1	9,206.3
OVEC	631.4	550.3	404.7	374.6	445.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,406.2
TVA	555.9	465.8	424.4	257.7	224.4	75.9	109.3	162.4	152.5	286.3	245.8	243.2	3,203.7
Total	4,940.9	4,147.9	3,819.6	3,559.1	2,990.2	1,868.5	2,037.2	2,022.6	1,626.1	1,870.3	1,653.1	2,398.2	32,933.7

Table 9-4 Real-time scheduled gross export volume by interface (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	53.8	33.2	29.8	17.5	31.2	38.0	39.8	38.7	41.1	34.7	7.6	28.8	394.2
CPLW	0.0	0.0	0.0	0.0	0.0	2.8	5.0	0.0	0.0	0.0	0.0	0.0	7.8
DUK	32.3	15.9	15.3	21.7	18.1	150.5	234.8	207.6	247.8	49.7	75.8	56.2	1,125.8
LGEE	0.0	1.6	1.6	0.2	4.5	0.1	3.3	0.9	0.4	4.8	0.0	0.0	17.5
MISO	903.7	909.0	684.0	829.8	1,160.5	2,689.0	2,390.4	2,059.2	2,486.5	3,273.7	1,613.2	2,152.9	21,152.0
ALTE	201.2	243.3	109.5	147.7	200.1	501.7	604.1	510.3	659.2	795.6	343.0	528.8	4,844.6
ALTW	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	4.3
AMIL	0.5	0.7	0.5	4.4	0.8	11.5	11.7	3.7	1.3	0.1	0.0	1.1	36.2
CIN	82.7	102.6	59.0	139.8	241.7	789.4	559.2	435.9	577.7	957.8	538.2	590.2	5,074.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	32.3	36.4	23.0	55.8	109.4	137.0	157.5	122.8	181.6	208.6	99.8	98.9	1,263.1
MEC	484.0	449.2	405.8	426.6	477.4	530.1	509.1	498.8	475.3	504.1	482.2	504.6	5,747.1
MECS	51.9	27.3	26.2	22.8	33.0	263.4	60.0	103.4	110.9	217.0	44.9	94.0	1,054.9
NIPS	0.0	0.0	0.0	0.0	0.0	3.5	1.5	0.0	0.0	0.0	0.0	0.0	5.0
WEC	47.5	49.4	59.9	32.7	98.1	452.5	487.2	384.4	480.5	589.9	105.2	335.3	3,122.4
NYISO	1,809.4	1,336.2	1,290.2	1,560.2	1,125.7	1,505.2	1,893.3	2,083.5	1,449.1	1,149.9	1,256.8	2,030.7	18,490.2
HUDS	0.2	0.0	0.0	0.0	9.0	30.5	0.0	0.0	0.0	12.4	24.2	0.0	76.2
LIND	190.7	161.4	63.0	73.5	39.9	61.3	83.3	143.8	134.7	105.7	112.0	219.3	1,388.7
NEPT	476.1	406.8	395.1	472.5	329.7	437.1	451.8	494.9	462.2	350.5	344.7	395.5	5,016.9
NYIS	1,142.4	768.0	832.1	1,014.2	747.2	976.5	1,358.2	1,444.7	852.1	681.3	775.9	1,415.9	12,008.4
OVEC	24.0	21.7	17.8	14.3	14.1	14.2	14.8	14.7	14.2	16.6	16.9	20.5	203.8
TVA	9.8	16.6	12.5	5.5	30.6	111.1	126.9	63.8	145.5	55.6	26.6	91.5	696.0
Total	2,833.0	2,334.1	2,051.2	2,449.4	2,384.8	4,510.9	4,708.4	4,468.4	4,384.6	4,585.0	2,996.9	4,380.7	42,087.3

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a path on which scheduled imports or exports will flow.[13] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled path from a generation control area (GCA) to a load control area (LCA), this path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the PJM/MISO Interface based on the scheduled path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the PJM/MISO Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SouthIMP interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent the locational price impact of flows between PJM and external sources of energy and that reflect the underlying economic fundamentals across balancing authority borders.[14]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[15] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. Dynamic interface pricing calculations use actual system conditions to determine a set of weights for each external pricing point in an interface price definition. The weights are designed so that the interface price reflects actual system conditions. However, the weights are an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Table 9-18 presents the interface pricing points used in 2016. On September 16, 2014, PJM updated the mappings of external balancing authorities to individual pricing points. The MMU recommends that PJM review these mappings, at least annually, to reflect the fact that changes to the system topology can affect the impact of external power sources on PJM.

The interface pricing method implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are static, and are modified by PJM only occasionally.[16] The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions.

The contract transmission path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The breaking of transactions into portions can be a way to manipulate markets and the result of such behavior can be incorrect and noncompetitive pricing of transactions.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP,

13 There are multiple paths between any generation and load balancing authority. Market participants select the path based on transmission service availability and the transmission costs for moving energy from generation to load and interface prices.

14 See the *2007 State of the Market Report for PJM*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

15 See "Interface Pricing Point Assignment Methodology," (August 28, 2014) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>. PJM periodically updates these definitions on its website.

16 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario Interface Pricing Point.

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.[17]

In the Real-Time Energy Market, in 2016, there were net scheduled exports at 10 of PJM's 18 interface pricing points eligible for real-time transactions.[18] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 87.9 percent of the total net scheduled exports: PJM/MISO with 61.6 percent, PJM/NEPTUNE with 16.9 percent and PJM/NYIS with 9.4 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 30.8 percent of the total net PJM scheduled exports in the Real-Time Energy Market. Six PJM interface pricing points had net scheduled imports, with two importing interface pricing points accounting for 79.9 percent of the total net scheduled imports: PJM/SouthIMP with 67.6 percent and PJM/Ontario Independent Market Operator (IMO) with 12.3 percent of the net scheduled import volume.[19]

Table 9-5 Real-time scheduled net interchange volume by interface pricing point (GWh): 2016[20]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	569.0	393.1	377.4	209.1	137.7	100.6	221.5	200.8	137.5	10.4	11.6	144.0	2,512.5
MISO	(432.1)	(510.3)	(344.4)	(375.3)	(885.1)	(2,547.9)	(2,252.9)	(1,928.1)	(2,330.0)	(3,123.5)	(1,461.3)	(2,046.5)	(18,237.3)
NORTHWEST	(1.2)	(3.3)	(0.6)	(2.4)	(1.6)	(0.3)	(0.2)	(0.2)	(0.2)	(0.3)	(0.0)	0.0	(10.1)
NYISO	(1,082.5)	(649.7)	(463.8)	(722.1)	(324.1)	(602.1)	(939.7)	(1,202.1)	(734.5)	(510.4)	(656.9)	(1,230.3)	(9,118.1)
HUDSONTP	(0.2)	0.0	0.0	0.0	(9.0)	(30.4)	0.0	0.0	0.0	(12.3)	(24.1)	0.0	(76.0)
LINDENVFT	(189.6)	(160.8)	(56.0)	(1.3)	(36.4)	(37.4)	(56.0)	(139.0)	(129.1)	(101.5)	(110.3)	(218.7)	(1,236.1)
NEPTUNE	(476.1)	(406.8)	(395.1)	(472.5)	(329.6)	(437.0)	(451.8)	(494.9)	(462.1)	(350.5)	(344.7)	(395.5)	(5,016.6)
NYIS	(416.6)	(82.1)	(12.7)	(248.3)	50.9	(97.3)	(431.9)	(568.2)	(143.3)	(46.0)	(177.9)	(616.1)	(2,789.5)
OVEC	607.4	528.6	387.0	360.3	431.1	(14.2)	(14.8)	(14.7)	(14.2)	(16.6)	(16.9)	(20.5)	2,202.4
Southern Imports	2,543.6	2,123.0	1,872.2	1,685.2	1,331.8	730.8	727.5	809.7	618.2	1,071.9	895.2	1,348.8	15,757.9
CPLEIMP	4.1	3.3	6.9	44.6	8.3	13.6	10.1	21.5	8.1	1.2	2.8	1.2	125.6
DUKIMP	40.6	14.0	3.5	0.2	5.3	10.3	10.5	4.8	0.0	28.5	4.2	28.8	150.7
NCMPAIMP	120.5	135.3	153.9	159.3	198.3	102.7	82.8	74.6	51.3	197.4	182.9	174.1	1,633.0
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	2,378.4	1,970.4	1,708.0	1,481.1	1,119.9	604.2	624.2	708.8	558.9	844.8	705.3	1,144.7	13,848.6
Southern Exports	(96.3)	(67.6)	(59.3)	(45.1)	(84.4)	(309.3)	(412.6)	(311.1)	(435.4)	(146.3)	(115.5)	(177.9)	(2,260.9)
CPLEEXP	(23.8)	(11.6)	(4.8)	(0.2)	(1.0)	(4.3)	(4.6)	(2.8)	(1.9)	(19.7)	(1.7)	(22.3)	(98.6)
DUKEXP	(4.8)	(4.6)	(5.8)	(0.3)	0.0	(1.8)	(75.3)	(124.2)	(138.0)	(22.9)	(52.4)	(27.7)	(457.7)
NCMPAEXP	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(67.7)	(51.4)	(48.7)	(44.6)	(83.4)	(303.3)	(332.7)	(184.1)	(295.5)	(103.7)	(61.5)	(127.9)	(1,704.6)
Total	2,107.9	1,813.8	1,768.4	1,109.7	605.4	(2,642.4)	(2,671.2)	(2,445.7)	(2,758.6)	(2,714.8)	(1,343.8)	(1,982.5)	(9,153.6)

17 The MMU does not believe that it is appropriate to allow the use of the Southwest pricing point for grandfathered transactions, and recommends that no further such agreements be entered into.

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

19 In the Real-Time Energy Market, two PJM interface pricing points had a net interchange of zero (Southeast and Southwest).

20 The totals in the real-time interface pricing point tables have been adjusted to reflect after the fact interface pricing point adjustments made to individual transactions. After the fact adjustments are necessary to ensure compliance with the interface pricing methods described in section 2.6A.1.B and 2.6A.2.B of the PJM Tariff. Previously reported totals did not include these after the fact adjustments. See the *2016 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for adjusted 2015 totals.

Table 9-6 Real-time scheduled gross import volume by interface pricing point (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	569.0	393.3	381.9	209.7	137.7	100.7	226.5	227.4	147.8	11.1	13.7	146.1	2,564.9
MISO	470.0	395.0	335.9	452.1	273.8	134.0	133.2	115.7	152.3	148.3	145.2	103.8	2,859.3
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	726.9	686.3	824.9	837.5	801.6	903.1	950.0	869.8	707.7	639.0	599.0	799.6	9,345.4
HUDSONTP	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.2
LINDENVFT	1.2	0.5	7.0	72.2	3.6	23.8	27.3	4.8	5.6	4.2	1.8	0.6	152.6
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.4
NYIS	725.7	685.8	817.9	765.2	798.0	879.1	922.7	864.9	701.9	634.8	597.2	798.9	9,192.2
OVEC	631.4	550.3	404.7	374.6	445.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,406.2
Southern Imports	2,543.6	2,123.0	1,872.2	1,685.2	1,331.8	730.8	727.5	809.7	618.2	1,071.9	895.2	1,348.8	15,757.9
CPLEIMP	4.1	3.3	6.9	44.6	8.3	13.6	10.1	21.5	8.1	1.2	2.8	1.2	125.6
DUKIMP	40.6	14.0	3.5	0.2	5.3	10.3	10.5	4.8	0.0	28.5	4.2	28.8	150.7
NCMPAIMP	120.5	135.3	153.9	159.3	198.3	102.7	82.8	74.6	51.3	197.4	182.9	174.1	1,633.0
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	2,378.4	1,970.4	1,708.0	1,481.1	1,119.9	604.2	624.2	708.8	558.9	844.8	705.3	1,144.7	13,848.6
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,940.9	4,147.9	3,819.6	3,559.1	2,990.2	1,868.5	2,037.2	2,022.6	1,626.1	1,870.3	1,653.1	2,398.2	32,933.7

Table 9-7 Real-time scheduled gross export volume by interface pricing point (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	0.0	0.2	4.5	0.7	0.0	0.1	5.0	26.7	10.4	0.7	2.1	2.1	52.4
MISO	902.2	905.3	680.4	827.4	1,158.9	2,681.9	2,386.1	2,043.8	2,482.3	3,271.7	1,606.4	2,150.3	21,096.6
NORTHWEST	1.2	3.3	0.6	2.4	1.6	0.3	0.2	0.2	0.2	0.3	0.0	0.0	10.1
NYISO	1,809.4	1,336.1	1,288.7	1,559.6	1,125.7	1,505.2	1,889.7	2,071.9	1,442.2	1,149.4	1,255.9	2,029.8	18,463.5
HUDSONTP	0.2	0.0	0.0	0.0	9.0	30.5	0.0	0.0	0.0	12.4	24.2	0.0	76.2
LINDENVFT	190.7	161.4	63.0	73.5	39.9	61.3	83.3	143.8	134.7	105.7	112.0	219.3	1,388.7
NEPTUNE	476.1	406.8	395.1	472.5	329.7	437.1	451.8	494.9	462.2	350.5	344.7	395.5	5,016.9
NYIS	1,142.4	767.9	830.6	1,013.6	747.2	976.4	1,354.6	1,433.1	845.2	680.8	775.1	1,415.0	11,981.7
OVEC	24.0	21.7	17.8	14.3	14.1	14.2	14.8	14.7	14.2	16.6	16.9	20.5	203.8
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	96.3	67.6	59.3	45.1	84.4	309.3	412.6	311.1	435.4	146.3	115.5	177.9	2,260.9
CPLEEXP	23.8	11.6	4.8	0.2	1.0	4.3	4.6	2.8	1.9	19.7	1.7	22.3	98.6
DUKEXP	4.8	4.6	5.8	0.3	0.0	1.8	75.3	124.2	138.0	22.9	52.4	27.7	457.7
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	67.7	51.4	48.7	44.6	83.4	303.3	332.7	184.1	295.5	103.7	61.5	127.9	1,704.6
Total	2,833.0	2,334.1	2,051.2	2,449.4	2,384.8	4,510.9	4,708.4	4,468.4	4,384.6	4,585.0	2,996.9	4,380.7	42,087.3

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.[21] Day-ahead energy market schedules need to be cleared through the day-ahead energy market process in order to become an approved schedule. The day-ahead energy market transactions are financially binding, but will not physically flow unless they are also submitted in the Real-Time Energy Market. In the Day-Ahead Energy Market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up to congestion; and dispatchable.[22]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by market participants. In Table 9-8, Table 9-9, and Table 9-10, the scheduled interface designation is determined by the transmission reservation that was acquired and associated with the day-ahead market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP interface price. As a result, a market participant who plans to submit a transaction from SPP to PJM may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM but may select SouthIMP as the import pricing point when submitting the transaction in the Day-Ahead Energy Market. In the scheduled interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the scheduled interface pricing point tables, the import transaction would appear as scheduled through the SouthIMP/EXP interface pricing point, which reflects the expected power flow.

Table 9-8 through Table 9-10 show the day-ahead scheduled interchange totals at the individual interfaces. Net scheduled interchange in the Day-Ahead Energy Market is shown by interface for 2016 in Table 9-8, while gross scheduled imports and exports are shown in Table 9-9 and Table 9-10.

In the Day-Ahead Energy Market, in 2016, there were net scheduled exports at nine of PJM's 20 interfaces. The top three net exporting interfaces in the Day-Ahead Energy Market accounted for 69.0 percent of the total net scheduled exports: PJM/MidAmerican Energy Company (MEC) with 27.0 percent, PJM/Neptune (NEPT) with 24.3 percent and PJM/Alliant East (ALTE) with 17.7 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 40.5 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market. In 2016, there were net exports in the Day-Ahead Energy Market at five of the ten separate interfaces that connect PJM to MISO. Those five interfaces represented 59.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Ten PJM interfaces had net scheduled imports, with the top two importing interfaces accounting for 84.3 percent of the total net imports: PJM/DUK with

21 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.

22 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

50.5 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 33.8 percent of the net import volume. The four interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together had net scheduled exports in the Day-Ahead Energy Market. In 2016, there were net imports in the Day-Ahead Energy Market at four of the ten separate interfaces that connect PJM to MISO. Those four interfaces represented 9.8 percent of the total net PJM scheduled imports in the Day-Ahead Energy Market.[23]

Table 9-8 Day-Ahead scheduled net interchange volume by interface (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(38.7)	(25.1)	82.3	49.1	5.3	8.9	64.8	66.3	(28.3)	(7.6)	3.6	(11.0)	169.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	0.0	0.0	0.0	1.3
DUK	499.6	409.2	95.2	199.1	354.4	104.6	7.7	102.2	55.4	242.0	222.6	251.1	2,543.1
LGEE	0.0	0.8	0.0	0.7	4.4	0.2	(0.2)	(0.2)	(0.0)	0.0	0.0	0.0	5.6
MISO	(330.7)	(344.3)	(188.5)	(323.1)	(746.1)	(1,642.4)	(1,301.4)	(1,281.9)	(1,501.6)	(1,816.3)	(1,089.4)	(1,381.5)	(11,947.2)
ALTE	(148.5)	(153.0)	(56.3)	(87.6)	(155.7)	(421.2)	(455.9)	(430.8)	(547.6)	(594.4)	(260.7)	(388.8)	(3,700.4)
ALTW	(2.8)	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.3)	0.0	0.0	(3.3)
AMIL	7.9	15.5	102.6	91.5	0.0	(9.2)	(6.6)	0.0	0.0	0.0	0.0	0.0	201.7
CIN	44.2	22.3	37.9	13.0	(12.1)	(133.1)	(42.6)	(43.6)	(30.5)	(182.6)	(246.9)	(190.0)	(764.1)
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	28.4	32.8	28.3	10.2	0.0	0.0	0.0	0.0	(11.3)	(0.0)	0.0	0.0	88.3
MEC	(482.9)	(443.5)	(411.3)	(404.8)	(479.8)	(500.8)	(481.3)	(491.2)	(469.1)	(494.8)	(475.2)	(513.7)	(5,648.3)
MECS	265.8	210.1	165.8	86.6	(3.4)	(202.4)	17.7	(15.8)	(89.1)	(180.2)	(16.6)	(63.3)	175.2
NIPS	4.7	18.6	4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.8
WEC	(47.5)	(48.0)	(59.9)	(32.0)	(95.2)	(375.7)	(332.8)	(300.4)	(353.9)	(362.9)	(89.9)	(225.7)	(2,324.0)
NYISO	(955.7)	(626.3)	(515.6)	(611.2)	(428.6)	(640.7)	(955.9)	(1,048.7)	(652.1)	(432.2)	(504.1)	(1,084.9)	(8,455.8)
HUDS	(3.2)	0.0	0.0	0.0	(7.8)	(23.6)	0.0	0.0	0.0	(9.7)	(31.5)	0.0	(75.7)
LIND	(13.0)	(9.0)	0.8	68.1	(3.7)	(10.0)	(10.0)	(15.6)	(15.4)	(8.1)	(13.7)	(35.2)	(64.8)
NEPT	(478.8)	(412.8)	(401.8)	(474.5)	(343.3)	(443.6)	(445.6)	(497.2)	(466.8)	(354.1)	(361.3)	(395.1)	(5,074.8)
NYIS	(460.8)	(204.4)	(114.6)	(204.9)	(73.8)	(163.4)	(500.3)	(536.0)	(169.8)	(60.3)	(97.6)	(654.6)	(3,240.5)
OVEC	467.9	378.2	278.1	268.5	308.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,701.1
TVA	51.6	41.9	79.9	78.0	59.5	(57.4)	(56.3)	(31.9)	(75.4)	7.6	18.3	7.3	123.1
Total without Up To Congestion	(306.0)	(165.6)	(168.6)	(339.0)	(442.8)	(2,226.8)	(2,241.2)	(2,192.9)	(2,201.9)	(2,006.5)	(1,348.9)	(2,219.0)	(15,859.2)
Up To Congestion	919.2	717.8	372.5	1,083.2	326.7	306.3	225.8	(225.1)	134.6	321.4	1,448.1	1,046.4	6,676.8
Total	613.2	552.2	203.9	744.2	(116.1)	(1,920.5)	(2,015.4)	(2,418.0)	(2,067.4)	(1,685.1)	99.2	(1,172.6)	(9,182.4)

23 In the Day-Ahead Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

Table 9-9 Day-Ahead scheduled gross import volume by interface (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	2.2	3.9	105.7	65.0	33.8	40.9	97.9	97.2	6.2	18.8	10.0	2.2	483.7
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	0.0	0.0	0.0	1.3
DUK	499.8	409.2	95.2	199.1	354.4	134.1	63.3	114.5	79.7	242.0	222.6	251.1	2,665.0
LGEE	0.0	0.8	0.0	0.7	4.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	6.0
MISO	409.3	329.4	360.9	241.8	29.4	49.5	66.8	65.2	7.6	0.9	9.1	27.5	1,597.4
ALTE	7.4	0.8	0.0	6.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.8
ALTW	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
AMIL	7.9	15.5	102.6	91.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	217.5
CIN	55.2	26.4	38.3	19.6	0.5	1.5	0.5	8.6	1.0	0.0	8.2	3.3	163.1
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	28.4	32.8	28.3	15.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	104.5
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	305.8	234.6	187.3	109.0	28.9	47.9	66.3	56.6	6.6	0.9	0.9	24.2	1,068.9
NIPS	4.7	18.6	4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.8
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	525.5	496.2	636.2	690.4	605.0	731.5	750.5	750.2	575.9	521.7	459.9	641.2	7,384.2
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	0.1	2.0	72.1	0.4	1.4	2.3	0.5	0.9	1.2	0.7	0.0	81.7
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	525.5	496.2	634.2	618.3	604.6	730.1	748.1	749.7	575.0	520.5	459.2	641.2	7,302.5
OVEC	467.9	378.2	278.1	268.5	308.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,701.1
TVA	54.3	49.9	81.7	82.2	70.1	5.1	0.0	1.2	6.4	37.6	28.2	46.3	463.0
Total without Up To Congestion	1,959.0	1,667.7	1,557.9	1,547.7	1,405.5	961.2	978.4	1,029.5	675.8	821.0	729.9	968.3	14,301.9
Up To Congestion	3,229.4	2,963.8	2,571.5	2,552.6	2,445.0	2,331.7	2,573.5	2,098.4	1,857.6	1,520.9	3,064.5	3,086.5	30,295.6
Total	5,188.4	4,631.5	4,129.4	4,100.3	3,850.5	3,292.9	3,551.9	3,127.9	2,533.4	2,342.0	3,794.4	4,054.8	44,597.4

Table 9-10 Day-Ahead scheduled gross export volume by interface (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	40.9	29.1	23.5	15.9	28.5	31.9	33.0	30.9	34.5	26.4	6.4	13.3	314.2
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	0.2	0.0	0.0	0.0	0.0	29.5	55.6	12.3	24.4	0.0	0.0	0.0	122.0
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.4
MISO	740.0	673.7	549.4	564.9	775.5	1,691.9	1,368.2	1,347.0	1,509.2	1,817.2	1,098.5	1,409.0	13,544.6
ALTE	155.9	153.7	56.3	94.3	155.7	421.2	455.9	430.8	547.6	594.4	260.7	388.8	3,715.2
ALTW	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	0.0	4.1
AMIL	0.0	0.0	0.0	0.0	0.0	9.2	6.6	0.0	0.0	0.0	0.0	0.0	15.8
CIN	11.0	4.1	0.5	6.6	12.6	134.6	43.1	52.2	31.5	182.7	255.1	193.3	927.2
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	0.0	0.0	0.0	4.8	0.0	0.0	0.0	0.0	11.3	0.0	0.0	0.0	16.1
MEC	482.9	443.5	411.3	404.8	479.8	500.8	481.3	491.2	469.1	494.8	475.2	513.7	5,648.3
MECS	40.0	24.5	21.5	22.4	32.3	250.4	48.5	72.4	95.7	181.1	17.6	87.5	893.7
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	47.5	48.0	59.9	32.0	95.2	375.7	332.8	300.4	353.9	362.9	89.9	225.7	2,324.0
NYISO	1,481.2	1,122.5	1,151.8	1,301.6	1,033.6	1,372.2	1,706.3	1,798.9	1,227.9	953.9	964.0	1,726.1	15,840.0
HUDS	3.2	0.0	0.0	0.0	7.8	23.6	0.0	0.0	0.0	9.7	31.5	0.0	75.7
LIND	13.0	9.1	1.2	4.0	4.1	11.4	12.3	16.1	16.3	9.3	14.5	35.2	146.5
NEPT	478.8	412.8	401.8	474.5	343.3	443.6	445.6	497.2	466.8	354.1	361.3	395.1	5,074.8
NYIS	986.2	700.6	748.8	823.2	678.4	893.5	1,248.5	1,285.6	744.8	580.8	556.8	1,295.8	10,543.0
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	2.7	7.9	1.8	4.2	10.6	62.5	56.3	33.1	81.8	30.0	9.9	39.0	339.9
Total without Up To Congestion	2,265.0	1,833.3	1,726.5	1,886.6	1,848.3	3,188.0	3,219.6	3,222.4	2,877.7	2,827.5	2,078.8	3,187.3	30,161.0
Up To Congestion	2,310.2	2,246.1	2,199.0	1,469.4	2,118.3	2,025.4	2,347.7	2,323.5	1,723.1	1,199.5	1,616.4	2,040.1	23,618.8
Total	4,575.2	4,079.3	3,925.5	3,356.0	3,966.6	5,213.4	5,567.4	5,546.0	4,600.8	4,027.0	3,695.2	5,227.5	53,779.8

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-11 through Table 9-16 show the day-ahead scheduled interchange totals at the interface pricing points. In 2016, up to congestion transactions accounted for 67.9 percent of all scheduled import MW transactions and 43.9 percent of all scheduled export MW transactions in the Day-Ahead Energy Market. The day-ahead net scheduled interchange in 2016, including up to congestion transactions, is shown by interface pricing point in Table 9-11. Scheduled up to congestion transactions by interface pricing point in 2016 are shown in Table 9-12. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-13 and Table 9-15, while gross scheduled import and export up to congestion transactions are show in Table 9-14 and Table 9-16.

There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO). The NIPSCO interface pricing point was created when the individual balancing authorities that integrated to form MISO still operated independently. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the formation of the MISO RTO, all real-time transactions sourcing or sinking in NIPSCO are represented on the NERC Tag as sourcing or sinking in MISO, and thus receive the MISO interface pricing point in the Real-Time Energy Market. For this reason, it was no longer possible to receive the NIPSCO interface pricing point in the Real-Time Energy Market after the integration of NIPSCO into MISO.

After NIPSCO integrated into MISO on May 1, 2004, PJM kept the NIPSCO interface pricing point for the purpose of facilitating the long term day-ahead positions created at the NIPSCO Interface prior to the integration. However, the NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market today, and is available for all market participants to use as the pricing point for day-ahead imports, exports and wheels, INCs, DECs and up to congestion transactions. The NIPSCO interface pricing point continues to also be used as an eligible source or sink for new FTRs.

In 2016, the day-ahead net scheduled interchange at the NIPSCO interface pricing point was -5,755.5 GWh (Table 9-11). Table 9-12 shows that all -5,755.5 GWh of day-ahead net scheduled interchange submitted at the NIPSCO interface pricing point were made up of up to congestion transactions. While there is no corresponding interface pricing point available for real-time transaction scheduling, a real-time LMP is still calculated. This real-time price is used for balancing the deviations between the Day-Ahead and Real-Time Energy Markets.

PJM consolidated the Southeast and Southwest interface pricing points to a single interface pricing point with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006. At that time, the real-time Southeast and Southwest interface pricing points remained only to support certain grandfathered agreements with specific generating units and to price energy under the reserve sharing agreement with VACAR. The reserve sharing agreement allows for the transfer of energy during emergencies. Interchange transactions created as part of the reserve sharing agreement are currently settled at the Southeast interface price. PJM also kept the day-ahead Southeast and Southwest interface pricing points to facilitate long-term day-ahead positions that were entered prior to the consolidation.

Maintaining outdated definitions of interface pricing points is unnecessary, inconsistent with the tariff and creates artificial opportunities for gaming by virtual transactions and FTRs. The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point.

In the Day-Ahead Energy Market, in 2016, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 60.1 percent of the total net scheduled exports: PJM/NIPSCO with 23.0 percent, PJM/NEPTUNE with 18.8 percent and PJM/NORTHWEST with 18.3 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

27.9 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market (the PJM/HUDSONTP and PJM/LINDENVFT Interface Pricing Point had net scheduled imports). Nine PJM interface pricing points had net scheduled imports, with three importing interface pricing points accounting for 73.0 percent of the total net scheduled imports: PJM/Ohio Valley Electric Corporation (OVEC) with 37.0 percent, PJM/SouthImp with 20.4 percent and PJM/Southeast with 15.7 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) had net scheduled exports in the Day-Ahead Energy Market; however, the PJM/HUDSONTP and PJM/LINDENVFT interface pricing points had net scheduled imports that represented 6.9 percent of the total PJM net scheduled imports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in 2016, up to congestion transactions had net scheduled exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points eligible for up to congestion transactions accounted for 95.4 percent of the total net up to congestion scheduled exports: PJM/NIPSCO with 69.3 percent and PJM/SouthEXP with 26.1 percent of the net scheduled export 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) had net scheduled import up to congestion transactions in the Day-Ahead Energy Market. Nine PJM interface pricing points had net scheduled up to congestion imports, with the top three importing interface pricing points accounting for 66.2 percent of the total net up to congestion imports: PJM/OVEC with 27.9 percent, PJM/MISO with 21.7 percent and PJM/Southeast with 16.6 percent of the net import up to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 17.0 percent of the total net scheduled up to congestion exports in the Day-Ahead Energy Market.[24]

Table 9-11 Day-ahead scheduled net interchange volume by interface pricing point (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	436.0	266.7	41.0	84.5	(158.6)	2.2	56.2	(57.1)	(24.6)	46.8	77.3	191.4	961.9
MISO	339.9	400.1	207.7	78.1	(161.6)	(1,152.6)	(641.6)	(878.1)	(736.3)	(1,182.5)	9.5	(769.1)	(4,486.5)
NIPSCO	(449.8)	(694.3)	(836.0)	(384.8)	(246.8)	(260.9)	(520.9)	(694.0)	(479.8)	(189.8)	(533.1)	(465.4)	(5,755.5)
NORTHWEST	(46.8)	(240.9)	(309.1)	(360.9)	(548.0)	(288.1)	(417.2)	(443.4)	(405.5)	(515.9)	(534.5)	(475.6)	(4,586.0)
NYISO	(707.4)	(484.3)	(399.7)	(309.5)	45.2	(436.0)	(867.8)	(901.7)	(469.0)	(303.6)	(160.5)	(912.8)	(5,907.2)
HUDSONTP	143.3	48.7	28.1	72.0	111.7	44.3	33.1	68.3	64.2	41.5	76.0	111.4	842.6
LINDENVFT	14.3	(4.3)	28.6	123.3	38.9	(2.4)	34.3	4.5	(20.1)	(6.9)	75.7	(39.9)	245.9
NEPTUNE	(462.5)	(420.6)	(386.5)	(401.0)	(264.6)	(433.0)	(438.8)	(483.8)	(440.0)	(317.4)	(279.7)	(376.1)	(4,703.9)
NYIS	(402.5)	(108.2)	(69.8)	(103.8)	159.2	(44.9)	(496.4)	(490.7)	(73.1)	(20.8)	(32.5)	(608.3)	(2,291.8)
OVEC	975.9	767.8	833.9	597.9	345.0	339.6	311.9	378.9	241.0	231.8	274.8	571.3	5,869.9
Southern Imports	1,026.0	1,097.6	1,051.4	1,325.0	1,104.2	730.2	896.3	875.5	496.8	683.8	1,274.0	1,269.6	11,830.5
CPLEIMP	2.2	3.9	6.9	4.6	4.6	2.2	7.0	9.9	2.2	3.0	2.8	2.2	51.5
DUKIMP	133.2	54.1	24.5	45.8	47.1	50.5	40.4	104.1	1.3	15.0	3.9	22.0	541.8
NCMPAIMP	137.5	144.6	152.9	152.2	198.0	98.7	77.9	77.1	49.6	192.2	179.6	176.5	1,637.0
SOUTHEAST	123.3	187.8	196.4	331.3	225.3	168.3	216.0	289.7	178.7	191.3	233.5	415.9	2,757.5
SOUTHWEST	220.0	258.8	277.7	476.8	333.3	210.5	282.7	285.3	189.9	153.9	518.6	395.1	3,602.8
SOUTHIMP	409.7	448.3	392.9	314.3	296.0	200.0	272.2	109.3	75.2	128.5	335.6	257.9	3,239.9
Southern Exports	(960.6)	(560.6)	(385.3)	(286.1)	(495.6)	(854.9)	(832.4)	(698.1)	(689.9)	(455.7)	(308.3)	(582.1)	(7,109.5)
CPLEEXP	(38.7)	(27.4)	(22.0)	(15.0)	(26.9)	(31.2)	(32.3)	(30.4)	(34.1)	(25.0)	(6.1)	(12.7)	(301.7)
DUKEXP	(0.2)	0.0	0.0	0.0	0.0	0.0	(14.6)	0.0	0.0	0.0	0.0	0.0	(14.8)
NCMPAEXP	(2.2)	(1.7)	(1.5)	(1.0)	(1.6)	(0.8)	(0.7)	(0.5)	(0.4)	(1.4)	(0.3)	(0.5)	(12.6)
SOUTHEAST	(46.6)	(21.3)	(10.5)	(7.4)	(44.4)	(15.6)	(12.4)	(16.2)	(14.6)	(25.3)	(29.3)	(20.4)	(264.1)
SOUTHWEST	(335.8)	(235.9)	(236.3)	(184.3)	(253.5)	(520.8)	(445.1)	(462.4)	(410.0)	(306.3)	(114.7)	(398.3)	(3,903.5)
SOUTHEXP	(537.0)	(274.3)	(115.0)	(78.4)	(169.1)	(286.6)	(327.2)	(188.7)	(230.9)	(97.8)	(157.9)	(150.1)	(2,613.0)
Total	613.2	552.2	203.9	744.2	(116.1)	(1,920.5)	(2,015.4)	(2,418.0)	(2,067.4)	(1,685.1)	99.2	(1,172.6)	(9,182.4)

24 In the Day-Ahead Energy Market, six PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP and PJM/NCMPAEXP) had up to congestion net interchange of zero.

Table 9-12 Up to congestion scheduled net interchange volume by interface pricing point (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	127.6	32.2	(127.6)	(21.5)	(187.6)	(45.5)	(9.4)	(112.8)	(30.1)	45.9	76.7	167.2	(84.9)
MISO	511.3	567.9	287.0	180.8	133.7	82.2	253.5	(13.3)	311.4	154.3	632.6	143.3	3,244.6
NIPSCO	(449.8)	(694.3)	(836.0)	(384.8)	(246.8)	(260.9)	(520.9)	(694.0)	(479.8)	(189.8)	(533.1)	(465.4)	(5,755.5)
NORTHWEST	436.0	202.5	102.1	43.9	(68.2)	167.4	55.4	30.2	54.9	(36.3)	(67.3)	17.8	938.6
NYISO	248.3	141.9	115.9	301.7	473.8	204.4	87.3	146.1	182.0	129.3	343.3	172.1	2,546.2
HUDSONTP	146.5	48.7	28.1	72.0	119.5	67.8	33.1	68.3	64.2	51.2	107.5	111.4	918.3
LINDENVFT	27.3	4.7	27.8	55.2	42.6	7.7	44.2	20.0	(4.7)	1.2	89.4	(4.7)	310.7
NEPTUNE	16.2	(7.7)	15.2	73.5	78.8	10.7	6.8	13.4	26.8	36.7	81.6	19.0	370.9
NYIS	58.3	96.2	44.7	101.1	233.0	118.3	3.3	44.4	95.7	40.2	64.8	46.4	946.3
OVEC	508.0	389.6	555.7	329.4	42.2	339.6	311.9	378.9	241.0	231.8	274.8	571.3	4,174.4
Southern Imports	454.6	601.5	635.3	899.6	636.0	550.0	735.2	661.3	404.4	385.4	1,013.2	970.0	7,946.4
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	123.3	187.8	196.4	331.3	225.3	168.3	216.0	289.7	178.7	191.3	233.5	415.9	2,757.5
SOUTHWEST	220.0	258.8	277.7	476.8	333.3	210.5	282.7	285.3	189.9	153.9	518.6	395.1	3,602.8
SOUTHIMP	111.3	154.9	161.2	91.4	77.4	171.2	236.4	86.3	35.8	40.2	261.1	159.0	1,586.1
Southern Exports	(916.8)	(523.6)	(360.0)	(266.0)	(456.4)	(730.9)	(687.3)	(621.6)	(549.3)	(399.3)	(292.0)	(529.8)	(6,333.0)
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	(46.6)	(21.3)	(10.5)	(7.4)	(44.4)	(15.6)	(12.4)	(16.2)	(14.6)	(25.3)	(29.3)	(20.4)	(264.1)
SOUTHWEST	(335.8)	(235.9)	(236.3)	(184.3)	(253.5)	(520.8)	(445.1)	(462.4)	(410.0)	(306.3)	(114.7)	(398.3)	(3,903.5)
SOUTHEXP	(534.3)	(266.4)	(113.2)	(74.2)	(158.5)	(194.5)	(229.8)	(143.1)	(124.7)	(67.7)	(148.0)	(111.1)	(2,165.5)
Total Interfaces	919.2	717.8	372.5	1,083.2	326.7	306.3	225.8	(225.1)	134.6	321.4	1,448.1	1,046.4	6,676.8
INTERNAL	24,226.4	22,049.2	19,069.1	17,215.0	20,137.1	21,334.5	23,341.3	20,303.1	17,715.0	18,431.5	21,932.5	24,883.0	250,637.6
Total	25,145.5	22,767.0	19,441.6	18,298.2	20,463.8	21,640.8	23,567.1	20,077.9	17,849.6	18,752.9	23,380.6	25,929.3	257,314.4

Table 9-13 Day-ahead scheduled gross import volume by interface pricing point (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	552.8	451.6	246.1	232.9	195.2	208.4	249.1	145.8	79.7	80.1	149.6	261.6	2,852.8
MISO	800.0	781.2	484.9	339.3	279.6	256.0	429.5	270.2	491.5	292.4	794.9	386.2	5,605.6
NIPSCO	136.1	156.0	154.1	137.3	285.6	154.0	128.2	44.0	22.2	102.1	49.3	66.8	1,435.7
NORTHWEST	500.4	323.7	232.6	186.5	211.3	353.7	304.7	239.4	252.0	144.4	246.6	332.3	3,327.8
NYISO	1,018.7	888.2	917.5	1,124.3	1,175.6	1,043.3	986.3	960.9	811.4	708.7	857.3	1,001.9	11,494.0
HUDSONTP	186.5	93.2	55.8	83.6	125.6	75.3	34.6	69.1	65.0	53.2	110.0	147.1	1,099.1
LINDENVFT	53.5	51.4	58.5	168.9	86.0	29.1	65.3	37.5	23.0	19.7	121.4	53.0	767.4
NEPTUNE	103.7	101.1	89.3	96.8	92.8	70.7	70.1	33.8	38.0	59.5	86.9	38.4	881.0
NYIS	675.1	642.5	713.8	774.9	871.2	868.3	816.3	820.5	685.5	576.3	539.0	763.3	8,746.6
OVEC	1,154.4	933.2	1,042.7	755.1	599.1	547.3	557.8	592.1	379.8	330.5	422.6	736.5	8,051.0
Southern Imports	1,026.0	1,097.6	1,051.4	1,325.0	1,104.2	730.2	896.3	875.5	496.8	683.8	1,274.0	1,269.6	11,830.5
CPLEIMP	2.2	3.9	6.9	4.6	4.6	2.2	7.0	9.9	2.2	3.0	2.8	2.2	51.5
DUKIMP	133.2	54.1	24.5	45.8	47.1	50.5	40.4	104.1	1.3	15.0	3.9	22.0	541.8
NCMPAIMP	137.5	144.6	152.9	152.2	198.0	98.7	77.9	77.1	49.6	192.2	179.6	176.5	1,637.0
SOUTHEAST	123.3	187.8	196.4	331.3	225.3	168.3	216.0	289.7	178.7	191.3	233.5	415.9	2,757.5
SOUTHWEST	220.0	258.8	277.7	476.8	333.3	210.5	282.7	285.3	189.9	153.9	518.6	395.1	3,602.8
SOUTHIMP	409.7	448.3	392.9	314.3	296.0	200.0	272.2	109.3	75.2	128.5	335.6	257.9	3,239.9
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	5,188.4	4,631.5	4,129.4	4,100.3	3,850.5	3,292.9	3,551.9	3,127.9	2,533.4	2,342.0	3,794.4	4,054.8	44,597.4

Table 9-14 Up to congestion scheduled gross import volume by interface pricing point (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	244.4	217.0	77.5	126.9	166.2	160.4	182.8	89.2	73.2	79.2	148.7	237.4	1,802.9
MISO	714.2	718.6	426.1	281.9	279.1	254.4	428.9	261.6	490.5	292.4	786.7	382.8	5,317.4
NIPSCO	136.1	156.0	154.1	137.3	285.6	154.0	128.2	44.0	22.2	102.1	49.3	66.8	1,435.7
NORTHWEST	500.4	323.7	232.6	186.5	211.3	353.7	304.7	239.4	252.0	144.4	246.6	332.3	3,327.8
NYISO	493.2	392.0	281.3	433.9	570.5	311.8	235.8	210.7	235.6	187.0	397.4	360.7	4,109.9
HUDSONTP	186.5	93.2	55.8	83.6	125.6	75.3	34.6	69.1	65.0	53.2	110.0	147.1	1,099.1
LINDENVFT	53.4	51.3	56.5	96.8	85.6	27.7	63.0	37.0	22.1	18.5	120.7	53.0	685.7
NEPTUNE	103.7	101.1	89.3	96.8	92.8	70.7	70.1	33.8	38.0	59.5	86.9	38.4	881.0
NYIS	149.6	146.4	79.6	156.6	266.6	138.2	68.1	70.9	110.6	55.8	79.8	122.1	1,444.2
OVEC	686.5	555.0	764.5	486.6	296.3	547.3	557.8	592.1	379.8	330.5	422.6	736.5	6,355.4
Southern Imports	454.6	601.5	635.3	899.6	636.0	550.0	735.2	661.3	404.4	385.4	1,013.2	970.0	7,946.4
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	123.3	187.8	196.4	331.3	225.3	168.3	216.0	289.7	178.7	191.3	233.5	415.9	2,757.5
SOUTHWEST	220.0	258.8	277.7	476.8	333.3	210.5	282.7	285.3	189.9	153.9	518.6	395.1	3,602.8
SOUTHIMP	111.3	154.9	161.2	91.4	77.4	171.2	236.4	86.3	35.8	40.2	261.1	159.0	1,586.1
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Interfaces	3,229.4	2,963.8	2,571.5	2,552.6	2,445.0	2,331.7	2,573.5	2,098.4	1,857.6	1,520.9	3,064.5	3,086.5	30,295.6

Table 9-15 Day-ahead scheduled gross export volume by interface pricing point (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	116.8	184.8	205.1	148.4	353.8	206.2	192.9	202.9	104.3	33.3	72.3	70.1	1,890.9
MISO	460.1	381.0	277.3	261.2	441.2	1,408.6	1,071.0	1,148.4	1,227.9	1,474.9	785.4	1,155.2	10,092.1
NIPSCO	586.0	850.3	990.1	522.1	532.3	414.9	649.1	738.0	502.0	291.8	582.4	532.2	7,191.3
NORTHWEST	547.2	564.7	541.7	547.4	759.3	641.9	721.9	682.8	657.5	660.3	781.1	807.9	7,913.8
NYISO	1,726.1	1,372.6	1,317.2	1,433.8	1,130.3	1,479.3	1,854.1	1,862.6	1,280.5	1,012.3	1,017.9	1,914.7	17,401.2
HUDSONTP	43.2	44.5	27.8	11.7	13.8	31.0	1.5	0.7	0.8	11.7	34.0	35.7	256.5
LINDENVFT	39.1	55.7	29.9	45.6	47.1	31.5	31.1	33.0	43.1	26.6	45.7	93.0	521.5
NEPTUNE	566.2	521.6	475.8	497.8	357.3	503.6	508.9	517.6	477.9	376.9	366.6	414.5	5,584.9
NYIS	1,077.5	750.7	783.7	878.7	712.0	913.2	1,312.7	1,311.2	758.6	597.0	571.5	1,371.5	11,038.4
OVEC	178.5	165.4	208.8	157.1	254.0	207.7	245.9	213.2	138.7	98.7	147.8	165.2	2,181.1
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	960.6	560.6	385.3	286.1	495.6	854.9	832.4	698.1	689.9	455.7	308.3	582.1	7,109.5
CPLEEXP	38.7	27.4	22.0	15.0	26.9	31.2	32.3	30.4	34.1	25.0	6.1	12.7	301.7
DUKEXP	0.2	0.0	0.0	0.0	0.0	0.0	14.6	0.0	0.0	0.0	0.0	0.0	14.8
NCMPAEXP	2.2	1.7	1.5	1.0	1.6	0.8	0.7	0.5	0.4	1.4	0.3	0.5	12.6
SOUTHEAST	46.6	21.3	10.5	7.4	44.4	15.6	12.4	16.2	14.6	25.3	29.3	20.4	264.1
SOUTHWEST	335.8	235.9	236.3	184.3	253.5	520.8	445.1	462.4	410.0	306.3	114.7	398.3	3,903.5
SOUTHEXP	537.0	274.3	115.0	78.4	169.1	286.6	327.2	188.7	230.9	97.8	157.9	150.1	2,613.0
Total	4,575.2	4,079.3	3,925.5	3,356.0	3,966.6	5,213.4	5,567.4	5,546.0	4,600.8	4,027.0	3,695.2	5,227.5	53,779.8

Table 9-16 Up to congestion scheduled gross export volume by interface pricing point (GWh): 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	116.8	184.8	205.1	148.4	353.8	206.0	192.2	202.0	103.3	33.3	72.0	70.1	1,887.7
MISO	202.9	150.8	139.1	101.1	145.4	172.3	175.4	274.9	179.1	138.1	154.1	239.6	2,072.8
NIPSCO	586.0	850.3	990.1	522.1	532.3	414.9	649.1	738.0	502.0	291.8	582.4	532.2	7,191.3
NORTHWEST	64.4	121.2	130.5	142.6	279.5	186.3	249.3	209.2	197.1	180.6	313.9	314.5	2,389.2
NYISO	244.9	250.0	165.4	132.2	96.7	107.4	148.5	64.6	53.5	57.6	54.1	188.6	1,563.7
HUDSONTP	40.1	44.5	27.8	11.7	6.1	7.5	1.5	0.7	0.8	2.0	2.6	35.7	180.8
LINDENVFT	26.1	46.6	28.7	41.6	43.0	20.0	18.8	16.9	26.8	17.3	31.3	57.8	374.9
NEPTUNE	87.5	108.8	74.0	23.3	14.0	60.0	63.3	20.4	11.2	22.7	5.3	19.4	510.1
NYIS	91.3	50.1	34.9	55.5	33.6	19.9	64.9	26.5	14.9	15.6	15.0	75.7	497.8
OVEC	178.5	165.4	208.8	157.1	254.0	207.7	245.9	213.2	138.7	98.7	147.8	165.2	2,181.1
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	916.8	523.6	360.0	266.0	456.4	730.9	687.3	621.6	549.3	399.3	292.0	529.8	6,333.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	46.6	21.3	10.5	7.4	44.4	15.6	12.4	16.2	14.6	25.3	29.3	20.4	264.1
SOUTHWEST	335.8	235.9	236.3	184.3	253.5	520.8	445.1	462.4	410.0	306.3	114.7	398.3	3,903.5
SOUTHEXP	534.3	266.4	113.2	74.2	158.5	194.5	229.8	143.1	124.7	67.7	148.0	111.1	2,165.5
Total Interfaces	2,310.2	2,246.1	2,199.0	1,469.4	2,118.3	2,025.4	2,347.7	2,323.5	1,723.1	1,199.5	1,616.4	2,040.1	23,618.8

Table 9-17 Active real-time and day-ahead scheduling interfaces: 2016[25]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	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

25 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of December 31, 2016, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Figure 9-3 PJM's footprint and its external day-ahead and real-time scheduling interfaces

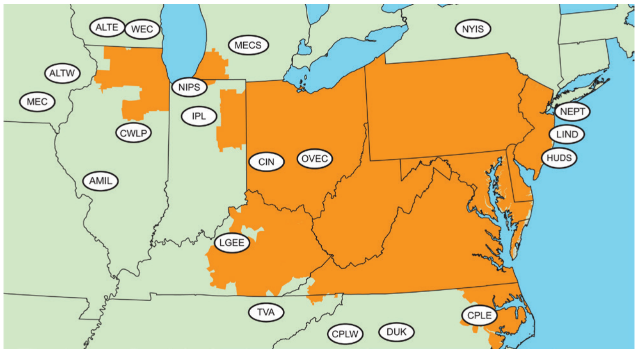


Table 9-18 Active day-ahead and real-time scheduled interface pricing points: 2016[26]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDSONTP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPTUNE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at a specific interface. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[27]

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

26 The NIPSCO interface pricing point is valid only in the Day-Ahead Energy Market.

27 See the *2012 State of the Market Report for PJM*, Volume II, 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 2016, there were net scheduled flows of 5,239 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 2016, net scheduled interchange was -9,154 GWh and net actual interchange was -7,967 GWh, a difference of 1,186 GWh. In 2015, net scheduled interchange was 15,717 GWh and net actual interchange was 15,368 GWh, a difference of 349 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.[28]

Table 9-19 shows that in 2016, the Wisconsin Energy Corporation (WEC) interface had the largest loop flows of any interface with -2,856 GWh of net scheduled interchange and 9,774 GWh of net actual interchange, a difference of 12,630 GWh.

Table 9-19 Net scheduled and actual PJM flows by interface (GWh): 2016

	Actual	Net Scheduled	Difference (GWh)
CPLE	4,670	177	4,493
CPLW	(1,188)	4	(1,192)
DUK	2,659	3,597	(937)
LGEE	2,850	1,973	877
MISO	(19,986)	(10,484)	(9,502)
ALTE	(5,871)	(3,478)	(2,393)
ALTW	(2,614)	324	(2,938)
AMIL	2,237	4,008	(1,772)
CIN	(6,429)	(3,283)	(3,145)
CWLP	(546)	0	(546)
IPL	(694)	(946)	252
MEC	(3,864)	(5,332)	1,468
MECS	(3,827)	1,057	(4,884)
NIPS	(8,151)	23	(8,174)
WEC	9,774	(2,856)	12,630
NYISO	(8,760)	(9,131)	371
HUDS	(76)	(76)	0
LIND	(1,236)	(1,236)	0
NEPT	(5,017)	(5,017)	0
NYIS	(2,431)	(2,802)	371
OVEC	4,887	2,202	2,685
TVA	6,900	2,508	4,392
Total	(7,967)	(9,154)	1,186

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.[29] 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

28 See PJM. "Manual 12: Balancing Operations," Revision 35 (August 25, 2016).

29 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. See "Reliability Functional Model," <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf>. (August 2008)

authority, whereas scheduled transactions are assigned to interfaces based solely on the OASIS path that the market participants reflect the transmission path into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 9-20 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP interface pricing points were created as part of operating agreements with external balancing authorities, and reflect the same physical ties as the SouthIMP and SouthEXP interface pricing points.

Because the SouthIMP and SouthEXP interface pricing points are the same physical point, if there are net actual exports from the PJM footprint to the southern region, by definition, there cannot be net actual imports into the PJM footprint from the southern region and therefore there will not be actual flows at the SouthIMP interface pricing point. In the case of PJM's southern border, loop flows can be analyzed by comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points. To accurately calculate the loop flows from the southern region, the net actual flows from the southern region are compared to the net scheduled flows from the southern region. The net actual flows from the southern region are determined by summing the total southern import actual flows (27,584 GWh) and the total southern export actual flows (-11,693 GWh) for 15,891 GWh of net imports. The net scheduled flows from the southern region are determined by summing the total southern import scheduled flows (15,758 GWh) and the total southern export scheduled flows (-2,261 GWh) for 13,497 GWh of net imports. In 2016, the loop flows at the southern region were the difference between the southern region net scheduled flows (13,497 GW) and the southern region net actual flows (15,891 GWh) for a total of 2,394 GWh of loop flows.

The IMO interface pricing point with the Ontario IESO was created to reflect the fact that transactions that originate or sink in the Ontario Independent Electricity System Operator (IMO) balancing authority create physical flows that are split between the MISO and NYISO interface pricing points depending on transmission system conditions, so a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Table 9-20 shows actual flows associated with the IMO interface pricing point as zero because there is no PJM/IMO Interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 9-20 Net scheduled and actual PJM flows by interface pricing point (GWh): 2016[30]

	Actual	Net Scheduled	Difference (GWh)
IMO	0	2,512	(2,512)
MISO	(19,986)	(18,237)	(1,749)
NORTHWEST	0	(10)	10
NYISO	(8,760)	(9,118)	359
HUDSONTP	(76)	(76)	0
LINDENVFT	(1,236)	(1,236)	0
NEPTUNE	(5,017)	(5,017)	0
NYIS	(2,431)	(2,789)	359
OVEC	4,887	2,202	2,685
Southern Imports	27,584	15,758	11,826
CPLEIMP	0	126	(126)
DUKIMP	0	151	(151)
NCMPAIMP	0	1,633	(1,633)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	27,584	13,849	13,735
Southern Exports	(11,693)	(2,261)	(9,432)
CPLEEXP	0	(99)	99
DUKEXP	0	(458)	458
NCMPAEXP	0	(0)	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(11,693)	(1,705)	(9,989)
Total	(7,967)	(9,154)	1,186

Table 9-21 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the IMO entered the PJM energy market. For example, Table 9-23 shows that the 2,538 GW of gross scheduled transactions that were mapped to the IMO interface pricing point were comprised of 13

30 The totals in the scheduled and actual interface pricing point tables have been adjusted to reflect after the fact interface pricing point adjustments made to individual transactions. After the fact adjustments are necessary to ensure compliance with the interface pricing methods described in section 2.6A.1.B and 2.6A.2.B of the PJM Tariff. Previously reported totals did not include these after the fact adjustments. See the *2016 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for adjusted 2015 totals.

GWh of exports through the NYISO and 2,525 GWh of imports through MISO.

Table 9-21 shows that in 2016, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 13,849 GWh of net scheduled interchange and 27,584 GWh of net actual interchange, a difference of 13,735 GWh.

Table 9-21 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): 2016

	Actual	Net Scheduled	Difference (GWh)
MISO	(19,986)	(15,712)	(4,274)
NORTHWEST	0	(10)	10
NYISO	(8,760)	(9,131)	371
HUDSONTP	(76)	(76)	0
LINDENVFT	(1,236)	(1,236)	0
NEPTUNE	(5,017)	(5,017)	0
NYIS	(2,431)	(2,802)	371
OVEC	4,887	2,202	2,685
Southern Imports	27,584	15,758	11,826
CPLEIMP	0	126	(126)
DUKIMP	0	151	(151)
NCMPAIMP	0	1,633	(1,633)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	27,584	13,849	13,735
Southern Exports	(11,693)	(2,261)	(9,432)
CPLEEXP	0	(99)	99
DUKEXP	0	(458)	458
NCMPAEXP	0	(0)	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(11,693)	(1,705)	(9,989)
Total	(7,967)	(9,154)	1,186

PJM attempts to ensure that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC Tag. Assigning prices in this manner is a reasonable approach to ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this method does not address loop flow issues.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game the markets.

The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loop flow would be reduced.

The MMU also recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows.

Table 9-22 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the interface pricing points that were assigned to energy transactions that had paths at each of PJM's interfaces. For example, Table 9-22 shows that in 2016, the majority of imports to the PJM energy market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the IMO Interface, and thus actual flows were assigned the IMO interface pricing point (601 GWh). The majority of exports from the PJM energy market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM energy market at the MISO Interface, and were assigned the MISO interface pricing point (-4,177 GWh).

Table 9-22 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): 2016

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(5,871)	(3,478)	(2,393)	HUDS		(76)	(76)	0
	IMO	0	358	(358)		HUDSONTP	(76)	(76)	0
	MISO	(5,871)	(4,753)	(1,118)	IPL		(694)	(946)	252
	SOUTHEXP	0	(0)	0		IMO	0	105	(105)
	SOUTHIMP	0	918	(918)		MISO	(694)	(1,074)	380
ALTW		(2,614)	324	(2,938)		SOUTHIMP	0	23	(23)
	MISO	(2,614)	324	(2,938)	LGEE		2,850	1,973	877
AMIL		2,237	4,008	(1,772)		SOUTHEXP	(6,755)	(18)	(6,737)
	MISO	2,237	839	1,397		SOUTHIMP	9,604	1,990	7,614
	SOUTHIMP	0	3,169	(3,169)	LIND		(1,236)	(1,236)	0
CIN		(6,429)	(3,283)	(3,145)		LINDENVFT	(1,236)	(1,236)	0
	IMO	0	601	(601)	MEC		(3,864)	(5,332)	1,468
	MISO	(6,429)	(4,177)	(2,251)		IMO	0	2	(2)
	NORTHWEST	0	(10)	10		MISO	(3,864)	(5,332)	1,468
	SOUTHEXP	0	(11)	11		SOUTHEXP	0	(2)	2
	SOUTHIMP	0	314	(314)		SOUTHIMP	0	0	(0)
CPLE		4,670	177	4,493	MECS		(3,827)	1,057	(4,884)
	CPLEEXP	0	(99)	99		IMO	0	1,459	(1,459)
	CPLEIMP	0	126	(126)		MISO	(3,827)	(972)	(2,855)
	DUKIMP	0	5	(5)		SOUTHEXP	0	(6)	6
	NCMPAIMP	0	306	(306)		SOUTHIMP	0	576	(576)
	SOUTHEXP	(1,987)	(296)	(1,691)	NEPT		(5,017)	(5,017)	0
	SOUTHIMP	6,657	135	6,522		NEPTUNE	(5,017)	(5,017)	0
CPLW		(1,188)	4	(1,192)	NIPS		(8,151)	23	(8,174)
	DUKIMP	0	1	(1)		MISO	(8,151)	18	(8,169)
	NCMPAIMP	0	3	(3)		SOUTHIMP	0	5	(5)
	SOUTHEXP	(1,250)	(8)	(1,243)	NYIS		(2,431)	(2,802)	371
	SOUTHIMP	62	8	55		IMO	0	(13)	13
CWLP		(546)	0	(546)		NYIS	(2,431)	(2,789)	359
	MISO	(546)	0	(546)	OVEC		4,887	2,202	2,685
DUK		2,659	3,597	(937)		OVEC	4,887	2,202	2,685
	DUKEXP	0	(458)	458	TVA		6,900	2,508	4,392
	DUKIMP	0	145	(145)		SOUTHEXP	(1,267)	(696)	(571)
	NCMPAEXP	0	(0)	0		SOUTHIMP	8,167	3,204	4,963
	NCMPAIMP	0	1,324	(1,324)	WEC		9,774	(2,856)	12,630
	SOUTHEXP	(434)	(668)	234		IMO	0	0	(0)
	SOUTHIMP	3,093	3,254	(161)		MISO	9,774	(3,110)	12,884
						SOUTHIMP	0	254	(254)
					Grand Total		(7,967)	(9,154)	1,186

Table 9-23 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-22. Table 9-23 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-23 shows that in 2016, 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 MISO interface pricing point, had a path that entered the PJM energy market at the AMIL Interface (839 GWh). The majority of exports from the PJM energy market for which a market participant specified a load control area for which it was assigned the MISO interface pricing point, had a path that exited the PJM energy market at the MEC Interface (-5,332 GWh).

Table 9-23 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): 2016

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(99)	99	NCMPAIMP		0	1,633	(1,633)
	CPLE	0	(99)	99		CPLE	0	306	(306)
CPLEIMP		0	126	(126)		CPLW	0	3	(3)
	CPLE	0	126	(126)		DUK	0	1,324	(1,324)
DUKEXP		0	(458)	458	NEPTUNE		(5,017)	(5,017)	0
	DUK	0	(458)	458		NEPT	(5,017)	(5,017)	0
DUKIMP		0	151	(151)	NORTHWEST		0	(10)	10
	CPLE	0	5	(5)		CIN	0	(10)	10
	CPLW	0	1	(1)	NYIS		(2,431)	(2,789)	359
	DUK	0	145	(145)		NYIS	(2,431)	(2,789)	359
HUDSONTP		(76)	(76)	0	OVEC		4,887	2,202	2,685
	HUDS	(76)	(76)	0		OVEC	4,887	2,202	2,685
IMO		0	2,512	(2,512)	SOUTHEXP		(11,693)	(1,705)	(9,989)
	ALTE	0	358	(358)		ALTE	0	(0)	0
	CIN	0	601	(601)		CIN	0	(11)	11
	IPL	0	105	(105)		CPLE	(1,987)	(296)	(1,691)
	MEC	0	2	(2)		CPLW	(1,250)	(8)	(1,243)
	MECS	0	1,459	(1,459)		DUK	(434)	(668)	234
	NYIS	0	(13)	13		LGEE	(6,755)	(18)	(6,737)
	WEC	0	0	(0)		MEC	0	(2)	2
LINDENVFT		(1,236)	(1,236)	0		MECS	0	(6)	6
	LIND	(1,236)	(1,236)	0		TVA	(1,267)	(696)	(571)
MISO		(19,986)	(18,237)	(1,749)	SOUTHIMP		27,584	13,849	13,735
	ALTE	(5,871)	(4,753)	(1,118)		ALTE	0	918	(918)
	ALTW	(2,614)	324	(2,938)		AMIL	0	3,169	(3,169)
	AMIL	2,237	839	1,397		CIN	0	314	(314)
	CIN	(6,429)	(4,177)	(2,251)		CPLE	6,657	135	6,522
	CWLP	(546)	0	(546)		CPLW	62	8	55
	IPL	(694)	(1,074)	380		DUK	3,093	3,254	(161)
	MEC	(3,864)	(5,332)	1,468		IPL	0	23	(23)
	MECS	(3,827)	(972)	(2,855)		LGEE	9,604	1,990	7,614
	NIPS	(8,151)	18	(8,169)		MEC	0	0	(0)
	WEC	9,774	(3,110)	12,884		MECS	0	576	(576)
NCMPAEXP		0	(0)	0		NIPS	0	5	(5)
	DUK	0	(0)	0		TVA	8,167	3,204	4,963
						WEC	0	254	(254)
					Grand Total		(7,967)	(9,154)	1,186

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 recently 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.[31]

NERC Tag Data

An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag data includes 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. Additionally, 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.[32]

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. Additionally, 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 only 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.

31 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.

32 141 FERC ¶ 61,235 (2012). *Availability of E-Tag Information to Commission Staff.*

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, and requests that FERC and NERC ensure that the underlying data are provided to market monitors and other approved entities.

Generation and Load Data

Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

Market areas are transparent in providing real-time load while nonmarket areas are not. For example, PJM posts real-time load via its eDATA application. Most nonmarket balancing authorities provide only the expected peak load on their individual web sites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU requests, 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

If interface prices were defined in a comparable manner by PJM and MISO, and if time lags were not built into the rules governing interchange 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 these conditions do not exist is important in explaining the observed relationship between interface prices and inter-RTO power flows, and those price differentials.

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, as well as for all buses in the PJM model, 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 MISO interface definition for PJM currently consists of all PJM generator buses which are spread across the entire PJM system. The interface definitions led to questions about the level of congestion included in interchange pricing.[33] [34]

PJM modified the definition of the PJM/MISO interface price effective June 1, 2014. PJM's new MISO interface

33 See "LMP Aggregate Definitions," (December 14, 2016) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/lmp-aggregate-definitions.ashx>. PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

34 Based on information obtained from MISO's extranet <http://extranet.midwestiso.org> (Accessed January 23, 2017).

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 ten ties composed of MISO and PJM monitored facilities. MISO is currently planning to modify their MISO/PJM interface definition to match PJM's PJM/MISO interface definition, effective June 1, 2017.

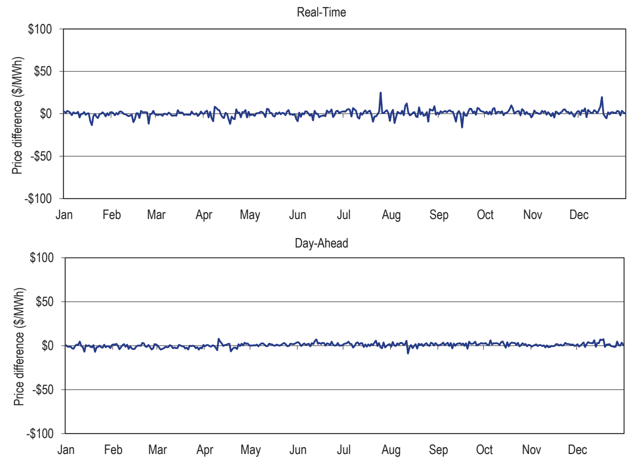
Real-Time and Day-Ahead PJM/MISO Interface Prices

In 2016, the direction of flow was consistent with price differentials in 58.1 percent of the hours. Table 9-24 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. Figure 9-4 shows the underlying hourly variability in prices. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-28).

Table 9-24 PJM and MISO flow based hours and average hourly price differences: 2016

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	4,965	$5.05
	Consistent Flow (PJM to MISO)	4,480	$5.13
	Inconsistent Flow (MISO to PJM)	485	$4.33
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	3,819	$6.21
	Consistent Flow (MISO to PJM)	621	$5.91
	Inconsistent Flow (PJM to MISO)	3,198	$6.27
	No Flow	1	$9.99

Figure 9-4 Real-time and day-ahead daily hourly average price difference (MISO/PJM Interface minus PJM/MISO Interface): 2016



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In 2016, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 5,101 hours (58.1 percent of all hours), and was inconsistent with price differentials in 3,683 hours (41.9 percent of all hours). Table 9-25 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 3,683 hours where flows were in a direction inconsistent with price differences, 2,698 of those hours (73.3 percent) had a price difference greater than or equal to $1.00 and 988 of those hours (26.8 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $186.11. Of the 5,101 hours where flows were consistent with price differences, 4,000 of those hours (78.4 percent) had a price difference greater than or equal to $1.00 and 1,252 of all such hours (24.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $260.63.

Table 9-25 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: 2016

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	3,683	100.0%	5,101	100.0%
$1.00	2,698	73.3%	4,000	78.4%
$5.00	988	26.8%	1,252	24.5%
$10.00	519	14.1%	601	11.8%
$15.00	333	9.0%	358	7.0%
$20.00	244	6.6%	247	4.8%
$25.00	191	5.2%	177	3.5%
$50.00	60	1.6%	46	0.9%
$75.00	21	0.6%	13	0.3%
$100.00	11	0.3%	8	0.2%
$200.00	0	0.0%	3	0.1%
$300.00	0	0.0%	0	0.0%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[35]

PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. PJM currently uses two buses within NYISO to calculate the PJM/NYIS interface pricing point LMP while NYISO calculates the PJM interface price (represented by the Keystone proxy bus) based on the assumption that 40 percent of the scheduled energy will flow across the PJM/NYISO border on the Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines.

The existing definition interface definition was created to reflect the impact of the ConEd wheeling arrangement. On April 28, 2016, Con Edison announced its intent to terminate the wheeling agreement effective May 1, 2017. The end of the wheeling agreement means that the expected actual power flows will change and therefore the definition of the interface price needs to change. Effective May 1, 2017, PJM will replace the old PJM/NYIS interface price definition. The new PJM/NYIS interface price will be based on four buses within NYISO. These buses were chosen based on the assumption that, in the absence of the wheeling arrangement, 68 percent of the scheduled energy will flow across the PJM/NYISO border on the Branchburg to Ramapo PAR controlled tie, and the remaining 32 percent will enter the NYISO on free flowing A/C tie lines.

Real-Time and Day-Ahead PJM/NYISO Interface Prices

In 2016, 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 56.3 percent of the hours in 2016. Table 9-26 shows the number of hours and average hourly price differences between the PJM/NYIS Interface and the NYIS/PJM proxy bus based on LMP differences and flow direction. Figure 9-5 shows the underlying hourly variability in prices. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-28).

35 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

Table 9-26 PJM and NYISO flow based hours and average hourly price differences: 2016[36]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	3,843	$10.58
	Consistent Flow (PJM to NYIS)	2,792	$10.67
	Inconsistent Flow (NYIS to PJM)	1,051	$10.35
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	4,941	$8.08
	Consistent Flow (NYIS to PJM)	2,157	$7.11
	Inconsistent Flow (PJM to NYIS)	2,784	$8.83
	No Flow	0	$0.00

Figure 9-5 Real-time and day-ahead daily hourly average price difference (NY/PJM proxy - PJM/NYIS Interface): 2016

Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In 2016, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 4,949 hours (56.3 percent of all hours), and was inconsistent with price differences in 3,835 hours (43.7 percent of all hours). Table 9-27 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 3,835 hours where flows where flows were in a direction inconsistent with price differences, 3,261 of those hours (85.0 percent) had a price difference greater than or equal to $1.00 and 1,727 of all those hours (45.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $984.25. Of the 4,949 hours where flows were consistent with price differences, 4,321 of those hours (87.3 percent) had a price difference greater than or equal to $1.00 and 2,372 of all such hours (47.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $977.45.

Table 9-27 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: 2016

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	3,835	100.0%	4,949	100.0%
$1.00	3,261	85.0%	4,321	87.3%
$5.00	1,727	45.0%	2,372	47.9%
$10.00	872	22.7%	1,027	20.8%
$15.00	521	13.6%	489	9.9%
$20.00	352	9.2%	337	6.8%
$25.00	279	7.3%	263	5.3%
$50.00	99	2.6%	97	2.0%
$75.00	43	1.1%	45	0.9%
$100.00	22	0.6%	29	0.6%
$200.00	6	0.2%	12	0.2%
$300.00	3	0.1%	9	0.2%
$400.00	2	0.1%	7	0.1%
$500.00	2	0.1%	5	0.1%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Table 9-28, including average prices and measures of variability.

36 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Table 9-28 PJM, NYISO and MISO real-time and day-ahead border price averages: 2016

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Hourly Price	PJM Price at ISO Border	$24.75	$25.61	$25.27	$25.75
	ISO Price at PJM Border	$24.84	$25.77	$25.44	$26.45
	Difference at Border (PJM-ISO)	($0.09)	($0.16)	($0.17)	($0.70)
	Average Absolute Value of Hourly Difference at Border	$9.17	$5.55	$3.29	$2.56
	Sign Changes per Day	6.2	7.1	3.3	3.6
Standard Deviation	PJM Price at ISO Border	$15.37	$13.64	$10.87	$8.91
	ISO Price at PJM Border	$31.50	$12.35	$11.15	$8.54
	Difference at Border (PJM-ISO)	$30.22	$12.59	$4.52	$3.53

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 62.2 percent of the hours in 2016. Table 9-29 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.

Table 9-29 PJM and NYISO flow based hours and average hourly price differences (Neptune): 2016

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	5,777	$15.15
	Consistent Flow (PJM to NYIS)	5,461	$15.28
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	316	$12.79
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	3,007	$9.17
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	2,939	$9.27
	No Flow	68	$4.63

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").[37] The PJM Out Service is covered by normal PJM OASIS business operations.[38] 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, 2016, the rate for the nonfirm service released by default was $10 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

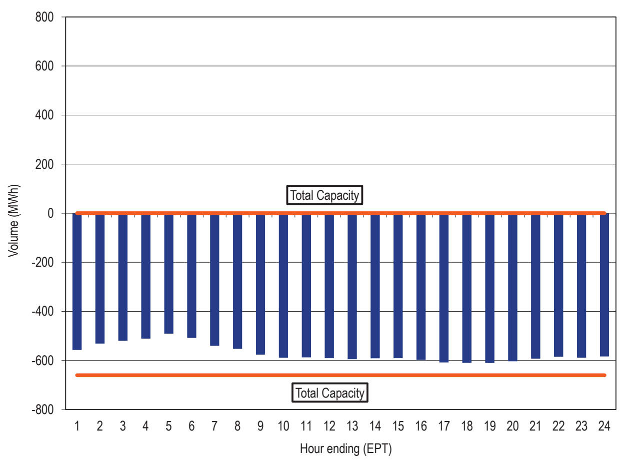
Table 9-30 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July, 2007. Table 9-30 shows that in 2016, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-6 shows the hourly average flow across the Neptune Line for 2016.

37 See OASIS "PJM Business Practices for Neptune Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/neptune-oasis-Business-practices-doc-clean.ashx>.
38 See OASIS "Regional Transmission and Energy Scheduling Practices," (March 31, 2016) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Table 9-30 Percent of scheduled interchange across the Neptune line by primary rights holder: July, 2007 through December, 2016

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
January	NA	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%
March	NA	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%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	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%
August	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%
October	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%
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 9-6 Neptune hourly average flow: 2016



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). The flows were consistent with price differentials in 60.5 percent of the hours in 2016. Table 9-31 shows the number of hours and average hourly price differences between the PJM/LIND Interface and the NYIS/Linden bus based on LMP differences and flow direction.

Table 9-31 PJM and NYISO flow based hours and average hourly price differences (Linden): 2016

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	5,410	$10.58
	Consistent Flow (PJM to NYIS)	5,313	$10.64
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	97	$7.46
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	3,374	$8.64
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	3,279	$8.77
	No Flow	95	$4.25

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").[39] The PJM Out Service is covered by normal PJM OASIS business operations.[40] 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.

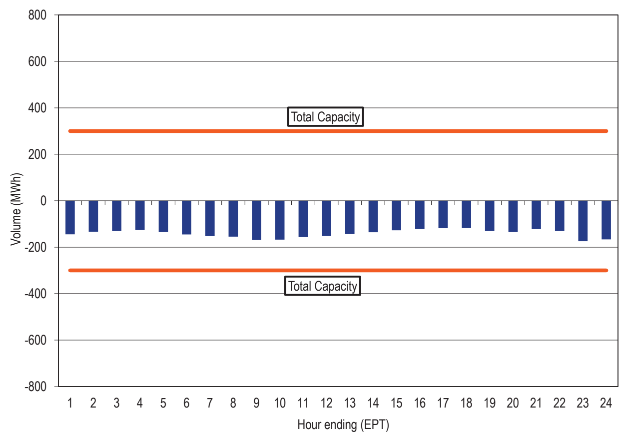
Linden VFT Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily 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, 2016, the rate for the nonfirm service released by default was $6 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-32 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November, 2009 through December, 2016

	2009	2010	2011	2012	2013	2014	2015	2016
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	94.95%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	96.46%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%	49.32%
May	NA	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%
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	100.00%	100.00%
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%	100.00%
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%	100.00%
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%	100.00%
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%

Table 9-32 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-32 shows that in 2016, the primary rights holder was responsible for the majority of the scheduled interchange across the Linden VFT Line. Figure 9-7 shows the hourly average flow across the Linden VFT Line for 2016.

Figure 9-7 Linden hourly average flow: 2016[41]



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 (ConEd) 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 have 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 11.2 percent

39 See OASIS "PJM Business Practices for Linden VFT Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/linden-vft-oasis-Business-practices-doc-clean.ashx>.

40 See OASIS "Regional Transmission and Energy Scheduling Practices," <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

41 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.

of the hours in 2016. Table 9-33 shows the number of hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-33 PJM and NYISO flow based hours and average hourly price differences (Hudson): 2016[42]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	5,408	$11.19
	Consistent Flow (PJM to NYIS)	981	$8.06
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	4,427	$11.88
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	3,376	$8.08
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	904	$7.53
	No Flow	2,471	$8.28

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").[43] The PJM Out Service is covered by normal PJM OASIS business operations.[44] 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.

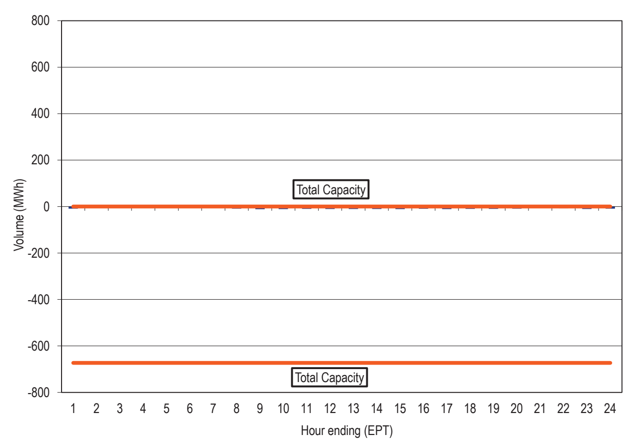
Hudson Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by scheduled on a NERC tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily 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, 2016, the rate for the nonfirm service released by default was $10 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-34 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-34 shows that in 2016, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Hudson Line in all months where scheduled interchange occurred. Figure 9-8 shows the hourly average flow across the Hudson Line for 2016.

Table 9-34 Percent of scheduled interchange across the Hudson Line by primary rights holder: May, 2013 through December, 2016

	2013	2014	2015	2016
January	NA	51.22%	16.27%	100.00%
February	NA	49.00%	14.67%	NA
March	NA	40.40%	71.88%	NA
April	NA	100.00%	100.00%	NA
May	100.00%	26.87%	100.00%	100.00%
June	100.00%	5.89%	59.72%	100.00%
July	100.00%	18.51%	84.34%	NA
August	100.00%	75.17%	65.48%	NA
September	100.00%	75.31%	78.73%	NA
October	100.00%	99.71%	18.65%	100.00%
November	85.57%	99.60%	24.67%	100.00%
December	28.32%	1.68%	100.00%	NA

Figure 9-8 Hudson hourly average flow: 2016



42 The Hudson line was out of service for all but 946 hours in 2016.

43 See OASIS "PJM Business Practices for Hudson Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-Business-practices.ashx>.

44 See OASIS "Regional Transmission and Energy Scheduling Practices," <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Interchange Activity During High Load Hours

The PJM metered system peak load during 2016 was 152,177 MW in the HE 1500 on August 11, 2016. PJM did not declare any emergency alerts, warnings or actions in that hour. PJM did not make any emergency energy purchases or sales in that hour. During the month of August, 2016, PJM was a net scheduled exporter of energy in 725 of the 744 hours (97.4 percent of all hours). During those 725 hours, the average hourly scheduled exports were 3,389 MW (representing 3.1 percent of the average hourly load of 106,359 MW in August, 2016). PJM was a net exporter of energy in all hours on August 11, 2016, with average hourly scheduled exports of 2,663 MW. As higher cost generation was called on to meet PJM demand during the peak, PJM's interface price LMPs increased. While PJM's interface prices increased, the interface prices of neighboring markets also increased. The net effect of the increased LMPs between market areas was the continued incentive to buy out of the PJM Energy Market and sell into the neighboring balancing authorities, as the PJM interface LMPs remained lower than its neighbors interface LMPs. There was a reduction in exports during hours ending 1300, 1400 and 1500 in response to price signals particularly at the PJM/MISO interface. During those hours, PJM's PJM/MISO interface price was lower than MISO's MISO/PJM interface price, and the average hourly net exports reduced from 2,077 MW in the three hours prior to approximately 940 MW over the peak.

Operating Agreements with Bordering Areas

To improve reliability and reduce potential seams issues, PJM and its neighbors have developed operating agreements. These agreements include operating agreements with MISO and the NYISO, a reliability agreement with TVA, an operating agreement with Duke Energy Progress, Inc., a reliability coordination agreement with VACAR South, a balancing authority operations agreement with the Wisconsin Electric Power Company (WEC) and a Northeastern planning coordination protocol with NYISO and ISO New England.

Table 9-35 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-35 Summary of elements included in operating agreements with bordering areas

Agreement:	PJM-MISO	PJM-NYISO	PJM-TVA	PJM-DEP	PJM-VACAR	PJM-WEP	Northeastern Protocol
Data Exhange							
Real-Time Data	YES	YES	YES	YES	YES	YES	NO
Projected Data	YES	YES	YES	YES	NO	NO	NO
SCADA Data	YES	YES	YES	YES	NO	NO	NO
EMS Models	YES	YES	YES	YES	NO	NO	YES
Operations Planning Data	YES	YES	YES	YES	NO	NO	YES
Available Flowgate Capability Data	YES	YES	YES	YES	NO	NO	YES
Near-Term System Coordination							
Operating Limit Violation Assistance	YES	YES	YES	YES	YES	NO	NO
Over/Under Voltage Assistance	YES	YES	YES	YES	YES	NO	NO
Emergency Energy Assistance	YES	YES	NO	YES	YES	NO	NO
Outage Coordination	YES	YES	YES	YES	YES	NO	NO
Long-Term System Coordination	YES	YES	YES	YES	NO	NO	YES
Congestion Management Process							
ATC Coordination	YES	YES	YES	YES	NO	NO	NO
Market Flow Calculations	YES	YES	YES	NO	NO	NO	NO
Firm Flow Entitlements	YES	YES	YES	NO	NO	NO	NO
Market to Market Redispatch	YES - Redispatch	YES - Redispatch	NO	YES - Dynamic Schedule	NO	NO	NO
Joint Checkout Procedures	YES	YES	YES	YES	NO	YES	NO

PJM-MISO = MISO/PJM Joint Operating Agreement

PJM-NYISO = New York ISO/PJM Joint Operating Agreement

PJM-TVA = Joint Reliablity Coordination Agreement Between PJM - Tennessee Valley Authority (TVA)

PJM-DEP = Duke Energy Progress (DEP) - PJM Joint Operating Agreement

PJM-VACAR = PJM-VACAR South Reliability Coordination Agreement

PJM-WEP = Balancing Authority Operations Coordination Agreement Between Wisconsin Electric Power Company and PJM Interconnection, LLC

Northeastern Protocol = Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol

PJM and MISO Joint Operating Agreement[45]

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.[46]

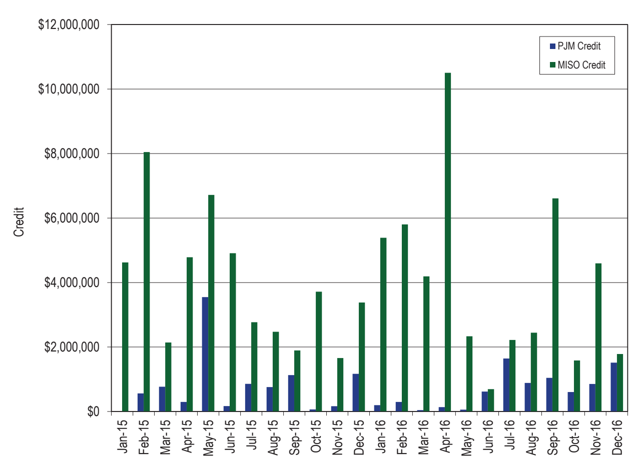
Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses 10 buses along the PJM/MISO border to calculate the PJM/MISO interface pricing point LMP while MISO uses all of the PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.[47] MISO is currently planning to modify their MISO/PJM interface definition to match PJM's PJM/MISO interface definition on June 1, 2017.[48]

Coordinated flowgates (CF) are flowgates that are monitored and/or controlled by PJM or MISO, on which only one has a significant impact (defined as a greater than five percent impact based on transmission distribution factors and/or generation to load distribution factors). 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, 2016, PJM had 130 flowgates eligible for M2M (Market to Market) coordination. In 2016, PJM added 53 flowgates and deleted 33 flowgates, leaving 150 flowgates eligible for M2M coordination as of December 31, 2016. As of January 1, 2016, MISO had 207 flowgates eligible for M2M coordination. In 2016, MISO added 227 flowgates and deleted 166 flowgates, leaving 268 flowgates eligible for M2M coordination as of December 31, 2016.

The firm flow entitlement (FFE) represents the amount of historic 2004 flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the nonmonitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the nonmonitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the nonmonitoring RTO's market flow and their FFE. In 2016, market to market operations resulted in MISO and PJM redispatching units to control congestion on M2M flowgates and in the exchange of payments for this redispatch. Figure 9-9 shows credits for coordinated congestion management between PJM and MISO.

Figure 9-9 Credits for coordinated congestion management: 2015 and 2016[49]



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/media/documents/merged-tariffs/miso-joa.pdf>.

46 See "PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common.aspx>.

47 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

48 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>.

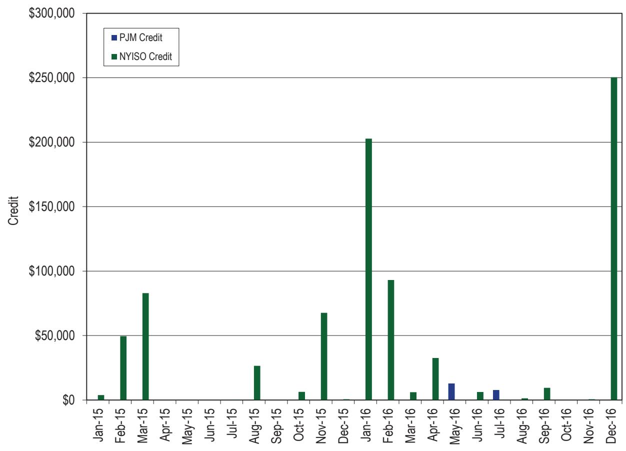
49 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)[50]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders.

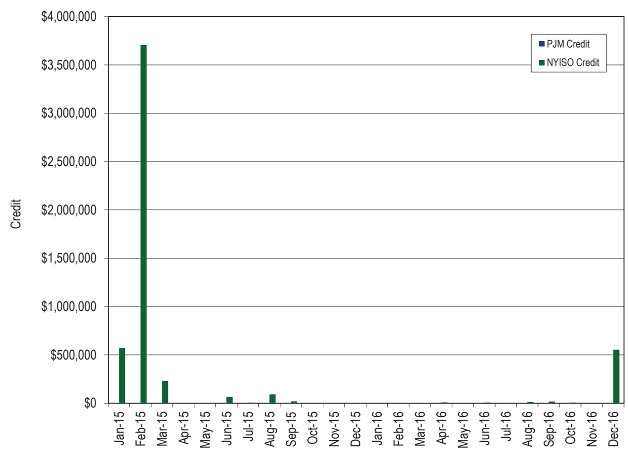
In 2016, market to market operations resulted in NYISO and PJM redispatching units to control congestion on M2M flowgates and in the exchange of payments for this redispatch. Figure 9-10 shows credits for coordinated congestion management between PJM and NYISO.

Figure 9-10 Credits for coordinated congestion management (flowgates): 2015 and 2016[51]



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 Ramapo 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.[52] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during coordinated operations. The Ramapo PAR settlements are determined based on whether the measured real-time flow on each of the Ramapo 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. In 2016, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 9-11 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

Figure 9-11 Credits for coordinated congestion management (Ramapo PARs): 2015 and 2016[53]



PJM and TVA Joint Reliability Coordination Agreement (JRCA)[54]

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

50 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (May 26, 2016) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

51 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

52 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (May 26, 2016) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

53 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

54 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>.

and TVA honor constraints on the other's flowgates in their Available Transmission Capability (ATC) calculations. Additionally, 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 2016.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[55]

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[56] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. At that time, Progress Energy Carolinas Inc., now a subsidiary of Duke, changed its name to Duke Energy Progress (DEP).

The PJM/DEP JOA states that the Marginal Cost Proxy Method (MCPM) will be used in the determination of the CPLEIMP and CPLEEXP interface price. Section 2.6A (2) of the PJM Tariff describes the process of calculating the interface price under the MCPM. Under the MCPM, PJM compares the individual bus LMP (as calculated by PJM) for each DEP generator in the PJM model with a telemetered output greater than zero MW to the marginal cost for that generator.

For the CPLEIMP price (imports to PJM), PJM uses the lowest LMP of any generator bus in the DEP balancing authority area, with an output greater than zero MW that has an LMP less than its marginal cost for each five minute interval. If no generator with an output greater than zero MW has an LMP less than its marginal cost, then the import price is the average of the bus LMPs for the set of generators in the DEP area with an output greater than zero MW that PJM determines to be the marginal units in the DEP area for that five minute interval. PJM determines the marginal units in the DEP area by summing the output of the units serving load in the DEP area in ascending order by the units' marginal costs until the sum equals the real time load in the DEP area. Units in the DEP area with marginal costs at or above that of the last unit included in the sum are the marginal units for the DEP area for that interval.

PJM calculates the CPLEEXP price for exports from PJM to DEP as the highest LMP of any generator bus in the DEP area with an output greater than zero MW (excluding nuclear and hydro units) that has an LMP greater than its marginal cost in the 5 minute interval.[57] If no generator with an output greater than zero MW has an LMP greater than its marginal cost, then the export price will be the average of the bus LMPs for the set of generators with an output greater than zero MW that PJM determines to the be marginal units in the same manner as described for the CPLEIMP interface price. The hourly integrated import and export prices are the average of all of the 5 minute intervals in each hour.

The MCPM calculation is based on the DEP units modeled in the PJM market that have an output greater than zero, and only uses the units whose output exceeds the reported DEP real-time load. When new units are added to the DEP footprint, and existing units in the DEP footprint retire, PJM does not have complete data to calculate the interface price. These new units can impact the interface price in several ways. By not having the additional units modeled, these units cannot be considered to be marginal units, and therefore cannot set price. For the import price, if the PJM calculated LMP of one of the new units were to be lower than any currently modeled unit, then PJM's CPLEIMP pricing point would be lower, and PJM would pay less for imports. If the PJM calculated LMP of one of the new units were to be higher than any currently modeled unit,

55 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc.," (December 3, 2014) <http://www.pjm.com/media/documents/merged-tariffs/progress-joa.pdf>.

56 See *PJM Interconnection, L.L.C and Progress Energy Carolinas*, Inc. Docket No. ER10-713-000 (February 2, 2010).

57 The MMU has objected to the omission of nuclear and hydro units from the calculation. This omission is not included in the definition of the MCPM interface pricing method in the PJM Tariff, but is included as a special condition in the PJM/DEP JOA. The MMU does not believe it is appropriate to exclude these units from the calculation as these units could be considered marginal and impact the prices.

then PJM's CPLEEXP pricing point would be higher, and PJM would receive more for exports.

Not maintaining a current set of units in the DEP footprint in PJM's network model limits PJM's ability to recognize which units are marginal and it is often not possible to calculate the CPLEIMP and CPLEEXP interface prices using the MCPM. By not maintaining a complete set of units in the DEP footprint, the reported output of the modeled units are often insufficient to cover the reported real time load, and therefore no units are considered marginal. When this occurs, the MMU believes that the CPLEIMP and CPLEEXP pricing points should revert to the SOUTHIMP and SOUTHEXP interface prices, but this has not happened. When this occurs, PJM uses the high-low interface pricing method as described in Section 2.6A (1) of the PJM Tariff. The MMU does not believe that this is appropriate, and does not see the basis for this approach in either the PJM Tariff or the PJM/DEP JOA.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies planned to operate separately for a period of time, they have a joint dispatch agreement, and a joint open access transmission tariff.[58] On October 3, 2014, Duke Energy Progress (DEP) and PJM submitted revisions to the JOA to include a new Appendix B, update references to DEP's current legal name, and incorporate other revisions.[59] The MMU submitted a protest to this filing noting that the existing JOA depends on the specific characteristics of PEC as a standalone company, and the assumptions reflected in the current JOA no longer apply under the DEP joint dispatch agreement.[60] As noted in the 2010 filing, "the terms and conditions of the bilateral agreement among PEC and PJM are grounded in an appreciation of their systems as they exist at the time of the effective date of the JOA, but they fully expect that evolving circumstances, protocols and requirements will require that they negotiate, in good faith, a response to such changes."[61] The joint dispatch agreement changed the unique operational relationship that existed when the congestion management protocol was established. However, the merged company has not engaged in discussions with PJM as to whether the congestion management protocol that was "tailored to their [PJM and PEC] unique operational relationship" is still appropriate, or whether the congestion management protocol needs to be revised. The existing JOA does not apply to the merged company and should be terminated.

Article 14 of the JOA provides details of the PJM/DEP congestion management agreement (CMA). The purpose of the CMA is to allow "DEP to quickly respond to the LMP values sent by PJM to DEP. This quick response will help manage the congestion on the PJM transmission system by maintaining flows within established limits and stabilizing PJM LMP values, and will help reduce the need to use the TLR process to relieve the congestion by maintaining power flows within established reliability limits." Congestion is managed by using a dynamic schedule between CPLE and PJM. DEP responds to the dynamic pricing signal sent by PJM by increasing generation, which creates energy flow in the direction from CPLE to PJM or by decreasing generation, which creates energy flow in the direction from PJM to CPLE. The dynamic schedule calls for more DEP generation when the DEP marginal cost of online generation is less than the CPLE LMP, and it calls for less DEP generation when the DEP marginal cost exceeds the CPLE LMP. The economic energy flow on the dynamic schedule reduces congestion.

The amount of congestion relief is limited by the amount of energy that can flow on the dynamic schedule. Several factors determine this limit, including: the physical limitations of DEP's units; ATC limits on the transmission path between CPLE and PJM; the actual confirmed transmission acquired in advance by DEP. Section 14.4.1 of the JOA states that:

> The transmission service used on the DEP transmission system to support the process described in this Article will be a non-firm point to point reservation from DEP to PJM made by DEP. The Dynamic Schedule will be limited to the point to point reservation. The transmission service used on the PJM transmission system will be network secondary service.

58 See "Duke Energy Carolinas, LLC, Carolina Power & Light tariff filing," Docket No. ER12-1338-000 (July 12, 2012) and "Duke Energy Carolinas, LLC, Carolina Power & Light Joint Dispatch Agreement filing," Docket No. ER12-1343-000 (July 11, 2012).

59 See *Duke Energy Progress, Inc. and PJM Interconnection, L.L.C*, Docket No. ER15-29-000 (October 3, 2014).

60 See Protest and Motion for Rehearing of the Independent Market Monitor for PJM in Docket No. ER15-29-000 (October 24, 2014).

61 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.C.C. and Progress Energy Carolinas, Inc., Docket No. ER10-713-000 (March 10, 2010) at 2. Section 3.3 of the PJM-Progress JOA.

In 2016, DEP acquired the required transmission service in only 974 of the 8,874 hours (11.1 percent of all hours), with an average capacity of approximately 150 MW. At most, DEP could have increased their generation to help manage constraints via a sale of power to PJM 11.1 percent of the time in 2016, and the maximum redispatch would have been only 150 MW, on average.

A CMA that can only be used in 11.1 percent of all hours is not an effective approach to congestion management. The MMU recommends that PJM immediately provide the required 12-month notice to DEP to unilaterally terminate the Joint Operating Agreement.

PJM and VACAR South Reliability Coordination Agreement[62]

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement which provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement remained in effect in 2016.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[63]

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 2016.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[64]

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 2016.

Interface Pricing Agreements with Individual Balancing Authorities

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.

The PJM/DEP JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the Marginal Cost Proxy Pricing method.[65] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the high-low pricing method as defined in Section 2.6A (1) of the PJM Tariff.

Table 9-36 shows the real-time LMP calculated per the PJM/PEC JOA and the high/low pricing method used by Duke and NCMPA for 2016. The values shown in Table 9-36 are the average LMP over all hours in 2016, regardless of whether interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from -$0.27 with Duke to $0.03 with NCMPA.[66] This means that under the specific interface pricing agreements, NCMPA would receive, on average, $0.03 more for importing energy into PJM than if they were to receive the SouthIMP pricing point. But Duke would receive, on average, $0.27 less for importing energy into PJM than if they were to receive the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from $0.10 with NCMPA to $0.74 with PEC. This means that under the specific interface pricing agreements, PEC

62 See "PJM-VACAR South RC Agreement," (November 7, 2014) <http://www.pjm.com/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>.

63 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, LLC," (July 20, 2013) <http://www.pjm.com/~/media/documents/agreements/balancing-authority-operations-coordination-agreement.ashx>.

64 See "Northeastern ISO/RTO Planning Coordination Protocol," (December 8, 2004) <http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>.

65 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).

66 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

would pay, on average, $0.74 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point.

Table 9-36 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: 2016

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$26.84	$27.39	$27.11	$27.11	($0.27)	$0.28
PEC	$26.94	$27.85	$27.11	$27.11	($0.17)	$0.74
NCMPA	$27.14	$27.21	$27.11	$27.11	$0.03	$0.10

Table 9-37 shows the day-ahead LMP calculated per the PJM/PEC JOA and the high/low pricing method used by Duke and NCMPA for 2016. The values shown in Table 9-37 are the average LMP over all hours in 2016, regardless of whether interchange transactions settled at those pricing points or not. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from -$0.09 with PEC to $0.30 with NCMPA. This means that under the specific interface pricing agreements, NCMPA would receive, on average, $0.30 more for importing energy into PJM than if they were to receive the SouthIMP pricing point. But PEC would receive, on average, $0.09 less for importing energy into PJM than if they were to receive the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from $0.38 with NCMPA to $0.82 with PEC. This means that under the specific interface pricing agreements, PEC would pay, on average, $0.82 more for exporting energy from PJM than if they were to pay the SouthEXP pricing point.

Table 9-37 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: 2016

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$27.73	$28.06	$27.61	$27.60	$0.12	$0.46
PEC	$27.52	$28.43	$27.61	$27.60	($0.09)	$0.82
NCMPA	$27.91	$27.98	$27.61	$27.60	$0.30	$0.38

It is not clear that agreements between PJM and neighboring external entities, in which those entities receive some of the benefits of the PJM LMP market without either integrating into an LMP market or applying LMP internally, are in the best interest of PJM's market participants. In the case of the DEP JOA for example, the merger between Progress and Duke has resulted in a single, combined entity where one part of that entity (Duke Energy Progress) is engaged in congestion management with PJM while the other part of the entity (Duke) is not.

Other Agreements with Bordering Areas

Consolidated Edison Company of New York, Inc. (Con Edison) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New Jersey on lines controlled by PJM.[67] This wheeled power creates loop flow across the PJM system. The Con Edison contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001.[68]

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[69] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special protocol indefinitely.[70] The Commission approved transmission service agreements that provide for Con Edison to take firm point-to-point service going forward under the PJM OATT. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU, that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[71] The settlement defined Con Edison's cost responsibility for upgrades included in the PJM Regional Transmission Expansion Plan. Con Edison is responsible for required transmission enhancements, and must pay the associated charges during the term of its service, and any subsequent

67 See the *2016 Quarterly State of the Market Report for PJM: January through September*, Section 4 – "Energy Market Uplift" for the operating reserve credits paid to maintain the power flow established in the Con Edison wheeling contracts.

68 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

69 See FERC Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

70 132 FERC ¶ 61,221 (2010).

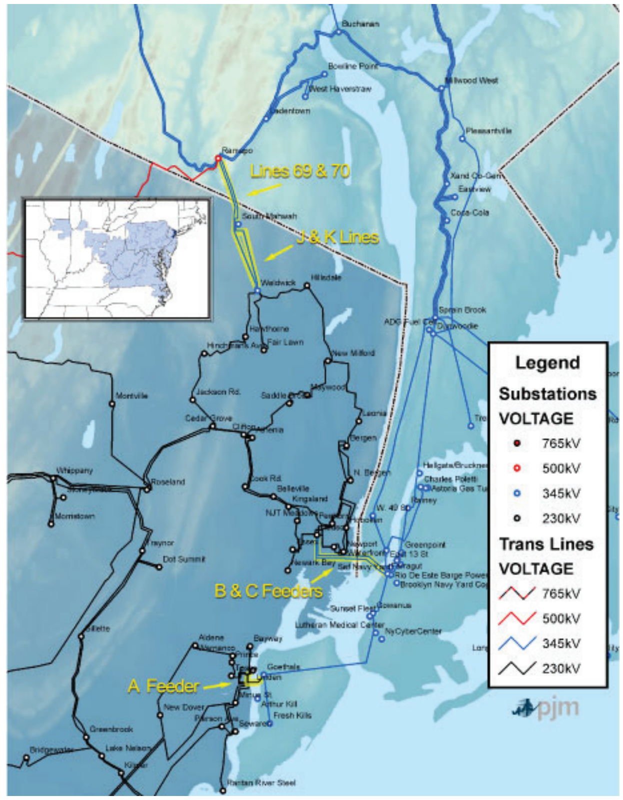
71 *See, e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010).

roll over of the service.[72] Con Edison's rolled over service became effective on May 1, 2012. At that time, Con Edison became responsible for the entire 1,000 MW of transmission service and all associated charges and credits.

The Con Edison protocol models a fixed MW level flowing from NYISO to PJM over the JK (Ramapo - Waldwick) interface, and from PJM to NYISO over the ABC (Hudson - Farragut and Linden - Goethals) interface (See Figure 9-12).

On April 28, 2016, Con Edison announced its intent to terminate its 1,000 MW long-term firm point-to-point transmission service, effective May 1, 2017. Upon termination of the transmission reservation, the Con Edison protocol would also be terminated. On October 4, 2016, the NYISO and PJM issued a draft white paper to begin discussions for developing alternative designs for using the ABC and JK interfaces upon expiration of the Con Edison protocol effective May, 1, 2017.[73] The draft white paper proposal includes modifications to the existing PJM-NY AC Proxy Bus definition to include the JK and ABC lines and the inclusion of the JK and ABC lines in the market-to-market PAR coordination process. The proposal also includes provisions for determining the target flows over the JK and ABC interfaces. The proposed target flows will be based on a static interchange percentage and will continue to include a percentage of the Rockland Electric Company (RECO) load. Additionally, the PJM and NYISO proposal also includes an operational base flow (OBF) of 400 MW from NYISO to PJM over the JK Interface and 400 MW from PJM to NYISO over the ABC Interface.

Figure 9-12 Con Edison Protocol



Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

The number of PJM issued TLRs of level 3a or higher decreased from 22 in 2015 to nine in 2016.[74] The number of different flowgates for which PJM declared a TLR 3a or higher decreased from nine in 2015 to one in 2016. The total MWh of transactions curtailed increased by 70.9 percent from 62,778 MWh in 2015 to 107,291 MWh in 2016.

72 The terms of the settlement state that Con Edison shall have no liability for transmission enhancement charges prior to the commencement of, or after the termination of, the term of the rolled over service.

73 See *"Con Ed/PSEG Wheel Replacement Proposal,"* (December 19, 2016) which can be accessed at: <http://www.pjm.com/~/media/library/reports-notices/special-reports/20161004-coned-pseg-wheel-replacement-proposal.ashx>.

74 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2015 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

The number of MISO issued TLRs of level 3a or higher decreased from 90 in 2015 to 77 in 2016. The number of different flowgates for which MISO declared a TLR 3a or higher decreased from 24 in 2015 to 22 in 2016. The total MWh of transaction curtailments increased by 9.3 percent from 116,938 MWh in 2015 to 127,785 MWh in 2016.

The number of NYISO issued TLRs of level 3a or higher decreased from four in 2015 to one in 2016. The number of different flowgates for which NYISO declared a TLR 3a or higher were one in 2015, and one in 2016. The total MWh of transaction curtailments decreased by 92.8 percent from 3,027 MWh in 2015 to 217 MWh in 2016.

Table 9-38 PJM MISO, and NYISO TLR procedures: 2013 through 2016

	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-13	4	42	2	3	17	1	13,453	103,463	1,045
Feb-13	4	26	0	3	10	0	14,609	66,086	0
Mar-13	0	39	0	0	13	0	0	53,122	0
Apr-13	1	45	0	1	20	0	84	64,938	0
May-13	10	29	0	7	14	0	879	20,778	0
Jun-13	4	25	1	1	11	1	5,036	76,240	4,102
Jul-13	12	28	0	2	9	0	88,623	80,328	0
Aug-13	4	19	0	4	8	0	3,469	38,608	0
Sep-13	6	33	0	5	14	0	7,716	90,188	0
Oct-13	2	42	0	1	20	0	534	72,121	0
Nov-13	2	27	0	2	8	0	11,561	52,508	0
Dec-13	0	16	0	0	5	0	0	20,257	0
Jan-14	3	19	0	3	10	0	1,852	11,683	0
Feb-14	0	29	1	0	10	1	0	33,189	991
Mar-14	0	11	0	0	7	0	0	14,842	0
Apr-14	0	6	0	0	3	0	0	1,233	0
May-14	0	9	0	0	4	0	0	53,153	0
Jun-14	0	19	0	0	7	0	0	24,614	0
Jul-14	1	13	1	1	6	1	317	26,616	0
Aug-14	0	7	0	0	3	0	0	6,319	0
Sep-14	1	11	0	1	4	0	935	87,296	0
Oct-14	1	5	0	1	5	0	1,386	20,581	0
Nov-14	0	10	0	0	6	0	0	23,736	0
Dec-14	2	2	0	2	2	0	1,792	1,264	0
Jan-15	2	8	1	1	4	1	7,293	626	2,261
Feb-15	6	11	2	2	6	1	37,222	9,173	331
Mar-15	8	0	1	3	0	1	14,704	0	435
Apr-15	2	6	0	2	3	0	1,033	23,518	0
May-15	1	8	0	1	2	0	961	12,048	0
Jun-15	1	20	0	1	4	0	205	42,063	0
Jul-15	2	10	0	2	4	0	1,360	9,796	0
Aug-15	0	9	0	0	3	0	0	7,041	0
Sep-15	0	6	0	0	4	0	0	5,789	0
Oct-15	0	4	0	0	4	0	0	4,212	0
Nov-15	0	2	0	0	2	0	0	1,797	0
Dec-15	0	4	0	0	1	0	0	875	0
Jan-16	6	0	0	1	0	0	83,752	0	0
Feb-16	2	0	0	1	0	0	23,096	0	0
Mar-16	0	5	0	0	3	0	0	6,556	0
Apr-16	0	6	0	0	2	0	0	2,034	0
May-16	0	6	0	0	4	0	0	5,360	0
Jun-16	0	5	1	0	2	1	0	18,121	217
Jul-16	0	18	0	0	8	0	0	38,815	0
Aug-16	0	16	0	0	3	0	0	30,181	0
Sep-16	0	8	0	0	4	0	0	19,394	0
Oct-16	0	3	0	0	2	0	0	1,702	0
Nov-16	0	9	0	0	3	0	0	5,622	0
Dec-16	1	1	0	1	1	0	443	0	0

Table 9-39 Number of TLRs by TLR level by reliability coordinator: 2016[75]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2016	MISO	33	21	0	8	15	0	77
	NYIS	1	0	0	0	0	0	1
	ONT	10	0	0	0	0	0	10
	PJM	4	3	0	1	1	0	9
	SOCO	0	1	0	0	0	0	1
	SWPP	54	23	0	45	22	0	144
	TVA	41	65	0	4	18	0	128
	VACS	1	1	0	0	0	0	2
Total		144	114	0	58	56	0	372

Up to Congestion

The original purpose of up to congestion transactions (UTC) was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Energy Market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the Real-Time Energy Market.[76]

Following the elimination of the requirement to procure and pay for transmission for up to congestion transactions effective September 17, 2010, the volume of transactions increased dramatically.

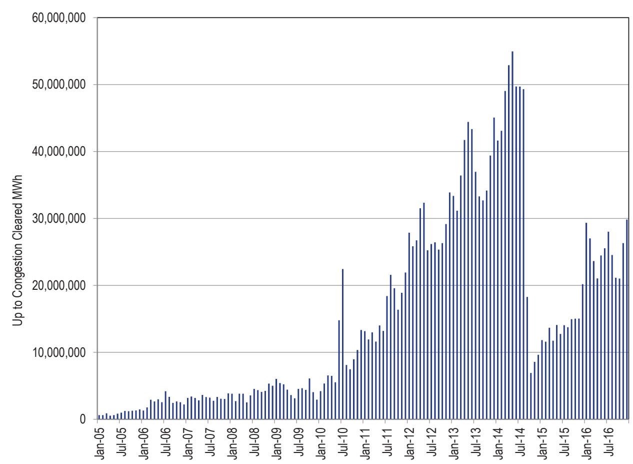
Up to congestion transactions impact the day-ahead dispatch and unit commitment. Despite that, up to congestion transactions do not pay operating reserves charges. Up to congestion transactions also negatively affect FTR funding.[77]

On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[78]

As a result of the requirement to pay uplift charges and the uncertainty about the level of the required uplift charges, market participants reduced up to congestion trading effective September 8, 2014. There was an increase in up to congestion volume starting in December 2015, coincident with the expiration of the fifteen month limit on the payment of prior uplift charges (Figure 9-13). Section 206(b) of the Federal Power Act states that "…the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date…"[79]

The average number of up to congestion bids submitted in the Day-Ahead Energy Market increased by 80.0 percent, from 86,656 bids per day in 2015 to 156,021 bids per day in 2016. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 78.5 percent, from 462,118 MWh per day in 2015, to 824,885 MWh per day in 2016.

Figure 9-13 Monthly up to congestion cleared bids in MWh: 2005 through 2016



75 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.

76 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

77 See the *2016 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.

78 148 FERC ¶ 61,144 (2014) *Order Instituting Section 206 Proceeding and Establishing Procedures.*

79 16 U.S.C. § 824e.

Table 9-40 Monthly volume of cleared and submitted up to congestion bids: 2015 and 2016[80]

	Bid MW					Bid Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-15	5,546,341	2,401,938	184,935	26,556,180	34,689,394	198,934	97,676	9,072	1,280,378	1,586,060
Feb-15	5,375,057	2,198,495	235,687	30,708,158	38,517,397	199,947	97,499	8,555	1,504,921	1,810,922
Mar-15	6,104,575	3,878,773	590,547	43,668,068	54,241,963	219,079	120,017	18,573	1,806,387	2,164,056
Apr-15	7,172,015	3,787,440	656,913	41,264,789	52,881,157	268,196	112,440	19,215	1,568,301	1,968,152
May-15	9,104,665	4,738,308	866,026	45,821,190	60,530,188	352,787	142,643	29,817	1,870,020	2,395,267
Jun-15	7,686,270	3,678,135	717,311	46,563,639	58,645,356	273,749	107,444	18,962	1,918,405	2,318,560
Jul-15	8,797,317	3,600,463	703,906	52,774,024	65,875,710	317,439	121,991	22,398	2,143,611	2,605,439
Aug-15	9,354,801	4,090,172	916,209	61,589,135	75,950,316	328,224	141,549	31,332	2,691,409	3,192,514
Sep-15	9,741,094	4,098,270	737,792	63,708,128	78,285,283	349,715	129,051	28,325	3,027,147	3,534,238
Oct-15	8,508,535	5,028,169	708,089	60,656,099	74,900,892	340,586	154,204	31,377	2,997,443	3,523,610
Nov-15	7,042,648	4,898,979	854,557	49,740,632	62,536,817	287,080	154,016	32,505	2,454,927	2,928,528
Dec-15	7,718,227	5,068,244	700,702	60,230,661	73,717,834	348,160	181,451	36,546	3,035,860	3,602,017
Jan-16	11,319,511	7,453,438	1,014,763	80,909,489	100,697,200	477,343	219,598	39,513	3,737,937	4,474,391
Feb-16	12,155,175	7,740,113	1,363,163	85,132,591	106,391,042	422,382	228,823	42,609	3,306,154	3,999,968
Mar-16	11,714,639	7,934,801	1,415,976	88,260,658	109,326,075	382,177	225,473	36,332	3,131,152	3,775,134
Apr-16	9,823,079	6,559,076	1,305,759	74,723,429	92,411,342	397,591	189,981	29,138	3,760,097	4,376,807
May-16	9,513,613	6,823,576	1,095,593	71,945,618	89,378,399	404,406	207,483	32,187	3,824,204	4,468,280
Jun-16	10,535,566	7,229,295	934,909	90,318,486	109,018,256	393,040	205,237	34,318	3,980,024	4,612,619
Jul-16	11,954,606	10,034,200	1,573,690	111,637,376	135,199,873	432,142	273,349	36,430	4,583,276	5,325,197
Aug-16	11,435,407	7,826,884	1,203,704	89,117,338	109,583,333	396,134	258,077	33,330	4,352,104	5,039,645
Sep-16	8,865,500	7,188,474	793,894	76,390,509	93,238,378	286,637	236,555	29,616	3,813,679	4,366,487
Oct-16	7,621,317	6,486,553	725,041	75,471,554	90,304,464	292,479	268,611	35,720	4,237,454	4,834,264
Nov-16	9,347,175	7,739,170	1,092,482	83,836,320	102,015,146	361,868	273,254	32,322	4,613,501	5,280,945
Dec-16	9,648,240	7,976,967	856,973	91,141,019	109,623,199	446,573	295,302	29,569	5,778,358	6,549,802
TOTAL	1,343,027,316	1,266,276,494	85,265,273	4,105,750,738	6,800,319,822	34,979,592	29,299,971	2,255,096	157,863,266	224,397,925

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-15	2,047,961	414,985	83,498	9,285,631	11,832,075	85,916	23,956	3,520	486,044	599,436
Feb-15	1,569,220	485,647	48,134	9,492,364	11,595,365	66,858	27,559	2,228	502,766	599,411
Mar-15	1,463,247	769,655	105,300	11,338,070	13,676,272	69,309	36,927	6,028	615,310	727,574
Apr-15	1,669,627	643,703	128,394	9,294,533	11,736,258	79,809	26,693	5,148	472,254	583,904
May-15	2,510,355	873,849	174,280	10,524,318	14,082,802	114,601	34,456	6,437	544,781	700,275
Jun-15	1,490,960	779,517	171,815	10,311,431	12,753,722	68,977	27,114	4,044	544,756	644,891
Jul-15	1,669,277	619,731	130,423	11,629,796	14,049,226	74,525	25,144	3,979	604,939	708,587
Aug-15	1,253,587	817,265	149,825	11,536,005	13,756,682	63,587	30,965	7,162	735,877	837,591
Sep-15	1,500,472	932,971	137,868	12,389,538	14,960,850	87,789	34,368	8,008	914,610	1,044,775
Oct-15	1,396,515	1,046,675	118,879	12,454,398	15,016,467	89,960	42,045	7,036	971,644	1,110,685
Nov-15	1,378,299	1,011,236	87,438	12,556,360	15,033,334	82,884	38,897	6,684	928,551	1,057,016
Dec-15	1,612,284	1,453,772	117,749	16,996,215	20,180,020	112,519	55,720	8,200	1,261,471	1,437,910
Jan-16	2,944,505	2,026,327	274,430	24,103,637	29,348,899	170,082	69,173	10,390	1,577,269	1,826,914
Feb-16	2,719,184	2,001,418	244,646	22,049,244	27,014,492	126,889	67,289	9,850	1,251,383	1,455,411
Mar-16	2,370,270	2,001,360	198,400	19,061,805	23,631,834	105,098	65,977	8,070	1,085,479	1,264,624
Apr-16	2,348,160	1,264,954	204,465	17,214,976	21,032,555	140,346	48,085	7,067	1,740,662	1,936,160
May-16	2,209,309	1,882,586	235,696	20,137,089	24,464,680	156,256	64,333	6,665	1,987,586	2,214,840
Jun-16	2,178,050	1,871,788	153,654	21,334,532	25,538,023	128,728	62,438	6,906	1,621,997	1,820,069
Jul-16	2,335,606	2,109,811	237,917	23,341,287	28,024,621	120,775	79,269	7,902	1,587,513	1,795,459
Aug-16	1,914,794	2,139,929	183,616	20,303,066	24,541,404	91,351	85,598	7,902	1,522,203	1,707,054
Sep-16	1,706,788	1,572,221	150,834	17,714,998	21,144,842	76,662	74,123	8,808	1,502,828	1,662,421
Oct-16	1,387,294	1,065,855	133,639	18,431,481	21,018,269	84,852	78,316	10,892	1,768,967	1,943,027
Nov-16	2,772,101	1,323,987	292,429	21,932,490	26,321,007	142,207	69,987	8,539	1,889,760	2,110,493
Dec-16	2,904,123	1,857,750	182,373	24,882,966	29,827,212	163,420	96,565	6,814	2,375,795	2,642,594
TOTAL	448,039,823	425,507,083	27,984,144	1,153,107,399	2,054,638,449	13,321,535	11,149,940	774,979	58,252,555	83,499,009

80 See the *2016 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for the monthly volume of cleared and submitted up to congestion bids: 2009 through 2016.

In 2016, the cleared MW volume of up to congestion transactions was comprised of 9.2 percent imports, 7.0 percent exports, 0.8 percent wheeling transactions and 83.0 percent internal transactions. Less than 0.1 percent of the up to congestion transactions had matching real-time energy market transactions.

Up to Congestion Credit Risk

On August 29, 2014, FERC issued an order which created an obligation for up to congestion transactions (UTCs) to pay any uplift determined to be appropriate after Commission review, effective from September 8, 2014.[81] As of March 1, 2017, the Commission has not ruled on whether up to congestion transactions will be charged for uplift accrued during this time. On January 19, 2017, a notice of proposed rulemaking was issued to address UTC uplift for all RTOs/ISOs.[82] The outcome of the investigation in PJM will be held in abeyance pending the outcome of the NOPR proceeding.[83]

During the 15 month refund period of September 8, 2014, through December 7, 2015, 185,303,891 MWh of up to congestion transactions cleared the Day-Ahead Market and are subject to potential uplift charges for that period. Based on the volume of cleared up to congestion transactions and the potential uplift obligation on a per MWh basis, the obligation to pay is estimated to be between $18.5 million and $370.6 million. As potential obligations, this exposure creates a credit risk for those UTC traders who engaged in UTC transactions during this period. Table 9-41 shows the levels of credit risk associated with the cleared up to congestion transactions, depending on the uplift charge that may be imposed on these transactions.

81 148 FERC ¶ 61,144 (2014) *Order Instituting Section 206 Proceeding and Establishing Procedures.*

82 *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 158 FERC ¶ 61,047.

83 158 FERC ¶ 61,038 at P 3 (January 19, 2017).

Table 9-41 Credit risk associated with varying levels of potential uplift: September 8, 2014 through December 7, 2015

Uplift ($/MWh)	Credit risk if uplift is applied to both sides of UTC
$0.05	$18,530,389
$0.10	$37,060,778
$0.15	$55,591,167
$0.20	$74,121,556
$0.25	$92,651,945
$0.30	$111,182,334
$0.35	$129,712,724
$0.40	$148,243,113
$0.45	$166,773,502
$0.50	$185,303,891
$0.55	$203,834,280
$0.60	$222,364,669
$0.65	$240,895,058
$0.70	$259,425,447
$0.75	$277,955,836
$0.80	$296,486,225
$0.85	$315,016,614
$0.90	$333,547,003
$0.95	$352,077,393
$1.00	$370,607,782

PJM market participants that cleared UTCs during the specified refund period of September 8, 2014 through December 7, 2015, would be responsible to pay uplift based on their cleared up to congestion volume and the uplift charge if FERC orders that UTCs pay such uplift charges. Analysis of the cleared up to congestion transactions during the refund period of September 8, 2014, through December 7, 2015, showed that the top 10 market participants would be responsible for 53.7 percent of the uplift.

The credit risk exposure to companies that traded UTCs during this period is substantial, including the possible bankruptcy of one or more companies if FERC orders that UTCs pay such uplift charges. The actual risk depends in significant part on how the companies have managed their potential exposure as they continued to trade UTCs with knowledge of the risks. These companies do not appear to have informed PJM of how or if they have managed this exposure.

The total uplift amount has already been paid by other PJM members. Thus, the risk to other PJM members has been realized. The risk that UTC traders will not be able to cover their credit exposure otherwise related to their trading activity is addressed by existing PJM credit policies. If a UTC trader went into bankruptcy as a result of the uplift risk, the exposure to other PJM members is that they will not be repaid the level of uplift that should have been paid by UTC transactions.

Absent further Commission action, the increase in UTC uplift payment risk appears to have ended as a result of the expiration of the fifteen month limit on the payment of prior uplift charges.[84]

Attachment Q: PJM Credit Policy of the PJM Open Access Transmission Tariff provides that:

> Each Participant is also required to provide with its application information as to any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.[85]

The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions during the refund period of September 8, 2014, through December 7, 2015. To the full extent of its authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. PJM should also calculate the UTC uplift charge contingency in a manner appropriate for the evaluation of any contingency. By definition, assessing a contingency requires a reasonable exercise of discretion. PJM should develop a reasonable assessment of the risk associated with the UTC uplift allocation and the appropriate approach to managing this risk. Zero risk is not within a reasonable range. The MMU recognizes that the exact amount of the exposure is not known. If PJM does not have the authority to take such steps, PJM should request guidance from FERC.

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 can also be achieved by submitting a transaction that is in the opposite direction of a portion of a larger transaction schedule. 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).

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.

84 16 U.S.C. § 824e.
85 See OATT Attachment Q § I.A.4.

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling.

Elimination of Ontario Interface Pricing Point

The PJM/IMO interface pricing point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO interface pricing points. PJM created the PJM/IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

Prior to June 1, 2015, the PJM/IMO interface pricing point was defined as the LMP at the IESO Bruce bus. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The noncontiguous nature of the PJM/IMO interface pricing point creates opportunities for market participants to engage in sham scheduling activities. For example, a market participant can use two separate transactions to create a flow from Ontario to MISO. In this example, the market participant uses the PJM energy market as a temporary generation and load point by first submitting a wheeling transaction from Ontario, through MISO and into PJM, then by submitting a second transaction from PJM to MISO. These two transactions, combined, create an actual flow along the Ontario/MISO Interface. Through sham scheduling, the market participant receives settlements from PJM when no changes in generation occur. This activity is similar to that observed when PJM had a Southwest and Southeast interface pricing point. During that time, market participants would use the PJM spot market as a temporary load and generation point to wheel transactions through the PJM energy market. This was done to take advantage of the price differences between the interfaces without providing the market benefits of congestion relief.

A new PJM/IMO interface price method was implemented on June 1, 2015. The new method uses a dynamic weighting of the PJM/MISO interface price and the PJM/NYIS interface price, based on the performance of the Michigan-Ontario PARs. When the absolute value of the actual flows on the PARs are greater than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be equal to the PJM/MISO interface price (i.e. 100 percent weighting on the PJM/MISO interface). When actual flows on the PARs are in the opposite direction of the scheduled flows on the PARs, the PJM/IMO interface price will be equal to the PJM/NYIS interface price (i.e. 100 percent weighting on the PJM/NYIS interface). When the absolute value of the actual flows on the PARs are less than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be a combination to the PJM/MISO interface price and the PJM/NYIS interface price. In this case the weightings of the PJM/MISO and PJM/NYIS interface prices are determined based on the scheduled and actual flows. For example, in a given interval, the scheduled flow on the Michigan-Ontario PARs is 1,000 MW, and the actual flow is 800 MW. If in that same interval, the PJM/MISO interface price is $45.00 and the PJM/NYIS interface price $30.00, the PJM/IMO interface price would be calculated with a weighting of 80 percent of the PJM/MISO interface price ($45.00 * 0.8, or $36.00) and 20 percent of the PJM/NYIS interface price ($30.00 * 0.2, or $6.00), for a PJM/IMO interface price of $42.00.[86]

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

86 See "IMO Interface Definition Methodology Report," presented to the MIC (February 11, 2015) <http://www.pjm.com/~/media/committees-groups/committees/mic/20150211/20150211-item-08b-imo-interface-definition-methodology-report.ashx>.

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 2016, of the 2,538 GWh of the gross scheduled transactions between PJM and IESO, 2,525 GWh (99.5 percent) wheeled through MISO (see Table 9-23). The MMU recommends that PJM eliminate the PJM/IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the PJM/MISO interface pricing point.[87]

PJM and NYISO Coordinated Interchange Transactions

Coordinated transaction scheduling (CTS) provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated.[88] The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price ITSCED results with the NYISO. The NYISO compares the PJM/NYISO interface price with its RTC calculated NYISO/PJM interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

The ITSCED application runs approximately every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for 2016. Table 9-42 shows that over all 12 forecast ranges, ITSCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 41.1 percent of the intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.63 per MWh. In 5.1 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $53.05 when the price difference was greater than $20.00, and $60.06 when the price difference was greater than -$20.00.

Table 9-42 Differences between forecast and actual PJM/NYIS interface prices: 2016

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	1.8%	$53.05
$10 to $20	3.7%	$13.61
$5 to $10	7.0%	$7.02
$0 to $5	41.1%	$1.63
$0 to -$5	36.1%	$1.53
-$5 to -$10	4.5%	$6.94
-$10 to -$20	2.5%	$13.89
< -$20	3.3%	$60.06

Table 9-43 shows how the accuracy of the ITSCED forecasted LMPs changes as the cases approach real-time. In the final ITSCED results prior to real time, in 77.6 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 75.7 percent in the 135 minute ahead ITSCED results.

87 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

88 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

Table 9-43 Differences between forecast and actual PJM/NYIS interface prices: 2016

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	1.5%	$48.24	1.3%	$47.42	1.4%	$50.02	2.8%	$57.05
$10 to $20	4.0%	$13.63	3.2%	$13.66	3.1%	$13.36	4.1%	$13.69
$5 to $10	7.0%	$7.02	7.2%	$6.96	6.4%	$7.01	7.0%	$7.07
$0 to $5	37.8%	$1.77	41.2%	$1.67	43.8%	$1.55	43.7%	$1.55
$0 to -$5	37.9%	$1.68	36.3%	$1.57	35.8%	$1.44	33.9%	$1.36
-$5 to -$10	5.3%	$6.93	4.8%	$6.95	3.9%	$6.95	3.8%	$6.95
-$10 to -$20	2.9%	$13.76	2.7%	$13.85	2.4%	$14.00	2.1%	$14.04
< -$20	3.7%	$61.92	3.3%	$58.36	3.2%	$58.19	2.7%	$60.25

In 5.5 percent of the intervals in the thirty-minute ahead forecast, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price difference was $57.05 when the price difference was greater than $20.00, and $60.25 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 ITSCED forecast ability during periods of cold and hot weather. For example, Table 9-44 shows that in January, 2016, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP in the thirty-minute ahead forecast, was greater than $20.00 in 6.8 percent of the intervals, compared to 3.4 percent of the intervals in May, 2016.

Table 9-44 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): 2016

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
	> $20	3.8%	2.1%	1.5%	3.6%	1.0%	1.9%	3.3%	4.5%	3.7%	3.2%	2.5%	2.8%	2.8%
	$10 to $20	4.7%	2.2%	1.9%	3.0%	1.6%	3.0%	6.7%	7.3%	6.0%	6.5%	2.3%	3.5%	4.1%
	$5 to $10	5.7%	3.4%	6.4%	6.8%	4.9%	5.6%	9.9%	9.3%	7.6%	12.1%	6.1%	5.4%	7.0%
~ 30 Minutes Prior to Real-Time	$0 to $5	42.2%	43.8%	47.5%	43.8%	50.7%	48.5%	39.5%	39.4%	39.8%	38.7%	46.5%	43.6%	43.7%
	$0 to -$5	32.9%	38.9%	35.2%	33.5%	34.8%	33.3%	31.8%	29.3%	33.3%	30.5%	36.7%	36.6%	33.9%
	-$5 to -$10	5.0%	5.1%	4.0%	3.9%	2.8%	2.8%	3.0%	3.2%	4.0%	5.2%	3.2%	3.8%	3.8%
	-$10 to -$20	2.7%	2.5%	1.4%	2.0%	1.7%	1.9%	2.1%	2.5%	2.6%	2.3%	1.5%	1.6%	2.1%
	< -$20	3.0%	2.1%	2.1%	3.5%	2.4%	3.0%	3.6%	4.5%	3.1%	1.5%	1.2%	2.8%	2.7%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
	> $20	2.8%	1.3%	0.7%	1.5%	0.4%	0.5%	2.3%	2.1%	2.4%	1.3%	0.4%	1.3%	1.4%
	$10 to $20	3.4%	1.8%	1.1%	1.8%	1.6%	2.2%	5.5%	6.0%	4.7%	5.3%	1.9%	2.0%	3.1%
	$5 to $10	5.3%	3.4%	4.9%	6.0%	3.8%	5.8%	10.1%	10.3%	7.0%	10.6%	5.1%	4.2%	6.4%
~ 45 Minutes Prior to Real-Time	$0 to $5	40.2%	41.9%	49.0%	43.4%	51.0%	50.6%	40.9%	38.8%	40.7%	39.4%	46.9%	42.4%	43.8%
	$0 to -$5	36.2%	41.7%	36.9%	37.1%	36.0%	32.1%	31.8%	31.3%	34.1%	33.1%	39.2%	40.4%	35.8%
	-$5 to -$10	4.6%	4.6%	3.6%	3.8%	2.9%	3.1%	3.3%	3.5%	4.8%	5.6%	3.4%	4.2%	3.9%
	-$10 to -$20	3.9%	2.7%	1.8%	2.4%	1.7%	2.1%	2.2%	2.3%	2.7%	2.9%	1.7%	2.4%	2.4%
	< -$20	3.6%	2.7%	2.0%	4.0%	2.6%	3.5%	3.9%	5.7%	3.6%	1.8%	1.4%	3.2%	3.2%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
	> $20	2.5%	1.1%	0.4%	1.0%	0.6%	0.2%	3.0%	1.9%	1.9%	1.6%	0.4%	1.2%	1.3%
	$10 to $20	3.1%	1.2%	0.8%	1.9%	1.9%	3.0%	6.7%	5.2%	5.1%	5.1%	1.7%	2.7%	3.2%
	$5 to $10	4.8%	3.7%	6.2%	5.9%	4.8%	7.7%	10.7%	11.3%	7.8%	12.2%	6.2%	5.0%	7.2%
~ 90 Minutes Prior to Real-Time	$0 to $5	35.6%	38.0%	44.3%	40.5%	49.5%	49.9%	39.2%	37.5%	37.2%	41.0%	46.1%	35.6%	41.2%
	$0 to -$5	39.0%	44.4%	39.6%	38.4%	35.7%	30.7%	31.5%	31.6%	36.0%	27.8%	37.4%	44.3%	36.3%
	-$5 to -$10	6.8%	5.8%	4.6%	5.0%	3.5%	2.7%	3.0%	4.3%	5.1%	7.1%	4.5%	5.3%	4.8%
	-$10 to -$20	4.2%	2.9%	1.7%	3.0%	1.6%	2.3%	2.5%	2.6%	2.9%	3.3%	2.2%	2.7%	2.7%
	< -$20	4.0%	3.0%	2.3%	4.2%	2.4%	3.5%	3.5%	5.7%	4.1%	1.9%	1.4%	3.1%	3.3%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
	> $20	2.6%	1.4%	0.9%	2.2%	0.6%	0.2%	4.6%	1.3%	1.8%	0.4%	0.2%	1.5%	1.5%
	$10 to $20	4.5%	2.7%	1.9%	4.8%	2.2%	2.6%	8.1%	6.4%	5.3%	4.7%	1.7%	2.7%	4.0%
	$5 to $10	6.4%	5.0%	7.8%	7.5%	5.8%	6.7%	8.6%	11.2%	7.8%	8.1%	4.7%	3.8%	7.0%
~ 135 Minutes Prior to Real-Time	$0 to $5	39.1%	41.4%	50.4%	41.7%	47.5%	33.2%	30.8%	33.7%	33.9%	31.8%	38.8%	31.1%	37.8%
	$0 to -$5	32.8%	39.1%	31.4%	33.1%	35.6%	44.5%	37.2%	34.4%	37.2%	38.3%	44.5%	47.3%	37.9%
	-$5 to -$10	6.3%	4.6%	3.7%	4.4%	3.6%	3.7%	3.7%	4.4%	6.3%	10.7%	5.9%	6.1%	5.3%
	-$10 to -$20	4.4%	2.8%	1.6%	2.4%	2.0%	3.3%	2.5%	2.9%	3.4%	3.8%	2.5%	3.6%	2.9%
	< -$20	4.0%	3.1%	2.3%	4.0%	2.7%	5.8%	4.6%	5.7%	4.2%	2.3%	1.6%	3.9%	3.7%

Table 9-45 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): 2016

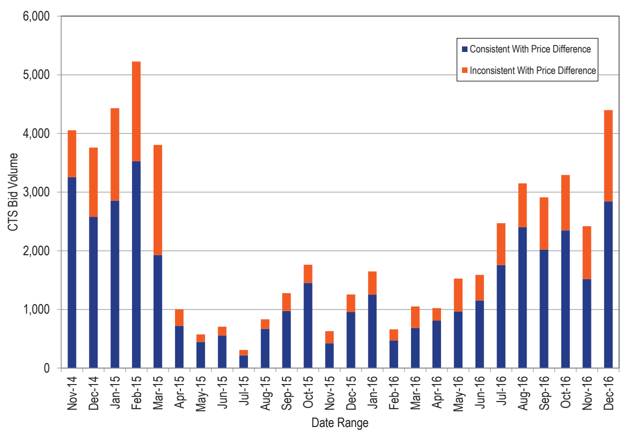
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$68.70	$44.33	$60.00	$63.63	$50.72	$52.49	$52.71	$55.31	$63.93	$50.27	$47.34	$61.05	$57.05
	$10 to $20	$14.17	$13.44	$13.88	$13.35	$12.62	$13.26	$13.58	$13.71	$14.14	$13.54	$13.71	$13.88	$13.69
	$5 to $10	$7.03	$6.73	$6.72	$7.00	$6.84	$7.08	$7.38	$7.28	$7.09	$7.19	$7.00	$6.89	$7.07
	$0 to $5	$1.39	$1.40	$1.68	$1.68	$1.58	$1.51	$1.51	$1.65	$1.52	$1.78	$1.54	$1.41	$1.55
	$0 to -$5	$1.35	$1.43	$1.48	$1.34	$1.43	$1.24	$1.31	$1.34	$1.34	$1.56	$1.24	$1.23	$1.36
	-$5 to -$10	$7.28	$6.84	$6.90	$7.02	$6.84	$7.02	$6.91	$6.93	$7.20	$6.82	$6.71	$6.82	$6.95
	-$10 to -$20	$14.09	$13.89	$13.76	$13.45	$13.03	$13.89	$14.60	$14.82	$14.61	$13.75	$13.02	$14.86	$14.04
	< -$20	$57.70	$53.28	$82.66	$61.94	$65.90	$50.41	$58.93	$63.19	$48.63	$39.37	$43.29	$82.18	$60.25
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	$60.63	$40.00	$53.12	$49.96	$38.61	$29.25	$45.58	$50.57	$62.65	$27.21	$38.63	$56.48	$50.02
	$10 to $20	$14.09	$13.48	$12.87	$13.30	$12.60	$11.98	$13.27	$13.22	$13.79	$13.84	$13.06	$13.05	$13.36
	$5 to $10	$7.01	$6.95	$6.74	$6.87	$6.62	$7.09	$7.32	$7.19	$7.00	$6.88	$6.82	$7.20	$7.01
	$0 to $5	$1.49	$1.44	$1.61	$1.64	$1.57	$1.52	$1.53	$1.64	$1.56	$1.79	$1.49	$1.40	$1.55
	$0 to -$5	$1.50	$1.47	$1.59	$1.41	$1.45	$1.25	$1.34	$1.38	$1.42	$1.63	$1.39	$1.37	$1.44
	-$5 to -$10	$7.00	$6.81	$6.70	$7.27	$6.92	$6.94	$7.04	$7.02	$7.08	$6.85	$6.97	$6.80	$6.95
	-$10 to -$20	$14.19	$14.74	$13.74	$13.73	$13.26	$13.97	$14.12	$13.92	$14.25	$13.78	$14.19	$13.70	$14.00
	< -$20	$59.29	$55.49	$54.85	$62.44	$61.91	$50.67	$54.08	$59.75	$51.37	$43.84	$46.93	$83.80	$58.19
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	$53.97	$47.24	$55.93	$50.95	$40.31	$28.37	$43.68	$37.60	$67.65	$27.22	$33.36	$61.43	$47.42
	$10 to $20	$13.91	$14.36	$13.48	$13.36	$12.28	$13.24	$13.82	$13.45	$14.22	$13.66	$13.75	$13.75	$13.66
	$5 to $10	$7.06	$7.06	$6.79	$6.81	$6.52	$6.94	$7.15	$7.14	$7.12	$6.90	$6.89	$6.88	$6.96
	$0 to $5	$1.60	$1.54	$1.70	$1.71	$1.73	$1.74	$1.59	$1.73	$1.69	$1.87	$1.63	$1.40	$1.67
	$0 to -$5	$1.67	$1.67	$1.68	$1.56	$1.59	$1.37	$1.43	$1.51	$1.61	$1.75	$1.45	$1.52	$1.57
	-$5 to -$10	$7.10	$6.80	$6.77	$7.07	$7.12	$6.97	$6.89	$7.02	$7.00	$6.83	$6.84	$7.01	$6.95
	-$10 to -$20	$13.86	$14.05	$13.49	$14.07	$13.15	$13.72	$14.19	$14.19	$13.78	$13.52	$13.70	$14.13	$13.85
	< -$20	$57.60	$57.18	$51.97	$61.85	$58.53	$49.54	$58.66	$65.98	$49.38	$43.58	$46.82	$80.83	$58.36
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	$52.85	$48.09	$50.44	$43.40	$43.26	$27.17	$40.64	$32.75	$70.15	$21.90	$25.40	$70.98	$48.24
	$10 to $20	$14.00	$14.07	$12.88	$14.00	$13.03	$12.37	$13.67	$13.17	$13.78	$13.81	$13.68	$14.47	$13.63
	$5 to $10	$6.85	$7.19	$6.72	$6.96	$6.69	$7.09	$7.25	$7.33	$7.17	$7.05	$6.72	$6.86	$7.02
	$0 to $5	$1.72	$1.70	$1.93	$1.84	$1.88	$1.64	$1.71	$1.78	$1.79	$1.91	$1.65	$1.52	$1.77
	$0 to -$5	$1.81	$1.74	$1.66	$1.60	$1.60	$1.59	$1.51	$1.60	$1.77	$1.89	$1.61	$1.76	$1.68
	-$5 to -$10	$6.88	$6.80	$6.69	$7.04	$7.05	$7.08	$7.05	$7.03	$6.97	$7.06	$6.70	$6.83	$6.93
	-$10 to -$20	$13.97	$14.03	$13.91	$13.92	$13.05	$13.09	$14.09	$14.17	$13.35	$13.60	$13.87	$14.03	$13.76
	< -$20	$60.01	$65.73	$50.65	$60.59	$61.55	$60.48	$70.08	$72.90	$52.00	$41.15	$46.11	$74.35	$61.92

The NYISO uses PJM's ITSCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO approves CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the ITSCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences between forecast and actual LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve charges are applied and CTS transactions are optional, the CTS proposal represents a small incremental step toward better interface pricing. The 75 minute time lag associated with scheduling energy transactions in the NYISO should be shortened. Reducing this time lag could significantly improve pricing efficiency at the PJM/NYISO border for non-CTS transactions and for CTS transactions.

CTS transactions were evaluated for each 15 minute interval. From November 4, 2014, through December 31, 2016, 55,764 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 16,984 (30.5 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 30.5 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 69.5 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, 2014 through December, 2016



The data reviewed show that ITSCED is not a highly accurate predictor of the real-time PJM/NYIS interface prices. If this remains true, it will limit the effectiveness of CTS in improving interface pricing between PJM and NYISO.

Reserving Ramp on the PJM/NYISO Interface

Prior to the implementation of CTS, PJM held ramp space for all transactions submitted between PJM and the NYISO as soon as the NERC Tag was approved. At that time, once transactions were evaluated by the NYISO through their real-time market clearing process, any adjustments made to the submitted transactions would be reflected on the NERC Tags and the PJM ramp was adjusted accordingly.

As part of this process, PJM was often required to make adjustments to transactions on its other interfaces in order to bring total system ramp back to within its limit. The default ramp limit in PJM is +/- 1,000 MW. For example, the ramp in a given interval is currently -1,000 MW, consisting of 2,000 MW of imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. If, through the NYISO real-time market clearing process, the NYISO only approves 1,000 MW of the imports, the other 1,000 MW of import transactions from the NYISO would be curtailed. The ramp in this interval would then be -2,000 MW, consisting of the 1,000 MW of cleared imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. PJM would then be required to curtail an additional 1,000 MW of exports at its other interface to bring the limit back to within +/- 1,000. These curtailments were made on a last in first out basis as determined by the timestamp on the NERC Tag.

With the implementation of the CTS product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, does PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process would violate ramp, PJM would make additional adjustments based on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO interface from holding (or creating) ramp until NYISO has completed its economic evaluation and the transactions are approved through the NYISO market clearing process.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO have proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market Initiative. While the mechanics of transaction evaluation have yet to be determined, the coordinated transaction scheduling (CTS) proposal would provide 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 would be based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED). Unlike the PJM/NYISO CTS process in which the NYISO performs the evaluation, the PJM/MISO CTS process will use a joint clearing process in which both RTOs will share forward looking prices. MISO does not currently have an application comparable to PJM's ITSCED to provide forward-looking prices but is developing a tool.

To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for 2016. Table 9-46 shows that over all 12 forecast ranges, ITSCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 42.2 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.56. In 4.7 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $53.05 when the price difference was greater than $20.00, and $64.90 when the price difference was greater than -$20.00.

Table 9-46 Differences between forecast and actual PJM/MISO interface prices: 2016

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	1.5%	$53.05
$10 to $20	3.9%	$13.48
$5 to $10	7.3%	$7.06
$0 to $5	42.2%	$1.56
$0 to -$5	35.4%	$1.42
-$5 to -$10	4.1%	$6.98
-$10 to -$20	2.3%	$13.85
< -$20	3.2%	$64.90

Table 9-47 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time. In the final ITSCED results prior to real time, in 77.4 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 75.8 percent in the 135 minute ahead ITSCED results.

Table 9-47 Differences between forecast and actual PJM/MISO interface prices: 2016

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	1.2%	$37.90	1.0%	$41.68	1.0%	$45.97	2.6%	$56.55
$10 to $20	4.5%	$13.60	3.5%	$13.35	3.2%	$13.25	4.3%	$13.56
$5 to $10	7.5%	$7.10	7.2%	$7.00	6.7%	$7.02	7.4%	$7.07
$0 to $5	37.7%	$1.67	43.8%	$1.58	45.4%	$1.50	44.6%	$1.51
$0 to -$5	38.1%	$1.54	35.0%	$1.41	34.4%	$1.31	32.8%	$1.31
-$5 to -$10	4.7%	$6.95	3.9%	$6.98	3.9%	$7.00	3.5%	$6.97
-$10 to -$20	2.6%	$13.81	2.4%	$14.03	2.3%	$13.81	2.0%	$13.81
< -$20	3.7%	$64.17	3.2%	$64.91	3.2%	$65.90	2.8%	$64.77

In 5.4 percent of the intervals in the thirty-minute ahead forecast, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price differences were $56.55 when the price difference was greater than $20.00, and $64.77 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 ITSCED forecast ability during periods of cold and hot weather. For example, Table 9-48 shows that in January, 2016, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP in the thirty-minute ahead forecast, was greater than $20.00 in 3.4 percent of the intervals, compared to 3.0 percent of the intervals in May, 2016.

Table 9-48 Monthly Differences between forecast and actual PJM/MISO interface prices (percent of intervals): 2016

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	1.3%	1.0%	0.8%	3.9%	0.8%	2.5%	2.6%	5.3%	3.8%	3.6%	2.8%	2.3%	2.6%
	$10 to $20	3.8%	1.5%	1.9%	4.0%	1.6%	3.4%	6.9%	7.0%	6.3%	8.5%	2.3%	4.3%	4.3%
	$5 to $10	5.9%	5.1%	6.2%	9.0%	5.3%	6.7%	10.2%	9.5%	7.1%	12.4%	4.9%	5.9%	7.4%
	$0 to $5	49.5%	49.5%	50.1%	41.0%	49.0%	45.9%	39.8%	39.9%	40.0%	39.0%	49.3%	42.7%	44.6%
	$0 to -$5	32.5%	37.2%	33.3%	29.9%	35.9%	31.7%	32.1%	28.6%	32.4%	28.0%	34.8%	37.2%	32.8%
	-$5 to -$10	3.1%	3.2%	4.6%	4.7%	3.7%	3.1%	3.2%	3.2%	3.2%	4.0%	3.0%	3.5%	3.5%
	-$10 to -$20	1.8%	1.3%	1.6%	3.1%	1.4%	2.6%	1.9%	1.8%	2.7%	2.2%	1.5%	2.3%	2.0%
	< -$20	2.1%	1.3%	1.5%	4.5%	2.2%	4.0%	3.3%	4.8%	4.5%	2.4%	1.4%	1.8%	2.8%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	0.4%	0.2%	0.0%	1.3%	0.2%	1.1%	1.1%	2.8%	1.8%	1.0%	0.8%	0.7%	1.0%
	$10 to $20	2.1%	0.9%	1.2%	3.1%	1.2%	2.1%	5.1%	4.9%	4.9%	8.0%	0.9%	3.3%	3.2%
	$5 to $10	5.0%	3.4%	5.4%	7.4%	4.6%	6.1%	11.0%	11.6%	6.1%	10.3%	4.2%	4.7%	6.7%
	$0 to $5	48.8%	49.6%	50.5%	41.9%	49.4%	49.3%	42.6%	39.8%	40.9%	40.5%	50.2%	41.6%	45.4%
	$0 to -$5	35.4%	39.3%	34.5%	32.5%	37.3%	30.2%	31.7%	29.9%	34.8%	30.3%	37.1%	40.4%	34.4%
	-$5 to -$10	3.4%	3.6%	5.3%	5.8%	3.5%	3.4%	2.8%	3.3%	3.7%	4.4%	3.6%	4.4%	3.9%
	-$10 to -$20	2.4%	1.5%	1.7%	3.3%	1.4%	3.2%	2.3%	2.0%	2.7%	2.6%	1.4%	2.8%	2.3%
	< -$20	2.5%	1.5%	1.5%	4.7%	2.2%	4.6%	3.5%	5.7%	5.1%	2.9%	1.7%	2.1%	3.2%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	0.4%	0.4%	0.0%	1.1%	0.3%	1.1%	1.9%	2.4%	1.9%	1.3%	0.7%	1.1%	1.0%
	$10 to $20	2.1%	0.6%	1.2%	3.3%	1.4%	3.1%	6.4%	4.9%	4.4%	8.4%	1.7%	4.1%	3.5%
	$5 to $10	4.0%	3.8%	6.3%	8.1%	5.2%	6.9%	11.6%	11.9%	7.7%	10.9%	4.9%	4.3%	7.2%
	$0 to $5	44.9%	47.3%	46.7%	38.5%	51.1%	50.8%	40.9%	39.1%	38.7%	41.3%	49.9%	36.7%	43.8%
	$0 to -$5	39.9%	40.8%	36.8%	34.9%	34.8%	27.3%	31.6%	30.8%	35.3%	28.4%	36.1%	43.4%	35.0%
	-$5 to -$10	3.6%	4.1%	5.4%	4.9%	3.5%	3.2%	2.5%	3.1%	4.0%	4.5%	3.4%	5.2%	3.9%
	-$10 to -$20	2.4%	1.5%	2.1%	4.1%	1.5%	3.2%	1.7%	2.0%	2.7%	2.5%	1.5%	3.2%	2.4%
	< -$20	2.7%	1.4%	1.5%	5.1%	2.0%	4.6%	3.5%	5.6%	5.1%	2.8%	1.8%	2.1%	3.2%
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	1.2%	0.5%	0.9%	3.7%	0.3%	0.5%	2.4%	1.7%	1.8%	0.6%	0.3%	0.8%	1.2%
	$10 to $20	3.7%	2.1%	3.4%	8.1%	2.5%	2.4%	9.3%	6.2%	5.5%	4.8%	1.5%	3.9%	4.5%
	$5 to $10	6.2%	6.3%	11.6%	11.6%	7.0%	5.4%	9.0%	11.1%	6.4%	7.5%	4.3%	3.8%	7.5%
	$0 to $5	47.6%	51.5%	50.9%	39.8%	47.0%	30.7%	31.9%	31.3%	28.2%	25.8%	40.5%	28.1%	37.7%
	$0 to -$5	33.6%	33.0%	26.4%	26.2%	35.2%	45.2%	36.7%	37.0%	43.8%	44.3%	45.7%	49.6%	38.1%
	-$5 to -$10	3.2%	3.8%	4.2%	4.0%	4.0%	4.3%	4.1%	3.6%	5.2%	8.7%	4.2%	6.5%	4.7%
	-$10 to -$20	1.7%	1.3%	1.2%	2.0%	1.6%	4.5%	2.3%	2.4%	3.5%	4.9%	1.7%	4.5%	2.6%
	< -$20	2.8%	1.5%	1.3%	4.7%	2.4%	7.1%	4.5%	6.7%	5.7%	3.4%	1.9%	2.7%	3.7%

Table 9-49 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): 2016

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
	> $20	$85.38	$37.24	$65.07	$72.07	$45.00	$46.76	$52.95	$47.64	$64.22	$56.53	$53.16	$49.76	$56.55
	$10 to $20	$14.45	$12.98	$14.05	$14.18	$12.57	$13.22	$13.25	$13.08	$13.72	$13.70	$13.68	$13.56	$13.56
	$5 to $10	$6.87	$6.97	$6.91	$6.87	$7.01	$6.99	$7.16	$7.34	$7.27	$7.23	$6.70	$7.07	$7.07
~ 30 Minutes Prior to Real-Time	$0 to $5	$1.39	$1.47	$1.75	$1.88	$1.54	$1.38	$1.53	$1.49	$1.41	$1.58	$1.42	$1.27	$1.51
	$0 to -$5	$1.30	$1.42	$1.53	$1.58	$1.47	$1.15	$1.27	$1.19	$1.21	$1.31	$1.18	$1.15	$1.31
	-$5 to -$10	$6.99	$6.74	$6.98	$7.08	$6.67	$7.23	$6.79	$7.06	$7.00	$7.06	$7.13	$6.91	$6.97
	-$10 to -$20	$13.76	$14.26	$13.58	$13.62	$12.95	$13.78	$13.47	$14.12	$13.93	$13.57	$14.42	$14.39	$13.81
	< -$20	$57.03	$63.48	$72.35	$74.53	$58.63	$60.22	$64.50	$65.04	$61.15	$66.91	$63.07	$69.65	$64.77
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
	> $20	$98.60	$28.62	$30.01	$37.14	$27.39	$31.78	$44.48	$40.89	$67.39	$43.20	$41.94	$43.14	$45.97
	$10 to $20	$13.74	$12.76	$12.35	$13.52	$12.53	$12.76	$12.85	$13.41	$13.55	$13.37	$12.77	$13.52	$13.25
	$5 to $10	$6.96	$6.64	$6.58	$6.88	$6.89	$6.92	$7.21	$7.17	$7.32	$7.09	$6.78	$7.25	$7.02
~ 45 Minutes Prior to Real-Time	$0 to $5	$1.36	$1.47	$1.69	$1.76	$1.54	$1.41	$1.52	$1.57	$1.51	$1.58	$1.36	$1.23	$1.50
	$0 to -$5	$1.24	$1.39	$1.51	$1.59	$1.44	$1.16	$1.27	$1.18	$1.21	$1.37	$1.16	$1.24	$1.31
	-$5 to -$10	$7.15	$6.98	$6.86	$7.12	$6.81	$7.02	$6.97	$7.11	$6.88	$7.13	$7.00	$6.96	$7.00
	-$10 to -$20	$14.27	$13.89	$13.38	$13.43	$13.35	$13.94	$13.19	$14.57	$14.28	$13.59	$14.34	$13.62	$13.81
	< -$20	$56.70	$62.62	$74.91	$78.32	$60.75	$59.65	$62.11	$68.60	$62.91	$67.08	$63.23	$71.09	$65.90
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
	> $20	$39.11	$25.93	$20.37	$28.70	$29.10	$34.12	$44.33	$40.30	$65.48	$40.22	$40.73	$32.33	$41.68
	$10 to $20	$13.35	$13.35	$13.10	$13.61	$12.35	$12.97	$13.15	$13.32	$13.38	$13.27	$13.29	$14.38	$13.35
	$5 to $10	$6.89	$6.60	$6.38	$6.80	$6.85	$6.85	$7.18	$7.10	$7.22	$7.36	$7.03	$7.09	$7.00
~ 90 Minutes Prior to Real-Time	$0 to $5	$1.45	$1.50	$1.78	$1.88	$1.63	$1.59	$1.52	$1.58	$1.56	$1.70	$1.44	$1.28	$1.58
	$0 to -$5	$1.36	$1.48	$1.65	$1.71	$1.50	$1.29	$1.35	$1.24	$1.27	$1.36	$1.22	$1.39	$1.41
	-$5 to -$10	$6.98	$7.10	$6.67	$7.15	$6.92	$7.04	$6.86	$6.97	$6.98	$7.16	$7.04	$6.93	$6.98
	-$10 to -$20	$14.19	$14.54	$13.92	$13.65	$12.67	$14.01	$13.82	$14.66	$14.63	$14.39	$14.36	$13.69	$14.03
	< -$20	$53.40	$64.69	$74.26	$74.36	$60.33	$58.91	$63.06	$69.15	$61.32	$67.30	$60.70	$68.47	$64.91
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
	> $20	$25.59	$26.55	$27.64	$29.57	$28.31	$29.27	$43.47	$33.53	$66.83	$53.77	$46.15	$35.97	$37.90
	$10 to $20	$13.74	$13.90	$12.96	$14.38	$12.57	$12.80	$13.90	$13.10	$13.48	$13.26	$13.88	$13.97	$13.60
	$5 to $10	$7.12	$6.76	$6.84	$7.10	$6.79	$6.89	$7.28	$7.36	$7.42	$7.49	$6.87	$7.06	$7.10
~ 135 Minutes Prior to Real-Time	$0 to $5	$1.62	$1.71	$2.09	$2.04	$1.71	$1.42	$1.47	$1.52	$1.49	$1.79	$1.47	$1.30	$1.67
	$0 to -$5	$1.46	$1.60	$1.64	$1.64	$1.56	$1.51	$1.50	$1.35	$1.48	$1.67	$1.42	$1.64	$1.54
	-$5 to -$10	$6.77	$6.84	$6.71	$7.13	$6.79	$7.11	$6.99	$6.85	$6.98	$7.13	$7.04	$6.86	$6.95
	-$10 to -$20	$14.21	$13.86	$13.63	$13.81	$12.55	$13.94	$13.77	$14.12	$13.43	$13.61	$14.61	$14.12	$13.81
	< -$20	$50.87	$60.13	$73.80	$74.73	$63.54	$65.24	$69.72	$67.19	$58.88	$61.77	$58.76	$56.46	$64.17

The data reviewed show that ITSCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. If this remains true, it will limit the effectiveness of CTS in improving interface pricing between PJM and MISO.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving nonfirm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system if necessary to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participant pays in order for their transaction to continue to flow.

The MMU recommended that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations addressed most of the MMU concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be appropriate to address this exposure.

Table 9-50 shows that since the inception of the business rule change on April 12, 2013, there was uncollected congestion in only one month, January 2016. The negative congestion means that market participants who used the not willing to pay congestion transmission option for their wheel through transactions had transactions that flowed in the direction opposite to congestion. When market participants use the not willing to pay congestion product, it also means that they are not willing to receive congestion credits, which was the case in January 2016.

Table 9-50 Monthly uncollected congestion charges: 2010 through 2016

Month	2010	2011	2012	2013	2014	2015	2016
Jan	$148,764	$3,102	$0	$5	$0	$0	($44)
Feb	$542,575	$1,567	($15)	$249	$0	$0	$0
Mar	$287,417	$0	$0	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0	$0
May	$41,025	$0	($27)	$0	$0	$0	$0
Jun	$169,197	$1,354	$78	$0	$0	$0	$0
Jul	$827,617	$1,115	$0	$0	$0	$0	$0
Aug	$731,539	$37	$0	$0	$0	$0	$0
Sep	$119,162	$0	$0	$0	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0	$0
Nov	$30,843	($795)	($4,678)	$0	$0	$0	$0
Dec	$127,176	($659)	($209)	$0	$0	$0	$0
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$0	($44)

Spot Imports

Prior to April 1, 2007, PJM did not limit nonfirm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using nonfirm point-to-point service. Spot market imports, nonfirm point-to-point and network services that are willing to pay congestion, all termed willing to pay congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. Under this approach, market participants could offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange.

However, PJM has interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[89] The result is that the availability of spot import service is limited by ATC and not all spot transactions are approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

The spot import rules provide incentives to hoard spot import capability. In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[90] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within two hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

These changes did not fully resolve the issue. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing related congestion is preferable. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the queue time of the reservations intraday, and two hours when queued the day prior. On June 23, 2009, PJM implemented the new business rules.

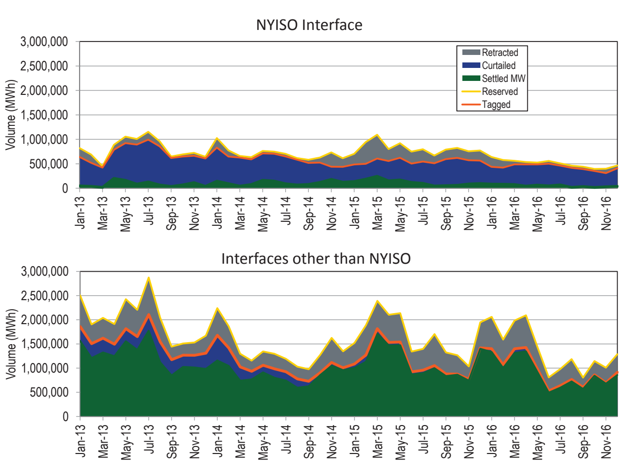
Figure 9-15 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 2013 through December 2016. The yellow line shows the total monthly MWh of spot import service reserved and the orange line shows the total monthly MWh of tagged spot import service. The gray shaded

89 See OASIS "Modifications to the Practices of Non-Firm and Spot Market Import Service," (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>.

90 See OASIS "Regional Transmission and Energy Scheduling Practices," (March 31, 2016) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

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 9-15 shows that while there are proportionally fewer retracted MWh on the NYISO Interface than on all other interfaces, the NYISO has proportionally more curtailed MWh. This is a result of the NYISO market clearing process.

Figure 9-15 Spot import service use: 2013 through 2016



The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all nonfirm point-to-point willing to pay congestion imports and exports) at all PJM interfaces.

Interchange Optimization

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible for PJM system operators to reliably predict the quantity or sustainability of such imports. The inability to predict interchange volumes creates additional challenges for PJM dispatch in trying to meet loads, especially on high-load days. If all external transactions were submitted as real-time dispatchable transactions during emergency conditions, PJM would be able to include interchange transactions in its supply stack, and dispatch only enough interchange to meet the demand.

The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the prior day to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes.[91] 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.

91 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order 764.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point-to-point transmission. An interchange cap is a nonmarket intervention which should be a temporary solution and should be replaced with a market-based solution as soon as possible. Since the approval of this process on October 30, 2014, PJM has not yet needed to implement an interchange cap.

The purpose of the interchange cap is to help ensure that actual interchange more closely meets operators' expectations of interchange levels when internal PJM resources, e.g. CTs or demand response, were dispatched to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange then materializes; therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift.

PJM will notify market participants of the possible use of the interchange cap the day before. The interchange cap will be implemented for the forecasted peak and surrounding hours during emergency conditions.

The interchange cap will limit the acceptance of spot import and hourly nonfirm point to point interchange (imports and exports) not submitted as real-time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly nonfirm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap.

The calculation of the interchange cap is based on the operator expectation of interchange at the time the cap is calculated plus an additional margin. The margin is set at 700 MW, which is half of the largest contingency on the system. The additional margin also allows interchange to adjust to the loss of a unit or deviation between actual load and forecasted load. The interchange cap is based on the maximum sustainable interchange from PJM reliability studies.

45 Minute Schedule Duration Rule

PJM limits the change in interchange volumes on 15 minute intervals. These changes are referred to as ramp. The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit per 15 minute interval was based on the availability of ramping capability by generators in the PJM system. The limit is consistent with the view that the available generation in the PJM system can only move 1,000 MW over any 15 minute period. The PJM ramp limit is designed to limit the change in the amount of imports or exports in each 15 minute interval to account for the physical characteristics of the generation to respond to changes in the level of imports and exports. For example, if at 0800 the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intra-hour LMP changes. This activity was due to market participants' ability to observe price differences between RTOs in the first third of the hour, and predict the direction of the price difference on an hourly integrated basis. Large quantities of MW would then be scheduled between the RTOs for the last 15 minute interval to capture those hourly integrated price differences with relatively little risk of prices changing. This increase in interchange on 15 minute intervals created operational control issues, and in some cases led to an increase in uplift charges due to calling on resources with minimum run times greater than 15 minutes needed to support the interchange transactions. As a result, a new business rule was proposed and approved that required all transactions to be at least 45 minutes in duration.

On June 22, 2012, FERC issued Order No. 764, which required transmission providers to give transmission customers the option to schedule transmission service at 15 minute intervals to reflect more accurate power production forecasts, load and system conditions.[92] [93] On

92 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
93 Order No. 764 at P 51.

April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order 764.[94]

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.[95]

MISO Multi-Value Project Usage Rate ("MUR")

A multi-value project (MVP) is a project, as defined by MISO, that 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.[96] On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[97] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[98] 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.[99] 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.[100] 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.[101]

On July 13, 2016, FERC issued an Order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[102] 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."[103] 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 2017 through 2036.[104] 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: 2017 through 2036

Year	Total Indicative MVP Usage Rate ($/MWh)
2017	$1.39
2018	$1.63
2019	$1.84
2020	$1.86
2021	$1.90
2022	$1.89
2023	$1.88
2024	$1.87
2025	$1.84
2026	$1.81
2027	$1.78
2028	$1.75
2029	$1.72
2030	$1.69
2031	$1.66
2032	$1.63
2033	$1.60
2034	$1.57
2035	$1.54
2036	$1.52

94 *See Id.* at P 12.

95 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

96 See MISO, "Multi Value Project Portfolio Analysis," <https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MVPAnalysis.aspx>.

97 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).

98 133 FERC ¶ 61,221 (2010); *order on reh'g*, 137 FERC ¶ 61,074 (2011).

99 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).

100 *Id.* at 780.

101 *Id.* at 779.

102 156 FERC ¶ 61,034 (2016).

103 *Id.* at P 55.

104 See MISO, "Schedule 26A Indicative Annual Charges," (August 29, 2016) <https://www.misoenergy.org/_layouts/miso/ecm/redirect.aspx?id=230305>.

Ancillary Service Markets

The United States Federal Energy Regulatory Commission (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 the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of formulaic rates or cost.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market, the PJM DASR Market, and the PJM Regulation Market for 2016.

Table 10-1 The Tier 2 Synchronized Reserve Market results were competitive

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

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

Table 10-2 The Day-Ahead Scheduling Reserve Market results were competitive

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

- The Day-Ahead Scheduling Reserve Market structure was evaluated as not competitive because market participants failed the three pivotal supplier test in 18.3 percent of all cleared hours in 2016.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices. Offers above \$0.00 set the clearing price in 3,842 hours (43.8 percent).
- Market design was evaluated as mixed because the DASR product does not include performance obligations, and the three pivotal supplier test and appropriate market power mitigation should be added to the market to ensure that market power cannot be exercised at times of system stress.

Table 10-3 The Regulation Market results were competitive

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

- The regulation market structure was evaluated as not competitive for 2016 because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 92.2 percent of the hours in 2016.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for 2016 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in noncompetitive behavior.
- Market performance was evaluated as competitive, despite significant issues with the market design.

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the Real-Time Energy Market.

- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Overview

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[3]

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off-line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. The primary reserve requirement in the RTO Zone was raised on January 8, 2015, to 2,175 MW of which at least 1,700 MW must be available within the Mid-Atlantic Dominion (MAD) Subzone. Adjustments to the primary reserve requirement can occur when grid maintenance or outages change the largest contingency. The hourly average primary reserve requirement in the RTO Zone in 2016 was 2,185.7 MW. The primary reserve requirement in the MAD Subzone was 1,710.7 MW.

Tier 1 Synchronized Reserve

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

Tier 1 synchronized reserve is part of primary reserve and 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 reserve. The market solution estimates tier 1 synchronized reserve as available 10-minute ramp from the energy dispatch. In 2016, there was an average hourly supply of 1,263.1 MW of tier 1 for the RTO Synchronized Reserve Zone, and an average hourly supply of 1,081.8 MW of tier 1 in the Mid-Atlantic Dominion Subzone.
- **Demand.** The default hourly required synchronized reserve requirement is 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid the average of five minute LMPs during the event, rather than hourly integrated LMP, plus $50/MW. This is the Synchronized Energy Premium Price. The synchronized reserve event response credits for tier 1 response are independent of the tier 2 synchronized reserve market clearing price and independent of the nonsynchronized reserve market clearing price.

  Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 75.1 percent actually responded during the six distinct synchronized reserve events with duration of 10 minutes or longer in 2016.
- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is the five-minute LMP plus $50 per MWh. A tariff change included in the shortage pricing tariff changes (October 1, 2012) added the requirement to pay tier 1 synchronized reserve the tier 2 synchronized reserve market clearing price whenever the

3 See PJM. "Manual 10: Pre-Scheduling Operations," Revision. 34 (July 1, 2016), p. 24.

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, resulting in a windfall payment of $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015 and in 2016, payments to tier 1 synchronized reserve resources when the NSRMCP was above $0.00 were $4,948,084.

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 incur costs to be synchronized, that have an obligation to respond with corresponding penalties, and that must be dispatched in order to satisfy the synchronized reserve requirement.

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

Market Structure

- **Supply.** In 2016, the supply of offered and eligible synchronized reserve was 21,090.2 MW in the RTO Zone of which 6,921.2 MW (including 1,506.0 MW of DSR) was available to the MAD Subzone.
- **Demand.** The default hourly required synchronized reserve requirement was 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves. After subtracting the tier 1 synchronized reserve estimate from the default requirement, the hourly average required tier 2 synchronized reserve was 315.6 MW in the MAD Subzone and 563.1 MW in the RTO.
- **Market Concentration.** In 2016, the weighted average HHI for tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 6116 which is classified as highly concentrated. The MMU calculates that 87.2 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone.

  In 2016, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 5092 which is classified as highly concentrated. The MMU calculates that 45.3 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone.

  The MMU concludes from these results that 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 2016.

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. 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. There has been less than complete compliance with the tier 2 synchronized reserve must offer requirement.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) Subzone was $4.15 per MW in 2016, a decrease of $5.97, 41.0 percent, from 2015.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $4.88 per MW in 2016, a decrease of $7.00, 58.9 percent, from 2015.

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. The market 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.

Market Structure

- **Supply.** In 2016, the supply of eligible nonsynchronized reserve was 2,358.2 MW in the RTO Zone and 1,726.9 MW in MAD Subzone.
- **Demand.** Demand for nonsynchronized reserve is the remaining primary reserve requirement after tier 1 synchronized reserve is estimated and tier 2 synchronized reserve is scheduled.[4] In the RTO Zone, the market cleared an hourly average of 919.6 MW of nonsynchronized reserve in 2016. The MAD Subzone cleared an average of 341.0 MW in 2016.
- **Market Concentration.** In 2016, the weighted average HHI for cleared nonsynchronized reserve in the MAD Subzone was 3459 which is classified as highly concentrated. In the RTO Zone the weighted average HHI was 3436, which is also highly concentrated. The MMU calculates that 53.3 percent of hours would have failed a three pivotal supplier test in the MAD Subzone and 1.2 percent of hours would have failed a three pivotal supplier test in the RTO Zone.

Market Conduct

- **Offers.** No offers are made for nonsynchronized reserve by resource owners. 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 cleared hours (284 hours) in the RTO Reserve Zone was $0.21 per MW in 2016 and in 97.6 percent of hours the market clearing price was $0.00. The MAD Subzone cleared separately from the RTO Zone in 27 hours in 2016, with a weighted average price of $0.21.

Secondary Reserve

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

PJM maintains a day-ahead, offer based market for 30-minute day-ahead secondary reserve.[5] The Day-Ahead Scheduling Reserves 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.[6]

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 thirty minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In 2016, the average available hourly DASR was 34,776 MW.
- **Demand.** The DASR requirement in 2016 was 5.70 percent of peak load forecast, down from 5.93 percent in 2015. The average DASR MW purchased was 4,996.8 MW per hour in 2016.
- **Concentration.** In 2016, the DASR Market failed the three pivotal supplier test in 18.3 percent of hours.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In 2016, a daily average of 36.2 percent

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

5 See PJM. "Glossary,"<http://www.pjm.com/Glossary.aspx>.

6 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 166 §11.1.

of units offered above $0.00. In 2016, a daily average of 13.3 percent of units offered above $5.

- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR.

Market Performance

- **Price.** In 2016, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.61, a decrease from $2.99 per MW in 2015.

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 lost opportunity cost. The RegA signal is designed for energy unlimited resources with physically constrained ramp ability. The RegD signal is designed for energy limited resources with very fast ramp rates. In the Regulation Market RegD MW are converted to marginal effective MW using a marginal rate of substitution (MRTS), called a marginal benefit function (MBF). Correctly implemented, the MBF would define and be used as 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 2016, the average hourly eligible supply of regulation for off peak hours was 1,243.6 actual MW (941.3 effective MW). This was an increase of 87.1 actual MW (an increase of 75.0 effective MW) from 2015, when the average hourly eligible supply of regulation was 1,156.5 actual MW (866.3 effective MW). In 2016, the average hourly eligible supply of regulation for on peak hours was 1,155.4 actual MW (920.2 effective MW). This was a decrease of 3.9 actual MW (an increase of 3.4 effective MW) from 2015, when the average hourly eligible supply of regulation was 1,159.3 actual MW (916.8 effective MW).
- **Demand.** The hourly regulation demand was set to 525.0 effective MW for off peak hours (00:00 to 04:59) and 700.0 effective MW for on peak hours (05:00 to 23:59).
- **Supply and Demand.** The off peak regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources totaling, on an hourly average basis, 516.1 actual MW in 2016. This is an increase of 7.2 actual MW from 2015, when the average hourly total regulation cleared MW for off peak hours were 508.9 actual MW. The peak regulation requirement of 700.0 effective MW was provided by a combination of RegA and RegD resources totaling, on an hourly average basis, 635.9 actual MW in 2016. This is a decrease of 39.6 actual MW from 2015, where the average hourly regulation cleared MW for on peak hours were 675.5 actual MW.

  The ratio of the average hourly eligible supply of regulation to average hourly regulation demand for on peak hours was 1.82 in 2016. This is an increase of 5.8 percent from 2015, when the ratio was 1.72. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required for off peak hours was 2.41 in 2016. This is an increase of 6.2 percent from the same period of 2015, when the ratio was 2.27.
- **Market Concentration.** In 2016, the three pivotal supplier test was failed in 92.2 percent of hours. In 2016, the weighted average HHI of RegA resources was 2748, which is highly concentrated and the weighted average HHI of RegD resources was 1864, which is highly concentrated. The weighted average HHI of all resources was 1156 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.[7] In 2016, there were 238 resources following the RegA signal and 55 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $15.72 per effective MW of regulation in 2016, a decrease of $16.20 per MW, or 50.8 percent, from the same period of 2015. The cost of regulation in 2016 was $18.13 per effective MW of regulation, a decrease of $20.23 per MW, or 52.7 percent, from 2015. The decreases in regulation price and regulation cost in 2016 resulted primarily from reductions in the LOC component of the regulation clearing prices due to lower energy prices in 2016 compared to 2015.
- **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, pricing, and settlement processes. If the Regulation Market were functioning efficiently, RegD and RegA resources would be paid the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the marginal benefit factor is not used in settlements. When the marginal benefit factor is above one, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the MBF is less than one, RegD resources are generally overpaid on a per effective MW basis. Currently, the MBF is less than one, resulting in persistent overpayment of RegD resources that creates an artificial incentive for inefficient entry of RegD resources. The MBF averaged less than one in each month of 2016, resulting in RegD resources being paid 1,565.7 percent more than they should have in 2016. In 2015, the MRTS averaged greater than one, resulting in RegD resources being paid 28.0 percent less than they should have been.
- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) is intended to measure the substitutability of RegD resources for RegA resources. The marginal benefit factor function is currently incorrectly defined and applied in the PJM market clearing and incorrectly describes the operational relationship between RegA and RegD regulation resources. Correctly defined, the MBF function represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation Market clearing and settlement. The current incorrect and inconsistent implementation of the MBF function has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement began to degrade the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation.
- **Interim changes to the MBF function.** On December 14, 2015, PJM changed the MBF curve in an attempt to reduce the over procurement of RegD. The modification to the marginal benefit curve did not correct the identified issues.
- **Changes to the Regulation Market.** Changes were approved by the Regulation Market Issues Senior Task Force ("RMISTF"), which went into effect in January of 2017. These include changing the definition of off-peak and on-peak hours (now called off-ramp and on-ramp hours) based on the season, increasing the effective MW requirement during on-ramp hours from 700 MW to 800 MW, 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 conditional neutrality requirement.

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).[8]

7 See the *2016 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

8 OATT Schedule 1 § 1.3BB.

In 2016, total black start charges were $67.0 million with $66.7 million in revenue requirement charges and $278.0 thousand in 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. 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 for 2016 ranged from $0.08 per MW-day in the DLCO Zone (total charges were $78,423) to $4.09 per MW-day in the PENELEC Zone (total charges were $4,528,821).

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 voltages on the transmission system and is essential to the flow of real power (measured in MW).

Reactive capability revenue requirements are based on FERC approved filings. Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing units in real time that provide reactive service. In 2016, total reactive charges were $303.7 million, a 5.7 percent increase from $287.2 million in 2015. Reactive capability revenue requirement charges increased from $276.7 million in 2015 to $301.2 million and reactive service charges fell from $10.5 million to $2.5 million in 2016. Total charges in 2016 ranged from $37 in the RECO Zone to $37.6 million in the AEP Zone.

Ancillary Services Costs per MWh of Load: 1999 through 2016

Table 10-4 shows PJM ancillary services costs for 1999 through 2016, per MWh of load. The rates are calculated as the total charges for the specified ancillary service divided by the total PJM real-time load in MWh. The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* 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 2016[9]

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	$0.34	$0.41	$0.09	$1.16
2012	$0.26	$0.40	$0.46	$0.04	$1.16
2013	$0.25	$0.39	$0.76	$0.04	$1.44
2014	$0.33	$0.40	$0.40	$0.12	$1.25
2015	$0.23	$0.41	$0.37	$0.11	$1.12
2016	$0.11	$0.41	$0.39	$0.05	$0.96

Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that 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, to prevent gaming. (Priority: Medium. New recommendation. Status: Not adopted.)

9 Note: The totals in this table account for after the fact billing adjustments made by PJM and may not match totals presented in past reports.

- 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.)
- The MMU recommends that the rule requiring the payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is above zero be eliminated immediately and that 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. 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: Not adopted.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM replace the DASR Market with a real-time secondary reserve product that is available and dispatchable in real time. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the three pivotal supplier test and market power mitigation be incorporated in the DASR Market. (Priority: Low. First reported 2009. 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 separate 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 a number of market design changes to improve the performance of the Regulation Market, including use of a single five minute clearing price based on actual LMP and actual LOC, modifications to the LOC calculation, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- The MMU recommends that PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM. (Priority: Low. First reported 2013. Status: Partially adopted, 2014.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted.)
- The MMU recommends that no payments be made to tier 1 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.)

Conclusion

The design of the PJM Regulation Market is significantly flawed. The market design has failed to correctly incorporate the marginal benefit factor, or marginal rate of technical substitution, in optimization, pricing and settlement. The market design uses the marginal benefit factor in the optimization (incorrectly) and pricing (correctly), but a mileage ratio instead of the marginal benefit factor in settlement. This failure to correctly and consistently incorporate marginal benefit factor 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 have led to the MMU's conclusion that the regulation market design is flawed.

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, compliance with calls to respond to actual synchronized reserve events, while showing improvement in 2016 remains less than 100 percent. For the six spinning events 10 minutes or longer in 2016, the average tier 2 synchronized reserve response was 85.5 percent of all scheduled MW.

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. Such 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 paid for their response if they do respond. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations. Overpayment of tier 1 resources based on this rule added $89.7 million to the cost of primary reserve in 2014, $34.1 million in 2015, and $4.9 million in 2016.

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

The MMU concludes that the regulation market results were competitive, although the market design is flawed. The MMU concludes that the synchronized reserve market results were competitive. The MMU concludes that the DASR market results were competitive, although there is concern about offers above the competitive level affecting prices.

Primary Reserve

NERC Performance Standard BAL-002-1, Disturbance Control Performance, requires PJM to carry sufficient contingency reserve to recover from a sudden loss of load (disturbance) within 15 minutes. The NERC requirement is 100 percent compliance and must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[10] PJM maintains 10 minute reserves (primary reserve) to ensure reliability in the event of disturbances. PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes.

Market Structure

Supply

In 2016, PJM's primary reserve requirement was 2,175 MW for the RTO Zone, and 1,700 MW for the MAD Subzone.[11] It is satisfied by tier 1 synchronized reserves, tier 2 synchronized reserves and non-synchronized reserves, subject to the requirement that synchronized reserves equal 100 percent of the largest contingency. The synchronized reserve requirement is 1,450 MW in both the Mid-Atlantic Dominion Subzone, and the RTO Zone. After the synchronized reserve requirement is satisfied, the remainder of primary reserves can come from the least expensive combination of synchronized and non-synchronized reserves.

Estimated tier 1 is credited against PJM's primary reserve requirement. In the MAD Subzone an average of 1,155.7 MW of tier 1 was identified by the ASO market solution as available hour ahead (Table 10-6).[12] Of this,

10 See PJM, "Manual 10: Pre-Scheduling Operations," revision 35, January 1, 2017, p. 24, 25

11 In this State of the Market Report, scheduled MW and average clearing prices are calculated differently for the RTO Zone than in prior reports. Formerly data were reported for three geographic structures for primary reserve and its component synchronized and non-synchronized reserve. Those three structures were, Full RTO Zone, Mid-Atlantic Dominion Subzone, and the RTO Zone excluding the Mid-Atlantic Subzone. In this report the term RTO Zone is the Full RTO Zone.

12 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.

an average of 1,082.2 MW of tier 1 was actually used by the market solution in satisfying the synchronized reserve requirement. This tier 1 reduced the amount of tier 2 and nonsynchronized reserve needed to fill the synchronized reserve and primary reserve requirements. Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement in only 3.0 percent of hours in 2016. In the RTO Zone, an average of 1,262.5 MW of tier 1 was available (Table 10-6). Tier 1 synchronized reserve fully satisfied the RTO Zone synchronized reserve requirement in 36.1 percent of all hours.

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). Offer MW and other non-cost offer details can be changed during the operating day. Owners are permitted to make resources unavailable for synchronized reserve daily or hourly but only if they are physically unavailable. Certain unit types including nuclear, wind, solar, landfill gas and batteries, are expected to have zero MW tier 2 synchronized reserve offer quantities.[13]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the RTO Zone there were 21,260.1 MW of tier 2 synchronized reserve offered daily. Of this 6,857.8 MW were located in the MAD Subzone (Figure 10-12) to meet the average tier 2 hourly demand of 397.6 MW (Table 10-5). In the RTO Zone outside the MAD Subzone, there was an average of 14,402.2 MW of offered Tier 2 supply, available to meet the average hourly demand of 655.7 MW (Table 10-6).

In the MAD Subzone, there was an average of 1,726.9 MW of eligible nonsynchronized reserve supply available to meet the average hourly demand of 425.7 MW (Table 10-6). In the RTO Zone, an hourly average of 2,358.2 MW supply was available to meet the average hourly demand of 448.1 MW (Table 10-5).

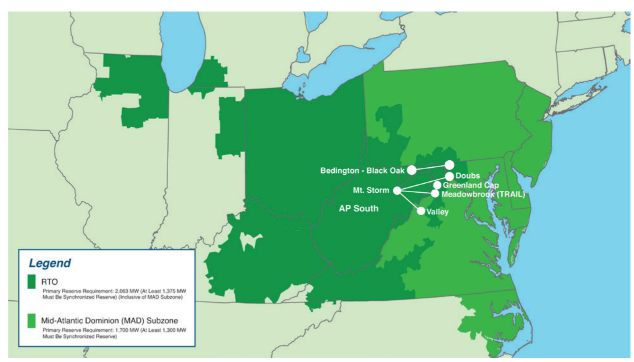
Demand

PJM requires that 150 percent of the largest contingency on the system be maintained as primary reserve. Adjustments to this value can occur when grid maintenance or outages change the largest contingency or in cases of hot weather alerts or cold weather alerts.

On February 22, 2016, the default primary reserve requirement in the RTO Reserve Zone was raised from 2,175 MW to 3,195 MW for 14 hours. On April 8, 2016, it was raised to 2,662 MW for 18 hours. On September 23, 2016, it was raised to 2,235 MW for 13 hours. On October 18, 19, and 20 it was raised to 3,900 MW for a total of 37 hours. These were the only adjustments to the RTO Zone primary reserve requirement in 2016. The hourly average RTO primary reserve requirement in 2016 was 2,185.7. In the MAD Subzone, the primary reserve requirement was raised to 1,775 MW for 21 hours on April 8 and raised to 3,900 MW for 37 hours during October 18, 19, and 20. It remained at 1,700 MW for all other hours in 2016. The hourly average primary reserve requirement for 2016 was 1,710.7 MW.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) Subzone.[14] Of the 2,175 MW RTO primary reserve requirement, 1,700 MW (Table 10-15) must be deliverable to the MAD Subzone (Figure 10-1).

Figure 10-1 PJM RTO Zone and MAD Subzone geography: 2016



The Mid-Atlantic Dominion Reserve (MAD) Subzone is generally defined dynamically by the most limiting constraint separating MAD from the PJM RTO Reserve Zone. However, PJM can override the dynamic determination of the most limiting constraint that defines

13 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 84.

14 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," Revision 84 (August 251, 2016), p. 87.

the MAD Subzone market. In 73.2 percent of hours in 2016 the most limiting constraint was the Bedington – Black Oak Interface. The AP South transfer interface constraint was the limiting constraint in 26.8 percent of hours. Through October 10, 2016, the Bedington – Black Oak Interface was almost exclusively the limiting constraint. AP South was the limiting constraint in 6.6 percent of hours from January 1, 2016 through October 10, 2016. On October 10, 2016, as a result of an outage of facilities that are part of the Bedington – Black Oak Interface, PJM dispatchers defined AP South as the limiting constraint for MAD. The outage was to last until October 24, but PJM dispatch continued to use the AP South Interface as the MAD constraint because of continuing outages in the region and unspecified system conditions. After October 10, 2016, the interface was AP South in one hundred percent of hours.

Starting in mid-October the availability of tier 1 MW fell in both the RTO Zone and the MAD Subzone (Table 10-5 and Table 10-6) requiring the increased use of tier 2 synchronized reserve to satisfy the synchronized reserve requirement. The reduction in tier 1 MW and increase in tier 2 MW is apparent in November 2016, but appears to reverse in December. December's return to normal T1, T2, and NSR ratios was accompanied by a significant and unusual increase in the use of tier 1 biasing (Table 10-14). The reported tier 1 MW are net of PJM biasing.

PJM requires that synchronized reserves equal at least 100 percent of the largest contingency. This means that 1,450 MW of the primary reserve requirement must be synchronized reserve for both RTO Reserve Zone and the Mid Atlantic Dominion Reserve Subzone.

Table 10-5 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: 2016

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW	Total Primary Reserve MW
2016	Jan	1,263.5	228.5	295.9	1,787.9
2016	Feb	1,230.1	241.5	302.2	1,773.8
2016	Mar	993.3	485.7	265.7	1,744.7
2016	Apr	912.4	565.0	289.2	1,766.5
2016	May	956.5	511.3	292.2	1,760.0
2016	Jun	1,116.9	348.4	368.7	1,834.0
2016	Jul	1,254.7	208.8	621.3	2,084.7
2016	Aug	1,228.4	239.7	669.1	2,137.2
2016	Sep	1,170.6	293.0	603.7	2,067.2
2016	Oct	1,086.1	481.3	508.7	2,076.2
2016	Nov	774.8	687.8	360.4	1,822.9
2016	Dec	995.0	479.6	520.7	1,995.3
2016	Average	1,081.8	397.5	424.8	1,904.2

Table 10-6 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: 2016

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW	Total Primary Reserve MW
2016	Jan	1,659.4	374.5	319.1	2,353.0
2016	Feb	1,564.1	411.4	329.4	2,304.9
2016	Mar	1,089.1	818.1	300.0	2,207.2
2016	Apr	1,011.7	878.3	318.0	2,207.9
2016	May	1,160.9	722.6	349.5	2,233.0
2016	Jun	1,546.0	497.1	384.2	2,427.3
2016	Jul	1,663.8	360.1	634.0	2,657.9
2016	Aug	1,605.6	419.0	682.4	2,707.0
2016	Sep	1,290.4	578.6	617.5	2,486.5
2016	Oct	802.7	982.4	524.0	2,309.1
2016	Nov	810.8	1,014.1	375.4	2,200.4
2016	Dec	953.1	807.3	533.0	2,293.4
2016	Average	1,263.1	655.3	447.2	2,365.6

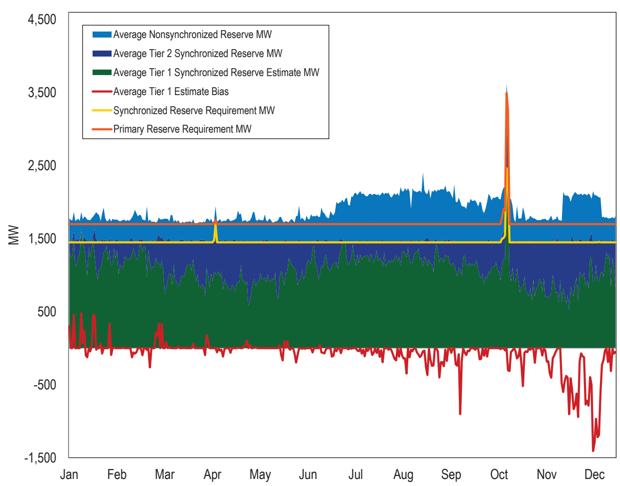
Supply and Demand

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).

The ASO jointly optimizes energy, synchronized reserves, and nonsynchronized reserves based on forecast system conditions to determine the most economic set of reserve resources to commit for the upcoming operating hour (before the hour commitments). IT-SCED runs at 15 minute intervals and jointly optimizes energy and reserves given the ASO's inflexible unit commitments. IT-SCED estimates available tier 1 synchronized reserve and can commit additional reserves (flexibly or inflexibly) if needed. RT-SCED runs at five minute intervals and produces load forecasts up to 20 minutes ahead. The RT-SCED estimates the available tier 1, provides a real-time ancillary services solution and can commit additional tier 2 resources (flexibly or inflexibly) if needed.

Figure 10-2 illustrates how the ASO satisfies the primary reserve requirement (orange line) for the Mid-Atlantic Dominion Subzone. For the Mid-Atlantic Dominion Reserve Zone primary reserve solution the ASO must first satisfy the synchronized reserve requirement (yellow line) which is generally 1,450 MW in the MAD Subzone. Since the market solution considers tier 1 synchronized reserve to be zero cost, the ASO first estimates how much tier 1 synchronized reserve (green area) is available. If there is 1,450 MW of tier 1 available then ASO jointly optimizes synchronized reserve and nonsynchronized reserve to assign the remaining primary reserve up to 1,700 MW. If there is not 1,450 MW of tier 1 then the remaining synchronized reserve requirement up to 1,450 MW is filled with tier 2 synchronized reserve (dark blue area). After 1,450 MW of synchronized reserve are assigned, the remaining 250 MW of the primary reserve requirement is filled by jointly optimizing synchronized reserve and nonsynchronized reserve (light blue area). Since nonsynchronized reserve is priced lower than or equal to synchronized reserve, almost all primary reserve between 1,450 MW and 1,700 MW is filled by nonsynchronized reserve.

Figure 10-2 Mid-Atlantic Dominion Subzone primary reserve MW by source (Daily Averages): 2016



The solution method is similar for the RTO Reserve Zone (Figure 10-3) except that the required primary reserve MW is 2,175 MW.[15] Figure 10-3 shows how the hour ahead ASO satisfies the primary reserve requirement for the RTO Zone.

Figure 10-3 RTO Reserve Zone primary reserve MW by source (Daily Averages): 2016

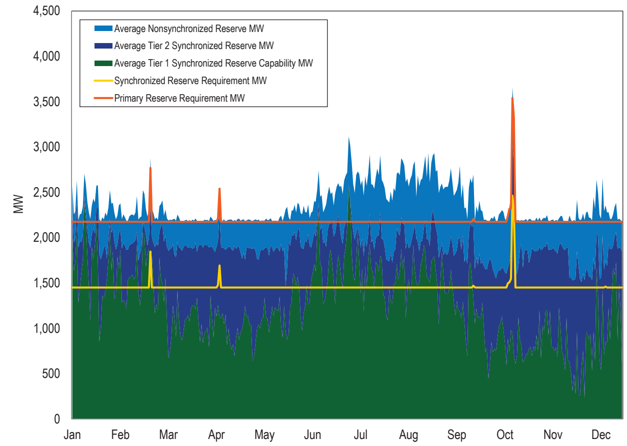


Figure 10-2 and Figure 10-3 show that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements both in the RTO Zone and the Mid-Atlantic Dominion (MAD) Subzone.

Price and Cost

There is a separate price and cost for each component of primary reserve. In the market solution the cost of tier 1 synchronized reserves is zero except in defined circumstances, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point nor is there an obligation to ramp up during a synchronized reserve event. Tier 1 is credited when it responds to a synchronized reserve event. In addition, despite the absence of a performance obligation and an incremental cost to provide tier 1, PJM's current market rules require that tier 1 synchronized reserves be paid the tier 2 synchronized reserve market price in any hour that the nonsynchronized reserve market clears with a price above $0.

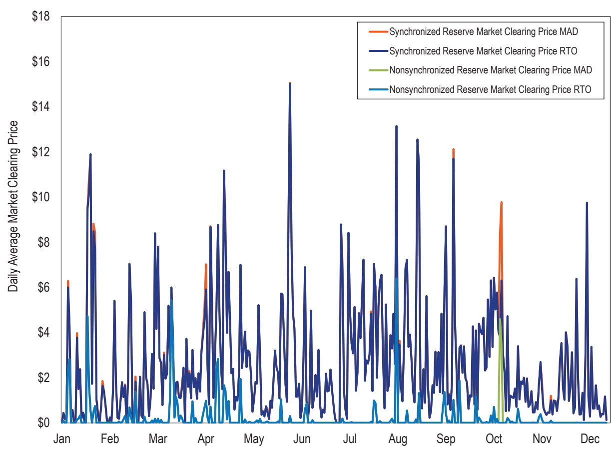
Under PJM's current market optimization approach, as available primary reserve approaches the primary reserve requirement the cost to serve the next MW of primary reserve is the nonsynchronized reserve market clearing price (light blue area in both Figure 10-2 and Figure 10-3).

In times of nonsynchronized reserve shortage, the price of nonsynchronized reserve will be capped at the penalty factor of $850 per MW. PJM will review the penalty factor annually.

15 Although tier 1 has a price of zero, changes made with shortage pricing on November 1, 2012, have given tier 1 a very high cost in some hours. This high cost raises questions about the economics of the solution method used by the ASO, IT-SCED, and RT-SCED market solutions which assume zero cost.

Figure 10-4 shows daily average synchronized and nonsynchronized market clearing prices in 2016.

Figure 10-4 Daily weighted average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: 2016



The cost of meeting PJM's primary reserve requirement (Figure 10-3) is shown in Table 10-7. Under most market conditions, most primary reserve identified by the hour ahead market solution is provided at no incremental cost by nonsynchronized reserve and tier 1 synchronized reserve. The "Cost per MW" column is the total credits divided by the total MW of reserves. The "All-In Cost" column is the total credits paid divided by the load, or the total cost per MWh of energy to satisfy the primary reserve requirement. Table 10-7 shows that the cost per MW of Tier 1 reserves is $5.13 dollars and 59.1 percent greater than the cost of tier 2 reserves entirely as a result of paying tier 1 reserves when the price of nonsynchronized reserves is greater than zero.

Table 10-7 MW credited, price, cost, and all-in price for primary reserve and its component products, RTO Reserve Zone: 2016

Product	MW Share of Primary Reserve Requirement	MW	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve	All-In Cost
Tier 1 Synchronized Reserve Response	NA	4,629	$382,585	NA	$82.65	$0.00
Tier 1 Synchronized Reserve Estimated	3.0%	358,172	$4,948,084	$0.00	$13.81	$0.01
Tier 2 Synchronized Reserve Scheduled	33.8%	3,993,399	$34,670,737	$4.88	$8.68	$0.04
Non Synchronized Reserve Scheduled	63.1%	7,453,849	$7,193,007	$0.18	$0.97	$0.01
Primary Reserve (total of above)	100.0%	11,810,049	$47,194,413	$1.76	$4.00	$0.06

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 measured as the lower of the available 10 minute ramp and the difference between the economic dispatch point and the economic maximum output. Tier 1 resources are identified by the market solution. The sum of their 10 minute availability equals available tier 1 synchronized reserve (green area of Figure 10-2 and Figure 10-3). Tier 1 synchronized reserve is the first element of primary reserve identified by the market software and is available at zero incremental cost unless called to respond to a synchronized reserve event or unless 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 as defined below. Demand resources are not available for tier 1 synchronized reserve.

Tier 1 synchronized reserve is estimated and is credited towards the synchronized reserve requirement in the hourly primary reserve market solution. There have been issues with the Tier 1 estimate, and the process for estimating Tier 1 synchronized reserve has been refined. Beginning January 2015, DGP (Degree of Generator Performance) was introduced as a metric to improve the accuracy of the tier 1 MW estimate used by the market solution. DGP is calculated for all online resources for each market solution. DGP measures how closely the unit has been following economic dispatch for the past 30 minutes. The available tier 1 MW estimated by the market solution for each resource is adjusted by its DGP percent. 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.[16]

In 2016, PJM estimated tier 1 MW for an average of 144 units as part of the solution each hour. The average tier 1 synchronized reserve DGP was 86.4 percent for those 144 units.

The supply of tier 1 synchronized reserve available to the market solution is further adjusted by eliminating tier 1 MW from units that cannot reliably provide synchronized reserve. These units are identified as nuclear, wind, solar, energy storage, and hydro units.[17] These units will be credited the synchronized energy premium price, like any other responding unit, if they respond to a spinning event. These units will not, however, be paid as tier 1 resources when the Nonsynchronized Reserve Market Clearing Price goes above $0.

In 2016, in the RTO Reserve Zone, the average hourly estimated tier 1 synchronized reserve was 1,263.1 MW (Table 10-8). In 36.2 percent of hours, 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.

In 2016, in the MAD Reserve Subzone the average hour ahead estimated tier 1 synchronized reserve was 1,081.8 MW (Table 10-8). Of the 1,081.8 MW, 526.6 MW was in the MAD Subzone and the rest was available from the RTO. In 3.0 percent of hours, the estimated tier 1 synchronized reserve available in MAD was greater than the subzone requirement for synchronized reserve and no Tier 2 Synchronized Reserve Market was needed.

Table 10-8 Monthly average market solution Tier 1 Synchronized Reserve (MW) identified hourly: 2016

Year	Month	Average Hourly Tier 1 Local To MAD	Tier 1 Synchronized Reserve From non-MAD	Average Hourly Tier 1 Used in MAD	Average Hourly Tier 1 Used in non-MAD
2016	Jan	586.1	659.3	1,245.4	1,659.4
2016	Feb	609.3	635.9	1,245.2	1,564.1
2016	Mar	402.4	660.7	1,063.0	1,089.1
2016	Apr	341.7	620.2	961.9	1,011.7
2016	May	408.2	613.9	1,022.1	1,160.9
2016	Jun	638.4	504.0	1,142.5	1,546.0
2016	Jul	756.7	513.5	1,270.2	1,663.8
2016	Aug	750.5	495.2	1,245.7	1,605.6
2016	Sep	658.9	566.8	1,225.7	1,290.4
2016	Oct	393.6	723.9	1,117.5	802.7
2016	Nov	385.2	478.6	863.8	810.8
2016	Dec	660.4	419.8	1,080.2	953.1
2016	Average	549.3	574.3	1,123.6	1,263.1

Demand

There is no required amount of tier 1 synchronized reserve. The tier 1 synchronized reserve for each online resource is estimated from its synchronized reserve ramp rate as part of each market solution. Given estimated tier 1, the market software (ASO) determines the demand for tier 2 and nonsynchronized reserve under the assumption that the estimated tier 1 will be available if needed. 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 minimize the total cost of primary reserves.

Supply and Demand

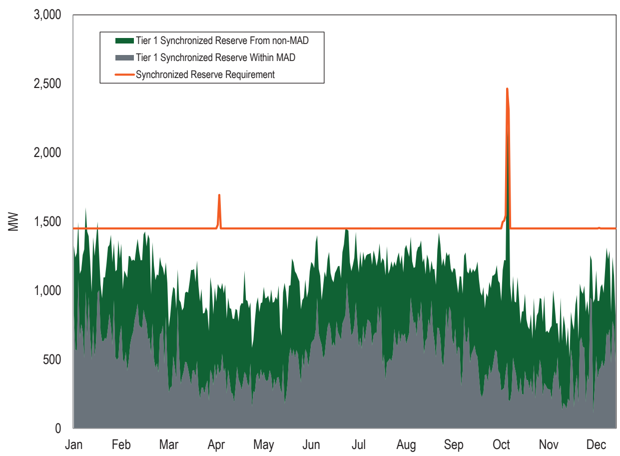
When solving for the synchronized reserve requirement the market solution first subtracts the amount of self-scheduled synchronized reserve from the requirement and then estimates the amount of tier 1. To improve its tier 1 estimates, PJM deselects certain resources from the tier 1 estimate. Tier 1 deselection is based on unit type.

16 PJM. Ancillary Services, "Communication of Synchronized Reserve Quantities to Resource Owners," <http://www.pjm.com/~/media/markets-ops/ancillary/communication-of-synchronized-reserve-quantities-to-resource-owners.ashx> (May 6, 2015).

17 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 83.

In the MAD Subzone, the market solution takes all tier 1 MW estimated to be available within the MAD Subzone (gray area of Figure 10-5). It then adds the tier 1 MW estimated to be available within the MAD Subzone from the RTO Zone (green area of Figure 10-5) up to the synchronized reserve requirement. If the total tier 1 synchronized reserve is less than the synchronized reserve requirement, the remainder of the synchronized reserve requirement is filled with tier 2 synchronized reserve (white area below the synchronized reserve required line in Figure 10-5).

Figure 10-5 Daily average tier 1 synchronized reserve supply (MW) in the MAD Subzone: 2016



Average demand for synchronized reserve in the RTO Zone in 2016 was 1,457.6 MW. There were temporary increases in the hourly synchronized reserve requirement to 2,130 MW on February 22, 2016, to 1,474.8 MW on April 7, 2016, to 1,692.6 MW on April 8, 2016, to 1,490.0 MW in September 23, to 1,900 MW on October 17, to 2,600 on October 19, and 20, and to 1,500 MW on December 20.

Tier 1 Synchronized Reserve Event Response

Tier 1 synchronized reserve is awarded credits when a synchronized reserve event occurs and it responds. These synchronized reserve event response credits for tier 1 response are independent of the tier 1 estimated, independent of the synchronized reserve market clearing price, and independent of the nonsynchronized reserve market clearing price. Credits are awarded to tier 1 synchronized reserve resources equal to the increase in MW output (or decrease in MW consumption for demand resources) for each five minute interval times the five minute LMP plus $50 per MW. During a synchronized reserve event, tier 1 credits are awarded to all units that increase their output during the event regardless of their estimated tier 1 MW, or tier 1 deselection status at market clearing time. Only units that have cleared the tier 2 market are not awarded tier 1 credits for increasing their output.

In 2016, tier 1 synchronized reserve synchronized reserve event response credits of $353,840 were paid for 4,308.8 MWh of tier 1 response at an average cost per MWh of $76.57, for 18 spinning event hours (Table 10-9).

Table 10-9 Tier 1 synchronized reserve event response costs: 2015 through 2016

Year	Month	Synchronized Reserve Event Response Hour Count	Total Credited Tier 1 Synchronized Reserve Event Response MWh	Total Tier 1 Synchronized Reserve Event Response Credits	Tier 1 Synchronized Reserve Event Response Cost Per MWh	Average Tier 1 MWh Response
2015	Jan	1	380.5	$61,487	$161.58	380.5
2015	Feb	2	210.7	$11,688	$55.47	105.4
2015	Mar	4	2,341.2	$123,069	$52.57	585.3
2015	Apr	5	1,364.6	$110,249	$80.79	272.9
2015	May	0	0.0	$0	$0.00	0.0
2015	Jun	0	0.0	$0	$0.00	0.0
2015	Jul	1	502.2	$25,540	$50.86	502.2
2015	Aug	2	613.9	$51,958	$84.63	307.0
2015	Sep	3	666.0	$32,902	$49.40	222.0
2015	Oct	0	0.0	$0	$0.00	0.0
2015	Nov	2	252.9	$15,914	$62.92	126.5
2015	Dec	2	602.9	$79,215	$131.39	301.4
2015	Total	22	6,935.1	$512,021	$73.83	315.2
2016	Jan	2	731.1	$70,330	$96.24	365.4
2016	Feb	2	675.0	$40,622	$60.18	337.5
2016	Mar	0	0.0	$0	$0.00	0.0
2016	Apr	1	339.0	$66,199	$195.27	339.0
2016	May	2	113.4	$9,790	$86.35	56.7
2016	Jun	1	206.9	$11,129	$53.78	206.9
2016	Jul	3	714.3	$58,114	$81.36	357.1
2016	Aug	1	334.5	$13,026	$38.95	334.5
2016	Sep	2	452.4	$34,824	$76.97	226.2
2016	Oct	2	281.1	$24,130	$85.85	140.5
2016	Nov	1	204.3	$10,910	$53.41	204.3
2016	Dec	1	256.8	$14,766	$57.50	256.8
2016	Total	18	4,308.8	$353,840	$76.57	235.4

Paying Tier 1 the Tier 2 Price

The market solutions treat tier 1 synchronized reserve as having zero marginal cost. The price for tier 1 synchronized reserves is zero as there is no marginal cost associated with having the ability to ramp up from the current economic dispatch point. 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. But 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. The nonsynchronized reserve market clearing price was above $0.00 in 297 hours in 2016. For those 297 hours, tier 1 synchronized reserve resources were paid a weighted average synchronized reserve market clearing price of $13.84 per MW and earned $4,948,084 in credits. In 2015, PJM paid $34,397,441 in credits for tier 1 estimated during the 1,081 hours when the nonsynchronized reserve market clearing price was above $0.

Table 10-10 Weighted price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: 2015 through 2016

Year	Month	Total Hours When NSRMCP>$0	Weighted Average SRMCP for Hours When NSRMCP>$0	Total Tier 1 MW Credited for Hours When NSRMCP>$0	Total Tier 1 Credits Paid When NSRMCP>$0	Average Tier 1 MW Paid
2015	Jan	145	$13.56	270,081	$3,662,674	1,862.6
2015	Feb	195	$24.56	373,536	$9,174,195	1,915.6
2015	Mar	179	$16.33	304,162	$4,967,882	1,699.2
2015	Apr	64	$25.19	101,487	$2,556,226	1,585.7
2015	May	75	$20.94	111,490	$2,335,087	1,486.5
2015	Jun	95	$17.64	185,149	$3,265,956	1,948.9
2015	Jul	46	$35.12	64,516	$2,265,614	1,402.5
2015	Aug	39	$22.73	51,398	$1,168,234	1,317.9
2015	Sep	49	$29.64	51,822	$1,535,903	1,057.6
2015	Oct	114	$16.98	127,919	$2,172,644	1,122.1
2015	Nov	29	$14.65	29,156	$427,056	1,005.4
2015	Dec	51	$16.07	53,898	$865,969	1,056.8
2015	Total	1,081	$19.95	1,724,614	$34,397,441	1,595.4
2016	Jan	41	$14.18	56,841	$806,038	1,386.4
2016	Feb	16	$9.42	24,752	$233,208	1,547.0
2016	Mar	73	$6.57	105,142	$690,294	1,440.3
2016	Apr	40	$28.83	38,662	$1,114,670	966.5
2016	May	22	$9.01	27,027	$243,515	1,228.5
2016	Jun	9	$15.24	11,630	$177,275	1,292.3
2016	Jul	10	$21.38	13,975	$298,736	1,397.5
2016	Aug	14	$32.45	19,649	$637,554	1,403.5
2016	Sep	9	$26.22	11,247	$294,857	1,249.7
2016	Oct	50	$12.12	33,761	$409,208	675.2
2016	Nov	12	$3.04	13,867	$42,216	1,155.6
2016	Dec	1	$0.58	888	$515	888.2
2016	Total	297	$13.84	357,442	$4,948,084	1,203.5

The additional payments to tier 1 synchronized reserves under the shortage pricing rule can be considered 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 as all estimated tier 1 receives the payment regardless of whether they provided any response during any spinning event. Tier 1 resources are not obligated to respond to synchronized reserve events. In 2016, 66.3 percent of the DGP adjusted market solution's estimated tier 1 resources MW actually responded during synchronized reserve events of greater than 10 minutes. Thus, 33.7 percent of DGP adjusted tier 1 estimated MW did not respond during spinning events. However, all resources that were included in the Tier 1 estimates were paid the Tier 2 price for their full estimated MW when the nonsynchronized reserve (NSR) price was greater than zero. Tier 2 synchronized reserve resources are paid the market clearing price for tier 2 because they stand ready to respond and incur costs to do so, have an obligation to perform and pay penalties for nonperformance. When the next MW of nonsynchronized reserve required to satisfy the primary reserve requirement increases in price from $0.00 per MW to $0.01 per MW, the cost of all tier 1 MW increases significantly.

In 2016, tier 1 synchronized reserve was paid $382,585 for responding to synchronized reserve events. Tier 1 synchronized reserve was paid $4.9 million simply because the NSRMCP was greater than $0.00 in 297 hours (Table 10-11).

Table 10-11 Payments to tier 1 synchronized reserve when the NSRMCP goes above $0: 2015 through 2016

		Synchronized Reserve Events			Hours When NSRMCP>$0		
Year	Month	Total MWh	Total Credits	Average MWh Per Event	Total MW	Total Credits	Average MW Per Hour
2015	Jan	381	$61,487	381	270,081	$3,662,674	1,863
2015	Feb	211	$11,688	105	373,536	$9,174,195	1,916
2015	Mar	2,341	$123,069	585	304,162	$4,967,882	1,699
2015	Apr	1,365	$110,249	273	101,487	$2,556,226	1,586
2015	May	0	$0	0	111,490	$2,335,087	1,487
2015	Jun	0	$0	0	185,149	$3,265,956	1,949
2015	Jul	502	$25,540	502	64,516	$2,265,614	1,403
2015	Aug	614	$51,958	307	51,398	$1,168,234	1,318
2015	Sep	666	$32,902	222	51,822	$1,535,903	1,058
2015	Oct	0	$0	0	127,919	$2,172,644	1,122
2015	Nov	253	$15,914	126	29,156	$427,056	1,005
2015	Dec	603	$79,215	301	53,898	$865,969	1,057
2015	Total	6,935	$512,021	315	1,724,614	$34,397,441	1,595
2016	Jan	754	$70,330	366	57,571	$806,038	1,556
2016	Feb	675	$40,622	338	24,752	$233,208	1,768
2016	Mar	0	$0	0	105,142	$690,294	1,440
2016	Apr	339	$66,199	339	38,662	$1,114,670	1,137
2016	May	113	$9,790	57	27,028	$243,515	1,229
2016	Jun	207	$11,129	207	11,630	$177,275	1,454
2016	Jul	714	$58,114	238	13,975	$298,736	1,398
2016	Aug	334	$13,026	334	19,650	$637,554	1,404
2016	Sep	452	$34,824	226	11,247	$294,857	1,250
2016	Oct	141	$24,130	141	33,761	$409,208	675
2016	Nov	204	$10,910	204	13,867	$42,216	1,156
2016	Dec	695	$43,512	347	888	$515	888
2016	Total	4,629	$382,585	233	358,172	$4,948,084	1,279

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.[18] Tier 1 should be compensated only for a response to synchronized reserve events, as it was before the shortage pricing changes. This compensation requires that when a synchronized reserve event is called, all tier 1 response is paid the average of five-minute LMPs during the event, rather than hourly integrated LMP, plus $50/MW, termed the Synchronized Energy Premium Price.

PJM's current tier 1 compensation rules are presented in Table 10-12. The MMU's recommended compensation rules for tier 1 MW are in Table 10-13.

Table 10-12 Tier 1 compensation as currently implemented by PJM

Tier 1 Compensation by Type of Hour as Currently Implemented by PJM		
Hourly Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh
NSRMCP>$0	T1 credits = T2 SRMCP * estimated tier 1 MW	T1 credits = T2 SRMCP * min(calculated tier 1 MW, actual response MWh)

Table 10-13 Tier 1 compensation as recommended by MMU

Tier 1 Compensation by Type of Hour as Recommended by MMU		
Hourly Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh

18 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 1 Estimate Bias

PJM's market solution software allows the dispatcher to bias the synchronized reserve solution by forcing the software to assume a different tier 1 MW value than it estimates. PJM no longer allows dispatchers to use tier 1 biasing in the intermediate and real-time SCED solutions, but tier 1 biasing is used in the hour ahead reserve market solution, ASO. Biasing means manually modifying (decreasing or increasing) the tier 1 synchronized reserve estimate of the market solution. This forces the market clearing engine to clear more or less tier 2 synchronized reserve and nonsynchronized reserve to satisfy the synchronized reserve and primary reserve requirements than would have cleared under the market solution. Negative biasing is the primary form of biasing actually used.

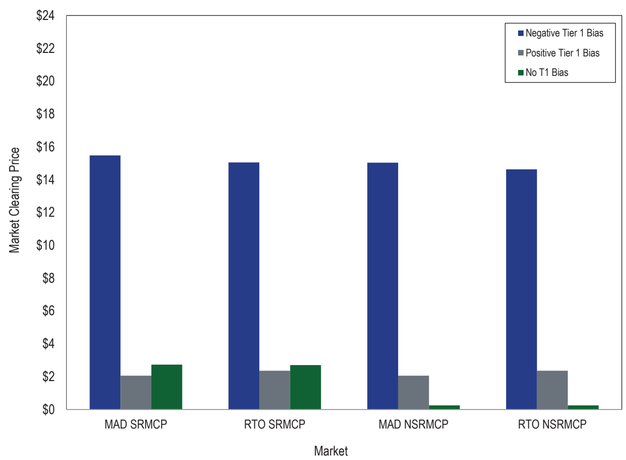
PJM uses tier 1 estimate biasing in the MAD Subzone and in the full RTO Zone of the ASO market solution (Table 10-14).

Table 10-14 RTO Zone ASO tier 1 estimate biasing: 2015 through 2016

Year	Month	Number of Hours Biased Negatively	Average Negative Bias (MW)	Number of Hours Biased Positively	Average Positive Bias (MW)
2015	Jan	67	(1,707.5)	9	580.6
2015	Feb	79	(753.2)	0	NA
2015	Mar	31	(862.9)	3	666.7
2015	Apr	36	(383.3)	0	NA
2015	May	50	(616.0)	13	646.2
2015	Jun	37	(828.4)	3	2,333.3
2015	Jul	9	(588.9)	18	519.4
2015	Aug	1	(1,000.0)	1	1,000.0
2015	Sep	7	(842.9)	2	1,979.5
2015	Oct	24	(979.2)	0	NA
2015	Nov	6	(1,158.3)	63	510.3
2015	Dec	4	(437.5)	102	557.8
2015	Total	351	(846.5)	214	977.1
2016	Jan	21	(682.7)	64	1,104.7
2016	Feb	27	(484.3)	12	762.5
2016	Mar	1	(400.0)	28	732.1
2016	Apr	31	(303.2)	22	502.1
2016	May	19	(452.4)	21	335.7
2016	Jun	46	(502.1)	3	500.0
2016	Jul	53	(532.1)	1	250.0
2016	Aug	134	(687.1)	1	1,000.0
2016	Sep	105	(864.7)	0	NA
2016	Oct	77	(729.9)	0	NA
2016	Nov	139	(877.0)	1	100.0
2016	Dec	262	(1,420.4)	0	NA
2016	Total	915	(661.3)	153	648.4

Tier 1 biasing is not mentioned in the PJM manuals and does not appear to be defined in any public document. PJM dispatchers use tier 1 biasing to compensate for uncertainty in short-term load forecasting and uncertainty about expected generator performance, which result in uncertainty about the accuracy of the market solution's tier 1 estimate. The purpose of tier 1 estimate biasing is to modify the demand for tier 2 and therefore the market results both for tier 2 synchronized reserve and for nonsynchronized reserve. Biasing the tier 1 estimate forces the market solution to clear more or less tier 2 and thus affects the price for tier 2 reserves. Figure 6 compares the average tier 2 and nonsynchronized reserve clearing price for the RTO Zone and MAD Subzone markets for all hours when tier 1 is biased negatively and all hours when tier 1 is biased positively.

Figure 10-6 Comparison of the market clearing prices for synchronized and nonsynchronized reserve in both the RTO Zone and MAD Subzone: 2016



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.

Tier 2 Synchronized Reserve Market

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves. When the synchronized reserve requirement cannot be met by tier 1 synchronized reserve, PJM clears a market to satisfy the requirement with tier 2 synchronized reserve. Tier 2 synchronized reserve is provided by online resources, either synchronized to the grid but not producing energy, or dispatched to provide synchronized reserve at an operating point below their economic dispatch point. Tier 2 synchronized reserve is also provided by demand resources that have offered to reduce load in the event of an synchronized reserve event. Tier 2 synchronized reserves are committed to be available in the event of a synchronized reserve event. Tier 2 resources have a must offer requirement. Tier 2 resources are scheduled by the ASO sixty minutes before the operating hour, are committed to provide synchronized reserve for the entire hour, and are paid the higher of the SRMCP or their offer price plus lost opportunity cost (LOC). Demand response resources are paid SRMCP.

Tier 2 synchronized reserve resources committed for a full hour by the hour ahead market solution are defined to be inflexible resources. Inflexible resources cannot be released for energy during the operating hour. Tier 2 synchronized reserve resources may also be inflexible because of asserted physical limitations. Such resources include synchronous condensers operating solely for the purpose of providing synchronized reserves and demand resources.

During the operating hour, the IT-SCED and the RT-SCED market solutions software can dispatch additional resources flexibly. A flexible commitment is one in which the IT-SCED or RT-SCED redispatches tier 1 generating resources to meet the synchronized and primary reserve requirements within the operational hour.

Market Structure

Supply

There is 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. 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.[19]

In 2016, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 6,921.2 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 21,090.2 MW of synchronized reserve offers (Figure 10-12).

The supply of tier 2 synchronized reserve in 2016 was sufficient to cover the 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 2016 was from CTs, 39.7 percent (Figure 10-7). Although demand resources are limited to 33 percent of the total synchronized reserve requirement, the amount of tier 2 synchronized reserve required in any hour is often much less than the full synchronized reserve requirement because so much of it is met with tier 1 synchronized reserve. This means that in many hours demand resources make up considerably more than 33 percent of the cleared tier 2 MW. The DR MW share of the total cleared Tier 2 Synchronized Reserve Market was 8.8 percent in 2016.[20] This is a decrease from the 17.7 percent share of the tier 2 market in 2015.

19 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 84 (August 25, 2016), p. 85.

20 The cap on demand response participation is defined in MW terms. There is no cap on the proportion of cleared demand response consistent with the MW cap.

Figure 10-7 Cleared tier 2 synchronized reserve average hourly MW per hour by unit type, RTO Zone: 2016

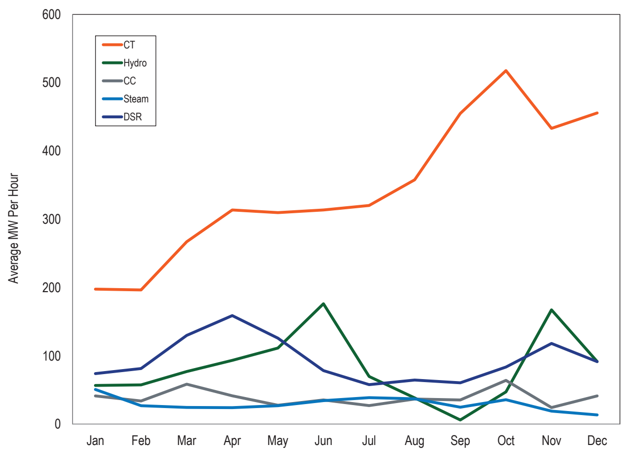
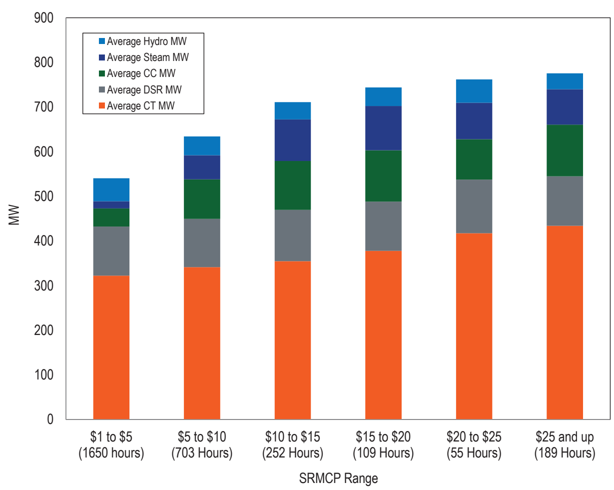


Figure 10-8 provides the average hourly cleared tier 2 MW by unit type by tier 2 clearing price range (SRMCP).

Figure 10-8 Average hourly tier 2 MW by unit type by SRMCP range: 2016



Demand

Effective January 8, 2015, the default synchronized reserve requirement was set at 1,450 MW in both the Mid-Atlantic Dominion Subzone and the RTO Zone (Table 10-15). There are two circumstances in which PJM may alter the synchronized reserve requirement from its default value. When PJM operators anticipate periods of heavy 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 escalating 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.[21] The synchronized reserve requirement was temporarily increased for the RTO Zone on February 22, 2016, for a 14 hour period to 2,130 MW, on April 8, 2016, for 24 hours to 1,775 MW, on September 23, 2016, for 13 hours to 1,490 MW, on October 17, 2016, for 4 hours to 1,900 MW, on October 19, 2016, for 19 hours to 2,600 MW, and on December 20, 2016, for 2 hours to 1,500 MW.

Table 10-15 Default Tier 2 Synchronized Reserve Markets required MW, RTO Zone and Mid-Atlantic Dominion Subzone

Mid-Atlantic Dominion Subzone			RTO Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010	Jan 1, 2015	1,300	Mar 15, 2010	Nov 12, 2012	1,350
Jan 1, 2015	Jan 8, 2015	1,342	Nov 12, 2012	Jan 8, 2015	1,375
Jan 8, 2015		1,450	Jan 8, 2015		1,450

PJM may also change the synchronized reserve requirement from its default value when grid maintenance or outages change the largest contingency. Figure 10-9 shows monthly average actual synchronized reserve requirements and the default synchronized reserve requirements. In 2016, there were no increases in the synchronized reserve requirement as a result of grid maintenance or outages.

21 PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) pp. 88.

Figure 10-9 Monthly average actual vs default synchronized reserve requirements, RTO Zone and MAD Subzone: 2015 through 2016

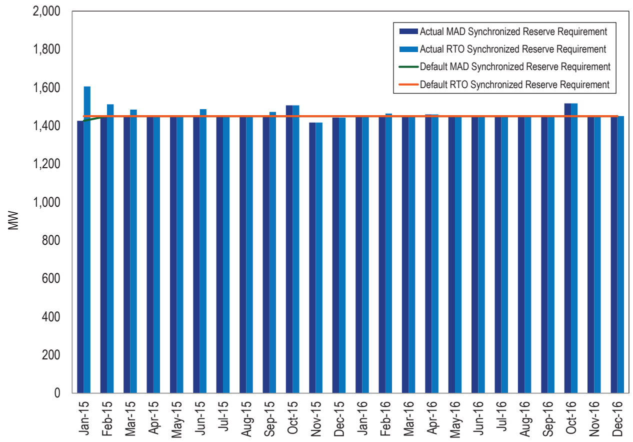
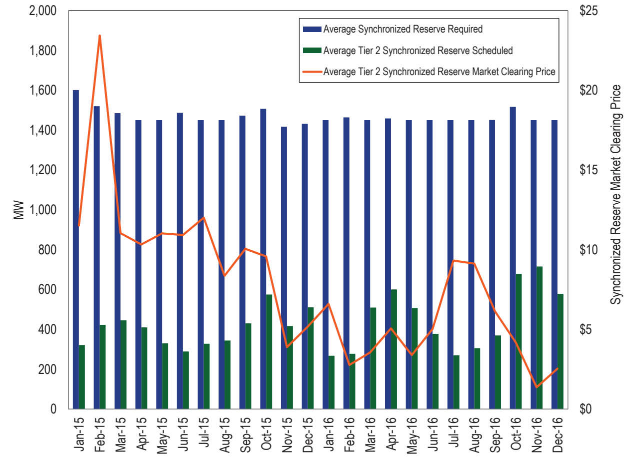


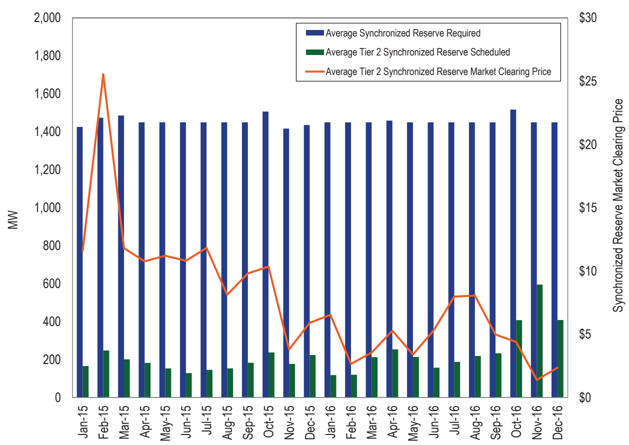
Figure 10-11 RTO monthly average tier 2 synchronized reserve scheduled MW: 2015 through 2016



The RTO Reserve Zone cleared an average of 448.1 MW of tier 2 synchronized reserves each hour in 2016. Of this, an average of 50.5 MW cleared within the RTO exclusive of MAD and 397.6 MW cleared in the MAD Subzone.

Figure 10-10 and Figure 10-11 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self-scheduled) in 2015 through 2016, for the RTO Reserve Zone and MAD Reserve Subzone.

Figure 10-10 MAD monthly average tier 2 synchronized reserve scheduled MW: 2015 through 2016



Market Concentration

The HHI for tier 2 synchronized reserve for cleared hours of the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in 2016 was 6116, which is defined as highly concentrated. This is an increase from the 5436 HHI in 2015. The largest hourly market share was 100 percent and 98.4 percent of all cleared hours had a maximum market share greater than or equal to 40 percent.

The HHI for tier 2 synchronized reserve for cleared hours of the full RTO Zone Tier 2 Synchronized Reserve Market in 2016 was 5092, which is defined as highly concentrated. This is an increase from the 4617 HHI in 2015. The largest hourly market share was 100 percent and 76.0 percent of cleared hours had a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 2.9 percent of all tier 2 synchronized reserve in 2016. In the RTO Zone, flexible synchronized reserve assigned was 3.3 percent of all tier 2 synchronized reserve during the same period.

The MMU calculates that 87.2 percent of hours would have failed the three pivotal supplier test in the MAD Subzone in 2016 for the inflexible Synchronized Reserve Market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-16) and 45.3 percent of hours would have failed a three pivotal supplier test in the RTO Zone during the same time period.

Table 10-16 Three pivotal supplier test results for the RTO Zone and MAD Subzone: 2015 and 2016

Year	Month	Mid Atlantic Dominion Reserve Subzone Pivotal Supplier Hours	RTO Reserve Zone Pivotal Supplier Hours
2015	Jan	46.0%	34.2%
2015	Feb	87.0%	29.9%
2015	Mar	42.0%	45.2%
2015	Apr	31.1%	48.4%
2015	May	61.2%	45.3%
2015	Jun	39.2%	26.5%
2015	Jul	32.0%	25.0%
2015	Aug	32.3%	24.9%
2015	Sep	56.1%	23.5%
2015	Oct	81.5%	57.9%
2015	Nov	73.2%	49.3%
2015	Dec	87.7%	73.2%
2015	Average	55.8%	40.3%
2016	Jan	82.7%	43.1%
2016	Feb	72.0%	39.6%
2016	Mar	93.4%	59.1%
2016	Apr	97.9%	55.6%
2016	May	94.2%	31.3%
2016	Jun	90.4%	27.4%
2016	Jul	79.4%	14.2%
2016	Aug	75.9%	14.4%
2016	Sep	84.3%	41.9%
2016	Oct	87.9%	80.9%
2016	Nov	96.0%	65.9%
2016	Dec	92.3%	69.8%
2016	Average	87.2%	45.3%

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 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, spin as a condenser status, and condense available status. The synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. The offer quantity is limited to the economic maximum. PJM monitors this offer by checking to ensure that all offers are greater than or equal to 90 percent of the resource's ramp rate times 10 minutes. A resource that is unable to participate in the synchronized reserve market during a given hour may set its hourly offer to 0.00 MW. Defined resources are not required to offer tier 2 because they cannot reliably provide synchronized reserve: nuclear, wind, solar, batteries and landfill gas.[22]

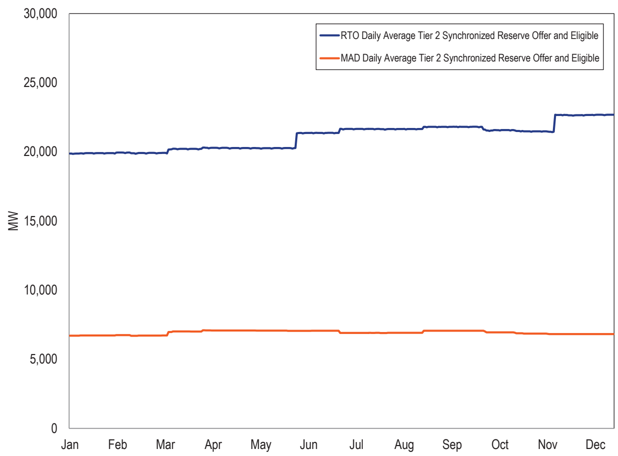
Figure 10-12 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone. In 2016, the ratio of online and eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 4.30 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 5.51.

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.[23] The Tier 2 Synchronized Reserve Market is not actually cleared based on daily offers but based on hourly updates to the daily offers. As a result of hourly updates the actual amount of eligible tier 2 MW can change significantly every hour (Figure 10-12). Changes to the hourly offer status are only permitted when resources are physically unable to provide tier 2. Changes to hourly eligibility levels are the result of online status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints. However, resource operators can make their units unavailable for an hour or block of hours without having to provide a reason. This means that while compliance with the must offer requirement can be done daily it is not possible to verify compliance with the tier 2 must offer requirement on an hourly basis.

22 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) p. 86.

23 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) p. 85, "Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT…"

Figure 10-12 Tier 2 synchronized reserve hourly offer and eligible volume (MW), averaged daily: 2016



Of all nonemergency resources capable of reliably producing synchronized reserve, an average of 11.4 percent of units capable of providing tier 2 synchronized reserve did not enter a daily tier 2 synchronized reserve offer for 2016.

The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW.

Figure 10-13 shows average offer MW volume by market and unit type for the MAD Subzone and Figure 10-14 shows average offer MW volume by market and unit type for the RTO Zone.

Figure 10-13 MAD average daily tier 2 synchronized reserve offer by unit type (MW): 2013 through 2016

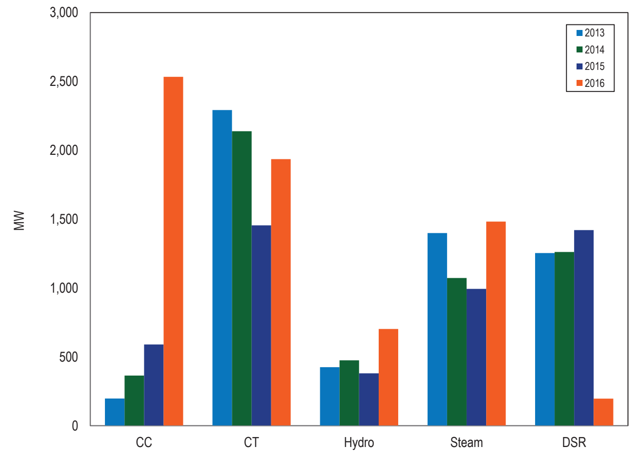
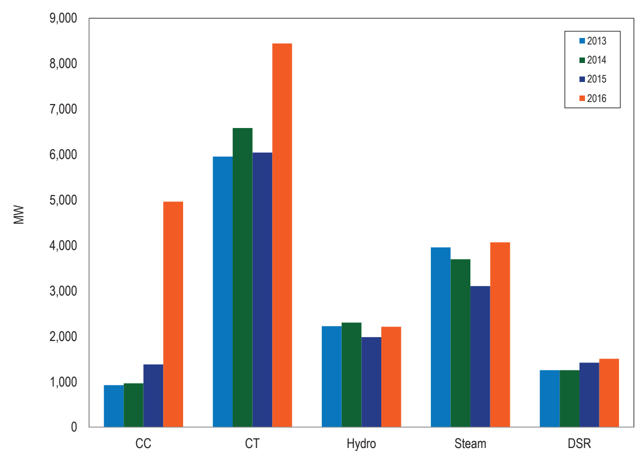


Figure 10-14 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): 2013 through 2016



Market Performance

Price

The price of tier 2 synchronized reserve is calculated in real time every five minutes and averaged each hour for the RTO Reserve Zone and the MAD Subzone. In hours where total tier 1 MW synchronized reserve MW is less than the synchronized reserve requirement, PJM must clear a tier 2 market for synchronized reserves.

In 2016, a tier 2 synchronized reserve market was cleared for the MAD Subzone in 90.5 percent of all hours. In 9.5 percent of hours there was enough tier 1 synchronized reserve to cover the full requirement. The MAD tier 2 market cleared an average of 258.5 MW at a weighted average clearing price of $4.15 compared to $10.12 in 2015.

In 2016, the Tier 2 Synchronized Reserve Market for the RTO Zone cleared an average of 455.3 MW at a weighted average price of $4.88 compared to $11.88 in 2015.

Table 10-17 Mid-Atlantic Dominion subzone, weighted average SRMCP and average scheduled, tier 1 estimated and demand response MW: 2015 through 2016

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)
2015	Jan	$11.59	166.1	607.0	62.4
2015	Feb	$25.54	247.8	635.3	55.7
2015	Mar	$11.80	201.7	494.6	59.2
2015	Apr	$10.77	182.4	386.7	83.4
2015	May	$11.21	153.6	596.2	74.5
2015	Jun	$10.81	129.1	758.6	39.0
2015	Jul	$11.82	145.8	654.4	38.4
2015	Aug	$8.12	153.7	650.2	44.8
2015	Sep	$9.81	183.4	506.9	53.1
2015	Oct	$10.35	237.2	347.9	101.4
2015	Nov	$3.80	177.1	460.1	91.8
2015	Dec	$5.90	224.1	328.2	94.9
2015	Average	$10.96	183.5	535.5	66.5
2016	Jan	$4.70	206.1	586.1	62.2
2016	Feb	$1.99	205.3	609.3	63.1
2016	Mar	$3.07	386.8	402.4	97.8
2016	Apr	$4.62	500.9	341.7	125.7
2016	May	$2.88	432.0	408.2	96.6
2016	Jun	$4.34	311.7	638.4	67.1
2016	Jul	$7.98	188.0	756.7	46.8
2016	Aug	$8.06	219.2	750.5	50.5
2016	Sep	$4.66	230.6	658.9	43.6
2016	Oct	$4.00	407.9	393.6	58.8
2016	Nov	$1.28	595.1	385.2	92.8
2016	Dec	$2.21	408.7	500.5	69.5
2016	Average	$4.15	341.0	539.2	72.9

In 98.7 percent of cleared hours, the synchronized reserve market clearing price was the same for both the MAD Subzone and the RTO Zone. In the 1.3 percent of hours when the price diverged, the average clearing price was $11.97 in the MAD Subzone, and $10.40 in the RTO Zone.

Supply, performance, and demand are reflected in the price of synchronized reserve. (Figure 10-10 and Figure 10-11).

Table 10-18 RTO zone weighted average SRMCP and average scheduled, tier 1 estimated and demand response MW: 2015 through 2016

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)
2015	Jan	$11.52	321.7	1,737.0	62.4
2015	Feb	$23.44	423.1	1,593.9	55.8
2015	Mar	$11.04	445.3	1,276.0	59.3
2015	Apr	$10.33	410.1	1,175.7	83.6
2015	May	$11.03	330.4	1,348.0	74.7
2015	Jun	$10.93	289.1	1,704.2	39.1
2015	Jul	$12.01	328.3	1,545.2	38.4
2015	Aug	$8.36	344.5	1,609.0	48.8
2015	Sep	$10.06	430.6	1,362.9	60.0
2015	Oct	$9.57	575.4	1,056.0	116.3
2015	Nov	$3.89	417.0	1,220.4	111.0
2015	Dec	$5.18	510.9	1,044.8	105.6
2015	Average	$10.61	402.2	1,389.4	71.3
2016	Jan	$6.64	269.5	1,659.4	74.3
2016	Feb	$2.76	277.9	1,564.1	81.5
2016	Mar	$3.56	510.2	1,089.1	130.0
2016	Apr	$5.06	602.2	1,011.7	159.3
2016	May	$3.39	508.3	1,160.9	125.8
2016	Jun	$5.03	378.3	1,546.0	78.4
2016	Jul	$9.32	270.5	1,663.8	59.6
2016	Aug	$9.13	306.0	1,605.6	64.5
2016	Sep	$5.62	364.6	1,290.4	60.7
2016	Oct	$4.17	678.9	802.7	83.5
2016	Nov	$1.37	715.6	810.8	117.7
2016	Dec	$2.54	578.6	953.1	92.5
2016	Average	$4.88	455.1	1,399.0	94.0

Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices do not always cover the full cost and final LOC for each resource. Because price formation occurs within the hour (on a five minute basis integrated over the hour) but the synchronized reserve commitment occurs prior to the hour, the realized within hour price can be zero even when some tier 2 synchronized reserve is cleared. All resources cleared in the market are guaranteed to be made whole and are paid if the SRMCP does not compensate them for their offer plus LOC.

The full cost of tier 2 synchronized reserve including payments for the clearing price and out of market costs is calculated and compared to the price. The closer the price to cost ratio is to one hundred percent, the more the market price reflects the full cost of tier 2 synchronized reserve. A price to cost ratio close to one hundred percent is an indicator of an efficient synchronized reserve market design.

In 2016, the price to cost (including self-scheduled) ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 52.3 percent (Table 10-19); the price to cost ratio of the MAD Subzone averaged 47.4 percent.

Table 10-19 RTO Zone, Mid-Atlantic Subzone tier 2 synchronized reserve MW, credits, weighted price, and cost (including self-scheduled): 2016

Zone	Year	Month	Tier 2 Credited MW	Tier 2 Credits	Weighted Average Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Cost	Price/Cost Ratio
MAD Subzone	2016	Jan	152,716	$1,059,179	$4.70	$6.94	67.8%
MAD Subzone	2016	Feb	142,661	$685,100	$1.99	$4.80	41.5%
MAD Subzone	2016	Mar	287,745	$1,944,418	$3.07	$6.76	45.4%
MAD Subzone	2016	Apr	359,895	$2,914,270	$4.62	$8.10	57.0%
MAD Subzone	2016	May	321,413	$2,004,008	$2.88	$6.23	46.2%
MAD Subzone	2016	Jun	224,449	$1,691,990	$4.34	$7.54	57.6%
MAD Subzone	2016	Jul	138,958	$1,717,849	$7.98	$12.36	64.5%
MAD Subzone	2016	Aug	163,120	$2,600,274	$8.06	$15.94	50.5%
MAD Subzone	2016	Sep	166,063	$1,689,999	$4.66	$10.18	45.8%
MAD Subzone	2016	Oct	303,495	$2,253,012	$4.00	$7.42	53.9%
MAD Subzone	2016	Nov	427,712	$2,024,198	$1.28	$4.73	27.1%
MAD Subzone	2016	Dec	302,517	$1,774,624	$2.21	$5.87	37.7%
MAD Subzone	2016	Total	2,990,744	$22,358,920	$4.15	$8.76	47.4%
RTO Subzone	2016	Jan	46,776	$781,997	$12.97	$16.72	77.6%
RTO Subzone	2016	Feb	50,546	$508,019	$4.94	$10.05	49.2%
RTO Subzone	2016	Mar	91,815	$924,834	$5.11	$10.07	50.7%
RTO Subzone	2016	Apr	72,943	$973,170	$7.35	$13.34	55.1%
RTO Subzone	2016	May	56,736	$602,225	$6.26	$10.61	59.0%
RTO Subzone	2016	Jun	47,925	$902,912	$8.25	$18.84	43.8%
RTO Subzone	2016	Jul	60,517	$1,095,385	$12.38	$18.10	68.4%
RTO Subzone	2016	Aug	64,555	$1,194,632	$11.84	$18.51	64.0%
RTO Subzone	2016	Sep	96,437	$1,672,654	$7.27	$17.34	41.9%
RTO Subzone	2016	Oct	201,595	$2,036,136	$4.43	$10.10	43.8%
RTO Subzone	2016	Nov	86,783	$661,372	$1.82	$7.62	23.9%
RTO Subzone	2016	Dec	126,027	$958,482	$3.31	$7.61	43.5%
RTO Subzone	2016	Total	1,002,655	$12,311,817	$7.16	$14.84	48.2%
RTO Zone	2016	Jan	199,492	$1,841,176	$6.64	$9.23	72.0%
RTO Zone	2016	Feb	193,207	$1,193,119	$2.76	$6.18	44.8%
RTO Zone	2016	Mar	379,560	$2,869,252	$3.56	$7.56	47.1%
RTO Zone	2016	Apr	432,838	$3,887,440	$5.08	$8.98	56.5%
RTO Zone	2016	May	378,149	$2,606,232	$3.39	$6.89	49.2%
RTO Zone	2016	Jun	272,374	$2,594,902	$5.03	$9.53	52.8%
RTO Zone	2016	Jul	199,475	$2,813,234	$9.32	$14.10	66.1%
RTO Zone	2016	Aug	227,675	$3,794,906	$9.13	$16.67	54.8%
RTO Zone	2016	Sep	262,500	$3,362,653	$5.62	$12.81	43.9%
RTO Zone	2016	Oct	505,090	$4,289,148	$4.17	$8.49	49.1%
RTO Zone	2016	Nov	514,496	$2,685,570	$1.37	$5.22	26.3%
RTO Zone	2016	Dec	428,544	$2,733,106	$2.54	$6.38	39.7%
RTO Zone	2016	Total	3,993,399	$34,670,737	$4.88	$9.34	52.3%

Compliance

The MMU has identified and quantified the actual performance of scheduled tier 2 synchronized reserve resources when called on to deliver during synchronized reserve events since 2011.[24] 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.[25] Tier 2 resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes. Penalties can be assessed for failure of a scheduled tier 2 resource to perform during any synchronized reserve event lasting 10 minutes or longer.

The MMU has reported the wide range of synchronized reserve event response levels and recommended that PJM take action to increase compliance rates. In 2015, there were 21 spinning events of which seven were 10 minutes or longer. In 2016, there were 16 spinning events of which six were 10 minutes or longer.

Tier 1 resource owners are paid for the actual amount of synchronized reserve they provide in response to a synchronized reserve event.[26] Tier 2 resources owner are paid for being available and responding but are not paid based on the actual response to a synchronized reserve event. Tier 1 resource owners do not have an obligation to respond and are not penalized for a failure to respond. Tier 2 resources owners are penalized for a failure to respond.

24 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.

25 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 84 (August 25, 2016) § 4.2.11 Verification, p. 97.

26 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) § 4.2.12 Non Performance, p. 98.

For synchronized reserve events of 10 minutes or longer that occurred in 2016, 11.4 percent of all scheduled tier 2 synchronized reserve MW were not delivered and were penalized (Table 10-20). In addition, a tier 2 resource will be penalized for the amount of MW it falls short of its offer for the entire hour, not just for the portion of the hour covered by the synchronized reserve event.[27] Resource owners are permitted to aggregate the response of multiple units to offset an under response from one unit with an overresponse from a different unit to reduce an under response penalty. The average number of days between events calculated by PJM Performance Compliance for 2016 was 13 days.[28]

Table 10-20 Synchronized reserve events 10 minutes or longer, tier 2 response compliance, RTO Reserve Zone: 2016

Spin Event (Day, Time)	Duration (Minutes)	Tier 1 Estimate (MW Adj by DGP)	Tier 1 Response (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	Tier 1 Response Percent	Tier 2 Response Percent
Jan 18, 2016 17:58	12	861.0	733.5	616.7	508.8	107.9	85.2%	82.5%
Feb 8, 2016 15:05	10	1,750.2	1,338.2	228.4	200.1	28.3	76.5%	87.6%
Apr 14, 2016 20:09	10	1,182.8	1,000.6	346.3	304.8	41.5	84.6%	88.0%
Jul 28, 2016 13:28	15	649.4	500.4	822.9	655.8	167.1	77.1%	79.7%
Nov 4, 2016 17:13	11	744.5	497.1	758.0	709.2	48.8	66.8%	93.6%
Dec 31, 2016 05:10	12	971.2	585.0	594.4	485.7	108.7	60.2%	81.7%
2016 Average	11.7	1,026.5	775.8	561.1	477.4	83.7	75.1%	85.5%

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[29] [30] A disturbance is defined as loss of generation and/or transmission resources. In the absence of a disturbance, PJM dispatchers have used synchronized reserve as a source of energy to provide relief from low ACE. There were two low ACE events in 2016, on February 28, 2016 for 8 minutes and on December 3 for 7 minutes. Such an event occurred on January 6, 2014. There were five low ACE events in 2014 and five low ACE events in 2015.

The risk of using synchronized reserves for energy or any other non-disturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for only up to thirty minutes. When the need is for reserve extending past thirty minutes secondary reserve is the appropriate source of the response. The use of synchronized reserve is an expensive solution during an hour when the hour ahead market solution and reserve dispatch indicated no shortage of primary reserve. PJM's primary reserve levels have been sufficient to recover from disturbances and should remain available in the absence of disturbance.

From January 2010 through December 2016, PJM experienced 190 synchronized reserve events (Table 10-21), approximately 2.5 events per month. During this period, synchronized reserve events had an average duration of 12.4 minutes. The average duration of spinning events has been lower in 2016 (8.5 minutes) than in any prior year (Figure 10-15). This corresponds with the higher rate of compliance by tier 2 synchronized reserve resources, and the higher rate of response by tier 1 resources to spinning event all calls.

27 See PJM. "Manual 28: Operating Agreement Accounting," Revision 75 (November 18, 2016) p. 47. *See also* "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) § 4.2.12 Non-Performance, p. 99.

28 "2016 Third Quarter Synchronized Reserve Performance & 2017 Synchronized Reserve Penalty Days," presentation to the Operating Committee, December 13, 2016. <http://www.pjm.com/~/media/committees-groups/committees/oc/20161213/20161213-item-16-2016-third-quarter-synchronized-reserve-performance-with-2017-penalty-days.ashx>.

29 2013 State of the Market Report for PJM, Appendix F – PJM's DCS Performance, pp 451-452.

30 See PJM. "Manual 12: Balancing Operations," Revision 34 (April 28, 2016) § 4.1.2 Loading Reserves pp. 36.

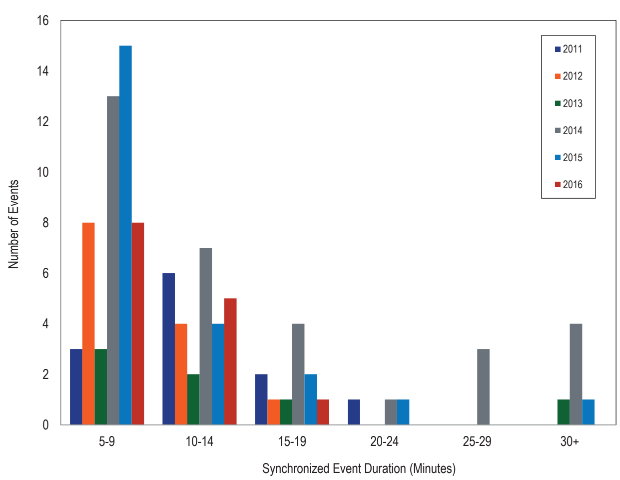
Table 10-21 Synchronized reserve events: January 2010 through December 2016

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10			
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12			
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6			
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6			
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5			
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7			
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8			
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7			
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9			
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10			
			DEC-15-2011 14:35	Mid-Atlantic	8			
			DEC-21-2011 14:26	RFC	18			

Table 10-21 Synchronized reserve events: January 2010 through December 2016 (continued)

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-22-2013 08:34	RTO	8	JAN-06-2014 22:01	RTO	68	JAN-07-2015 22:36	RTO	8	JAN-18-2016 17:58	RTO	12
JAN-25-2013 15:01	RTO	19	JAN-07-2014 02:20	RTO	25	FEB-24-2015 02:51	RTO	5	FEB-08-2016 15:05	RTO	10
FEB-09-2013 22:55	RTO	10	JAN-07-2014 04:18	RTO	34	FEB-26-2015 15:20	RTO	6	FEB-28-2016 18:29	RTO	8
FEB-17-2013 23:10	RTO	13	JAN-07-2014 11:27	RTO	11	MAR-03-2015 17:02	RTO	11	APR-14-2016 20:09	RTO	10
APR-17-2013 01:11	RTO	11	JAN-07-2014 13:20	RTO	41	MAR-16-2015 10:25	RTO	24	MAY-11-2016 15:55	RTO	6
APR-17-2013 20:01	RTO	9	JAN-10-2014 16:46	RTO	12	MAR-17-2015 23:34	RTO	17	JUN-01-2016 09:01	RTO	5
MAY-07-2013 17:33	RTO	8	JAN-21-2014 18:52	RTO	6	MAR-23-2015 23:44	RTO	15	JUL-06-2016 00:40	RTO	5
JUN-05-2013 18:54	RTO	20	JAN-22-2014 02:26	RTO	7	APR-06-2015 14:23	RTO	8	JUL-28-2016 13:28	RTO	15
JUN-08-2013 15:19	RTO	9	JAN-22-2014 22:54	RTO	8	APR-07-2015 17:11	RTO	31	AUG-31-2016 19:29	RTO	8
JUN-12-2013 17:35	RTO	10	JAN-25-2014 05:22	RTO	10	APR-15-2015 08:14	RTO	8	SEP-09-2016 19:11	RTO	6
JUN-30-2013 01:22	RTO	10	JAN-26-2014 17:11	RTO	6	APR-25-2015 03:21	RTO	9	SEP-11-2016 19:30	RTO	9
JUL-03-2013 20:40	RTO	13	JAN-31-2014 15:05	RTO	13	JUL-30-2015 14:04	RTO	10	OCT-12-2016 08:21	RTO	5
JUL-15-2013 18:43	RTO	29	FEB-02-2014 14:03	Dominion	8	AUG-05-2015 19:47	RTO	7	OCT-12-2016 14:40	RTO	7
JUL-28-2013 14:20	RTO	10	FEB-08-2014 06:05	Dominion	18	AUG-19-2015 16:47	RTO	9	NOV-04-2016 17:13	RTO	11
SEP-10-2013 19:48	RTO	68	FEB-22-2014 23:05	RTO	7	SEP-05-2015 01:16	RTO	7	DEC-03-2016 00:11	RTO	7
OCT-28-2013 10:44	RTO	33	MAR-01-2014 05:18	RTO	26	SEP-10-2015 10:12	RTO	8	DEC-31-2016 05:10	RTO	12
DEC-01-2013 11:17	RTO	9	MAR-05-2014 21:25	RTO	8	SEP-29-2015 00:58	Mid-Atlantic	11			
DEC-07-2013 19:44	RTO	7	MAR-13-2014 20:39	RTO	8	NOV-12-2015 16:42	RTO	8			
			MAR-27-2014 10:37	RTO	56	NOV-21-2015 17:17	RTO	8			
			APR-14-2014 01:16	RTO	10	DEC-04-2015 22:41	RTO	7			
			APR-25-2014 17:33	RTO	6	DEC-24-2015 17:42	RTO	8			
			MAY-01-2014 14:18	RTO	13						
			MAY-03-2014 17:11	RTO	13						
			MAY-14-2014 01:36	RTO	5						
			JUL-08-2014 03:07	RTO	9						
			JUL-25-2014 19:19	RTO	7						
			SEP-06-2014 13:32	RTO	18						
			SEP-20-2014 23:42	RTO	14						
			SEP-29-2014 10:08	RTO	15						
			OCT-20-2014 06:35	RTO	15						
			OCT-23-2014 11:03	RTO	27						
			NOV-01-2014 06:50	RTO	9						
			NOV-08-2014 02:08	RTO	8						
			NOV-22-2014 05:27	RTO	21						
			NOV-22-2014 08:19	RTO	10						
			DEC-10-2014 18:58	RTO	8						
			DEC-31-2014 21:42	RTO	12						

Figure 10-15 Synchronized reserve events duration distribution curve: 2011 through 2016



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. 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 always less than or equal to the synchronized reserve market clearing price. In most hours, the nonsynchronized reserve clearing price is zero.

Market Structure

Demand

PJM specifies that 1,700 MW of primary reserve must be available in the Mid-Atlantic Dominion Reserve Subzone, of which 1,450 MW must be synchronized reserve (Figure 10-2), and that 2,175 MW of primary reserve must be available in the RTO Reserve Zone of which 1,450 MW must be synchronized reserve (Figure 10-3). The balance of primary reserve can be made up by the most economic combination of synchronized and nonsynchronized reserve.

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 non-synchronized reserve. The hour ahead market solution considers the MW supply of nonsynchronized reserve to be all generation resources currently not synchronized to the grid but available and capable of providing energy within 10 minutes. Generators that have set themselves as unavailable or have set their output to be emergency-only will not be considered. The market solution considers the offered MW to be the lesser of the economic maximum or the ramp rate times10 minutes minus the startup and notification time. The offer price of nonsynchronized is the unit's opportunity cost of providing reserves.

The market solution optimizes synchronized reserve, nonsynchronized reserve, and energy to satisfy the primary reserve requirement at the lowest cost. Nonsynchronized reserve resources are scheduled economically based on LOC until the Primary Reserve requirement is filled. The nonsynchronized reserve market clearing price is determined at the end of the hour based on the LOC of the marginal unit. When a unit clears the nonsynchronized reserve market and is scheduled, it is committed to remain offline for the hour and available to provide 10 minute reserves.

Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[31] In 2016, an average of 341.0 MW of nonsynchronized reserve was scheduled hourly out of 1,726.9 eligible MW as part of the primary reserve requirement in the Mid-Atlantic Dominion Subzone. In 2016, an average of 919.6 MW of nonsynchronized reserve was scheduled hourly out of 2,358.2 MW eligible MW in the RTO Zone.

In 2016, CTs provided 35.0 percent of scheduled nonsynchronized reserve and hydro provided 64.3 percent. The remaining 0.7 percent of cleared nonsynchronized reserve was provided by diesel resources.

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in 2016. PJM market operations increased the required amount of primary reserve from 2,175 MW to 3,195 MW for a 14 hour period on February 22, 2016, in the RTO Zone, and to 3,900 MW

31 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 84 (August 25, 2016), p. 101.

for 16 hours on October 19, 2016. The required primary reserve was increased in the MAD Subzone from 1,700 to 1,775 MW and in the RTO Zone from 2,175 MW to 2,662 MW for 20 hours on April 7 and 8, 2016. The required primary reserve was increased to 2,235 MW in the RTO Zone for 13 hours on September 23, 2016 and to 3,900 MW for 19 hours on October 19, 2016.

Table 10-22 Nonsynchronized reserve market HHIs: 2016

Year	Month	MAD HHI	RTO HHI
2016	Jan	4347	4297
2016	Feb	4002	3981
2016	Mar	3262	3227
2016	Apr	3884	3808
2016	May	3539	3507
2016	Jun	3720	3701
2016	Jul	2887	2884
2016	Aug	2960	2955
2016	Sep	2511	2509
2016	Oct	2645	2638
2016	Nov	3729	3712
2016	Dec	4023	4008
2016	Average	3459	3436

Table 10-23 Nonsynchronized reserve market pivotal supply test: 2016

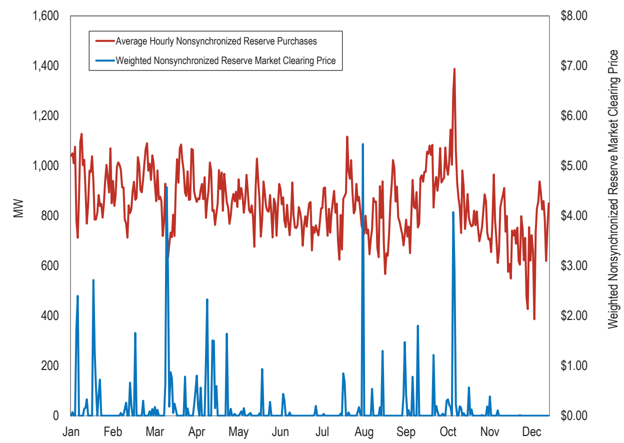
Year	Month	MAD Three Pivotal Supplier Hours	RTO Three Pivotal Supplier Hours
2016	Jan	35.6%	0.0%
2016	Feb	17.0%	0.0%
2016	Mar	12.6%	0.0%
2016	Apr	20.1%	0.0%
2016	May	43.0%	6.6%
2016	Jun	47.1%	1.6%
2016	Jul	98.7%	1.0%
2016	Aug	96.0%	0.0%
2016	Sep	93.7%	5.1%
2016	Oct	76.6%	0.2%
2016	Nov	29.8%	0.0%
2016	Dec	69.3%	0.0%
2016	Average	53.3%	1.2%

Price

The price of nonsynchronized reserve is calculated in real time every five minutes and averaged hourly for the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.

Figure 10-16 shows the daily average nonsynchronized reserve market clearing price and average scheduled MW for the RTO Zone. In the MAD Subzone in 2016, the average nonsynchronized market clearing price was $0.22 per MW. The hourly average nonsynchronized reserve assigned was 850.5 MW. The market cleared at a price greater than $0 in 297 hours. The maximum hourly clearing price was $85.65 per MW on August 11, 2016. The RTO Zone Nonsynchronized Reserve Market had an average nonsynchronized reserve market clearing price of $0.22 per MW. The hourly average reserve assigned was 850.6 MW. The market cleared at a price greater than zero in 284 hours. The maximum hourly clearing price was $85.65 per MW on August 11, 2016.

Figure 10-16 Daily average RTO zone nonsynchronized reserve market clearing price and MW purchased: 2016



Price and Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices sometimes do not cover the full LOC of each resource. All resources cleared in the market are guaranteed to be made whole and are paid uplift credits if the NSRMCP does not fully compensate them.

The full cost of nonsynchronized reserve including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-24). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of non-synchronized reserve.

In 2016, the price to cost ratio of the RTO Zone Nonsynchronized Reserve Market averaged 18.0 percent; and the price to cost ratio of the MAD Subzone averaged 19.9 percent.

Resources that are not synchronized to the grid are generally off because it is not economic for them to produce energy. A resource scheduled for nonsynchronized reserve is obligated to remain unsynchronized even if its LMP changes and it becomes economic to start. In that case, the unit has a positive LOC.

The nonsynchronized reserve market cleared at a price above $0 in only 3.2 percent of hours.

The costs of nonsynchronized reserves could be minimized if PJM committed nonsynchronized reserves in order from lowest LOC to highest and if PJM could flexibly substitute lower LOC units for higher LOC units in real time as system conditions changed. Under current rules, PJM is required to keep committed a unit for which the LOC increases within the hour even if lower LOC units are available as substitutes.

Table 10-24 RTO zone, MAD subzone nonsynchronized reserve MW, charges, price, and cost: 2016

Market	Year	Month	Total Nonsynchronized Reserve MW	Total Nonsynchronized Reserve Charges	Weighted Nonsynchronized Reserve Market Price	Nonsynchronized Reserve Cost	Price/Cost Ratio
RTO Zone Full	2016	Jan	688,475	$1,334,376	$0.30	$1.94	15.6%
RTO Zone Full	2016	Feb	638,024	$672,413	$0.11	$1.05	10.0%
RTO Zone Full	2016	Mar	657,739	$405,829	$0.31	$0.62	49.6%
RTO Zone Full	2016	Apr	644,913	$786,978	$0.35	$1.22	28.5%
RTO Zone Full	2016	May	636,927	$274,583	$0.05	$0.43	10.9%
RTO Zone Full	2016	Jun	579,356	$613,656	$0.04	$1.06	3.6%
RTO Zone Full	2016	Jul	604,267	$407,660	$0.07	$0.67	9.6%
RTO Zone Full	2016	Aug	585,751	$782,948	$0.25	$1.34	18.6%
RTO Zone Full	2016	Sep	616,146	$666,839	$0.15	$1.08	13.9%
RTO Zone Full	2016	Oct	722,690	$650,190	$0.42	$0.90	46.8%
RTO Zone Full	2016	Nov	554,057	$308,101	$0.03	$0.56	4.7%
RTO Zone Full	2016	Dec	525,505	$289,433	$0.00	$0.55	0.1%
RTO Zone Full	2016	Total	7,453,849	$7,193,007	$0.17	$0.95	18.0%
RTO Subzone	2016	Jan	3,376	$182,114	$4.17	$53.95	7.7%
RTO Subzone	2016	Feb	2,749	$51,558	$1.35	$18.76	7.2%
RTO Subzone	2016	Mar	9,288	$143,803	$2.68	$15.48	17.3%
RTO Subzone	2016	Apr	4,946	$165,834	$1.29	$33.53	3.9%
RTO Subzone	2016	May	2,622	$23,293	$0.15	$8.88	1.7%
RTO Subzone	2016	Jun	1,180	$17,851	$0.08	$15.13	0.5%
RTO Subzone	2016	Jul	386	$28,584	$0.81	$74.02	1.1%
RTO Subzone	2016	Aug	712	$107,938	$1.67	$151.68	1.1%
RTO Subzone	2016	Sep	269	$60,820	$3.52	$226.02	1.6%
RTO Subzone	2016	Oct	760	$48,744	$0.20	$64.16	0.3%
RTO Subzone	2016	Nov	1,033	$15,137	$0.04	$14.65	0.3%
RTO Subzone	2016	Dec	732	$3,862	$0.00	$5.27	0.0%
RTO Subzone	2016	Total	28,053	$849,538	$1.33	$56.79	2.3%
MAD	2016	Jan	685,099	$1,152,262	$0.28	$1.68	16.9%
MAD	2016	Feb	635,275	$620,855	$0.10	$0.98	10.3%
MAD	2016	Mar	648,451	$262,026	$0.27	$0.40	67.3%
MAD	2016	Apr	639,967	$621,144	$0.34	$0.97	35.0%
MAD	2016	May	634,305	$251,290	$0.05	$0.40	11.8%
MAD	2016	Jun	578,176	$595,805	$0.04	$1.03	3.7%
MAD	2016	Jul	603,881	$379,077	$0.06	$0.63	10.3%
MAD	2016	Aug	585,040	$675,010	$0.25	$1.15	21.4%
MAD	2016	Sep	615,877	$606,019	$0.15	$0.98	15.1%
MAD	2016	Oct	721,930	$601,446	$0.42	$0.83	50.6%
MAD	2016	Nov	553,023	$292,964	$0.03	$0.53	4.9%
MAD	2016	Dec	524,773	$285,572	$0.00	$0.54	0.1%
MAD	2016	Total	7,425,796	$6,343,470	$0.17	$0.84	19.6%

Secondary Reserve

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

PJM maintains a day-ahead, offer based market for 30-minute day-ahead secondary reserve.[32] The Day-Ahead Scheduling Reserves 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.[33]

Market Structure

Supply

DASR is offered by both generation and demand resources. DASR offers consist of price only. 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 thirty minutes, or the economic maximum MW minus the day-ahead dispatch point. For offline resources capable of being online in thirty minutes, the DASR quantity is the economic maximum. In 2016, the average available hourly DASR was 34,775 MW. This is a 4.7 percent decrease from 36,396.0 MW in 2015. The DASR hourly MW purchased averaged 6,072.5 MW, a small decrease from 6,113.1 MW in 2015. The market solution results in resources being scheduled.

The MMU recommends that PJM implement a real-time secondary reserve market.

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.[34] The intent of this proposal is to limit cleared DASR resources to those resources actually capable of providing reserves in the real-time market. Owners of excluded resources may request an exemption from their default non-eligibility.

On December 14, 2015, PJM announced a plan to recover DASR credits awarded to owners for units that clear the day-ahead scheduled reserve market but become unavailable through forced outage in real time.[35] The recovery would be for hours cleared from April 2015 through March 2016. This recovery is now expected to be implemented as a billing adjustment in the first quarter of 2017.

All generation resources are required to offer a price for DASR.[36] Of the 6,072.5 MW average hourly DASR cleared in 2016, 59.7 percent was from CTs, 13.4 percent was from steam, 18.0 percent was from hydro, and 7.6 percent was CCs. Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are eligible to provide DASR. In 2016, seven demand resources offered into the DASR Market.

Demand

Secondary reserve (30-minute reserve) requirements are determined by PJM for each reliability region. In the Reliability*First* (RFC) region, secondary reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[37] The RFC and Dominion secondary reserve requirements are added together to form a single RTO DASR requirement defined as a percent of the daily peak load forecast. For 2016, the DASR requirement is set to 5.70 percent of daily peak load forecast. This is down from 5.93 percent of peak load forecast for 2015. The DASR requirement is applicable for all hours of the operating day.

Effective March 1, 2015, the DASR requirement can be increased by PJM dispatch under conditions of "hot weather or cold weather alert or max emergency generation alert or other escalating emergency."[38] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[39] 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 2015 through October 2016, the SCD values are 3.45 percent for winter and 2.88 percent for summer. PJM Dispatch may also schedule additional Day-

32 See PJM. "Glossary,"<http://www.pjm.com/Glossary.aspx>.

33 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 166 §11.1.

34 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 169 §11.2.3 Day-Ahead Scheduling Reserve Market Rules.

35 See PJM Market Settlements Subcommittee Meeting, December 14, 2015, "Item 01 – CT LOC Reconciliation," <http://www.pjm.com/~/media/committees-groups/subcommittees/mss/20151214/20151214-item-01-ct-loc-reconciliation.ashx>.

36 See PJM Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 144 §11.2.3 Day-Ahead Scheduling Reserve Market Rules.

37 Manual 13: Emergency Operations," Revision 61 (January 1, 2017), p. 12.

38 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>.

39 See PJM. "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 11, 2016) p. 166 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.

Ahead Scheduling Reserves as deemed necessary for conservative operations.[40] 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.[41] The net result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances.

PJM invoked AFD on 14 days in 2015. In 2016, PJM invoked AFD on 22 days, averaging an additional fixed demand of 4,545.2 MW for each hour. A record of PJM's use of AFD is in Table 10-25. The use of AFD (and other conservative operations adjustments) impacts the DASR Market in several significant ways. Among them are higher clearing prices, more cleared units awarded DASR credits, and the payment of operating reserves and LOC to resources which have to be backed down uneconomically in order to meet the increase in combined day-ahead energy/secondary reserves.

Table 10-25 Adjusted Fixed Demand Days: 2016

Date	Number of Hours	Average Additional MW
14-Feb	24	3,008
7-Jul	24	4,609
8-Jul	24	3,636
14-Jul	24	5,762
15-Jul	24	2,826
18-Jul	24	2,826
22-Jul	24	2,506
23-Jul	24	3,388
24-Jul	24	4,273
25-Jul	24	4,186
26-Jul	24	5,388
27-Jul	24	4,553
28-Jul	24	4,444
12-Aug	24	4,982
13-Aug	24	6,023
14-Aug	23	4,716
15-Aug	24	5,284
16-Aug	24	5,050
29-Aug	24	5,006
8-Sep	24	5,969
9-Sep	19	5,245
10-Sep	24	6,310

An alternative to DASR would be to schedule secondary reserve in the real time market. The MMU recommends that PJM replace the DASR Market with a real-time secondary reserve product that is available and dispatchable in real time.

Market Concentration

From January 1, 2012 to April 30, 2015, no hours would have failed a three pivotal supplier test in the DASR Market. Beginning in May 2015, when PJM began to invoke adjusted fixed demand for conservative operations, the DASR Market began to fail the three pivotal supplier test (Table 10-26).

Table 10-26 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0: 2015 through 2016

Year	Month	Number of Hours When DASRMCP > $0	Percent of Hours Pivotal
2015	Jan	151	0.0%
2015	Feb	328	0.0%
2015	Mar	300	0.0%
2015	Apr	301	0.0%
2015	May	323	3.9%
2015	Jun	349	11.2%
2015	Jul	496	28.1%
2015	Aug	482	21.5%
2015	Sep	532	11.4%
2015	Oct	634	0.3%
2015	Nov	568	0.0%
2015	Dec	473	0.4%
2015	Average	411	6.4%
2016	Jan	326	0.3%
2016	Feb	235	0.4%
2016	Mar	369	1.9%
2016	Apr	392	0.0%
2016	May	259	4.2%
2016	Jun	193	6.2%
2016	Jul	474	38.0%
2016	Aug	402	42.8%
2016	Sep	383	45.7%
2016	Oct	373	35.1%
2016	Nov	351	20.8%
2016	Dec	209	23.9%
2016	Average	331	18.3%

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.[42] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The marginal cost of providing DASR is zero. All offers greater than zero constitute economic

40 See PJM "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) p. 167 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.

41 See PJM, "Manual 13: Emergency Operations" Revision 61, (January 1e 2017), p. 53 at 3.2 Conservative Operations

42 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 168.

withholding. In 2016, 36.2 percent of generation units offered DASR at a daily price above $0.00. This compares to 37.9 percent in 2015. In 2016, 13.3 percent of daily offers were above $5.00 per MW.

Market Performance

Between May and September 2015, the use of Adjusted Fixed Demand (AFD) by PJM Market Operations significantly increased the demand for DASR in 366 hours. For 45.2 percent of hours in 2016, DASR cleared at a price above $0.00 per MWh (Figure 10-17). In 2016, there were 22 AFD days. In 2015, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $2.99. In 2016, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.61. The average cleared MW in all hours was 4,996.8 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 6,066.1 MW. The highest DASR price was $72.92 on August 12, 2016.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market (Table 10-27). 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. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial. During the 522 hours when AFD was in effect, the weighted average DASR price was $9.30 compared to $2.69 for hours when DASRMCP was greater than $0.00 and PJM dispatch did not augment the requirement.

While the new rules allow PJM dispatch substantial discretion to add to DASR demand for a variety of reasons, the rationale for each specific increase is not always clear. The MMU recommends that PJM Market Operations attach a reason code to every hour in which PJM dispatch adds additional DASR MW above the default DASR hourly requirement. The addition of such a code would make the reason explicit, increase transparency and facilitate analysis of the use of PJM's ability to add DASR MW.

Table 10-27 DASR Market, regular hours vs. adjusted fixed demand hours: 2015 and 2016

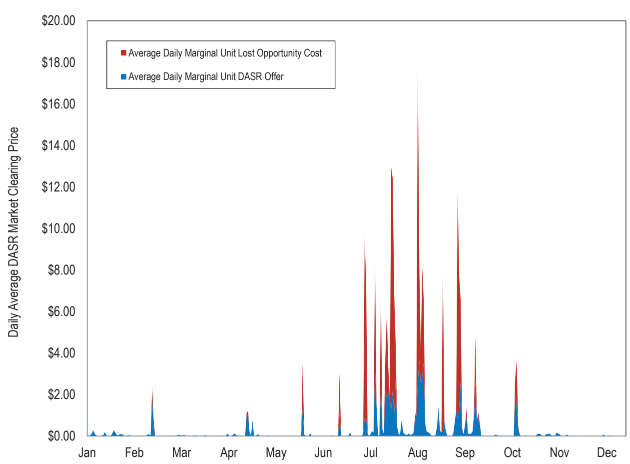
		Number of Hours DASRMCP>$0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2015	Jan	151		$0.19		112,373		4,902		$937	
2015	Feb	328		$4.03		113,797		4,868		$19,610	
2015	Mar	300		$0.59		96,315		4,116		$2,429	
2015	Apr	301		$0.04		80,798		4,085		$155	
2015	May	279	44	$3.66	$12.34	92,863	96,726	4,574	9,042	$16,750	$111,598
2015	Jun	255	94	$0.92	$13.82	104,388	105,190	5,152	8,895	$4,724	$122,908
2015	Jul	410	86	$1.36	$18.56	106,605	114,868	5,553	9,599	$7,565	$178,164
2015	Aug	459	23	$0.95	$14.79	105,509	110,753	5,766	9,701	$5,483	$143,459
2015	Sep	412	120	$0.31	$14.63	91,491	109,028	5,003	11,337	$1,550	$165,870
2015	Oct	634		$0.35		77,657		4,231		$1,500	
2015	Nov	568		$0.29		80,844		4,477		$1,279	
2015	Dec	473		$0.13		87,166		4,807		$617	
2015	Average	381	73	$1.07	$14.83	95,817	107,313	4,794	9,715	$5,217	$144,400
2016	Jan	326		$0.15		103,263		4,723		$720	
2016	Feb	212	24	$0.05	$3.10	102,040	107,852	4,640	6,830	$249	$21,167
2016	Mar	369		$0.04		83,994		4,175		$175	
2016	Apr	393		$0.26		80,925		4,083		$1,060	
2016	May	259		$0.43		89,181		4,228		$1,839	
2016	Jun	191		$0.53		111,102		5,377		$2,892	
2016	Jul	188	288	$0.71	$8.23	117,686	112,587	5,794	10,226	$4,117	$84,195
2016	Aug	247	143	$0.76	$10.82	122,187	113,823	6,076	11,150	$4,639	$120,663
2016	Sep	316	67	$1.11	$11.53	100,198	110,940	5,231	12,163	$5,792	$138,972
2016	Oct	373	0	$0.58	$0.00	82,824	0	4,265		$2,494	
2016	Nov	350	0	$0.10	$0.00	84,561	0	4,095		$420	
2016	Dec	210	0	$0.04	$0.00	102,293	0	4,444		$169	
2016	Average	286	75	$0.40	$4.81	98,355	63,600	4,761	10,092	$2,047	$91,249

The implementation of AFD in 367 hours of 2015 and 528 hours of 2016 significantly increased the cost of DASR as a result of increases in DASR MW cleared and corresponding increases in the DASR clearing prices (Table 10-28).

Table 10-28 DASR Market all hours of DASR market clearing price greater than $0: 2015 through 2016

Year	Month	Number of Hours DASRMCP > $0	Weighted DASR Market Clearing Price	Average Hourly RT Load MW	Total PJM Cleared DASR MW	Total PJM Cleared Additional DASR MW	Total Charges
2015	Jan	151	$0.19	112,373	740,268	0	$141,561
2015	Feb	328	$4.03	113,797	1,596,639	0	$6,431,987
2015	Mar	300	$0.59	96,315	1,234,905	0	$728,829
2015	Apr	301	$0.04	80,798	1,229,513	0	$46,584
2015	May	323	$5.73	93,389	1,673,983	159,559	$9,583,568
2015	Jun	349	$5.93	104,604	2,150,052	294,881	$12,757,966
2015	Jul	496	$5.94	108,038	3,102,087	260,120	$18,423,687
2015	Aug	482	$2.03	105,759	2,869,630	59,414	$5,816,401
2015	Sep	532	$6.00	95,447	3,421,690	525,883	$20,542,872
2015	Oct	634	$0.35	77,657	2,682,429	0	$951,264
2015	Nov	568	$0.29	80,844	2,542,795	0	$726,549
2015	Dec	473	$0.13	87,166	2,273,497	0	$291,725
2015	Average	411	$2.60	96,349	2,126,457	108,321	$6,370,250
2015	Total	4937			25,517,488	1,299,858	$76,442,995
2016	Jan	326	$0.15	103,263	1,539,783	0	$234,679
2016	Feb	212	$0.49	102,631	1,147,608	72,197	$560,692
2016	Mar	369	$0.04	83,994	1,540,415	0	$64,728
2016	Apr	393	$0.26	80,925	1,604,693	0	$416,418
2016	May	259	$0.43	89,181	1,094,991	0	$476,305
2016	Jun	191	$0.54	111,102	1,027,053	0	$552,455
2016	Jul	476	$6.20	114,601	4,034,436	1,161,661	$25,022,218
2016	Aug	390	$5.94	119,563	3,095,240	742,332	$18,400,638
2016	Sep	383	$4.51	102,077	2,467,814	409,330	$11,141,362
2016	Oct	373	$0.58	82,824	1,591,016	0	$930,355
2016	Nov	350	$0.10	84,561	1,433,267	0	$147,023
2016	Dec	210	$0.04	102,292	933,225	0	$33,582
2016	Average	328	$1.61	98,085	1,792,462	198,793	$4,831,704
2016	Total	3932			21,509,542	2,385,520	$57,980,453

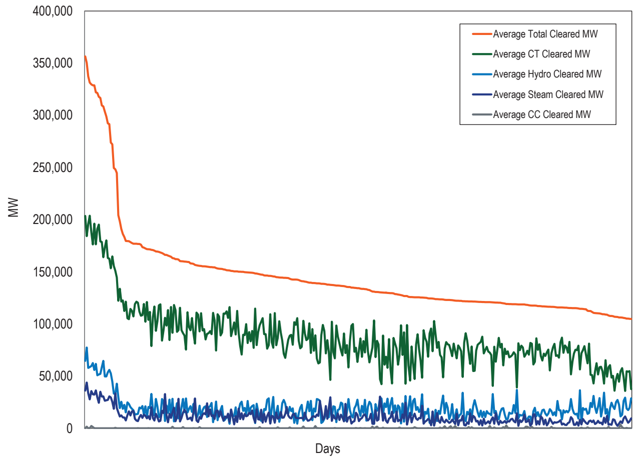
Figure 10-17 Daily average components of DASR clearing price ($/MW), marginal unit offer and LOC: 2016



When the DASR requirement is increased by PJM dispatch, the reserve requirement frequently cannot be met without redispatching online resources which significantly affects the price by creating an LOC. (Figure 10-17) DASR prices increase at peak loads as a result of high LOCs. For the first six months of 2016, with the exception of three days (February 14, May 26, and June 20, 2016) DASR prices were low to moderate and did not include any LOC. The third quarter of 2016 saw a significant number of AFD hours (504 hours) and a corresponding increase in the number of high DASR price days.

The red at the top of each high-priced day in Figure 10-17 shows the degree to which prices were determined by the LOC of the marginal unit(s). Figure 10-18 shows that when total DASR MW required is at its peak, a higher share of MW come from on line steam and CT units. While CTs have a low DASR related cost, steam units typically incur an LOC when redispatched to provide DASR. The redispatch of steam units to provide DASR has a significant impact on DASR prices.

Figure 10-18 Daily average DASR MW by unit type sorted from highest to lowest daily requirement: 2016



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. Significant technical and structural changes were made to the PJM Regulation Market in 2012.[43]

Market Design

The objective of PJM's regulation market design is to minimize the cost to provide regulation using two resource types, RegA and RegD, in a single market. The RegA signal is designed for energy unlimited resources (for example, thermal and/or hydro resources) with physically constrained ramp ability. The RegD signal is designed for energy limited resources with very fast ramp rates. Some resource types (such as some Combustion Turbines) can qualify as both RegA and RegD.

Regulation was historically provided by resources following the RegA signal. Since regulation service could be provided solely with RegA following resources, performance adjusted RegA MW are used as the common unit of measure, called effective MW, of regulation service provided in the PJM Regulation Market. The regulation requirement (the amount of regulation MW needed to control for ACE) is defined in terms of the total effective MW required to provide an expected amount of area control error (ACE) control.

In concept, the Regulation Market solution starts with an assumption of the effective regulation requirement being met entirely with performance adjusted RegA MW. When solving for the least cost combination of RegA and RegD MW to meet the effective regulation requirement, the Regulation Market will substitute RegD MW for RegA MW so long as it is economic (reduces total cost while maintaining a fixed level of control) to do so. The Regulation Market functions by converting performance adjusted RegD MW into their marginal effective MW equivalent using a marginal rate of technical substitution (MRTS) called a marginal benefit factor (MBF) function. The MBF is used to convert incremental additions of RegD MW into incremental effective MW. Correctly implemented, the total effective MW for a given amount of RegD MW are determined by the area under the MBF curve (the sum of the incremental effective MW contributions). This conversion into a common unit of measure allows a direct comparison of RegA and RegD offers. The MBF reflects the fact that each additional MW of RegD has a progressively smaller value defined as incremental effective MW. Total regulation provided by a given combination of RegA and RegD is defined in terms of total effective MW. In a correctly implemented market structure, all resources, either RegA or RegD, would be paid the same price per marginal effective MW provided.

To meet the objective of minimizing cost, the MBF function describing the engineering substitutability between RegA and RegD must be correctly defined and consistently applied throughout the market design, from optimization to settlement. Correctly implemented, the MBF would define and be used as the marginal rate of technical substitution (MRTS) between RegA and

43 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services," p. 271.

RegD, holding regulation service constant. Consistently applying the MBF from optimization to settlement is the only way to ensure that the engineering relationship is reflected in the relative value of RegA and RegD resources in the market price signals. That is not the case in PJM's current regulation market design. The MBF function is not correctly defined as the MRTS between RegA and RegD and it is not consistently applied throughout the market design, from optimization to settlement.

The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most hours and has provided a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. 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 MBF related issues with the Regulation Market have been raised in the PJM stakeholder process. In 2015, PJM stakeholders approved an interim, partial fix to the RegD over procurement problem which was implemented on December 14, 2015. The interim fix was designed to reduce the relative value of RegD MW in the optimization in all hours and to cap purchases of RegD MW during critical performance hours. But the interim fix did not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF. Additional changes were approved by the Regulation Market Issues Senior Task Force (RMISTF) in 2016, with an implementation date of January 2017, that introduced new signal designs and regulation requirements intended to improve system performance. These modifications include changing the definition of off-peak and on-peak hours (now called off-ramp and on-ramp hours) based on the season, increasing the effective MW requirement during on-ramp hours from 700 MW to 800 MW, 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. Like the interim fix implemented on December 14, 2015, the latest market changes still do not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF. The MMU and PJM are pursuing a comprehensive solution through the Regulation Market Issues Senior Task Force ("RMISTF").

Market solution software relevant to regulation consists of the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT-SCED) solving every 15 minutes; and the real-time security constrained economic dispatch market solution (RT-SCED) solving every five minutes. The market clearing price is determined by the Locational Pricing Calculator (LPC) that looks at the units cleared in the RT-SCED 15 minutes ahead of the pricing interval. The marginal price as identified by the LPC for each of these intervals is then averaged over the hour for an hourly regulation market clearing price.

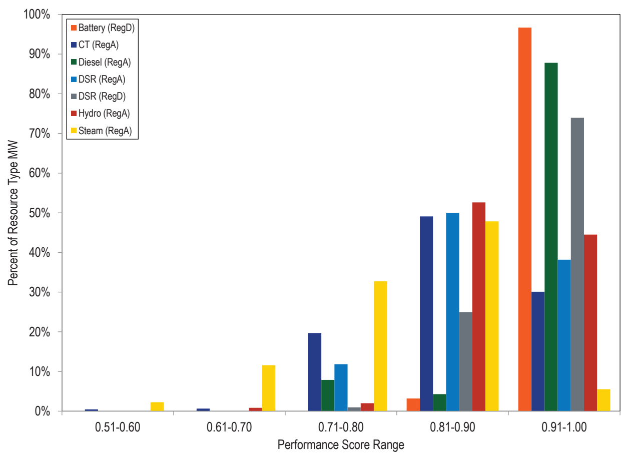
The regulation market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE (area control error). RegA is PJM's slow-oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, with slower ramp rates. RegD is PJM's fast-oscillation regulation signal and is designed for resources with limited ability to sustain energy output and with faster ramp rates. Resources must qualify to follow one or both of the RegA and RegD signals, but will be assigned by the market clearing engine to follow only one signal in a given market hour. The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW being offered); performance ($/mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The marginal benefit factor and performance score translate a RegD resource's capability (actual) MW into marginal effective MW and offers into $/effective MW.

The absence of a 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 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.[44]

Figure 10-19 and Figure 10-20 show the average performance score by resource type and the signal followed for 2016. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[45] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-20 shows, 95.9 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 18.1 percent of RegA resources had average performance scores within that range.

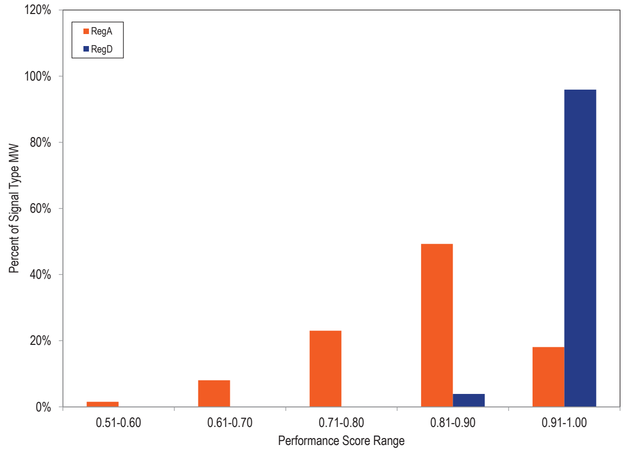
Figure 10-19 Hourly average performance score by unit type: 2016



44 PJM "Manual 12: Balancing Operations," Rev. 36 (February 1, 2017) at 4.5.6, p 54.

45 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either marginal benefit factor or performance factor.

Figure 10-20 Hourly average performance score by regulation signal type: 2016



PJM creates an individual resource's regulation signal by comparing the individual resource's TREG signal to the resource's MW output (or, for DR, load) to calculate the performance score based on delay, correlation, and precision. Performance scores are calculated using data every 10 seconds, but are reported on an hourly basis for each individual regulating resource.

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. The optimization of RegA and RegD assignments is dependent on the conversion of RegA and RegD MW into a common unit of measure (effective MW). The marginal benefit factor (MBF) is the marginal measure of substitutability of RegD resources for RegA resources in satisfying the regulation requirement at any combination of RegA and RegD MW that can be used to meet the regulation requirement.

The MBF, as the marginal rate of technical substitution between RegA and RegD resource MW for a given regulation requirement, defines specific combinations of RegA and RegD MW needed to meet specific regulation performance levels, defined as the amount of regulation that would be provided by a specified amount of RegA MW alone (which is the total effective MW requirement defined in terms of MW of RegA). The use of the MBF in the optimization should result in the selection of the least cost combination/ratio of RegA and RegD MW that achieves this level of specified regulation service when the prices of RegA and RegD are known. PJM's optimization engine has not properly implemented the MBF so that the market clearing combination of RegA and RegD MW is consistent with the combinations defined by the MBF curve.

At any valid combination of RegA and RegD, regulation offers are converted to dollars per effective MW by dividing the RegD offer by the corresponding MRTS associated with that combination of RegA and RegD. The marginal contribution of a RegD MW to total effective MW at a valid RegA/RegD combination is equal to the MRTS associated with that RegA/RegD combination.

For example, a 1.0 MW RegD resource with a total offer price of $2/MW with a marginal benefit factor of 0.5 and a performance score of 100 percent, would be calculated as offering 0.5 effective MW (0.5 marginal benefit factor times 1.00 performance score times 1 MW). The total offer price would be $4 per effective MW ($2/MW offer divided by the 0.5 effective MW).

PJM's market design does not correctly calculate total effective RegD MW. Under PJM's method, cleared RegD MW are converted to total effective MW by multiplying each resource's offered MW by the product of the resource specific marginal benefit factor and performance score. This resource specific block assignment approach undercounts total effective MW because the method fails to count part of the area under the MBF curve. Total effective RegD MW are correctly calculated as the area under the MBF curve.

Market Design Issues

Marginal Benefit Factor Not Reflected Consistently or Correctly in Market

The marginal benefit factor function is incorrectly defined and improperly implemented in the current PJM Regulation Market. The market results do not represent the least cost solution that is consistent with a specific level of regulation service.

Properly defined, the marginal benefit factor is the marginal rate of technical substitution between RegA and RegD MW at specific combinations of RegA and RegD that can be used to provide a defined level of regulation service. The specific combinations of RegA and RegD that can be used to provide a defined level of regulation service are feasible combinations of RegA and RegD. 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 marginal benefit factor 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.

The marginal benefit factor 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 adhered to a FERC order that required the marginal benefit factor be fixed at 1.0 for settlement calculations only. On October 2, 2013, the FERC directed PJM to eliminate the use of the marginal benefit factor 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.[46]

The result of the FERC directive is that the marginal benefit factor is used in the optimization (currently using the incorrect PJM MBF) to determine the relative value of additional MW of RegD, but the marginal benefit factor is not used in the settlement for RegD.

Resources are paid Regulation Market Clearing Price (RMCP) credits and lost opportunity cost credits. If a resource's lost opportunity costs for an hour are greater than its RMCP credits, that resource receives lost opportunity cost credits equal to the difference. PJM posts clearing prices for the Regulation Market (RMCCP, RMPCP and RMCP) in dollars per effective MW. The regulation market clearing price (RMCP in $/effective MW) for the hour is the simple average of the twelve 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

46 145 FERC ¶ 61,011 (2013).

the difference between the RMCP for the hour and the RMPCP for the hour.

If the marginal benefit factor were consistently applied in the optimization, clearing, pricing and settlement, every resource would receive the same clearing price per marginal effective MW provided to the system. Because the marginal benefit factor is not consistently applied in the optimization, clearing, pricing and settlement, resources do not receive the same clearing price per marginal effective MW provided to the system.

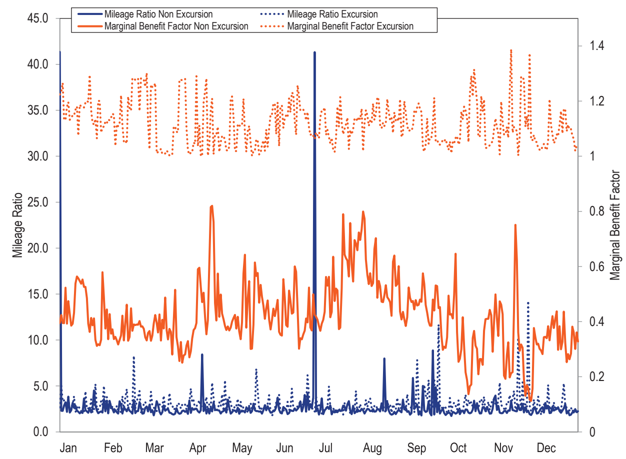
While prices are set on the basis of dollars per effective MW, only RegA resources receive payments (credits) that are consistent with this price per effective MW (RMCP).[47] RegA resources are paid the RMCCP per effective MW plus the RMPCP per effective MW. RegD resources do not receive payments consistent with this price per effective MW. RegD resources are paid the RMCCP per performance adjusted MW (not per effective MW) plus the RMPCP times the mileage ratio per performance adjusted MW (not per effective MW).[48] As a result the current market design does not send the correct price signal to the RegD resources.

Figure 10-21 compares the daily average marginal benefit factor and the mileage ratio for excursion and nonexcursion hours. Excursion hours (hours ending 7:00, 8:00, 18:00-21:00) are hours in which PJM has decided that more RegA is needed and has therefore limited the minimum marginal benefit factor that can be assigned to RegD MW to 1.0.[49] Once this limit is reached, the remaining regulation requirement satisfied with RegA MW.

The very high mileage ratios on January 1, 2016, and June 28, 2016, were a result of the mechanics of the mileage ratio calculation. The extreme mileage ratios result when the RegA signal is fixed to control ACE and the RegD signal is not. The result of a fixed RegA signal is that RegA mileage is very small and therefore the mileage ratio of RegD/RegA is very large.

This result demonstrates why it is not appropriate to use the mileage ratio, rather than the marginal benefit factor, to measure the relative value of RegA and RegD resources. In these events RegA resources are providing ACE control (regulation service) despite not changing MW output (no mileage), while the change in MW output from RegD resources (positive mileage) is alternating between helping and hurting ACE control.

Figure 10-21 Daily average marginal benefit factor and mileage ratio during excursion and nonexcursion hours: 2016



The current settlement process does not result in RegA and RegD resources being paid the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the marginal benefit factor is not used in settlements. When the marginal benefit factor is above one, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the marginal benefit factor is less than one, RegD resources are generally overpaid on a per effective MW basis. Currently, the marginal benefit factor is generally less than one, resulting in persistent overpayment of RegD resources.

The effect of using the mileage ratio instead of the marginal benefit factor to convert RegD MW into effective MW for purposes of settlement is illustrated in Table 10-29. Table 10-29 provides the monthly average payment by RegD per effective MW realized under the current, incorrect mileage ratio based settlement process and compares it to the dollar per effective MW that is

47 This is due to the fact that RegA resources performance adjusted MW are their effective MW as the MRTS of RegA resources is always equal to one, as effective MW are defined in terms of RegA performance adjusted MW.

48 Performance adjusted RegD MW are converted to effective MW by multiplying the performance adjusted MW by the market clearing MRTS.

49 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.7, p 70.

being paid to RegA MW and should be paid to RegD MW based on the MRTS based settlement process for each month in 2015 and 2016. As a result of the relative amount of RegD being procured, as well as the changes to the MRTS slope that went into effect on December 14, 2015, the MRTS averaged less than one in each month of 2016, resulting in RegD resources being paid $14.6 million (1,565.7 percent) more than they should have in 2016. In 2015, the MRTS averaged greater than one, resulting in RegD resources being paid $24.2 million (28.0 percent) less than they should have been.

Table 10-29 Average monthly price paid per effective MW of RegD and RegA under mileage and MRTS based settlement: 2015 through 2016.

		RegD Settlement Payments			
Year	Month	Mileage Based ($/Effective RegD MW)	Marginal Rate of Technical Substitution Based ($/Effective RegD MW)	RegA ($/Effective MW)	Percent RegD Under/Over Payment
2015	Jan	16.19	26.89	26.89	(39.8%)
	Feb	38.86	71.48	71.48	(45.6%)
	Mar	27.02	44.68	44.68	(39.5%)
	Apr	18.88	31.82	31.82	(40.7%)
	May	24.53	41.87	41.87	(41.4%)
	Jun	16.00	25.61	25.61	(37.5%)
	Jul	14.97	23.81	23.81	(37.1%)
	Aug	13.00	20.50	20.50	(36.6%)
	Sep	19.07	28.92	28.92	(34.1%)
	Oct	17.25	22.96	22.96	(24.9%)
	Nov	17.84	21.44	21.44	(16.8%)
	Dec	49.53	19.20	19.20	158.0%
Yearly Average		22.57	31.32	31.32	(28.0%)
2016	Jan	30.61	15.60	15.60	96.2%
	Feb	43.33	17.56	17.56	146.8%
	Mar	70.02	13.21	13.21	430.1%
	Apr	90.59	18.87	18.87	380.1%
	May	449.89	15.42	15.42	2,817.9%
	Jun	181.02	13.81	13.81	1,210.8%
	Jul	782.84	17.48	17.48	4,378.3%
	Aug	43.91	17.15	17.15	156.1%
	Sep	1,057.96	17.47	17.47	5,954.5%
	Oct	166.40	15.44	15.44	977.9%
	Nov	36.01	13.01	13.01	176.8%
	Dec	57.00	11.15	11.15	411.4%
Yearly Average		258.17	15.50	15.50	1,565.7%

Figure 10-22 shows, for 2016, the maximum, minimum and average marginal benefit factor, based on PJM's incorrect marginal benefit factor curve, by month, for excursion and nonexcursion hours. The average MBF during excursion hours for 2016 was 1.12, and the average MBF during nonexcursion hours for 2016 was 0.41. The average MBF for all hours in 2015 was 1.80. The marginal benefit factor (MBF) levels were a result of changes in the marginal benefit factor curve made effective on December 14, 2015, which reduced the relative value of RegD MW in the optimization in all hours. The slope of the benefit factor curve was changed to alter where it intercepts the x-axis, defined in terms of RegD MW as a percent of the regulation requirement, to 40 percent instead of 62 percent. PJM also capped the procurement of RegD MW during excursion hours at the point where the MBF on the curve is equal to 1.0.

Figure 10-22 Maximum, minimum, and average PJM calculated marginal benefit factor by month for excursion and nonexcursion hours: 2016

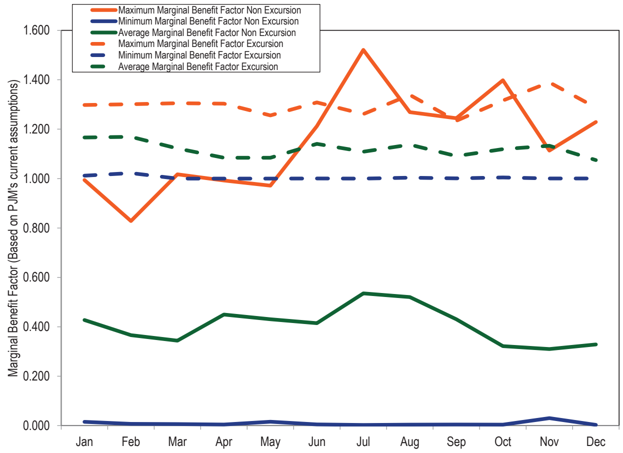
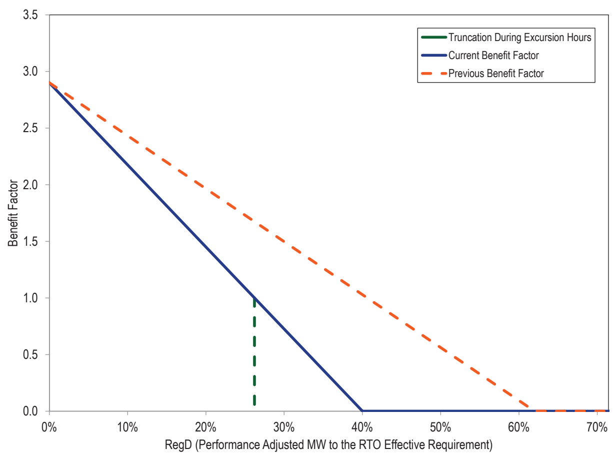


Figure 10-23 shows the marginal benefit factor curve (as incorrectly defined by PJM) before and after the December 14, 2015, modification. The modification to the marginal benefit factor curve reduced the amount of RegD procured, but did not correct for identified issues with the optimization engine.

Correcting the issues with the optimization engine would require correctly defining and using the marginal benefit factor curve, rather than continuing to incorrectly define the MBF as RegD MW cleared as a percentage of the effective MW target.

Figure 10-23 Marginal benefit factor curve before and after December 14, 2015, revisions by PJM



The MMU recommends that the Regulation Market be modified to incorporate a consistent and correct application of the marginal benefit factor throughout the optimization, assignment and settlement process.[50]

Incorrect MBF and Inconsistent Application of MBF in Optimization Causing Incorrect Proportion of RegD MW to Be Purchased

The current PJM MBF incorrectly defines the contribution of RegD MW as a percent of the regulation requirement rather than using the correct MBF, defined as the marginal rate of technical substitution between RegA and RegD.

As a result, the market clearing engine is not correctly maintaining the shares of RegA and RegD that are the basis of the MBF function. The MBF, as the marginal rate of technical substitution between RegA and RegD resource MW for a given regulation requirement, defines specific combinations/ratios of RegA and RegD MW that are needed to meet specified regulation performance goals. Properly implemented, the use of the MBF should result in the selection of the least cost combination of RegA and RegD MW.

Instead, the current market clearing engine uses the incorrect MBF function to adjust RegD offers (both MW and price) for purposes of rank ordering RegA and RegD resources in the supply stack and then clears RegA and RegD resources in price order until the calculated effective MW target is reached. In other words, PJM's market clearing engine rank orders resources by prices and then clears them as a single supply stack at the point of intersection of cumulative effective supply and the regulation requirement. Self scheduling or pricing at zero causes RegD resources to appear at the bottom of the supply stack, forcing the clearing engine to take the RegD MW so long as the MBF is greater than zero. This market clearing is done without confirming that the resulting combinations of RegA and RegD are feasible and can meet the defined demand for regulation. This guarantees that an increasing proportion of RegD MW in the market incorrectly appears as a cheap feasible source of incremental effective regulation MW regardless of whether there is sufficient RegA MW clearing the market to support this market solution.

50 See "Regulation Market Review," presented at the May 5, 2015 Operating Committee meeting. <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>.

The market design, combined with an increasing proportion of RegD offering at an effective price of zero, is that the market clears too much RegD relative to RegA MW.

This is illustrated in Table 10-30, for both the MBF curve used prior to December 14, 2015, and the current MBF curve. In Table 10-30, the contribution to the total regulation requirement of 700 MW for an on peak hour is given on both a performance adjusted actual RegD MW and effective RegD MW basis. For example, if the market cleared 280 MW of performance adjusted RegD (40 percent of the 700 performance adjusted MW needed) at a price of zero, the market clearing engine would determine it would need 149.9 MW of RegA to meet the 700 MW requirement using the previous MBF curve, and would need 294.0 MW using the current MBF curve. The resulting proportion of RegD to total regulation cleared would be 65 percent and 49 percent for the previous and current MBF curves, rather than the 40 percent that was assumed by the MBF function. Although there is a smaller difference between the proportion of RegD cleared under the current MBF curve and the correct amount, as compared to that of the previous MBF curve, the error still persists and is not eliminated by simply adjusting the curve. A full correction requires that the proportions assumed in the curve are maintained through the market clearing process.

The Effective MW of Regulation Purchased Are Understated

In 2015, the MMU determined that the regulation market optimization/market solution was understating the amount of effective MW provided by RegD. Rather than correctly calculating the total effective MW contribution of RegD MW based on the area under the marginal benefit factor curve, the regulation market optimization assigns the MBF associated with the last MW of a cleared unit to every MW of that unit (unit block). PJM calculates the total effective MW of a unit as the simple product of the MW and the MBF, rather than the area under the MBF. The result is that 100 MW of RegD (performance adjusted) provided by a single resource (one 100 MW unit) will appear to provide fewer total effective MW than 100 MW (performance adjusted) provided by two separate 50 MW units although they provide exactly the same total effective MW.

In addition, the MMU determined that the regulation market optimization/market solution treats all RegD resources with the same effective price as a single resource (price block) for purposes of assigning a benefit factor and calculating total effective MW. This means that all of the MW associated with multiple units with the same effective price (for example a price of zero) were assigned the MBF of the last MW of the last unit of that block of resources with the same effective price. PJM then calculates the total effective MW as the simple

Table 10-30 MBF assumed RegD proportions versus market solution realized RegD proportions[51]

RegD Percent of 700 MW	RegD MW (Performance Adjusted)	MBF (Previous)	MBF (Current)	Effective MW from RegD MW (Previous)	Effective MW from RegD MW (Current)	Residual A (700 MW Target, Previous)	Residual A (700 MW Target, Current)	RegD/ (RegA+RegD, Previous)	RegD/ (RegA+RegD, Current)
5%	35	2.67	2.54	97.41	95.16	602.59	604.84	5%	5%
10%	70	2.43	2.18	186.63	177.63	513.37	522.38	12%	12%
15%	105	2.20	1.81	267.67	247.41	432.33	452.59	20%	19%
20%	140	1.96	1.45	340.52	304.50	359.48	395.50	28%	26%
25%	175	1.73	1.09	405.18	348.91	294.82	351.09	37%	33%
30%	210	1.50	0.73	461.66	380.63	238.34	319.38	47%	40%
35%	245	1.26	0.36	509.96	399.66	190.04	300.34	56%	45%
40%	280	1.03	0.00	550.06	406.00	149.94	294.00	65%	49%
45%	315	0.80		581.99		118.01		73%	
50%	350	0.56		605.73		94.27		79%	
55%	385	0.33		621.28		78.72		83%	
60%	420	0.09		628.65		71.35		85%	

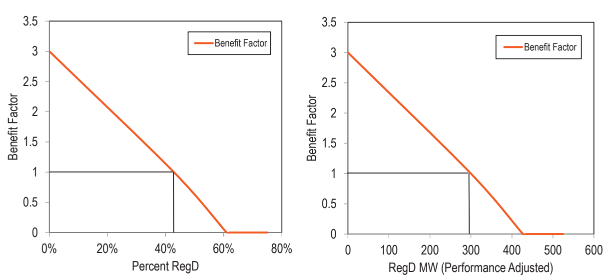
51 This example assumes that the calculation of effective MW from RegD was calculated correctly as the area under the MBF curve.

product of the MW and the MBF, rather than the area under the MBF curve. This resulted in understating total effective MW from RegD resources cleared at an effective price of zero or self-scheduled.

The identified total effective MW measurement issue was not fully addressed by the modification that was put into effect on December 14, 2015. The modification rank orders self-scheduled units and assigns the MBF of the last MW of each of these units to all MW of that unit. The result is to break up the RegD MW in the zero price or self-scheduled block into unit specific blocks of MW that are each assigned a unit specific benefit factor. The resulting unit block effective MW calculation for all units better approximates the area under the marginal benefit factor curve for those price block MW. A full correction of the effective MW calculation requires the use of the area under the curve.

An example illustrates the issue. Figure 10-24 shows the same marginal benefit factor curve, in terms of RegD percent (left diagram) and RegD MW (right diagram) in a scenario where 700 MW of effective MW are needed and the market clears 300 MW of RegD (actual MW), all priced at $0.00, and 400 MW of RegA. Figure 10-24 shows that the 300 MW of cleared RegD are 42.9 percent of total cleared actual MW and that the marginal benefit factor is 1.0.

Figure 10-24 Example marginal benefit line in percent RegD and RegD MW terms



Using PJM's price block/unit block method for the calculation of effective MW from RegD resources, all RegD resources are assigned the lowest marginal benefit factor associated with the last RegD MW purchased. In this example, all 300 MW have an MBF of 1.0. PJM calculates total effective MW from RegD resources to be 300 (300MW x 1.0 = 300 effective MW).

In Figure 10-25, PJM's price block/unit block calculation of total effective MW from RegD is represented by the area of the blue rectangle which is 400 effective MW.

PJM's unit block method is flawed. By assigning a single benefit value to every MW, the unit block method undervalues the amount of effective MW provided by RegD MW. This means that the amount of RegD and RegA cleared is not consistent with the combinations of RegD and RegA that will provide the target level of regulation service. This is because the marginal benefit curve represents a marginal rate of substitution between RegD and RegA MW, and the area under the curve, at any RegD amount, represents the total effective MW supplied by RegD at that point. In fact, RegD is providing effective MW equal to area defined by the green triangle and the blue rectangle in Figure 10-25. This corresponds to 600 effective MW being supplied by RegD resources, not 300 effective MW. This means that the actual total effective MW cleared in the market solution is 300 more effective MW than needed to meet the regulation requirement.

Figure 10-25 Illustration of correct method for calculating effective MW

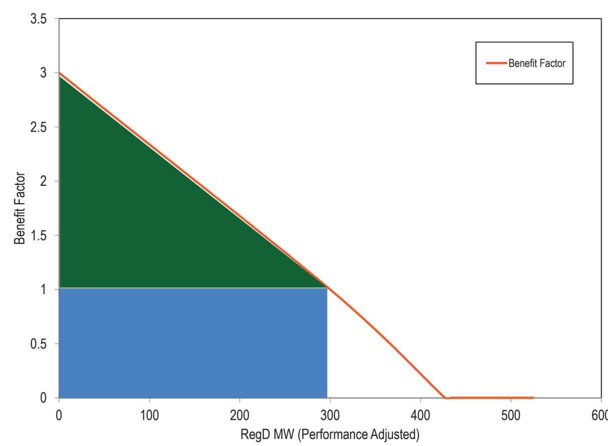


Figure 10-26 illustrates PJM's December 14, 2015, correction of the price block issue for RegD resources that clear with an effective price of zero. In this example, the PJM market clears two self-scheduled resources, one with 100 MW and one with 83 MW, for a total of 183 MW and a market MBF of 1.0. Prior to the correction, all 183 MW of RegD would have been assigned the MBF of 1.0.

After December 14, 2015, zero price offer and self scheduled resources are rank ordered by performance score and assigned unit specific MBF based on the MBF associated with the last MW of each unit that cleared. Using this approach, assuming the 83 MW resource was ranked higher than the 100 MW resource, the 83 MW resource would be assigned a unit specific benefit factor of 2.0 (see figure) and the 100 MW resource would be assigned a unit specific marginal benefit factor of 1.0 (see figure).

This correction did not address the unit block issue. PJM still calculates effective MW as the simple product of the MW and the MBF, rather than the area under the MBF curve for cleared MW, which results in an effective MW total of 269.9 MW, due to 169.9 effective MW being attributed to the 83 MW resource (83 MW times 2.0 BF) and 100 effective MW being attributed to the 100 MW resource (100 MW times 1.0 BF). Using the area under the curve approach would correctly result in a total effective MW total of 356.9 MW being attributed to the 183 MW cleared in the market, not the 266 total effective MW of the corrected method.

Figure 10-26 Example of pre and post December 14, 2015, total effective MW calculations for RegD MW offered at $0.00 or as self supply

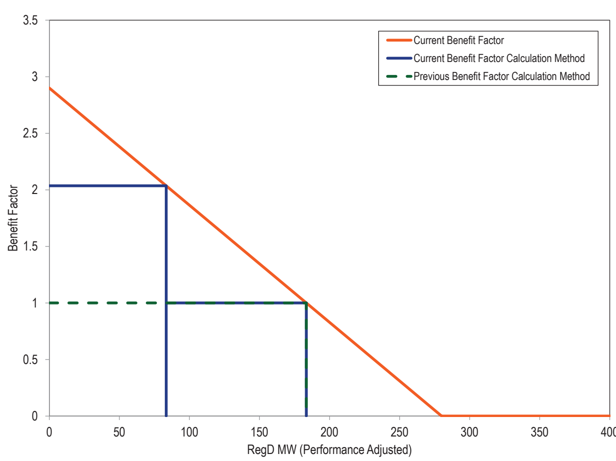
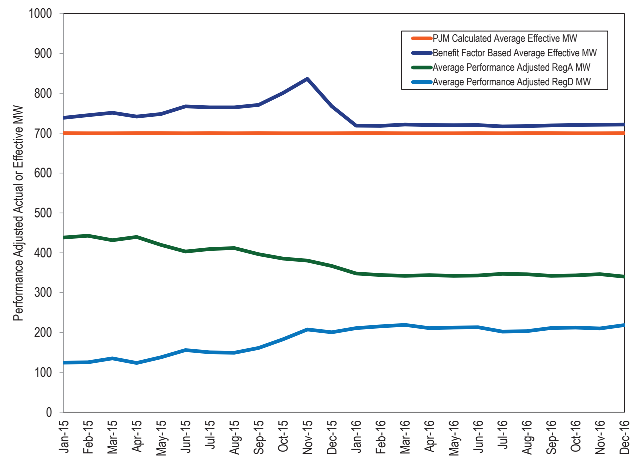


Figure 10-27 shows the average monthly peak total effective MW as calculated by PJM's incorrect effective MW accounting method(s) and as calculated by a correctly applied marginal benefit factor for the 2015 through 2016 period. The figure also shows the monthly average performance adjusted RegA MW and RegD MW cleared in the Regulation Market for the period. Figure 10-27 shows that PJM had been clearing an increasing surplus of total effective MW prior to December of 2015.

Figure 10-27 Average monthly peak total effective MW: PJM market calculated versus benefit factor based: 2015 through 2016



The excess procurement of RegD combined with the overpayment of RegD has resulted in an increase in the level of $0.00 offers from RegD resources. RegD MW providers are ensured that $0.00 offers will be cleared and will be paid a price determined by the offers of RegA resources. Figure 10-28 shows, by month, both an increasing amount and increasing proportion of cleared RegD MW with an effective price of $0.00. The figure also shows a corresponding increase in the total RegD MW clearing the market in the period between January 1, 2015 and December 31, 2015. The level of RegD clearing the market leveled off beginning in January 2016 because the market cleared the maximum allowed RegD actual MW. Figure 10-28 also shows that self-scheduling, the equivalent of offering RegD MW at $0.00, has increased.[52]

52 See the MMU's Regulation Market Review presentation from the May 5, 2015 Operating Committee. available at <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>.

Figure 10-28 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: 2015 through 2016

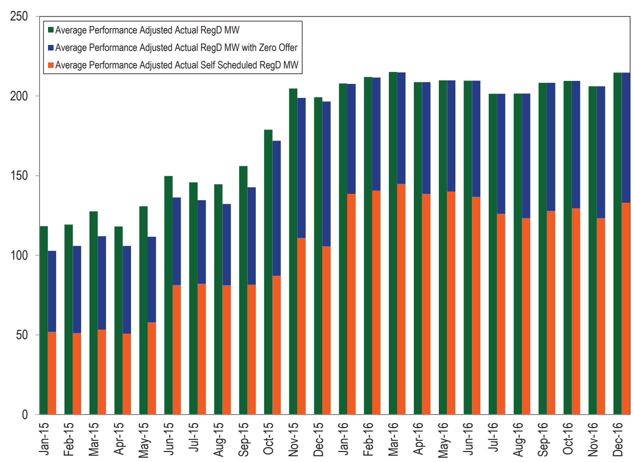
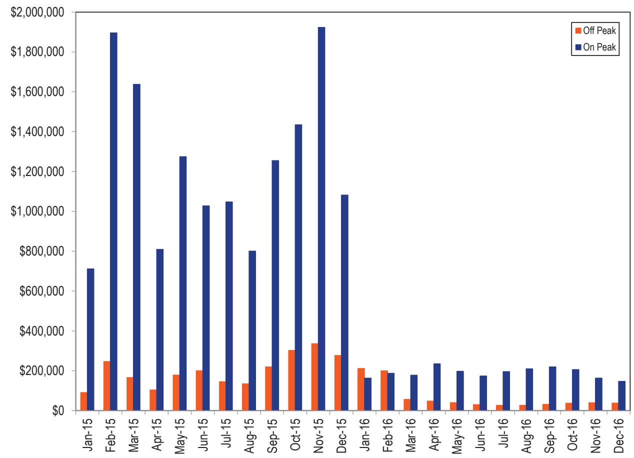


Figure 10-29 Cost of excess effective MW cleared by month, peak and off peak: 2015 through 2016



The Cost of Purchasing Too Many Regulation MW Due to Incorrect Effective MW Calculation Approach

Figure 10-29 shows the estimated cost of the excess effective MW cleared by month, peak and off peak, from January 1, 2015, through December 31, 2016, caused by PJM's incorrect approach(s) to calculating effective MW from RegD resources. To determine this excess cost, the total effective MW of RegD are calculated using the full area under the incorrect PJM marginal benefit factor curve, and the difference between that value and the one used by PJM is multiplied by the price in each hour. This excess cost calculation is a significant underestimate because it does not incorporate the correct MBF.

In 2016, the estimated total cost of excess effective RegD MW during on peak and off peak hours was $2.28 million and $0.79 million. In 2015, the estimated total cost of excess RegD MW during on peak and off peak hours was $14.90 million and $2.40 million. The implementation of the partial fix to the effective MW calculation and the changes in the marginal benefit factor curve in December of 2015 reduced, but did not eliminate, the excess effective MW clearing in the Regulation Market.

Market Structure

Supply

Table 10-31 shows capability MW (actual), average daily offer MW (actual), average hourly eligible MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in 2016. Total Effective MW are adjusted by the historic 100-hour moving average performance score and resource-specific benefit factor.[53] A resource must be either generation or demand. A resource can choose to follow both signals. For that reason, the sum of each signal type's capability can exceed the full regulation capability. Offered MW are calculated based on the daily offers from units that are categorized as available for the day. Eligible MW are calculated from the hourly offers from both units with daily offers and units that are categorized as unavailable for the day, but still offer MW into some hours. Additionally, units with daily offers are permitted to offer above or below their daily offer from hour to hour. Because of these hourly MW adjustments to MW offers beyond what was offered on a daily basis, the average hourly Eligible MW can be higher than the Offered MW. In 2016, the average hourly eligible supply of regulation for off peak hours was 1,243 .6 actual MW (941.3 effective MW). This was an increase of 87.1 actual MW (an increase of 75.0 effective MW) from 2015, when

53 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 and future analysis will show the effect of this correction.

the average hourly eligible supply of regulation was 1,156.5 actual MW (866.3 effective MW). In 2016, the average hourly eligible supply of regulation for on peak hours was 1,155.4 actual MW (920.2 effective MW). This was a decrease of 3.9 actual MW (an increase of 3.4 effective MW) from 2015, when the average hourly eligible supply of regulation was 1,159.3 actual MW (916.8 effective MW).

Table 10-31 PJM regulation capability, daily offer and hourly eligible: 2016[54] [55]

		By Resource Type			By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	Daily	8,217.7	8,185.0	32.7	7,872.6	656.2
Offered MW	Daily	2,943.6	2,930.0	13.6	2,659.1	284.5
Actual eligible MW	On Peak	1,155.4	1,141.1	14.3	777.3	378.1
	Off Peak	1,243.6	1,229.5	14.1	870.9	372.7
Effective eligible MW	On Peak	920.2	909.3	10.9	562.5	357.7
	Off Peak	941.3	931.5	9.8	615.0	326.4
Actual cleared MW	On Peak	635.9	627.9	8.0	410.0	225.9
	Off Peak	516.1	510.2	5.9	302.1	214.0
Effective cleared MW	On Peak	700.0	690.1	9.9	344.0	356.0
	Off Peak	525.1	517.7	7.3	248.3	276.8

Table 10-32 PJM regulation by source: 2015 and 2016[56]

	2015				2016			
Source	Number of Units	Adjusted Settled Regulation (MW)	Percent of Scheduled Regulation	Total Regulation Credits	Number of Units	Adjusted Settled Regulation (MW)	Percent of Scheduled Regulation	Total Regulation Credits
Battery	18	1,384,058.6	27.6%	$37,460,009	21	2,020,532.8	41.0%	$31,108,011
Coal	101	590,903.6	11.8%	$32,877,595	49	427,069.7	8.7%	$9,604,454
Hydro	40	936,094.4	18.6%	$37,607,500	39	926,915.3	18.8%	$18,261,418
Natural Gas	150	2,076,097.3	41.3%	$71,188,567	152	1,488,563.1	30.2%	$24,266,943
DR	38	35,731.5	0.7%	$1,047,198	35	70,795.6	1.4%	$1,090,169
Total	347	5,022,885.5	100.0%	$180,180,868	296	4,933,876.5	100.0%	$84,330,994

Table 10-32 provides the scheduled regulation in MW by source, the total scheduled regulation in MW provided by all resources (including DR), and the percent of scheduled regulation provided by each fuel type. In Table 10-32 the MW have been adjusted by the actual within hour performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted capability MW decreased from 5,022,885.5 MW in 2015 to 4,933,876.5 MW in 2016. The average proportion of regulation provided by battery units had the largest increase, providing 27.6 percent of regulation in 2015 and 41.0 percent of regulation in 2016. Natural gas units had the largest decrease in average proportion of regulation provided, decreasing from 41.3 percent in 2015, to 30.2 percent in 2016. The total regulation credits in 2016 were $84,330,994 down 53.2 percent from $180,180,868 in 2015.

Significant flaws in the regulation market design have led to a significant over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals have led to more storage projects entering PJM's interconnection queue, despite clear evidence that the market design is flawed and despite operational evidence that the RegD market is saturated (Table 10-33).

54 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
55 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.
56 Biomass data have been added to the natural gas category for confidentiality purposes.

Table 10-33 Active battery storage projects in the PJM queue system by submitted year: 2012 to 2016

Year	Number of Storage Projects	Total Capacity (MW)
2012	2	8.5
2013	0	0.0
2014	9	143.0
2015	41	311.6
2016	21	285.6
Total	73	748.7

The supply of regulation can also be affected by the retirement of regulating units. There were no regulating units that announced plans to retire through the end of 2016.

Although the marginal benefit factor for RegA resources is 1.0, the effective MW of RegA resources was lower than the offered MW in 2016, because the average performance score was less than 1.00. For 2016, the MW weighted average RegA performance score was 0.84 and there were 238 resources following the RegA signal.

For RegD resources, the total effective MW vary from actual MW because the marginal benefit factor for RegD resources can range from 2.9 to 0.0. In 2016, the marginal benefit factor, based on PJM's current assumed marginal benefit factor curve, for cleared RegD resources ranged from 0.003 to 1.521 with an average over all nonexcursion hours of 0.407 and from 1.000 to 1.389 with an average over all excursion hours of 1.119. In 2016, the MW weighted average RegD resource performance score was 0.95 and there were 55 resources following the RegD signal.

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 in 2016. A change to the regulation requirement was approved by the RMISTF in 2016, which was implemented in January 2017.. The regulation requirement was increased from 700 effective MW to 800 effective MW during on-ramp (formerly known as on-peak) hours.

Table 10-34 shows the average hourly required regulation by month and the ratio of supply to demand for both actual and effective MW, for on and off peak hours. The average hourly required regulation by month is an average of the on and off peak hours in the month.

Table 10-34 PJM Regulation Market required MW and ratio of eligible supply to requirement for on and off peak hours: 2015 and 2016

		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	
Peak	Month	2015	2016	2015	2016	2015	2016	2015	2016
On	Jan	675.8	657.5	700.1	700.1	1.82	1.83	1.33	1.34
	Feb	695.3	663.6	699.9	700.1	1.69	1.84	1.34	1.38
	Mar	689.5	640.6	700.0	700.0	1.67	1.90	1.33	1.39
	Apr	686.0	633.8	700.2	699.9	1.76	1.78	1.32	1.32
	May	690.2	625.4	700.1	699.9	1.66	1.82	1.31	1.29
	Jun	668.3	632.2	700.0	700.1	1.75	1.98	1.29	1.38
	Jul	663.3	628.7	700.0	700.0	1.75	1.85	1.30	1.37
	Aug	667.6	630.6	700.0	700.1	1.70	1.88	1.28	1.35
	Sep	674.5	628.5	700.1	700.1	1.71	1.95	1.30	1.38
	Oct	662.1	630.8	699.9	700.0	1.81	1.90	1.33	1.34
	Nov	679.0	628.6	699.8	700.1	1.78	1.89	1.31	1.37
	Dec	656.9	631.5	699.9	700.2	1.80	1.97	1.33	1.38
Off	Jan	495.8	553.8	525.5	525.0	2.07	2.15	1.46	1.56
	Feb	508.0	550.0	525.1	525.6	2.03	2.17	1.50	1.56
	Mar	497.7	517.0	525.3	525.0	2.06	2.25	1.43	1.57
	Apr	494.2	513.1	525.2	525.0	2.19	2.23	1.44	1.54
	May	499.0	504.5	525.0	525.0	2.07	2.24	1.37	1.52
	Jun	495.4	509.0	525.8	525.2	2.10	2.62	1.35	1.78
	Jul	490.7	506.9	525.3	525.0	2.24	2.42	1.46	1.65
	Aug	493.6	502.0	525.1	525.0	2.25	2.58	1.56	1.74
	Sep	501.8	508.3	525.1	525.0	2.25	2.47	1.58	1.65
	Oct	520.3	511.6	524.9	525.0	2.12	2.36	1.53	1.60
	Nov	566.3	502.4	525.1	525.0	2.03	2.49	1.41	1.73
	Dec	545.9	516.2	525.0	525.1	2.25	2.57	1.66	1.79

Market Concentration

In 2016, the effective MW weighted average HHI of RegA resources was 2748 which is highly concentrated and the weighted average HHI of RegD resources was 1864 which is also highly concentrated.[57] The weighted average HHI of all resources was 1156, which is moderately concentrated. The HHI of RegA resources and the HHI of RegD resources are higher than the HHI for all resources because different owners have large market shares in the RegA and RegD markets.

Table 10-35 includes a monthly summary of three pivotal supplier (TPS) results. In 2016, 92.2 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market in 2016 was characterized by structural market power. The TPS values are provided by PJM. The TPS results cannot be verified by the MMU or PJM because PJM does not save the necessary data. The MMU recommends that PJM save this data and make it available so that the TPS test calculations can be replicated by both PJM and the MMU. PJM has agreed that the lack of information is an issue but does not have a specific plan or timeline to resolve the issue.

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

Table 10-35 Regulation market monthly three pivotal supplier results: 2014 through 2016

	Percent of Hours Pivotal		
Month	2014	2015	2016
Jan	96.9%	97.8%	93.9%
Feb	98.7%	96.3%	90.9%
Mar	94.9%	97.3%	87.8%
Apr	89.0%	98.1%	93.5%
May	95.7%	99.3%	94.0%
Jun	99.4%	98.6%	89.3%
Jul	100.0%	98.8%	92.2%
Aug	99.7%	97.7%	93.7%
Sep	99.4%	97.1%	94.0%
Oct	99.1%	96.1%	90.6%
Nov	98.9%	99.2%	96.2%
Dec	98.1%	97.2%	90.4%
Average	97.5%	97.8%	92.2%

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.[58] When offering into the regulation market, regulating resources must submit a cost offer and may submit a price offer (capped at $100/MW) by 2:15 pm the day before the operating day.[59]

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 offers is not to exceed the increased fuel costs resulting from operating the regulating unit at a lower output level than its economically optimal output level, plus a $12.00/MW adder. The performance component for cost offers is not to exceed the increased costs (increased VOM and 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. On April 1, 2015, PJM added 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.[60]

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.[61]

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 10-37).[62] Figure 10-30 compares average hourly regulation and self scheduled regulation during on peak and off peak 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.[63] Self scheduled regulation comprised an average of 42.2 percent during on peak and 44.7 percent during off peak hours in 2016.

58 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.1, p 65.
59 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.6, p 70.
60 See PJM. "Manual 15: Cost Development Guidelines," Rev. 28 (October 18, 2016) at 11.8, p 65.
61 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.2, p 68.
62 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 75 (November 18 1, 2016) at 4.1, p 22.
63 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.9, p 79.

Figure 10-30 Off peak and on peak regulation levels: 2015 through 2016

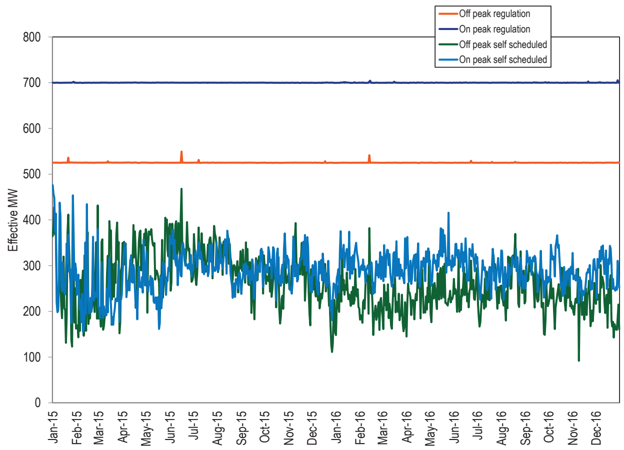


Table 10-36 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 51.6 percent of the total effective MW in December 2016) and a growing proportion of resources that self schedule (10.1 percent of all self scheduled MW in October 2012 and 24.4 percent of all self scheduled MW in December 2016). The increase in the share of RegD making up the total effective MW for 2016 (starting with the changes made to the MBF curve in December 2015), are due to the use of the unit block method of calculating the MBF over the previous price block method (See Figure 10-26).

Table 10-36 RegD self-scheduled regulation by month: October 2012 through December 2016

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	Percent of Total Self Scheduled	RegD Percent of Total Self Scheduled	RegD Percent of Total Effective MW
2012	Oct	66.3	71.8	264.7	658.1	40.2%	10.1%	10.9%
2012	Nov	74.4	88.3	196.5	716.5	27.4%	10.4%	12.3%
2012	Dec	82.5	88.8	188.8	701.1	26.9%	11.8%	12.7%
2013	Jan	35.7	82.5	133.6	720.0	18.6%	5.0%	11.5%
2013	Feb	84.8	90.2	212.2	724.3	29.3%	11.7%	12.5%
2013	Mar	80.1	119.3	279.8	680.7	41.1%	11.8%	17.5%
2013	Apr	82.3	106.9	266.0	594.1	44.8%	13.8%	18.0%
2013	May	74.0	109.0	268.2	616.2	43.5%	12.0%	17.7%
2013	Jun	79.6	122.7	334.9	730.6	45.8%	10.9%	16.8%
2013	Jul	77.6	120.4	303.6	822.9	36.9%	9.4%	14.6%
2013	Aug	83.6	127.6	366.0	756.8	48.4%	11.0%	16.9%
2013	Sep	112.2	152.1	381.6	669.9	57.0%	16.7%	22.7%
2013	Oct	120.2	163.7	349.6	613.3	57.0%	19.6%	26.7%
2013	Nov	133.9	175.7	396.5	663.3	59.8%	20.2%	26.5%
2013	Dec	136.5	180.7	313.6	663.5	47.3%	20.6%	27.2%
2013 Average		91.7	129.2	300.5	688.0	44.1%	13.6%	19.0%
2014	Jan	132.9	193.5	261.1	663.6	39.3%	20.0%	29.2%
2014	Feb	134.3	193.4	289.0	663.6	43.5%	20.2%	29.1%
2014	Mar	131.8	193.8	287.2	663.8	43.3%	19.9%	29.2%
2014	Apr	126.8	212.4	270.8	663.7	40.8%	19.1%	32.0%
2014	May	121.7	248.5	265.6	663.6	40.0%	18.3%	37.4%
2014	Jun	123.3	231.0	365.5	663.9	55.0%	18.6%	34.8%
2014	Jul	126.4	235.5	352.7	663.5	53.2%	19.0%	35.5%
2014	Aug	117.6	229.8	368.2	663.6	55.5%	17.7%	34.6%
2014	Sep	121.0	242.6	393.8	663.6	59.3%	18.2%	36.6%
2014	Oct	116.1	255.4	352.7	663.6	53.2%	17.5%	38.5%
2014	Nov	113.5	235.1	347.5	664.2	52.3%	17.1%	35.4%
2014	Dec	116.7	254.3	353.0	663.6	53.2%	17.6%	38.3%
2014 Average		123.5	227.1	325.6	663.7	49.1%	18.6%	34.2%
2015	Jan	116.4	250.1	304.8	663.7	45.9%	17.5%	37.7%
2015	Feb	111.3	245.8	242.6	663.5	36.6%	16.8%	37.0%
2015	Mar	113.8	255.2	229.9	663.8	34.6%	17.1%	38.5%
2015	Apr	110.1	248.2	283.7	663.7	42.7%	16.6%	37.4%
2015	May	121.8	265.1	266.7	663.6	40.2%	18.4%	39.9%
2015	Jun	158.9	283.1	321.2	663.7	48.4%	23.9%	42.6%
2015	Jul	161.4	278.3	314.0	663.8	47.3%	24.3%	41.9%
2015	Aug	159.5	276.0	300.7	663.6	45.3%	24.0%	41.6%
2015	Sep	155.4	289.2	286.0	663.5	43.1%	23.4%	43.6%
2015	Oct	147.1	299.0	292.8	663.4	44.1%	22.2%	45.1%
2015	Nov	164.9	302.1	298.1	664.2	44.9%	24.8%	45.5%
2015	Dec	144.6	317.2	260.7	663.9	39.3%	21.8%	47.8%
2015 Average		138.8	275.8	283.4	663.7	42.7%	20.9%	41.6%
2016	Jan	187.7	335.9	295.3	663.8	44.5%	28.3%	50.6%
2016	Feb	179.9	339.0	274.6	663.6	41.4%	27.1%	51.1%
2016	Mar	182.6	340.8	280.1	663.7	42.2%	27.5%	51.3%
2016	Apr	182.2	339.5	287.0	663.5	43.3%	27.5%	51.2%
2016	May	183.9	341.1	301.5	663.5	45.4%	27.7%	51.4%
2016	Jun	178.8	340.5	302.4	663.6	45.6%	26.9%	51.3%
2016	Jul	165.2	337.5	273.3	663.5	41.2%	24.9%	50.9%
2016	Aug	165.8	338.5	283.2	663.5	42.7%	25.0%	51.0%
2016	Sep	160.9	341.4	279.9	663.6	42.2%	24.2%	51.4%
2016	Oct	168.6	340.0	283.0	663.5	42.6%	25.4%	51.2%
2016	Nov	156.2	338.0	259.8	664.3	39.1%	23.5%	50.9%
2016	Dec	162.2	342.7	274.7	663.6	41.4%	24.4%	51.6%
2016 Average		172.8	339.6	282.9	663.7	42.6%	26.0%	51.2%

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 2016, 48.6 percent was purchased in the PJM market, 45.2 percent was self-scheduled, and 6.2 percent was purchased bilaterally (Table 10-37). Table 10-38 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for each year from 2012 to 2016. Table 10-37 and Table 10-38 are based on settled (purchased) actual MW.

In 2016, DR provided an average of 8.0 MW of regulation per hour during on peak hours (4.0 MW of regulation per hour during on peak hours in 2015), and an average of 5.9 MW of regulation per hour during off peak hours (3.2 MW of regulation per hour during off peak hours in 2015). Generating units supplied an average of 627.9 MW of regulation per hour during on peak hours (671.5 MW of regulation per hour during on peak hours in 2015), and an average of 510.2 MW per hour during off peak hours (505.6 MW of regulation per hour during off peak hours in 2015).

Table 10-37 Regulation sources: spot market, self-scheduled, bilateral purchases: 2015 through 2016

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)
2015	Jan	198,096.5	50.2%	173,319.4	43.9%	22,975.0	5.8%	394,390.9
2015	Feb	219,720.0	61.6%	116,607.5	32.7%	20,137.6	5.6%	356,465.0
2015	Mar	252,465.0	64.0%	122,001.9	30.9%	20,255.0	5.1%	394,721.8
2015	Apr	198,053.0	52.3%	159,511.3	42.1%	21,236.5	5.6%	378,800.8
2015	May	227,699.5	57.5%	148,998.3	37.6%	19,191.5	4.8%	395,889.3
2015	Jun	186,266.1	48.6%	174,157.4	45.5%	22,613.0	5.9%	383,036.5
2015	Jul	199,369.5	50.5%	172,743.7	43.7%	22,845.0	5.8%	394,958.2
2015	Aug	207,884.5	53.0%	162,197.5	41.3%	22,412.5	5.7%	392,494.5
2015	Sep	207,530.9	54.6%	150,467.7	39.6%	21,863.0	5.8%	379,861.6
2015	Oct	214,012.5	53.4%	169,283.3	42.2%	17,724.5	4.4%	401,020.3
2015	Nov	213,952.0	52.9%	172,561.3	42.7%	17,790.0	4.4%	404,303.3
2015	Dec	220,651.8	54.1%	166,189.2	40.7%	21,342.5	5.2%	408,183.5
Total		2,545,701.2	54.3%	1,888,038.5	40.3%	250,386.1	5.3%	4,684,125.8
2016	Jan	197,057.9	47.8%	193,581.9	47.0%	21,671.0	5.3%	412,310.8
2016	Feb	190,660.0	49.7%	173,440.5	45.2%	19,546.0	5.1%	383,646.6
2016	Mar	196,173.9	49.5%	178,413.1	45.0%	22,017.0	5.6%	396,604.0
2016	Apr	192,872.3	50.1%	173,661.5	45.2%	18,058.0	4.7%	384,591.8
2016	May	185,673.4	47.5%	185,240.7	47.4%	20,221.0	5.2%	391,135.2
2016	Jun	177,041.1	46.7%	180,678.3	47.7%	21,295.5	5.6%	379,014.9
2016	Jul	176,073.5	45.6%	167,839.7	43.5%	42,233.0	10.9%	386,146.2
2016	Aug	187,641.6	48.6%	171,902.4	44.6%	26,299.5	6.8%	385,843.5
2016	Sep	169,565.3	45.1%	171,293.3	45.5%	35,462.5	9.4%	376,321.1
2016	Oct	190,611.4	49.0%	174,453.7	44.8%	24,074.0	6.2%	389,139.0
2016	Nov	206,016.3	55.0%	155,359.8	41.5%	13,289.5	3.5%	374,665.6
2016	Dec	190,565.5	48.8%	176,628.1	45.2%	23,642.5	6.0%	390,836.1
Total		2,259,952.2	48.6%	2,102,493.0	45.2%	287,809.5	6.2%	4,650,254.7

Table 10-38 Regulation sources by year: 2012 through 2016

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	3,088,944.5	57.7%	2,064,156.7	38.5%	204,260.5	3.8%	5,357,361.7
2014	2,327,314.4	49.3%	2,161,996.5	45.8%	231,218.0	4.9%	4,720,528.9
2015	2,545,701.2	54.3%	1,888,038.5	40.3%	250,386.1	5.3%	4,684,125.8
2016	2,259,952.2	48.6%	2,102,493.0	45.2%	287,809.5	6.2%	4,650,254.7

Market Performance

Price

After regulation performance was implemented on October 1, 2012, both regulation price and regulation cost per MW were higher than they were prior to October 1, 2012, for each year until 2016 (Table 10-40). In 2016, the price and cost of regulation were lower than prior years. The weighted average RMCP for 2016 was $15.72 per effective MW. This is a 50.8 percent decrease from the weighted average RMCP of $31.92 per MW in 2015. The decrease in the regulation clearing price was the result of a reduction in energy prices and the related reduction in the LOC component of RMCP. The increase in self supply and $0.00 offers from RegD resources in 2016 also contributed to lower prices.

In September 2016, an issue was identified concerning the real time clearing price for five minute intervals in the regulation market. Regulation units available to set price in a given five minute interval are based on the latest five minute RT-SCED 15 minute look ahead scheduling and assignment of regulation resources. This means that at the end of an hour, pricing in five minute intervals starting at 00:45, 00:50, and 00:55 is based on RT-SCED scheduling information (regulation assignments) from 01:00, 01:05, and 01:10 of the following hour. In cases where units provided regulation in an hour, but are not assigned to provide regulation in the following hour, these deassigned units appeared as unavailable for purposes of determining price in the last three, five minute intervals of their assigned regulation hour (00:45, 00:50, and 00:55). The pricing algorithm instead used the list of resources assigned to regulation for the next hour to set the price in intervals 00:45, 00:50, and 00:55 of the current hour. The result was that the prices did not accurately reflect the units actually running in intervals 00:45, 00:50, and 00:55. In November 2016, PJM corrected this problem by forcing the pricing algorithm to use the regulation availability status of the current hour to determine which units are eligible to set the regulation price for the current hour.

Figure 10-31 shows the daily weighted average regulation market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market on an actual regulation capability MW basis. This data is based on actual five minute interval operational data. As Figure 10-31 illustrates, the LOC component (blue line) is the dominant component of the clearing price.

Figure 10-31 PJM regulation market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2016

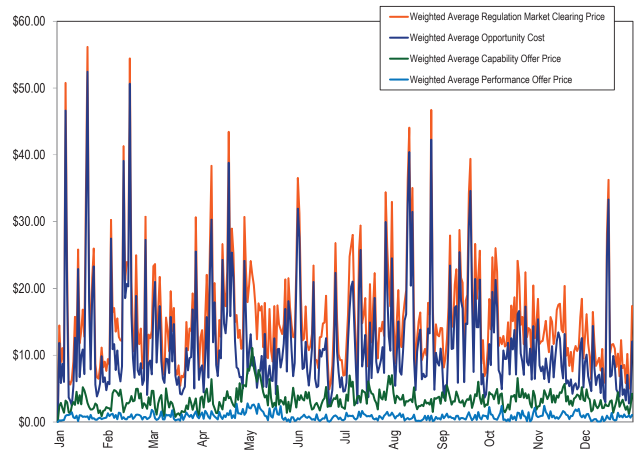


Table 10-39 shows the components of the monthly average regulation prices. NA is the unexplained portion of the total weighted average market price.

Table 10-39 PJM regulation market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price from five minute market solution data (Dollars per MW): 2016

Month	Weighted Average Regulation Marginal Unit LOC ($/Actual MW)	Weighted Average Regulation Marginal Unit Capability Offer ($/Actual MW)	Weighted Average Regulation Marginal Unit Performance Offer ($/Actual MW)	Weighted Average Regulation Market Clearing Price ($/ Actual MW)	NA	Weighted Average Regulation Market Price from Settlements ($/Actual MW)
Jan	$12.42	$2.57	$0.68	$15.67	$0.02	$15.65
Feb	$13.60	$3.35	$0.86	$17.82	$0.19	$17.63
Mar	$10.18	$2.35	$0.83	$13.37	($0.05)	$13.43
Apr	$14.22	$3.71	$1.18	$19.12	$0.04	$19.07
May	$9.83	$4.62	$1.27	$15.72	$0.05	$15.67
Jun	$10.35	$3.10	$0.57	$14.03	($0.00)	$14.03
Jul	$12.73	$4.26	$0.90	$17.88	$0.02	$17.86
Aug	$13.83	$3.15	$0.58	$17.56	($0.03)	$17.59
Sep	$13.59	$3.50	$0.75	$17.84	($0.07)	$17.91
Oct	$11.22	$3.59	$0.90	$15.70	$0.02	$15.68
Nov	$8.34	$3.74	$1.11	$13.19	$0.07	$13.12
Dec	$7.96	$2.72	$0.65	$11.33	$0.18	$11.15
Annual	$11.52	$3.39	$0.86	$15.77	$0.04	$15.73

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly and monthly average regulation price and regulation cost are shown in Table 10-40. Total scheduled regulation is based on settled (actual) MW. The total of all regulation charges for 2016 was $84.3 million, compared to $179.7 million for 2015.

Table 10-40 Total regulation charges: 2015 and 2016[64]

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2015	Jan	394,390.9	$13,057,184	$27.13	$33.11	81.9%
2015	Feb	356,465.0	$31,766,271	$73.24	$89.11	82.2%
2015	Mar	394,721.8	$21,883,006	$45.80	$55.44	82.6%
2015	Apr	378,800.8	$14,880,439	$32.76	$39.28	83.4%
2015	May	395,889.3	$21,038,444	$43.12	$53.14	81.1%
2015	Jun	383,036.5	$11,547,424	$25.94	$30.15	86.0%
2015	Jul	394,958.2	$11,488,410	$24.41	$29.09	83.9%
2015	Aug	392,494.5	$9,915,460	$20.85	$25.26	82.5%
2015	Sep	379,861.6	$13,646,465	$29.71	$35.92	82.7%
2015	Oct	401,020.3	$10,905,571	$23.12	$27.19	85.0%
2015	Nov	404,303.3	$10,221,684	$21.92	$25.28	86.7%
2015	Dec	408,183.5	$9,323,436	$19.58	$22.84	85.7%
2015 Annual		4,684,125.8	$179,673,795	$32.30	$38.82	83.7%
2016	Jan	412,310.8	$7,589,231	$15.65	$18.41	85.0%
2016	Feb	383,646.6	$7,677,113	$17.63	$20.01	88.1%
2016	Mar	396,604.0	$6,107,773	$13.43	$15.40	87.2%
2016	Apr	384,591.8	$8,367,326	$19.07	$21.76	87.7%
2016	May	391,135.2	$7,217,226	$15.67	$18.45	84.9%
2016	Jun	379,014.9	$5,993,073	$14.03	$15.81	88.7%
2016	Jul	386,146.2	$7,954,280	$17.86	$20.60	86.7%
2016	Aug	385,843.5	$7,703,653	$17.59	$19.97	88.1%
2016	Sep	376,321.1	$7,780,425	$17.91	$20.67	86.6%
2016	Oct	389,139.0	$7,018,089	$15.68	$18.03	87.0%
2016	Nov	374,665.6	$5,777,367	$13.12	$15.42	85.1%
2016	Dec	390,836.1	$5,113,222	$11.15	$13.08	85.2%
2016 Annual		4,650,254.7	$84,298,779	$15.73	$18.13	86.7%

64 Weighted average market clearing prices presented here are taken from PJM settlements data, and differ from the values reported in Table 10-39, which are from five minute interval operational data. The MMU is investigating the cause of the discrepancies with PJM.

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-41. Total scheduled regulation is based on settled actual MW.

Table 10-41 Components of regulation cost, 2016

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	412,310.8	$14.49	$1.97	$1.95	$18.41
Feb	383,646.6	$16.00	$2.61	$1.40	$20.01
Mar	396,604.0	$12.01	$2.25	$1.14	$15.40
Apr	384,591.8	$17.38	$2.70	$1.67	$21.76
May	391,135.2	$13.56	$3.49	$1.40	$18.45
Jun	379,014.9	$13.33	$1.38	$1.10	$15.81
Jul	386,146.2	$16.53	$2.27	$1.80	$20.60
Aug	385,843.5	$16.74	$1.66	$1.56	$19.97
Sep	376,321.1	$16.68	$2.32	$1.68	$20.67
Oct	389,139.0	$14.11	$2.73	$1.19	$18.03
Nov	374,665.6	$11.28	$3.11	$1.03	$15.42
Dec	390,836.1	$10.12	$1.72	$1.24	$13.08
Annual	4,650,254.7	$14.35	$2.35	$1.43	$18.13

Table 10-42 provides a comparison of the average price and cost for PJM regulation. The ratio of regulation market price to the actual cost of regulation in 2016 was 86.7 percent, a 3.5 percent increase from 83.2 percent in 2015.

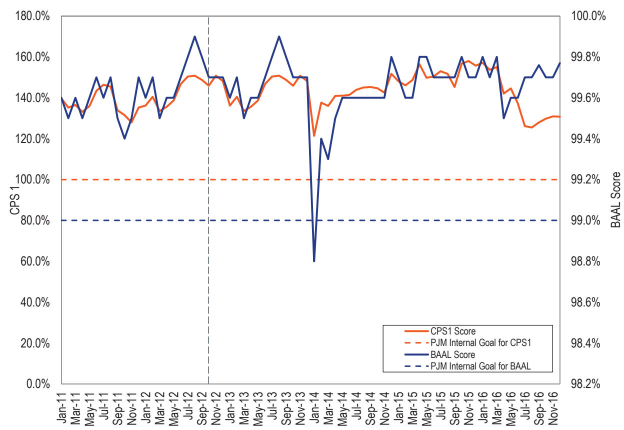
Table 10-42 Comparison of average price and cost for PJM regulation: 2009 through 2016

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$22.99	$30.68	74.9%
2010	$18.00	$32.86	54.8%
2011	$16.48	$29.72	55.5%
2012	$19.02	$25.32	75.1%
2013	$30.85	$35.79	86.2%
2014	$44.48	$53.82	82.6%
2015	$31.92	$38.36	83.2%
2016	$15.72	$18.13	86.7%

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-32 for every month from January 2011 through December 2016 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[65] 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.

Figure 10-32 PJM monthly CPS1 and BAAL performance: 2011 through 2016



Black Start Service

Black start service is necessary to ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating when disconnected from the grid.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for the costs associated with providing this service.

65 See the *2016 State of the Market Report for PJM*, Appendix F: Ancillary Services.

PJM defines required black start capability zonally, while recognizing that the most effective way to provide black start service may be across zones, and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners. Substantial rule changes to the black start restoration and procurement strategy were implemented on February 28, 2013, following a stakeholder process in the System Restoration Strategy Task Force (SRSTF) and the Markets and Reliability Committee (MRC) that approved the PJM and MMU joint proposal for system restoration. These changes gave PJM substantial flexibility in procuring black start resources and made PJM responsible for black start resource selection.

On July 1, 2013, PJM initiated its first RTO-wide request for proposals (RFP) under the new rules.[66] [67] PJM set a September 30, 2013, deadline for resources submitting proposals and requested that resources be able to provide black start by April 1, 2015. PJM identified zones with black start shortages, prioritized its selection process accordingly, and began awarding proposals on January 14, 2014. PJM and the MMU coordinated closely during the selection process.

PJM issued two incremental RFPs in 2014. On April 11, 2014, PJM sought additional black start in the AEP Zone and one proposal was selected. On November 24, 2014, PJM sought additional black start in northeastern Ohio and western Pennsylvania, but no proposals were selected because they did not meet the bid requirements. On July 28, 2015, PJM issued an Incremental Request for Proposals, for northeastern Ohio and western Pennsylvania together. On August 8, 2016, PJM made one award which will cover both areas.

Black start payments are nontransparent payments made to units by load to maintain adequate reliability to restart the system in case of a blackout. Current rules appear to prevent publishing detailed data regarding these black start resources, hindering transparency and competitive replacement RFPs. The MMU recommends that the current confidentiality rules be revised to allow disclosure of information regarding black start resources and their associated payments. In 2014, zonal reporting of black start payments was implemented, partially fulfilling the recommendation.

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.[68]

In 2016, total black start charges were $67.0 million, a $5.4 million (8.8 percent) increase from the 2015 level of $59.8 million. Operating reserve charges for black start service declined from $5.2 million in 2015 to $0.3 million in 2016. Table 10-43 shows total revenue requirement charges from 2010 through 2016. (Prior to December 2012, PJM did not define a black start operating reserve category. As a result of the changes in the black start operating reserve category, 2013 was the first full year operating reserves charges were allocated to black start, resulting in the increase in operating reserves charges. Starting in 2014, the ALR units began to be replaced with new black start units, resulting in a decline in operating reserve charges. Prior to December 2012, operating reserve charges resulting from units providing black start service were allocated as operating reserve charges for reliability in the western region.)

66 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).

67 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.

68 PJM. OATT Schedule 6A, paragraph. 25, 26 and 27 outline how charges are to be applied.

Table 10-43 Black start revenue requirement charges: 2010 through 2016

Year	Revenue Requirement Charges	Operating Reserves 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	$5,175,643	$61,601,291
2016	$66,741,122	$278,048	$67,019,170

Black start zonal charges in 2016 ranged from $0.08 per MW-day in the DLCO Zone (total charges were $78,423) to $4.09 per MW-day in the PENELEC Zone (total charges were $4,528,821). For each zone, Table 10-44 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point-to-point transmission customers paid on average $0.046 per MW of reserve capacity during 2016.

Table 10-44 Black start zonal charges for network transmission use: 2015 and 2016

	2015					2016				
Zone	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)
AECO	$624,656	$3,131	$627,787	891,878	$0.70	$2,432,809	$18,716	$2,451,526	934,325	$2.62
AEP	$13,530,162	$4,538,115	$18,068,277	8,908,957	$2.03	$14,637,807	$23,597	$14,661,404	9,049,387	$1.62
AP	$2,598,154	$69,722	$2,667,876	3,412,495	$0.78	$3,988,109	$2,304	$3,990,413	3,511,258	$1.14
ATSI	$2,770,257	$13,206	$2,783,463	4,512,167	$0.62	$3,011,659	$1,974	$3,013,634	4,522,442	$0.67
BGE	$9,275,300	$2,496	$9,277,796	2,432,798	$3.81	$7,118,955	$3,069	$7,122,024	2,456,555	$2.90
ComEd	$5,114,530	$49,723	$5,164,253	7,198,238	$0.72	$4,841,009	$32,496	$4,873,506	7,379,402	$0.66
DAY	$236,259	$7,929	$244,188	1,169,387	$0.21	$236,841	$8,784	$245,625	1,200,773	$0.20
DEOK	$1,159,327	$12,531	$1,171,858	1,863,325	$0.63	$1,149,177	$586	$1,149,763	1,875,018	$0.61
Dominion	$2,132,262	$12,719	$2,144,980	7,221,160	$0.30	$2,900,077	$22,117	$2,922,194	7,924,229	$0.37
DPL	$767,906	$19,766	$787,673	1,414,375	$0.56	$1,788,261	$8,852	$1,797,113	1,505,724	$1.19
DLCO	$104,264	$12,492	$116,756	982,836	$0.12	$50,509	$27,913	$78,423	1,026,264	$0.08
EKPC	$425,540	$0	$425,540	1,250,125	$0.34	$383,084	$1,039	$384,122	1,277,450	$0.30
JCPL	$4,745,965	$27,382	$4,773,347	2,057,469	$2.32	$6,828,734	$0	$6,828,734	2,129,425	$3.21
Met-Ed	$644,821	$72,118	$716,939	1,028,132	$0.70	$577,830	$85,238	$663,068	1,024,214	$0.65
PECO	$1,598,115	$23,957	$1,622,072	3,013,988	$0.54	$1,580,761	$1,253	$1,582,014	2,962,550	$0.53
PENELEC	$3,005,198	$2,881	$3,008,079	1,113,834	$2.70	$4,525,449	$3,372	$4,528,821	1,106,894	$4.09
Pepco	$1,239,205	$12,775	$1,251,979	2,315,962	$0.54	$2,526,099	$23,055	$2,549,154	2,293,978	$1.11
PPL	$446,074	$8,931	$455,004	2,933,870	$0.16	$1,143,784	$0	$1,143,784	2,948,093	$0.39
PSEG	$3,605,402	$12,058	$3,617,459	3,473,048	$1.04	$4,200,884	$2,303	$4,203,187	3,511,733	$1.20
RECO	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$2,402,254	$273,711	$2,675,965	2,605,457	$1.03	$2,819,285	$11,378	$2,830,663	2,593,427	$1.09
Total	$56,425,648	$5,175,643	$61,601,291	59,799,496	$1.03	$66,741,122	$278,048	$67,019,170	61,233,142	$1.09

Table 10-45 provides a revenue requirement estimate by zone for the 2016/2017, 2017/2018 and 2018/2019 delivery years.[69] 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, and owner provided cost estimates of incoming black start units, at the time of publication and may change significantly.

NERC – CIP

Currently, there is one black start resource recovering capital costs related to NERC – CIP requirements.[70] During 2015 and 2016 there have been no new requests for black start units to recover capital costs under NERC – CIP.

69 The Market Monitoring Unit was requested to provide estimated black start revenue requirements in the System Restoration Strategy Task Force group.

70 PJM. OATT Schedule 6A, p. 21. The Market Monitoring Unit shall include a descriptive summary of the new or additional Black Start NERC-CIP Capital costs requested by black Start Unit in aggregate basis such that no data is attributable to an individual Black Start Unit.

Table 10-45 Black start zonal revenue requirement estimate: 2016/2017 through 2018/2019 delivery years

Zone	2016 / 2017 Revenue Requirement	2017 / 2018 Revenue Requirement	2018 / 2019 Revenue Requirement
AECO	$2,850,000	$2,850,000	$2,800,000
AEP	$19,150,000	$19,200,000	$18,950,000
AP	$4,150,000	$4,150,000	$4,150,000
ATSI	$3,100,000	$3,100,000	$3,100,000
BGE	$8,400,000	$3,650,000	$3,550,000
ComEd	$5,100,000	$5,200,000	$4,750,000
DAY	$250,000	$300,000	$250,000
DEOK	$1,250,000	$1,250,000	$1,200,000
DLCO	$100,000	$100,000	$2,750,000
Dominion	$5,400,000	$5,400,000	$5,400,000
DPL	$2,600,000	$2,600,000	$2,500,000
EKPC	$450,000	$450,000	$300,000
JCPL	$7,200,000	$7,200,000	$7,150,000
Met-Ed	$700,000	$750,000	$600,000
PECO	$1,750,000	$1,900,000	$1,550,000
PENELEC	$4,700,000	$4,750,000	$4,500,000
Pepco	$2,700,000	$2,700,000	$2,650,000
PPL	$800,000	$800,000	$750,000
PSEG	$4,450,000	$4,500,000	$4,450,000
RECO	$0	$0	$0
Total	$75,100,000	$70,850,000	$71,350,000

Reactive Service

Suppliers of reactive power are compensated separately for reactive capability, day-ahead operating reserves, and for real-time lost opportunity costs. Compensation for reactive capability must be approved by FERC per Schedule 2 of the OATT. Generators may obtain FERC approval to recover a share of units' fixed costs by calculating a reactive revenue requirement, the reactive capability rate, and to collect such rates from PJM transmission customers.[71]

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).[72] While a fixed requirement for reactive power is not established, reactive power helps maintain appropriate voltages on the transmission system.

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements which are posted monthly on the PJM website.[73] Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.[74]

In 2016, the FERC has begun to reexamine its policies on reactive compensation.[75] 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. 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 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.[76] There is no support for the assertion 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 support for the assertion 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

71 See also PJM, Manual 27 (Open Access Transmission Tariff Accounting), Rev. 86, (January 26, 2017) at 3.

72 PJM OATT Schedule 2.

73 See PJM. Markets & Operations: Billing, Settlements & Credit <http://www.pjm.com/~/media/markets-ops/settlements/reactive-revenue-requirements-table-may-2016.ashx> (June 8, 2016).

74 PJM. OATT Schedule 2.

75 *See, e.g., 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).

76 *See Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 at 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.").

as a condition of receiving interconnection service from PJM and other markets.[77]

PJM requires a power factor of at least 0.95 leading to 0.90 lagging for synchronous units and at least 0.95 leading to 0.95 lagging for nonsynchronous units.[78] The regulations specify a minimum power factor range of 0.95 leading and 0.95 lagging power factor unless the market operators' rules specify otherwise.[79] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.[80] 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.

There are two ways to address the cost of reactive in the PJM market design.

Under the current capacity market rules, the gross costs of the entire plant, including any reactive costs, are included in the gross Cost of New Entry (CONE) and the revenues from reactive service capability rates are an offset to the gross CONE. The result is that, conceptually, the cost of reactive is not part of net CONE.[81] This is logically consistent with the separate collection of reactive costs through a cost of service rate in that there is no double counting if the revenue offset is done accurately. Under this approach there is a separate collection of reactive capability costs.

An alternative approach to the current treatment of reactive costs in the capacity market would be to include the gross costs of the entire plant including any reactive costs in the gross Cost of New Entry (CONE) but to calculate net CONE without a reactive revenue offset for reactive service capability rates. The result of this approach would be that the cost of reactive is part of net CONE. This is logically consistent with the elimination of the separate collection of reactive costs through a cost of service rate in that there is no double counting if done accurately. Under this approach there would be no separate collection of reactive capability costs.

PJM currently uses the first approach. There is no reason that PJM could not easily implement the second approach.

The second approach is preferable. The second approach relies on competitive markets to provide incentives to provide energy, both real and reactive, at the lowest possible cost. The second approach does not require the use of arbitrary, approximate and generally inaccurate allocators to determine the cost of providing reactive. The second approach does not require the use of estimated, average and inaccurate net reactive revenue offsets to calculate Net CONE. It is critical in the PJM Capacity Market that Net CONE be as accurate as possible. Only the second approach assures this.

Units are compensated for reactive capability costs under the second approach. But the compensation is based on the outcome of a competitive capacity market rather than based on current or historical cost of service filings for units or fleets of units.

The first approach, although internally logically consistent, relies on unnecessary and inaccurate approximations. The reactive allocator is such an approximation. The reactive revenue offset is an inaccurate estimate based on historical data from reactive revenue requirement filings. The reactive revenues used in the net CONE calculation are based on an average of reactive filings over the three years from 2005 through 2007 and therefore do not reflect even the allocated reactive costs and revenues for a new unit, as would be required to be consistent with the CONE

77 *See* 18 CFR § 35.28(f)(1); *Standardization of Generator Interconnection Agreements and Procedures*, 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); *Standardization of Small Generator Interconnection Agreements and Procedures*, 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).

78 *See* OATT Attachment O Appendix 2 § 4.7.

79 *See, e.g., id.* LGIA Article 9.6.1 ("Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis.").

80 *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 (2016); see also PJM Interconnection, L.L.C., 151 FERC ¶ 61,097 at P 28 (2015).

81 *See* OATT Attachment DD § 5.10(a)(iv).

logic.[82] To the extent that the reactive portion of the Net Energy and Ancillary Services Offset is inaccurate, the net CONE is inaccurate.

The reactive revenue offset is set equal to $ 2,199/MW-year in the PJM OATT.[83] This figure is the average annual reactive revenue for combustion turbines from 2005 through 2007, based on the actual costs reported to the Commission in reactive service filings of CTs, as developed by the MMU.

The Net Cost of New Entry is a key parameter in the PJM Capacity Market as it affects the location of the VRR or demand curve and thus has a direct impact on capacity market prices.[84]

If revenues for reactive capacity were removed from the Net Energy and Ancillary Services Revenue Offset, then the fixed costs for investment in reactive capability would be recoverable through the capacity market. By employing a simple and direct approach using CONE with no offset, the rules for cost of service compensation included in Schedule 2 could be eliminated and the requirement for cost of service filings would be eliminated.

As a result of the nature of reactive filings, it is not possible to identify the reactive capability revenues for all individual units that receive reactive capability revenues. As a result, the offer caps in the capacity market are not as accurate as they should be.

Relying on capacity markets instead of cost of service allocations would enhance competition and efficient pricing.

Actual experience with the cost of service approach suggests that customers would be better off under a competition based approach. The Commission's recent investigations into particular rates raises questions about the accuracy and basis of rates currently charged for reactive capability.

Cost of service ratemaking creates unnecessary monitoring difficulties. Because service providers do not have to file rates periodically, suppliers have no incentive to adjust reactive capability rates except when they increase. Suppliers have direct access to information about the costs for their own units; the Commission and other parties do not have such access. When rates are established on a fleet basis or result from a black box settlement, the ability of parties to review and challenge rates is further reduced.

The current FERC review provides an excellent opportunity to discard an anachronistic cost of service approach that has not been working well and that is inconsistent with markets and is unnecessary in organized markets.[85] Increased reliance on markets for the recovery of reactive capability costs would promote efficiency and consistency. Customers, market administrators and regulators will be better served by a simpler and more effective competition based approach.

The MMU recommends that separate payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market.

Improvements to Current Approach

If OATT Schedule 2 reactive capability payments are not eliminated, then the MMU recommends, at a minimum, that steps be taken to ensure that payments are based on capability that is measured in tests performed by PJM or demonstrated in market data showing actual reactive output and based on capability levels that are useful to PJM system operators to maintain system stability. The FERC recently has initiated a number of investigations into the basis for reactive rates, and the MMU has intervened in and is participating in those proceedings.[86]

Under the AEP method, units must establish their MVAR rating based on "the capability of the generators to produce VArs."[87] Typically this has meant reliance on manufacturers' specified nameplate power factor.[88] The Commission has noted a difference between tested

82 OATT Attachment DD § 5.10(a)(v)(A) ("The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.").

83 *Id.*

84 *Id.*

85 See FERC Docket No. AD16-17.

86 *See* FERC Dockets Nos. EL16-32, EL16-44, EL16-51, EL16-54, EL16-65, EL16-66, EL16-90, EL16-72, EL16-1004 and ER16-1456.

87 *AEP mimeo* at 31.

88 *See, e.g., id.*

reactive MVAR ratings and nameplate MVAR ratings and has, in a number of cases, set the issue of MVAR rating degradation for hearing.[89]

The Commission has identified a significant issue. There is no reason to use the nameplate MVAR rating to develop a reactive allocation and there is no basis in the AEP order for reliance on the nameplate MVAR rating. Nameplate reactive power ratings are generally higher than the actual ratings as defined by the PJM mandated tests of capability because nameplate power ratings are generally calculated using leading and lagging power factors that are lower than are achievable in real world operation. Although this issue is characterized as degradation, the difference between nameplate and tested capability exists even when units are new. Testing will reveal whether the tested capability degrades further. Reliance on tested results would address both the issue of degradation and the issue of theoretical versus actual MVAR ratings.

The estimated capability costs also include estimated heating losses relative to MVAR output.[90] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[91] Heating losses can be accurately calculated for each hour of operation if each unit had an accurate, recent D-curve test.

Cost of service rates are established under Schedule 2 of the OATT and may cover rates for single units or a fleet of units.[92] Until the Commission took corrective action, fleet rates remained in place in PJM even when the actual units in the fleet changed as a result of unit retirements or sales of units.[93] 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.[94] Fleet rates should be eliminated. Compensation should be based on unit specific costs. Fleet rates make it almost impossible to monitor whether compensation for reactive capability is based on actual unit specific performance and costs.

To the extent that the Commission decides that PJM and other markets should continue to rely on a cost of service method to compensate reactive capability, the rules should be modified to improve the accuracy of the calculations of reactive capability cost. Rates that do not accurately reflect the cost of the service provided are not just and reasonable.

Manufacturers' nameplate MVAR ratings and the corresponding theoretical power factors should not be relied upon to define the allocator used to calculate the costs of reactive capability. Current performance and testing show significant disparities between nameplate MVAR output and actual output. This is significant regardless of whether the cause is degradation of power factors or simply the difference between theoretical and tested power factors.[95] PJM determined in 1999 that nameplate MVAR and power factor ratings do not reflect the value to the system operator of a units' reactive output after it is interconnected at a specific location.[96] Only operator evaluation of reactive capability can provide a meaningful measure of reactive capability.

The information for MVAR ratings should come from data on the MVAR output provided. System operators can evaluate the usefulness and value of reactive capacity based on the actual availability and use of such capability.

Data from periodic testing for reactive capability is another approach to measuring MVAR output. Testing at relatively long intervals is not likely to be as accurate as actual market operations data, but it is more reliable than an untested and dated manufacturers' nameplate rating.

Fleet rates should be eliminated. Compensation should be based on unit specific costs. Fleet rates make it almost impossible to monitor whether compensation for reactive capability is based on actual unit specific performance and costs.

89 *See, e.g., Talen Energy Marketing, LLC*, 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.").

90 *See, e.g., id.* at P 10 n12 citing *PPL Energy Plus, LLC*, Letter Order, Docket No. ER08-1462-000 (Sept. 24, 2008); *Dynegy Midwest Generation, Inc.*, 125 FERC ¶ 61,280, at P 35 (2008).

91 *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.

92 *See, e.g.*, OATT Schedule 2; *Virginia Electric and Power Company*; 114 FERC ¶ 61,318 (2006).

93 *See PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.

94 *Id.*

95 In response to a 1999 low voltage event, PJM performed a root cause analysis. The analysis concluded that "PJM narrowly avoided a voltage collapse" and that "if PJM had realized that the MVAR reserves that the EMS indicated were available were not realistic, other action could have been take [sic] to stabilize the system." PJM State & Member Training Dept., Slides, Reactive Reserves and Generator D-Curves at 13 (included as an Attachment), which can be accessed at: <http://www.pjm.com/~/media/training/nerc-certifications/gen-exam-materials/gof/20160104-reactive-reserves-and-d-curve.ashx>.

96 *Id.*, including Attachment.

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.

Reactive service is supplied during normal operation as needed and directed by PJM dispatchers. Most reactive service is provided with no impact to operational dispatch. When a need for reactive service requires that a unit's MW output be reduced outside of its normal operational range, or when a unit is started to provide reactive power, it is logged by PJM dispatchers and will be paid reactive service credits in the zone or zones where the reactive service was provided proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.

Reactive capability rates 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.[97] Participants have not been properly including reactive revenues in capacity market offers, and the MMU has notified participants of its compliance concerns. The identification of revenues for reactive capability on a unit specific basis is necessary for the calculation of accurate avoidable cost rate offers and is needed to avoid disputes that could interfere with the orderly administration of RPM auctions. The MMU has sought to address this issue through participation in proceedings at the FERC concerning reactive capability rates for PJM units.

Reactive Costs

In 2016, total reactive charges were $303.7 million, a 5.7 percent increase from the 2015 level of $287.2 million.[98] Reactive service charges decreased in 2016 to $2.5 million from $10.5 million in 2015. All $2.5 million in 2016 were paid for reactive service provided by 37 units in 717 hours. The reason for the decline in reactive service charges from 2015 to 2016 is primarily milder weather in real time. Reactive Service Charges in the ComEd Zone accounted for 41.2 percent and DPL Zone accounted for about 31 percent of all generator redispatch.

Table 10-46 shows reactive service charges in 2015 and 2016, reactive capability revenue requirement charges and total charges.

97 See OATT Attachment DD §§ 6.4, 6.8(d).

98 See the *2015 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

Table 10-46 Reactive zonal charges for network transmission use: 2015 and 2016

	2015			2016		
Zone	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges
AECO	$17,555	$6,341,664	$6,359,219	$250	$5,696,217	$5,696,467
AEP	$458,265	$38,198,374	$38,656,639	$76,833	$37,516,646	$37,593,480
AP	$98,666	$16,666,745	$16,765,411	$1,440	$16,719,602	$16,721,042
ATSI	$3,844,142	$15,277,869	$19,122,011	$1,860	$22,005,585	$22,007,445
BGE	$63,849	$7,825,069	$7,888,919	$895	$7,569,685	$7,570,580
ComEd	$180,977	$25,334,050	$25,515,027	$1,025,426	$27,577,098	$28,602,524
DAY	$34,107	$8,487,449	$8,521,555	$501	$8,367,085	$8,367,586
DEOK	$53,426	$5,153,000	$5,206,427	$765	$5,714,975	$5,715,739
Dominion	$2,682,636	$29,848,959	$32,531,595	$19,204	$29,870,072	$29,889,277
DPL	$2,338,443	$11,292,982	$13,631,425	$776,536	$12,868,385	$13,644,920
DLCO	$25,334	$0	$25,334	$365	$0	$365
EKPC	$28,701	$2,154,987	$2,183,688	$162,131	$2,157,360	$2,319,491
JCPL	$39,781	$7,175,487	$7,215,268	$608	$8,789,073	$8,789,681
Met-Ed	$63,281	$7,730,837	$7,794,118	$15,525	$7,411,999	$7,427,525
PECO	$73,554	$17,744,319	$17,817,873	$1,113	$17,763,859	$17,764,972
PENELEC	$313,316	$7,303,956	$7,617,272	$250,696	$8,714,562	$8,965,257
Pepco	$69,105	$5,293,901	$5,363,006	$136,334	$6,051,301	$6,187,635
PPL	$81,863	$18,969,092	$19,050,955	$16,500	$21,662,713	$21,679,214
PSEG	$73,686	$28,662,896	$28,736,582	$1,133	$36,266,299	$36,267,431
RECO	$2,499	$0	$2,499	$37	$0	$37
(Imp/Exp/Wheels)	$0	$17,232,975	$17,232,975	$0	$18,490,950	$18,490,950
Total	$10,543,187	$276,694,611	$287,237,797	$2,488,153	$301,213,466	$303,701,619

Congestion and Marginal Losses

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is the sum of three components: the system marginal price (SMP) or energy component, the congestion component of LMP (CLMP), and the marginal loss component of LMP (MLMP).[1] SMP, MLMP and CLMP are products of the least cost, security constrained dispatch of system resources to meet system load.

SMP is the incremental price of energy for the system, given the current dispatch, at the load weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load weighted reference bus. The load weighted reference bus is not a fixed location but varies with the distribution of load at system load buses.

CLMP is the incremental price of congestion at each bus, based on the shadow prices associated with the relief of binding constraints in the security constrained optimization. CLMPs are positive or negative depending on location relative to binding constraints and relative to the load weighted reference bus. In an unconstrained system CLMPs will be zero.

MLMP is the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

Total losses refer to the total system-wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation.[2]

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units 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.[3] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.[4]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $361.6 million or 26.1 percent, from $1,385.3 million in 2015 to $1,023.7 million in 2016.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $531.7 million or 32.6 percent, from $1,632.1 million in 2015 to $1,100.4 million in 2016.
- **Balancing Congestion.** Balancing congestion costs increased by $170.1 million or 68.9 percent, from -$246.9 million in 2015 to -$76.8 million in 2016.
- **Real-Time Congestion.** Real-time congestion costs decreased by $451.3 million or 30.0 percent, from $1,504.9 million in 2015 to $1,053.6 million in 2016.

1 On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. The metrics reported in this section treat EKPC as part of MISO for the first hour of June 2013 and as part of PJM for the second hour of June 2013 through 2014.

2 See the 2014 SOM Technical Appendices for a full discussion of the relationship between marginal, average and total losses.

3 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.

4 The total congestion and marginal losses were calculated as of January 10, 2017, and are subject to change, based on continued PJM billing updates.

- **Monthly Congestion.** Monthly total congestion costs in 2016 ranged from $48.0 million in November to $121.4 million in September.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Conastone – Northwest Line, the Graceton Transformer, the Bagley – Graceton Line, the Cherry Valley Transformer, and the Cherry Valley Flowgate.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2016. The number of congestion event hours in the Day-Ahead Energy Market was about ten times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion event hours decreased significantly after September 8, 2014. The decrease was the result of the reduction in up to congestion (UTC) activity which was a result of FERC's UTC uplift refund notice, retroactive to September 8, 2014. However, day-ahead congestion frequency increased by 48.9 percent from 184,851 congestion event hours in 2015 to 275,298 congestion event hours in 2016. The increase was a result of the increase in UTC transactions that followed the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[5]

  Real-time congestion frequency decreased by 7.6 percent from 28,524 congestion event hours in 2015 to 26,369 congestion event hours in 2016.
- **Congested Facilities.** Day-ahead, congestion-event hours decreased on flowgates and interfaces and increased on lines and transformers. Real-time, congestion-event hours increased on flowgates and decreased on interfaces, lines and transformers.

  While Bedington - Black Oak, SENECA and AP South were in the list of constraints that were most frequently binding in the day-ahead market in 2015, interfaces did not bind as frequently in the day-ahead market in 2016.

  The Conastone – Northwest Line was the largest contributor to congestion costs in 2016. With $115.5 million in total congestion costs, it accounted for 11.3 percent of the total PJM congestion costs in 2016.
- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in 2016. ComEd had $303.6 million in total congestion costs, comprised of -$155.5 million in total load congestion payments, -$471.9 million in total generation congestion credits and -$12.8 million in explicit congestion costs. The Cherry Valley Transformer, the Cherry Valley Flowgate, the Braidwood - East Frankfort Line, the Mercer IP – Galesburg Flowgate, and the Byron - Cherry Valley Flowgate contributed $154.0 million, or 50.7 percent of the total ComEd control zone congestion costs.
- **Ownership.** In 2016, financial entities as a group were net recipients of congestion credits and physical entities were net payers of congestion charges. In 2016, financial entities received $9.4 million in congestion credits compared to $132.1 million in 2015. In 2016, physical entities paid $1,033.0 million in congestion charges, a decrease of $484.3 million or 31.9 percent compared to 2015.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $272.2 million or 28.1 percent, from $968.7 million in 2015 to $696.5 million in 2016. The loss MWh in PJM decreased by 1,087.4 GWh or 6.7 percent, from 16,241.3 GWh in 2015 to 15,153.9 GWh in 2016. The loss component of LMP decreased from $0.019 in 2015 to $0.015 or 22.8 percent in 2016.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2016 ranged from $36.6 million in May to $86.4 million in July.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $239.4 million or 23.6 percent, from $1,012.6 million in 2015 to $773.2 million in 2016.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $32.8 million or 74.9 percent, from -$43.9 million in 2015 to -$76.7 million in 2016.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2016 by $109.2 million or 32.5 percent, from $336.3 million in 2015, to $227.2 million in 2016.

5 *See* FERC Docket No. EL14-37.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $161.1 million or 25.7 percent, from -$627.4 million in 2015 to -$466.3 million in 2016.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $117.3 million or 15.5 percent, from -$757.9 million in 2015 to -$640.6 million in 2016.
- **Balancing Energy Costs.** Balancing energy costs increased by $56.3 million or 44.0 percent, from $127.8 million in 2015 to $184.0 million in 2016.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2016 ranged from -$57.8 million in July to -$26.1 million in May.

Conclusion

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

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. Total ARR and self scheduled FTR revenue offset only 63.8 and 86.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 and 2015 to 2016 planning periods. For the first seven months of the 2016 to 2017 planning period ARRs and self scheduled FTRs offset 82.3 percent of total congestion costs.

Locational Marginal Price (LMP)

Components

On June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While the use of a single node reference bus or a distributed load reference bus has no effect on the total LMP, the use of a single node reference bus or a distributed load reference bus will affect the components of LMP. With a distributed load reference bus, the energy component is a load-weighted system price. There is no congestion or losses included in the load weighted reference bus price, unlike the case with a single node reference bus.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus is the sum of three components: the system marginal price (SMP), marginal loss component of LMP (MLMP), and congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[6] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[7] 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. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation in the transmission constrained area.

6 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

7 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.

Table 11-1 shows the PJM real-time, load-weighted average LMP components for 2009 through 2016.[8]

The load-weighted average real-time LMP decreased $6.93 or 19.2 percent from $36.16 in 2015 to $29.23 in 2016. The load-weighted average congestion component increased by $0.0002 from $0.0356 in 2015 to $0.0358 in 2016. The load-weighted average loss component decreased by $0.004 from $0.019 in 2015 to $0.015 in 2016. The load-weighted average energy component decreased by $6.93 or 19.2 percent from $36.11 in 2015 to $29.18 in 2016.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2009 through 2016[9]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
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

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for 2009 through 2016.[10]

The load-weighted average day-ahead LMP decreased $7.05, or 19.2 percent, from $36.73 in 2015 to $29.68 in 2016. The load-weighted average congestion component decreased $0.10, or 38.9 percent, from $0.24 in 2015 to $0.14 in 2016. The load-weighted average loss component increased from -$0.014 in 2015 to -$0.013 in 2016. The load-weighted average energy component decreased $6.96, or 19.1 percent, from $36.51 in 2015 to $29.55 in 2016.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2009 through 2016

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
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)

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-3 for of 2015 and of 2016. In 2016, BGE had the highest real-time congestion component of all control zones and PECO had the lowest real-time congestion component.

8 The PJM real-time, load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the Real-Time Energy Market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load weighted prices. This after the fact adjustment means that the Real-Time Energy Market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM-wide real-time load-weighted LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP.

9 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.

10 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 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): 2015 and 2016

	2015				2016			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$35.85	$35.82	($1.16)	$1.19	$26.93	$29.54	($3.12)	$0.51
AEP	$33.90	$36.05	($1.39)	($0.76)	$29.14	$28.98	$0.39	($0.24)
AP	$38.04	$36.44	$1.44	$0.17	$29.75	$29.06	$0.69	$0.00
ATSI	$34.00	$35.60	($1.89)	$0.29	$29.78	$29.01	$0.13	$0.64
BGE	$47.22	$36.78	$8.69	$1.76	$38.62	$29.41	$8.16	$1.05
ComEd	$29.85	$35.28	($3.50)	($1.94)	$27.66	$29.11	($0.51)	($0.94)
DAY	$34.20	$35.90	($1.86)	$0.17	$29.36	$29.16	($0.25)	$0.45
DEOK	$33.28	$35.88	($1.17)	($1.42)	$28.62	$29.17	$0.16	($0.72)
DLCO	$32.21	$35.64	($2.75)	($0.69)	$29.20	$29.15	$0.29	($0.24)
Dominion	$41.42	$36.92	$3.98	$0.52	$32.15	$29.38	$2.62	$0.15
DPL	$42.27	$37.02	$3.38	$1.87	$29.66	$29.50	($0.67)	$0.83
EKPC	$32.93	$37.54	($2.97)	($1.64)	$28.21	$29.30	($0.31)	($0.78)
JCPL	$35.65	$36.07	($1.53)	$1.11	$26.36	$29.66	($3.59)	$0.29
Met-Ed	$35.79	$36.20	($1.07)	$0.67	$26.04	$29.16	($3.29)	$0.17
PECO	$35.11	$36.03	($1.68)	$0.76	$25.57	$29.25	($3.79)	$0.11
PENELEC	$36.13	$35.78	($0.28)	$0.63	$27.57	$28.80	($1.57)	$0.34
Pepco	$43.04	$36.56	$5.35	$1.12	$34.12	$29.42	$4.11	$0.59
PPL	$35.95	$36.40	($0.95)	$0.51	$25.43	$29.04	($3.60)	($0.01)
PSEG	$36.97	$35.47	$0.45	$1.04	$26.24	$29.23	($3.24)	$0.25
RECO	$37.58	$35.68	$0.84	$1.06	$27.05	$29.76	($3.01)	$0.30
PJM	$36.16	$36.11	$0.04	$0.02	$29.23	$29.18	$0.04	$0.01

The day-ahead components of LMP for each control zone are presented in Table 11-4 for of 2015 and of 2016. In 2016, BGE had the highest day-ahead congestion component of all control zones and JCPL had the lowest day-ahead congestion component.

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2015 and 2016

	2015				2016			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$36.86	$36.25	($0.13)	$0.75	$27.48	$30.02	($3.02)	$0.48
AEP	$34.20	$36.56	($1.80)	($0.57)	$29.46	$29.41	$0.30	($0.24)
AP	$37.95	$36.83	$1.16	($0.05)	$30.18	$29.40	$0.87	($0.09)
ATSI	$34.34	$35.99	($1.97)	$0.32	$29.77	$29.41	($0.04)	$0.40
BGE	$47.92	$36.98	$9.61	$1.33	$39.59	$29.98	$8.68	$0.93
ComEd	$29.45	$35.76	($4.81)	($1.50)	$28.00	$29.50	($0.72)	($0.79)
DAY	$34.39	$36.43	($2.35)	$0.31	$29.67	$29.46	($0.18)	$0.39
DEOK	$33.90	$36.69	($1.67)	($1.12)	$29.30	$29.61	$0.31	($0.62)
DLCO	$32.57	$36.07	($2.70)	($0.80)	$29.12	$29.57	($0.06)	($0.39)
Dominion	$43.09	$37.39	$5.20	$0.50	$33.02	$29.84	$3.01	$0.17
DPL	$42.28	$37.23	$3.62	$1.44	$31.00	$30.03	$0.27	$0.70
EKPC	$33.42	$38.22	($3.21)	($1.59)	$28.62	$29.79	($0.37)	($0.81)
JCPL	$36.86	$36.49	($0.47)	$0.85	$26.52	$30.01	($3.81)	$0.32
Met-Ed	$35.82	$36.27	($0.64)	$0.19	$26.22	$29.41	($3.23)	$0.04
PECO	$35.96	$36.23	($0.63)	$0.37	$25.90	$29.60	($3.77)	$0.07
PENELEC	$35.90	$36.09	($0.55)	$0.36	$27.86	$29.08	($1.42)	$0.21
Pepco	$44.38	$36.72	$6.81	$0.85	$34.95	$29.65	$4.77	$0.53
PPL	$36.62	$36.68	($0.14)	$0.08	$25.68	$29.36	($3.57)	($0.11)
PSEG	$37.82	$36.07	$0.83	$0.93	$26.83	$29.75	($3.30)	$0.38
RECO	$38.10	$36.28	$0.88	$0.94	$27.28	$30.03	($3.16)	$0.41
PJM	$36.73	$36.51	$0.24	($0.01)	$29.68	$29.55	$0.14	($0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-5 for of 2015 and of 2016.

Table 11-5 Hub real-time, load-weighted average LMP components (Dollars per MWh): 2015 and 2016

	2015				2016			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$32.44	$37.65	($3.08)	($2.13)	$27.97	$29.67	($0.47)	($1.23)
AEP-DAY Hub	$33.67	$36.90	($2.24)	($1.00)	$29.08	$29.41	$0.01	($0.34)
ATSI Gen Hub	$33.04	$35.83	($2.43)	($0.36)	$28.99	$28.81	($0.00)	$0.18
Chicago Gen Hub	$27.91	$34.41	($4.16)	($2.34)	$25.97	$28.65	($1.35)	($1.33)
Chicago Hub	$30.42	$36.13	($3.75)	($1.95)	$28.13	$29.45	($0.44)	($0.89)
Dominion Hub	$41.12	$37.33	$3.63	$0.16	$31.68	$29.61	$2.21	($0.13)
Eastern Hub	$40.03	$35.29	$3.03	$1.71	$28.74	$28.68	($0.72)	$0.78
N Illinois Hub	$29.35	$34.83	($3.44)	($2.04)	$27.21	$28.92	($0.64)	($1.07)
New Jersey Hub	$36.09	$35.66	($0.62)	$1.06	$26.32	$29.39	($3.35)	$0.28
Ohio Hub	$32.88	$36.08	($2.32)	($0.87)	$28.93	$29.08	$0.07	($0.22)
West Interface Hub	$34.67	$36.00	($0.71)	($0.62)	$29.87	$29.18	$0.90	($0.22)
Western Hub	$40.83	$38.59	$1.94	$0.30	$31.63	$30.58	$1.00	$0.05

The day-ahead components of LMP for each hub are presented in Table 11-6 for 2015 and 2016.

Table 11-6 Hub day-ahead, load-weighted average LMP components (Dollars per MWh): 2015 and 2016

	2015				2016			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$30.66	$33.21	($1.17)	($1.38)	$28.11	$29.60	($0.32)	($1.17)
AEP-DAY Hub	$32.77	$35.73	($2.32)	($0.64)	$28.89	$29.18	$0.06	($0.35)
ATSI Gen Hub	$29.05	$29.71	($0.60)	($0.05)	$26.12	$25.98	$0.10	$0.03
Chicago Gen Hub	$26.65	$32.83	($4.46)	($1.72)	$25.71	$28.49	($1.62)	($1.16)
Chicago Hub	$29.09	$34.97	($4.51)	($1.37)	$27.77	$29.17	($0.73)	($0.68)
Dominion Hub	$42.57	$37.38	$4.96	$0.24	$32.44	$29.87	$2.64	($0.07)
Eastern Hub	$42.19	$36.99	$3.71	$1.49	$30.84	$29.79	$0.29	$0.76
N Illinois Hub	$28.72	$34.91	($4.60)	($1.59)	$27.38	$29.04	($0.75)	($0.91)
New Jersey Hub	$37.29	$36.26	$0.18	$0.85	$26.65	$29.76	($3.45)	$0.34
Ohio Hub	$32.60	$35.61	($2.46)	($0.55)	$28.85	$29.08	$0.04	($0.27)
West Interface Hub	$35.10	$35.43	$0.05	($0.38)	$30.31	$29.68	$0.93	($0.30)
Western Hub	$38.34	$36.29	$2.11	($0.06)	$30.41	$29.17	$1.31	($0.06)

Component Costs

Table 11-7 shows the total energy, loss and congestion component costs and the total PJM billing for 2009 through 2016. These totals are actually net energy, loss and congestion costs. Total congestion and marginal loss costs decreased in 2016 compared to of 2015.

Table 11-7 Total PJM costs by component (Dollars (Millions)): 2009 through 2016[11 12]

	Component Costs (Millions)					
	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($629)	$1,268	$719	$1,358	$26,550	5.1%
2010	($798)	$1,635	$1,423	$2,260	$34,771	6.5%
2011	($794)	$1,380	$999	$1,585	$35,887	4.4%
2012	($593)	$982	$529	$918	$29,181	3.1%
2013	($688)	$1,035	$677	$1,025	$33,862	3.0%
2014	($978)	$1,466	$1,932	$2,421	$50,030	4.8%
2015	($627)	$969	$1,385	$1,727	$42,630	4.0%
2016	($466)	$697	$1,024	$1,254	$39,050	3.2%

11 The energy costs, loss costs and congestion costs include net inadvertent charges.
12 Total PJM billing is provided by PJM. The MMU is not able to verify the calculation.

Congestion

Congestion Accounting

Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[13] Total congestion costs are equal to the net implicit congestion bill plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

In the analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.

Load congestion payments and generation congestion credits are calculated for both the Day-Ahead and balancing energy markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions. Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Explicit Congestion Costs.** Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion costs equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit congestion costs are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent congestion charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[14]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion costs in each zone are the sum of the congestion costs associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can be both positive and negative. Total congestion costs, when positive, measure the total congestion payment

13 When the term *congestion charge* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

14 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

by a PJM member and when negative, measure the total congestion credit paid to a PJM member. Load congestion payments, when positive, measure the total congestion payment by a PJM member and when negative, measure the total congestion credit paid to a PJM member. Generation congestion credits, when negative, measure the total congestion payment by a PJM member and when positive, measure the total congestion credit paid to a PJM member. Explicit congestion costs, when positive, measure the congestion payment by a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit congestion costs are calculated for up to congestion transactions (UTCs).

The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[15]

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that congestion payments by load are offset by congestion revenues to generation, for the area analyzed. The net congestion bill is the source of payments to FTR holders. When load pays more for congestion in an area than generation receives, the positive difference is the source of payments to FTR holders as it is a measure of the value of transmission in bringing lower cost generation into the area.

Total congestion costs in PJM in 2016 were $1,023.7 million, which was comprised of load congestion payments of $400.8 million, generation credits of -$625.7 million and explicit congestion of -$2.9 million.

Total Congestion

Table 11-8 shows total congestion for 2008 through 2016. Total congestion costs in Table 11-8 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO and in the NYISO.[16 17]

Table 11-8 Total PJM congestion (Dollars (Millions)): 2008 through 2016

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,306	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,771	4.1%
2011	$999	(29.8%)	$35,887	2.8%
2012	$529	(47.0%)	$29,181	1.8%
2013	$677	28.0%	$33,862	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%

Table 11-9 shows the congestion costs by accounting category by market in 2016.

15 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs" <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

16 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.

17 See "NYISO Tariffs New York Independent System Operator, Inc.," (May 26, 2016) Section 35.12.1, Effective Date: October 22, 2014. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-9 Total PJM congestion costs by accounting category by market (Dollars (Millions)): 2008 through 2016

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$1,260.3	($1,133.1)	$203.0	$2,596.5	($225.9)	$79.2	($239.5)	($544.6)	$0.0	$2,051.8
2009	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$0.0	$719.0
2010	$376.4	($1,239.8)	$96.9	$1,713.1	($37.5)	$72.8	($179.5)	($289.8)	($0.0)	$1,423.3
2011	$400.5	($777.6)	$66.9	$1,245.0	$53.5	$109.5	($190.0)	($246.0)	$0.0	$999.0
2012	$122.7	($525.3)	$131.9	$779.9	($7.6)	$57.9	($185.4)	($250.9)	$0.0	$529.0
2013	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9
2014	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2
2015	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3
2016	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	($0.0)	$1,023.7

Table 11-10 and Table 11-11 show the total congestion costs for each transaction type in 2016 and 2015. Table 11-10 shows that in 2016 DECs paid $56.3 million in congestion cost in the day-ahead market, were paid $59.6 million in congestion credits in the balancing energy market, and were paid $3.3 million in net payment for congestion. In 2016, INCs were paid $33.1 million in congestion credits in the day-ahead market, paid $17.2 million in congestion cost in the balancing energy market and received $15.9 million in net payment for congestion. In 2016, up to congestion (UTCs) paid $32.7 million in congestion cost in the day-ahead market, were paid $47.0 million in congestion credits in balancing market and received $14.3 million in net payment for congestion.

Table 11-10 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 2016

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$56.3	$0.0	$0.0	$56.3	($59.6)	$0.0	$0.0	($59.6)	$0.0	($3.3)
Demand	$61.3	$0.0	$0.0	$61.3	$45.5	$0.0	$0.0	$45.5	$0.0	$106.8
Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	$0.0	$0.0	$4.9	$4.9	$0.0	$0.0	$0.0	$0.0	$0.0	$4.9
Explicit Congestion Only	($72.6)	$0.0	($0.5)	($73.1)	($9.8)	$0.0	$2.0	($7.9)	$0.0	($81.0)
Generation	$0.0	($1,043.0)	$0.0	$1,043.0	$0.0	$33.9	$0.0	($33.9)	$0.0	$1,009.1
Grandfathered Overuse	$0.0	$0.0	$0.3	$0.3	$0.0	$0.0	$0.2	$0.2	$0.0	$0.5
Import	$0.0	($6.3)	$0.1	$6.4	$0.0	($7.8)	$0.9	$8.8	$0.0	$15.2
INC	$0.0	$33.1	$0.0	($33.1)	$0.0	($17.2)	$0.0	$17.2	$0.0	($15.9)
Internal Bilateral	$382.4	$384.2	$1.8	($0.0)	$19.5	$19.5	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$32.7	$32.7	$0.0	$0.0	($47.0)	($47.0)	$0.0	($14.3)
Wheel In	$0.0	($22.1)	$1.7	$23.7	$0.0	($0.1)	$0.0	$0.1	$0.0	$23.8
Wheel Out	($22.1)	$0.0	$0.0	($22.1)	($0.1)	$0.0	$0.0	($0.1)	$0.0	($22.1)
Total	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.3	($43.9)	($76.8)	$0.0	$1,023.7

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 2015

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$81.4	$0.0	$0.0	$81.4	($97.6)	$0.0	$0.0	($97.6)	$0.0	($16.2)
Demand	$109.5	$0.0	$0.0	$109.5	$69.2	$0.0	$0.0	$69.2	$0.0	$178.7
Demand Response	($0.2)	$0.0	$0.0	($0.2)	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$4.9	$4.9	$0.0	$0.0	($0.0)	($0.0)	$0.0	$4.9
Export	($51.5)	$0.0	$0.7	($50.8)	($4.4)	$0.0	$1.9	($2.4)	$0.0	($53.3)
Generation	$0.0	($1,429.9)	$0.0	$1,429.9	$0.0	$113.7	$0.0	($113.7)	$0.0	$1,316.2
Grandfathered Overuse	$0.0	$0.0	($2.4)	($2.4)	$0.0	$0.0	$0.5	$0.5	$0.0	($1.9)
Import	$0.0	($37.1)	$1.4	$38.5	$0.0	($71.9)	$1.4	$73.3	$0.0	$111.8
INC	$0.0	$24.2	$0.0	($24.2)	$0.0	($5.1)	$0.0	$5.1	$0.0	($19.1)
Internal Bilateral	$449.4	$449.5	$0.1	$0.0	$33.7	$33.7	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$25.0	$25.0	$0.0	$0.0	($180.8)	($180.8)	$0.0	($155.9)
Wheel In	$0.0	$25.6	$20.6	($5.0)	$0.0	($0.5)	($0.6)	($0.1)	$0.0	($5.1)
Wheel Out	$25.6	$0.0	$0.0	$25.6	($0.5)	$0.0	$0.0	($0.5)	$0.0	$25.1
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3

Table 11-12 shows the change in total congestion cost incurred by transaction type from 2015 to 2016. Total congestion cost incurred by generation decreased by $307.1 million, total congestion cost incurred by demand decreased by $71.9 million, and the total congestion cost incurred by up to congestion transactions (UTCs) increased by $141.5 million.

Total day-ahead congestion costs paid by UTCs increased by $7.7 million from $25.0 million in 2015 to $32.7 million in 2016. Over the same period balancing congestion payments to UTCs decreased by $133.8 million, from $180.8 million in 2015 to $47.0 million in 2016. Overall, total congestion payments to UTC decreased by 90.8 percent between 2015 and 2016 primarily as a result of lower CLMPs. UTCs were paid $155.9 million in congestion in 2015 and $14.3 million in 2016.

Table 11-12 Change in total PJM congestion costs by transaction type by market: 2015 to 2016 (Dollars (Millions))

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	($25.1)	$0.0	$0.0	($25.1)	$38.0	$0.0	$0.0	$38.0	$0.0	$12.9
Demand	($48.2)	$0.0	$0.0	($48.2)	($23.7)	$0.0	$0.0	($23.7)	$0.0	($71.9)
Demand Response	$0.2	$0.0	$0.0	$0.2	($0.2)	$0.0	$0.0	($0.2)	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($21.1)	$0.0	($1.2)	($22.2)	($5.5)	$0.0	$0.0	($5.4)	$0.0	($27.7)
Generation	$0.0	$386.9	$0.0	($386.9)	$0.0	($79.8)	$0.0	$79.8	$0.0	($307.1)
Grandfathered Overuse	$0.0	$0.0	$2.7	$2.7	$0.0	$0.0	($0.3)	($0.3)	$0.0	$2.4
Import	$0.0	$30.8	($1.3)	($32.1)	$0.0	$64.1	($0.5)	($64.5)	$0.0	($96.6)
INC	$0.0	$8.9	$0.0	($8.9)	$0.0	($12.0)	$0.0	$12.0	$0.0	$3.2
Internal Bilateral	($67.1)	($65.3)	$1.7	($0.0)	($14.2)	($14.2)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$7.7	$7.7	$0.0	$0.0	$133.8	$133.8	$0.0	$141.5
Wheel In	$0.0	($47.7)	($19.0)	$28.7	$0.0	$0.4	$0.6	$0.2	$0.0	$28.9
Wheel Out	($47.7)	$0.0	$0.0	($47.7)	$0.4	$0.0	$0.0	$0.4	$0.0	($47.3)
Total	($208.9)	$313.5	($9.3)	($531.7)	($5.1)	($41.5)	$133.7	$170.1	$0.0	($361.6)

Monthly Congestion

Table 11-13 shows that monthly total congestion costs ranged from $48.0 million to $121.4 million in 2016.

Table 11-13 Monthly PJM congestion costs by market (Dollars (Millions)): 2015 and 2016

	Congestion Costs (Millions)							
	2015				2016			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$156.7	($24.4)	$0.0	$132.3	$123.5	($16.0)	$0.0	$107.6
Feb	$476.3	($46.4)	($0.0)	$429.8	$123.8	($12.5)	$0.0	$111.3
Mar	$140.9	($71.4)	$0.0	$69.5	$75.6	($2.2)	($0.0)	$73.3
Apr	$76.3	($4.9)	($0.0)	$71.4	$81.2	($3.0)	$0.0	$78.2
May	$128.9	($19.9)	$0.0	$109.0	$41.6	$7.5	($0.0)	$49.1
Jun	$114.0	($7.5)	($0.0)	$106.6	$68.2	($8.6)	($0.0)	$59.6
Jul	$97.4	($8.5)	($0.0)	$89.0	$124.4	($13.6)	($0.0)	$110.8
Aug	$64.2	($5.8)	$0.0	$58.4	$116.0	($5.0)	($0.0)	$111.0
Sep	$92.3	($15.3)	($0.0)	$77.0	$123.4	($2.1)	($0.0)	$121.4
Oct	$103.2	($16.8)	($0.0)	$86.4	$115.7	($12.6)	($0.0)	$103.1
Nov	$102.8	($10.8)	$0.0	$92.0	$48.9	($0.9)	($0.0)	$48.0
Dec	$79.1	($15.2)	$0.0	$63.9	$58.0	($7.8)	($0.0)	$50.3
Total	$1,632.1	($246.9)	$0.0	$1,385.3	$1,100.4	($76.8)	($0.0)	$1,023.7

Figure 11-1 shows PJM monthly total congestion cost for 2009 through 2016.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 through 2016

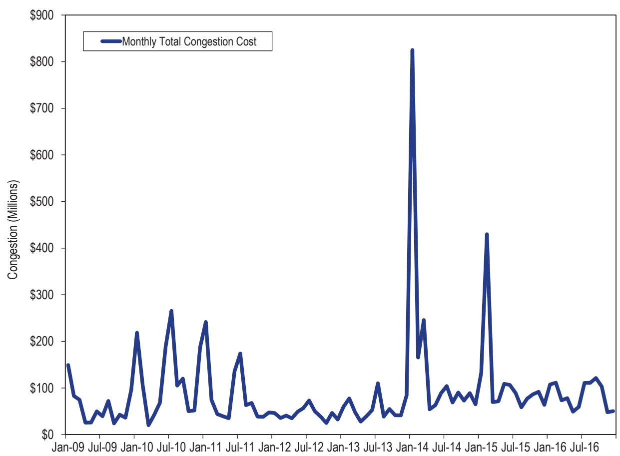


Table 11-14 shows the monthly total congestion costs for each virtual transaction type in 2016 and Table 11-15 shows the monthly total congestion costs for each virtual transaction type in 2015. Virtual transaction congestion costs, when positive, measure the total congestion cost to the virtual transaction and when negative, measure the total congestion credit to the virtual transaction. Table 11-14 and Table 11-15 show that UTCs paid day-ahead congestion costs and were paid balancing congestion credits in 2016 and 2015.

Table 11-14 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2016

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$6.8	($0.8)	$4.2	$10.1	($6.1)	($1.5)	($11.6)	($19.2)	($9.0)
Feb	$6.0	($1.0)	$1.2	$6.1	($8.1)	($0.5)	($6.3)	($14.9)	($8.8)
Mar	$5.1	($5.3)	$0.8	$0.5	($3.9)	$3.8	($1.2)	($1.3)	($0.8)
Apr	$5.0	($3.9)	($0.9)	$0.2	($5.1)	$4.3	($0.7)	($1.5)	($1.3)
May	$3.4	($8.9)	$0.8	($4.8)	($2.4)	$7.4	$1.8	$6.9	$2.1
Jun	$3.9	$0.0	$7.6	$11.6	($2.6)	($1.5)	($7.2)	($11.4)	$0.2
Jul	$3.5	$0.2	$5.5	$9.2	($6.0)	($1.7)	($7.5)	($15.2)	($5.9)
Aug	$7.4	($3.0)	$4.9	$9.3	($7.4)	$1.2	($5.5)	($11.8)	($2.5)
Sep	$6.8	($3.9)	$4.5	$7.4	($7.9)	$1.6	($1.2)	($7.6)	($0.2)
Oct	$4.9	($3.7)	$0.1	$1.3	($5.0)	$3.1	($4.0)	($5.8)	($4.5)
Nov	$1.7	($1.6)	$1.5	$1.6	($1.8)	$0.9	($1.0)	($1.9)	($0.3)
Dec	$1.7	($1.1)	$2.7	$3.4	($3.3)	$0.1	($2.7)	($5.9)	($2.5)
Total	$56.3	($33.1)	$32.7	$55.9	($59.6)	$17.2	($47.0)	($89.5)	($33.5)

Table 11-15 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2015

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$7.4	($3.2)	($3.4)	$0.8	($7.1)	$1.1	($11.3)	($17.4)	($16.6)
Feb	$11.1	$0.1	($37.6)	($26.4)	($15.4)	($0.6)	($13.0)	($29.0)	($55.4)
Mar	$9.6	($0.1)	$12.5	$22.0	($17.7)	$0.5	($55.1)	($72.3)	($50.3)
Apr	$4.3	($2.5)	$5.3	$7.1	($5.8)	$3.7	($10.0)	($12.2)	($5.0)
May	$5.1	($3.7)	$5.9	$7.3	($4.8)	($2.1)	($21.7)	($28.6)	($21.3)
Jun	$9.0	($3.2)	$6.6	$12.4	($9.5)	$0.2	($6.9)	($16.2)	($3.8)
Jul	$7.0	($3.0)	$4.7	$8.7	($7.5)	$3.5	($12.3)	($16.4)	($7.7)
Aug	$4.2	($1.8)	$2.8	$5.2	($4.4)	$0.5	($6.6)	($10.5)	($5.3)
Sep	$4.3	$0.1	$4.6	$9.1	($6.4)	($4.1)	($10.5)	($21.0)	($11.9)
Oct	$6.7	($1.7)	$9.6	$14.6	($6.8)	($0.5)	($14.0)	($21.3)	($6.7)
Nov	$5.9	($3.3)	$7.7	$10.4	($5.0)	$2.1	($7.5)	($10.4)	($0.1)
Dec	$6.7	($1.9)	$6.2	$11.0	($7.0)	$0.9	($11.9)	($18.0)	($6.9)
Total	$81.4	($24.2)	$25.0	$82.2	($97.6)	$5.1	($180.8)	($273.3)	($191.1)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours usually exceeds the number of constrained hours and the number of congestion-event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion. In 2016, there were 275,298 day-ahead, congestion-event hours compared to 184,851 day-ahead congestion-event hours in 2015. Of the 2016 day-ahead congestion-event hours, only 14,197 (5.2 percent) were also constrained in the Real-Time Energy Market. In 2016, there were 26,369 real-time, congestion-event hours compared to 28,524 real-time, congestion-event hours in 2015. Of the 2016 real-time congestion-event hours, 14,099 (53.5 percent) were also constrained in the Day-Ahead Energy Market.

The Conastone – Northwest Line was the largest contributor to total congestion costs in 2016. With $115.5 million in total congestion costs, it accounted for 11.3 percent of the total PJM congestion costs in 2016. The top five constraints in terms of congestion costs contributed $345.7 million, or 33.8 percent, of the total PJM congestion costs in 2016. The top five constraints were the Conastone – Northwest Line, the Graceton Transformer, the Bagley – Graceton Line, the Cherry Valley Transformer, and the Cherry Valley Flowgate.

Congestion by Facility Type and Voltage

In 2016, day-ahead, congestion-event hours decreased on flowgates and interfaces and increased on lines and transformers.

The decrease in day-ahead, congestion-event hours on flowgates was largely a result of the decrease of day-ahead, congestion-event hours on MISO flowgates. The day-ahead, congestion-event hours on flowgates in MISO decreased from 26,279 event hours in 2015 to 23,893 event hours in 2016. The decrease in day-ahead, congestion-event hours on interfaces was a result of the decrease of day-ahead, congestion-event hours on Bedington – Black Oak. The day-ahead, congestion-event hours on Bedington – Black Oak decreased from 2,933 event hours in 2015 to 1,515 event hours in 2016. The increase in day-ahead, congestion-event hours on lines was primarily a result of an increase in day-ahead, congestion-event hours incurred by lines in AEP and ComEd zones. The increase in day-ahead, congestion-event hours on transformers was primarily a result of the increase in day-ahead, congestion-event hours on transformers in the AEP and ComEd zones.

Real-time, congestion-event hours decreased on all types of facilities except flowgates. The increase in real-time, congestion-event hours on flowgates was primarily a result of the increase in real-time, congestion-event hours on flowgates in MISO. The real-time, congestion-event hours on flowgates in MISO increased from 4,861 event hours in 2015 to 4,920 event hours in 2016.

Day-ahead congestion costs decreased on all types of facilities in 2016 compared to 2015, primarily as a result of the decrease in day-ahead load-weighted CLMP.

Balancing congestion costs increased on all types of facilities except flowgates in 2016 compared to 2015. The decrease in balancing congestion costs on flowgates was primarily a result of the decrease in real-time, congestion-event hours on flowgates in MISO. The balancing congestion costs on flowgates in MISO decreased from -$20.7 million in 2015 to -$32.5 million in 2016.

Table 11-16 provides congestion-event hour subtotals and congestion cost subtotals comparing 2016 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[18] [19] Table 11-17 presents this information for 2015.

Table 11-16 Congestion summary (By facility type): 2016

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($30.8)	($261.2)	($16.5)	$213.9	($0.2)	$17.5	($15.6)	($33.2)	$180.7	23,964	6,033
Interface	$29.5	($20.5)	($2.5)	$47.6	$0.3	$0.4	$0.2	$0.1	$47.7	4,959	161
Line	$313.1	($256.5)	$44.7	$614.3	($1.6)	$9.7	($28.0)	($39.3)	$575.0	161,398	16,609
Other	$2.5	($1.7)	$0.6	$4.8	$0.3	($0.1)	($0.9)	($0.4)	$4.4	14,860	203
Transformer	$91.1	($113.9)	$14.5	$219.5	($2.1)	$3.0	($3.4)	($8.5)	$211.0	70,117	3,363
Unclassified	($0.1)	($0.2)	$0.1	$0.3	($1.3)	($2.0)	$3.8	$4.5	$4.8	NA	NA
Total	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	$1,023.7	275,298	26,369

18 Unclassified are congestion costs related to nontransmission facility constraints in the Day-Ahead Market and any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors. Nontransmission facility constraints include day-ahead market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

19 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Table 11-17 Congestion summary (By facility type): 2015

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	$25.2	($277.0)	($22.8)	$279.3	$1.7	$2.7	($25.1)	($26.1)	$253.2	26,279	5,394
Interface	$74.8	($316.9)	($30.1)	$361.6	$10.7	$28.8	$2.9	($15.1)	$346.5	9,208	2,052
Line	$397.9	($234.2)	$96.9	$729.0	($17.0)	$24.1	($145.6)	($186.6)	$542.4	107,542	17,449
Other	($0.2)	($1.2)	$0.3	$1.2	$0.1	$0.1	($0.1)	($0.1)	$1.2	1,976	38
Transformer	$116.6	($137.8)	$5.9	$260.3	$4.9	$13.4	($20.6)	($29.0)	$231.3	39,846	3,591
Unclassified	($0.1)	($0.6)	$0.1	$0.6	$0.1	$0.9	$10.8	$10.1	$10.7	NA	NA
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$1,385.3	184,851	28,524

Table 11-18 and Table 11-19 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 11-18. In 2016, there were 275,298 congestion-event hours in the Day-Ahead Energy Market. Of those day-ahead congestion-event hours, only 14,197 (5.2 percent) were also constrained in the Real-Time Energy Market. In 2015, of the 184,851 day-ahead congestion-event hours, only 15,209 (8.2 percent) were binding in the Real-Time Energy Market.[20]

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 11-19. In 2016, of the 26,369 congestion-event hours in the Real-Time Energy Market, 14,099 (53.5 percent) were also constrained in the Day-Ahead Energy Market. In 2015, of the 28,524 real-time congestion-event hours, 15,205 (53.3 percent) were also in the Day-Ahead Energy Market.

Table 11-18 Congestion event hours (day-ahead against real-time): 2015 and 2016

	Congestion Event Hours					
	2015			2016		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	26,279	2,504	9.5%	23,964	2,682	11.2%
Interface	9,208	1,503	16.3%	4,959	75	1.5%
Line	107,542	9,947	9.2%	161,398	9,216	5.7%
Other	1,976	0	0.0%	14,860	9	0.1%
Transformer	39,846	1,255	3.1%	70,117	2,215	3.2%
Total	184,851	15,209	8.2%	275,298	14,197	5.2%

Table 11-19 Congestion event hours (real-time against day-ahead): 2015 and 2016

	Congestion Event Hours					
	2015			2016		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	5,394	2,518	46.7%	6,033	2,657	44.0%
Interface	2,052	1,539	75.0%	161	85	52.8%
Line	17,449	9,949	57.0%	16,609	9,132	55.0%
Other	38	0	0.0%	203	9	4.4%
Transformer	3,591	1,199	33.4%	3,363	2,216	65.9%
Total	28,524	15,205	53.3%	26,369	14,099	53.5%

20 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 11-20 shows congestion costs by facility voltage class for 2016. Congestion costs in 2016 increased for facilities rated at 345 kV, 230 kV, 138 kV, 34 kV, 13 kV and 12 kV compared to 2015 (Table 11-21).

Table 11-20 Congestion summary (By facility voltage): 2016

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$2.1	($2.7)	$2.3	$7.1	$0.0	($0.0)	($0.0)	($0.0)	$7.1	2,193	5
500	$55.3	($42.1)	($1.2)	$96.2	$4.5	$4.4	$3.6	$3.8	$99.9	8,375	1,091
345	($14.5)	($170.2)	$20.6	$176.3	$1.0	$19.2	($25.7)	($43.8)	$132.5	48,376	4,714
230	$297.9	($102.0)	($2.1)	$397.8	$10.3	($0.4)	$3.6	$14.3	$412.1	43,862	7,939
161	($20.2)	($60.5)	($10.4)	$29.8	($2.6)	$4.4	$1.7	($5.2)	$24.6	5,262	1,427
138	$34.3	($275.4)	$26.2	$335.8	($5.7)	$18.6	($26.2)	($50.5)	$285.3	117,296	7,139
115	$21.5	($16.0)	$3.0	$40.5	($2.5)	$0.7	($3.9)	($7.1)	$33.4	22,359	1,201
69	$28.6	$15.0	$2.3	$15.8	($8.4)	($16.5)	($0.9)	$7.2	$23.0	22,822	2,794
34.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	48	0
34	$0.6	$0.0	$0.2	$0.8	($0.0)	$0.0	$0.1	$0.1	$0.8	4,607	59
13	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	59	0
12	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	39	0
Unclassified	($0.1)	($0.2)	$0.1	$0.3	($1.3)	($2.0)	$3.8	$4.5	$4.8	NA	NA
Total	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	$1,023.7	275,298	26,369

Table 11-21 Congestion summary (By facility voltage): 2015

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$25.0	($59.2)	($4.6)	$79.6	$3.7	$2.2	($2.0)	($0.4)	$79.2	4,286	238
500	$79.6	($324.9)	($27.9)	$376.5	$12.9	$28.9	($1.0)	($17.0)	$359.6	9,145	1,086
460	($0.0)	($3.6)	$0.3	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	1,360	0
345	($12.3)	($174.4)	$15.8	$177.9	$7.6	$7.4	($26.5)	($26.3)	$151.7	31,151	2,694
230	$362.1	($30.3)	$30.0	$422.4	($4.0)	($3.6)	($53.7)	($54.1)	$368.3	34,830	8,484
161	($19.5)	($55.9)	($7.8)	$28.5	($1.0)	$1.9	($2.9)	($5.7)	$22.8	4,279	1,533
138	$109.7	($290.8)	$36.8	$437.3	($9.8)	$35.0	($96.5)	($141.3)	$296.0	71,338	10,656
115	$26.2	($22.8)	$7.4	$56.4	$0.5	$0.5	($4.7)	($4.7)	$51.6	13,587	1,930
69	$43.3	($5.3)	$0.1	$48.6	($9.5)	($3.2)	($1.2)	($7.5)	$41.2	13,793	1,853
34	$0.1	$0.0	$0.2	$0.3	($0.0)	$0.0	$0.0	$0.0	$0.3	1,026	50
13	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	55	0
12	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
Unclassified	($0.1)	($0.6)	$0.1	$0.6	$0.1	$0.9	$10.8	$10.1	$10.7	NA	NA
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$1,385.3	184,851	28,524

Constraint Duration

Table 11-22 lists the constraints in 2015 and 2016 that were most frequently binding and Table 11-23 shows the constraints which experienced the largest change in congestion-event hours from 2015 to 2016.

Table 11-22 Top 25 constraints with frequent occurrence: 2015 and 2016

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2015	2016	Change	2015	2016	Change	2015	2016	Change	2015	2016	Change
1	Cherry Valley	Transformer	789	5,319	4,530	885	774	(111)	9%	61%	52%	10%	9%	(1%)
2	Olive	Other	0	6,092	6,092	0	0	0	0%	69%	69%	0%	0%	0%
3	Monroe - Vineland	Line	3,121	5,354	2,233	197	439	242	36%	61%	25%	2%	5%	3%
4	Bagley - Graceton	Line	3,544	3,313	(231)	1,973	1,685	(288)	40%	38%	(3%)	23%	19%	(3%)
5	Mercer IP - Galesburg	Flowgate	816	3,510	2,694	206	1,155	949	9%	40%	31%	2%	13%	11%
6	Conastone - Northwest	Line	2,536	2,776	240	1,734	1,840	106	29%	32%	3%	20%	21%	1%
7	Graceton	Transformer	270	3,117	2,847	88	1,298	1,210	3%	35%	32%	1%	15%	14%
8	Howard - Shelby	Line	1,370	4,169	2,799	0	0	0	16%	47%	32%	0%	0%	0%
9	Braidwood	Transformer	3,727	4,138	411	0	0	0	43%	47%	5%	0%	0%	0%
10	Elwood - Elwood	Other	1,464	3,849	2,385	0	0	0	17%	44%	27%	0%	0%	0%
11	West Moulton-City Of St. Marys	Line	447	3,718	3,271	0	0	0	5%	42%	37%	0%	0%	0%
12	East Danville - Banister	Line	3,465	3,643	178	126	20	(106)	40%	41%	2%	1%	0%	(1%)
13	Maywood	Transformer	0	3,422	3,422	0	0	0	0%	39%	39%	0%	0%	0%
14	Conastone - Peach Bottom	Line	230	2,407	2,177	73	699	626	3%	27%	25%	1%	8%	7%
15	E.K.P Hebron - Hebron	Line	215	3,016	2,801	0	0	0	2%	34%	32%	0%	0%	0%
16	Miami Fort	Transformer	815	3,002	2,187	3	4	1	9%	34%	25%	0%	0%	0%
17	Emilie - Falls	Line	1,159	2,617	1,458	268	329	61	13%	30%	17%	3%	4%	1%
18	Zion	Line	607	2,929	2,322	0	0	0	7%	33%	26%	0%	0%	0%
19	Gould Street - Westport	Line	789	2,782	1,993	23	27	4	9%	32%	23%	0%	0%	0%
20	Hudson	Transformer	511	2,795	2,284	0	0	0	6%	32%	26%	0%	0%	0%
21	Mardela - Vienna	Line	1,365	2,367	1,002	86	380	294	16%	27%	11%	1%	4%	3%
22	Reynolds - Magnetation	Flowgate	650	2,062	1,412	208	680	472	7%	23%	16%	2%	8%	5%
23	East Bend	Transformer	2,808	2,700	(108)	0	0	0	32%	31%	(1%)	0%	0%	0%
24	Clinch River	Transformer	478	2,557	2,079	0	0	0	5%	29%	24%	0%	0%	0%
25	Tanners Creek	Transformer	1,838	2,548	710	0	0	0	21%	29%	8%	0%	0%	0%

Table 11-23 Top 25 constraints with largest year-to-year change in occurrence: 2015 and 2016

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2015	2016	Change	2015	2016	Change	2015	2016	Change	2015	2016	Change
1	Olive	Other	0	6,092	6,092	0	0	0	0%	69%	69%	0%	0%	0%
2	Bunsonville - Eugene	Flowgate	3,762	0	(3,762)	748	0	(748)	43%	0%	(43%)	9%	0%	(9%)
3	Cherry Valley	Transformer	789	5,319	4,530	885	774	(111)	9%	61%	52%	10%	9%	(1%)
4	Graceton	Transformer	270	3,117	2,847	88	1,298	1,210	3%	35%	32%	1%	15%	14%
5	Maywood - Saddlebrook	Line	3,456	29	(3,427)	509	0	(509)	39%	0%	(39%)	6%	0%	(6%)
6	Bergen - New Milford	Line	2,970	72	(2,898)	795	1	(794)	34%	1%	(33%)	9%	0%	(9%)
7	Mercer IP - Galesburg	Flowgate	816	3,510	2,694	206	1,155	949	9%	40%	31%	2%	13%	11%
8	Maywood	Transformer	0	3,422	3,422	0	0	0	0%	39%	39%	0%	0%	0%
9	West Moulton-City Of St. Marys	Line	447	3,718	3,271	0	0	0	5%	42%	37%	0%	0%	0%
10	Oak Grove - Galesburg	Flowgate	3,356	1,336	(2,020)	1,306	174	(1,132)	38%	15%	(23%)	15%	2%	(13%)
11	Conastone - Peach Bottom	Line	230	2,407	2,177	73	699	626	3%	27%	25%	1%	8%	7%
12	E.K.P Hebron - Hebron	Line	215	3,016	2,801	0	0	0	2%	34%	32%	0%	0%	0%
13	Howard - Shelby	Line	1,370	4,169	2,799	0	0	0	16%	47%	32%	0%	0%	0%
14	Easton	Transformer	3,099	397	(2,702)	0	0	0	35%	5%	(31%)	0%	0%	0%
15	Monroe - Vineland	Line	3,121	5,354	2,233	197	439	242	36%	61%	25%	2%	5%	3%
16	Elwood - Elwood	Other	1,464	3,849	2,385	0	0	0	17%	44%	27%	0%	0%	0%
17	Zion	Line	607	2,929	2,322	0	0	0	7%	33%	26%	0%	0%	0%
18	Hudson	Transformer	511	2,795	2,284	0	0	0	6%	32%	26%	0%	0%	0%
19	Waukegan	Transformer	124	2,326	2,202	0	0	0	1%	26%	25%	0%	0%	0%
20	Miami Fort	Transformer	815	3,002	2,187	3	4	1	9%	34%	25%	0%	0%	0%
21	Mainesburg - Mansfield	Line	107	2,098	1,991	0	141	141	1%	24%	23%	0%	2%	2%
22	Bellefonte - Grangston	Line	82	2,203	2,121	0	0	0	1%	25%	24%	0%	0%	0%
23	SENECA	Interface	938	0	(938)	1,182	0	(1,182)	11%	0%	(11%)	13%	0%	(13%)
24	Clinch River	Transformer	478	2,557	2,079	0	0	0	5%	29%	24%	0%	0%	0%
25	Gould Street - Westport	Line	789	2,782	1,993	23	27	4	9%	32%	23%	0%	0%	0%

Constraint Costs

Table 11-24 and Table 11-25 present the top constraints affecting congestion costs by facility for 2016 and 2015. The Conastone – Northwest Line was the largest contributor to congestion costs in 2016. With $115.5 million in total congestion costs, it accounted for 11.3 percent of the total PJM congestion costs in 2016.

Table 11-24 Top 25 constraints affecting PJM congestion costs (By facility): 2016

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2016
1	Conastone - Northwest	Line	BGE	$114.8	$7.4	($4.6)	$102.8	$3.9	($2.4)	$6.5	$12.7	$115.5	11.3%
2	Graceton	Transformer	BGE	$53.1	($21.0)	($0.9)	$73.3	($0.9)	($4.7)	$1.8	$5.6	$78.9	7.7%
3	Bagley - Graceton	Line	BGE	$72.5	$5.8	($1.9)	$64.8	$2.7	($2.7)	$2.2	$7.7	$72.5	7.1%
4	Cherry Valley	Transformer	ComEd	$20.4	($27.9)	$3.9	$52.3	($3.0)	$2.6	($5.7)	($11.3)	$40.9	4.0%
5	Cherry Valley	Flowgate	MISO	($5.7)	($44.0)	($0.5)	$37.8	$0.0	$0.0	$0.0	$0.0	$37.8	3.7%
6	Conastone - Peach Bottom	Line	500	$27.9	($0.2)	$0.8	$28.9	$1.3	$0.9	$0.0	$0.4	$29.3	2.9%
7	Braidwood - East Frankfort	Line	ComEd	($3.8)	($38.2)	$0.8	$35.2	$0.5	$3.3	($3.5)	($6.3)	$28.9	2.8%
8	Mercer IP - Galesburg	Flowgate	MISO	($17.1)	($49.9)	($8.9)	$23.9	($0.2)	$3.6	$2.2	($1.6)	$22.3	2.2%
9	Byron - Cherry Valley	Flowgate	MISO	($5.5)	($22.6)	$0.9	$18.0	$0.0	$0.0	$0.0	$0.0	$18.0	1.8%
10	Milford - Steele	Line	DPL	($8.6)	($26.7)	$0.1	$18.1	$2.2	$1.4	($1.7)	($0.9)	$17.2	1.7%
11	AP South	Interface	500	$13.8	($4.9)	($1.9)	$16.8	$0.1	$0.1	$0.0	$0.0	$16.8	1.6%
12	Dixon - McGirr Rd	Flowgate	MISO	($5.0)	($22.9)	($1.2)	$16.7	$0.0	$0.0	$0.0	$0.0	$16.7	1.6%
13	Reynolds - Magnetation	Flowgate	MISO	($5.1)	($23.9)	$0.9	$19.8	$0.5	$1.5	($2.6)	($3.5)	$16.2	1.6%
14	Bedington - Black Oak	Interface	500	$9.5	($6.2)	($0.6)	$15.2	$0.2	$0.2	$0.1	$0.1	$15.3	1.5%
15	Coolspring - Milford	Line	DPL	$1.3	($11.8)	($0.0)	$13.1	($1.0)	($1.8)	$0.3	$1.1	$14.1	1.4%
16	Loudoun	Transformer	500	$1.1	($9.8)	($0.2)	$10.6	$1.5	$2.2	$3.4	$2.7	$13.3	1.3%
17	Person - Halifax	Flowgate	MISO	$29.9	$16.1	($0.2)	$13.5	$0.0	$0.0	($0.2)	($0.2)	$13.3	1.3%
18	Kanawha River - Matt Funk	Line	AEP	$2.7	($17.1)	($1.1)	$18.8	($0.7)	$2.5	($3.3)	($6.6)	$12.2	1.2%
19	Plymouth Meeting - Whitpain	Line	PECO	($0.6)	($10.9)	($0.1)	$10.2	($0.1)	$0.1	$0.2	($0.0)	$10.1	1.0%
20	AEP - DOM	Interface	500	$3.5	($4.5)	$0.2	$8.2	$0.3	($0.0)	$0.1	$0.3	$8.5	0.8%
21	Braidwood - East Frankfurt	Flowgate	MISO	($0.1)	($7.7)	$0.7	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	0.8%
22	Cherry Valley - Silver Lake	Flowgate	MISO	($1.8)	($9.4)	$0.8	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	0.8%
23	Brambleton - Loudoun	Line	Dominion	($2.9)	($10.2)	$0.2	$7.5	$0.2	($0.1)	$0.4	$0.6	$8.1	0.8%
24	Kanawha	Transformer	AEP	$0.1	($7.1)	$0.7	$7.9	$0.0	$0.0	$0.0	$0.0	$7.9	0.8%
25	Stockton - Kenney	Line	DPL	($2.5)	$3.4	($1.9)	($7.8)	$0.0	$0.0	$0.0	$0.0	($7.8)	(0.8%)

Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): 2015

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2015
1	Conastone - Northwest	Line	BGE	$100.9	($2.4)	$1.6	$105.0	($1.6)	($8.1)	($2.7)	$3.8	$108.8	7.9%
2	Bagley - Graceton	Line	BGE	$99.5	$5.6	$5.0	$98.9	($0.2)	($12.4)	($3.2)	$9.0	$107.9	7.8%
3	5004/5005 Interface	Interface	500	($23.0)	($134.8)	($9.2)	$102.6	$7.0	$22.5	$1.9	($13.6)	$89.0	6.4%
4	Bedington - Black Oak	Interface	500	$46.1	($45.2)	($7.2)	$84.1	$2.4	$2.2	$3.2	$3.5	$87.6	6.3%
5	Cherry Valley	Flowgate	MISO	($9.1)	($82.1)	$6.7	$79.6	$0.0	$0.0	$0.0	$0.0	$79.6	5.7%
6	AP South	Interface	500	$38.1	($22.8)	($5.5)	$55.4	$0.3	$0.2	$0.6	$0.7	$56.2	4.1%
7	AEP - DOM	Interface	500	$28.1	($28.0)	($1.1)	$55.0	$0.9	$1.6	($1.9)	($2.6)	$52.4	3.8%
8	Joshua Falls	Transformer	AEP	$9.7	($35.9)	($4.7)	$40.9	$0.7	($0.1)	$2.3	$3.1	$44.0	3.2%
9	Bergen - New Milford	Line	PSEG	$25.2	$18.4	$17.9	$24.7	($7.6)	$9.3	($51.2)	($68.1)	($43.5)	(3.1%)
10	Person - Halifax	Flowgate	MISO	$79.7	$29.2	($10.4)	$40.1	$0.0	($0.0)	($0.1)	($0.1)	$40.0	2.9%
11	Maywood - Saddlebrook	Line	PSEG	$8.9	$3.9	$7.5	$12.5	($4.7)	$9.0	($22.2)	($36.0)	($23.4)	(1.7%)
12	East	Interface	500	($13.0)	($37.6)	($2.1)	$22.4	($0.1)	$0.3	$0.5	$0.1	$22.6	1.6%
13	Easton	Transformer	DPL	$29.0	$6.6	($0.5)	$21.9	$0.0	$0.0	$0.0	$0.0	$21.9	1.6%
14	Glenarm - Windy Edge	Line	BGE	$3.3	($13.0)	$1.0	$17.3	$1.9	($1.9)	($0.7)	$3.2	$20.5	1.5%
15	Oak Grove - Galesburg	Flowgate	MISO	($16.1)	($44.8)	($6.3)	$22.4	$0.2	$1.1	($1.9)	($2.8)	$19.7	1.4%
16	Mahans Lane - Tidd	Line	AEP	$7.7	($13.3)	($1.6)	$19.4	$0.4	$1.1	$0.9	$0.2	$19.6	1.4%
17	East Danville - Banister	Line	AEP	$8.1	($7.6)	$2.0	$17.7	$0.5	($1.5)	($0.6)	$1.4	$19.1	1.4%
18	BCPEP	Interface	Pepco	$15.3	($3.0)	$0.1	$18.4	$0.0	$0.0	$0.0	$0.0	$18.4	1.3%
19	Braidwood - East Frankfort	Line	ComEd	($2.3)	($21.0)	$0.6	$19.4	$0.3	$0.4	($1.2)	($1.3)	$18.1	1.3%
20	Valley	Transformer	500	$17.4	($0.2)	$0.0	$17.7	$0.0	$0.0	$0.0	$0.0	$17.7	1.3%
21	Cloverdale	Transformer	AEP	$6.6	($9.8)	($1.4)	$15.0	$0.0	$0.0	$0.0	$0.0	$15.0	1.1%
22	Breed - Wheatland	Flowgate	MISO	($1.7)	($15.5)	$0.6	$14.4	$0.1	($0.6)	($0.7)	($0.0)	$14.4	1.0%
23	Miami Fort - Willey	Line	DEOK	($0.8)	($12.4)	$1.2	$12.8	$1.2	$0.7	($0.3)	$0.2	$13.0	0.9%
24	Central	Interface	500	($15.5)	($32.7)	($3.9)	$13.3	$0.1	$1.0	$0.3	($0.7)	$12.6	0.9%
25	West	Interface	500	($1.8)	($15.6)	($0.9)	$12.9	$0.2	$1.0	$0.1	($0.6)	$12.3	0.9%

Figure 11-2 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted, average CLMP in 2016. Figure 11-3 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time, load-weighted, average CLMP in 2016. Figure 11-4 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead, load-weighted, average CLMP in 2016.

Figure 11-2 Location of the top 10 constraints by PJM total congestion costs: 2016

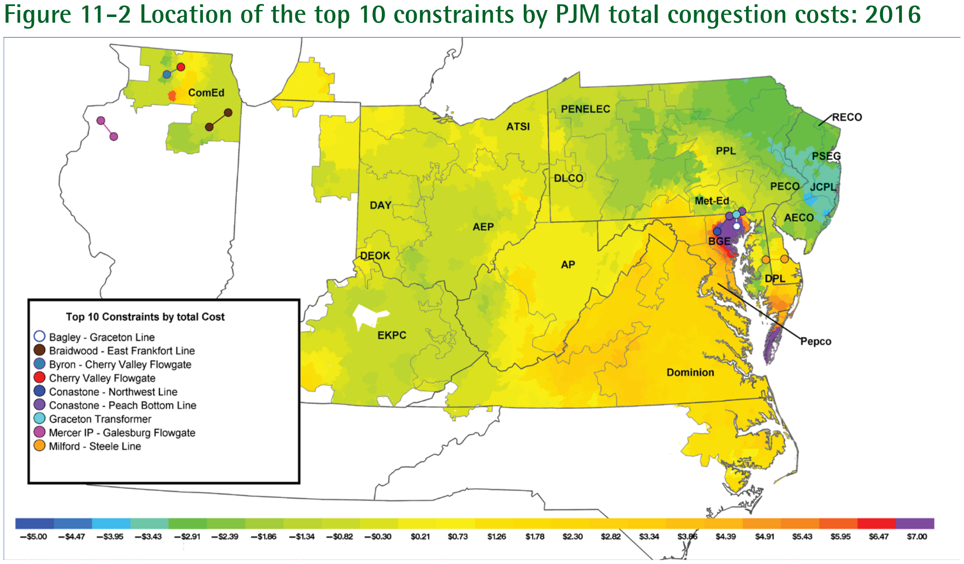


Figure 11-3 Location of the top 10 constraints by PJM balancing congestion costs: 2016

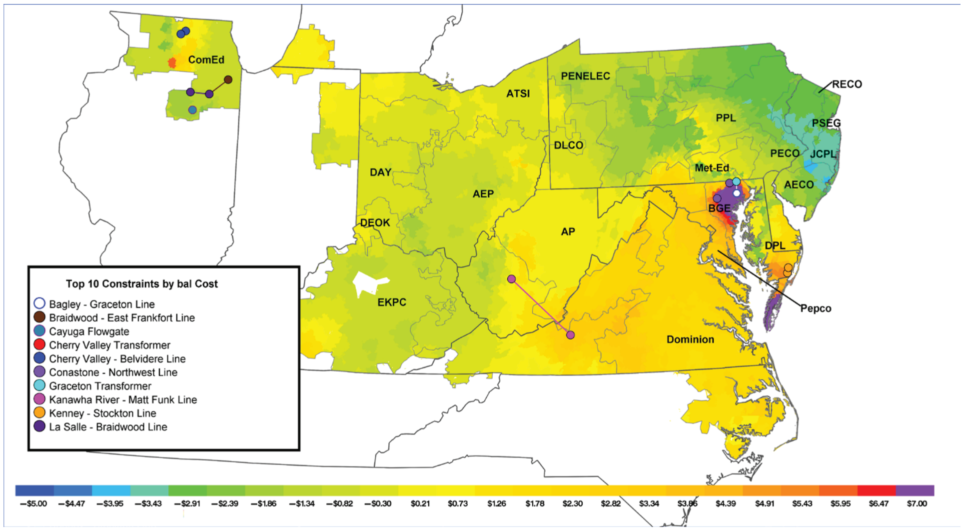
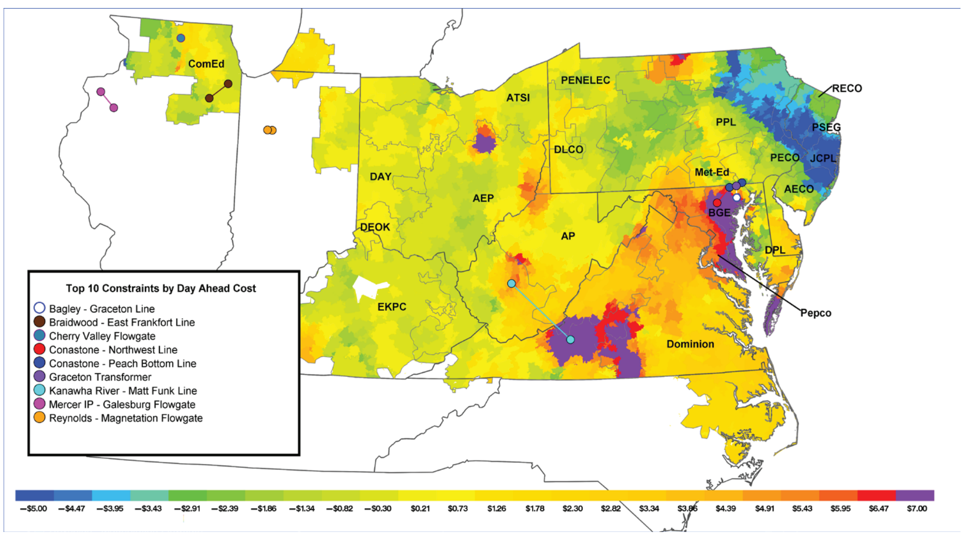


Figure 11-4 Location of the top 10 constraints by PJM day-ahead congestion costs: 2016



Congestion-Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[21] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[22] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of December 31, 2016, PJM had 150 flowgates eligible for M2M (Market to Market) coordination and MISO had 268 flowgates eligible for M2M coordination.

21 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>.

22 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 2.2.24, Effective Date: July 28, 2016. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-26 and Table 11-27 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 2016 and 2015, and which had the greatest congestion cost impact on PJM. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in 2016, the Cherry Valley Flowgate made the most significant contribution to positive congestion while the Cayuga Flowgate made the most significant contribution to negative congestion.

Table 11-26 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2016

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Cherry Valley	($5.7)	($44.0)	($0.5)	$37.8	$0.0	$0.0	$0.0	$0.0	$37.8	1,329	0
2	Mercer IP - Galesburg	($17.1)	($49.9)	($8.9)	$23.9	($0.2)	$3.6	$2.2	($1.6)	$22.3	3,510	1,155
3	Byron - Cherry Valley	($5.5)	($22.6)	$0.9	$18.0	$0.0	$0.0	$0.0	$0.0	$18.0	298	0
4	Dixon - McGirr Rd	($5.0)	($22.9)	($1.2)	$16.7	$0.0	$0.0	$0.0	$0.0	$16.7	1,779	0
5	Reynolds - Magnetation	($5.1)	($23.9)	$0.9	$19.8	$0.5	$1.5	($2.6)	($3.5)	$16.2	2,062	680
6	Person - Halifax	$29.9	$16.1	($0.2)	$13.5	$0.0	$0.0	($0.2)	($0.2)	$13.3	719	5
7	Braidwood - East Frankfurt	($0.1)	($7.7)	$0.7	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	616	0
8	Cherry Valley - Silver Lake	($1.8)	($9.4)	$0.8	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	484	0
9	Dumont	($1.4)	($10.3)	($1.3)	$7.6	$0.0	$0.0	$0.0	$0.0	$7.6	472	0
10	Alpine - Belvidere	($1.9)	($9.5)	($0.1)	$7.5	$0.0	$0.0	$0.0	$0.0	$7.5	496	0
11	Batesville - Hubble	($3.2)	($11.3)	($1.0)	$7.1	$0.5	($0.5)	($2.3)	($1.2)	$5.8	419	134
12	Westwood	($1.6)	($6.5)	($0.8)	$4.2	$0.4	$0.0	$0.3	$0.7	$4.9	950	137
13	Cayuga	($0.6)	($2.4)	($0.1)	$1.7	($0.6)	$3.9	($1.6)	($6.1)	($4.4)	147	74
14	Oak Grove - Galesburg	($3.3)	($8.3)	($1.1)	$3.9	$0.1	$0.2	$0.2	$0.1	$4.0	1,336	174
15	Michigan City - Bosserman	($0.6)	($5.1)	($1.7)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	623	0
16	Pleasant Prairie - Zion	($0.7)	($3.2)	$0.0	$2.5	$0.1	$0.2	($0.2)	($0.3)	$2.2	1,249	409
17	West Dekalb - Glidden	($0.4)	($2.5)	$0.1	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	318	0
18	Greentown	($0.1)	($1.2)	($0.1)	$1.1	$0.6	$3.6	($0.1)	($3.1)	($2.0)	164	26
19	Roxana - Praxair	($0.7)	($3.3)	($1.6)	$1.0	$0.7	($0.1)	($3.6)	($2.9)	($1.9)	884	143
20	Reynold - Monticello	($0.5)	($3.3)	$0.7	$3.5	$0.4	$1.1	($0.9)	($1.6)	$1.9	561	0

Table 11-27 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2015

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Cherry Valley	($9.1)	($82.1)	$6.7	$79.6	$0.0	$0.0	$0.0	$0.0	$79.6	1,348	0
2	Person - Halifax	$79.7	$29.2	($10.4)	$40.1	$0.0	($0.0)	($0.1)	($0.1)	$40.0	1,412	6
3	Oak Grove - Galesburg	($16.1)	($44.8)	($6.3)	$22.4	$0.2	$1.1	($1.9)	($2.8)	$19.7	3,356	1,306
4	Breed - Wheatland	($1.7)	($15.5)	$0.6	$14.4	$0.1	($0.6)	($0.7)	($0.0)	$14.4	1,358	149
5	Burnham - Munster	($0.0)	($10.7)	$1.1	$11.8	$0.0	$0.0	$0.0	$0.0	$11.8	1,748	0
6	Rising	$0.5	($11.8)	($6.6)	$5.7	$0.4	$0.0	$3.4	$3.7	$9.4	699	459
7	Bunsonville - Eugene	($3.1)	($17.8)	($7.6)	$7.2	$0.3	($0.2)	$1.5	$1.9	$9.1	3,762	748
8	Nelson	($2.9)	($11.3)	$0.8	$9.1	$0.0	$0.0	$0.0	$0.0	$9.1	708	0
9	Dixon - McGirr Rd	($3.1)	($11.0)	($0.0)	$7.9	$0.0	$0.0	$0.0	$0.0	$7.9	1,040	0
10	Michigan City - Laporte	$1.0	($6.9)	($0.4)	$7.5	$0.0	$0.0	$0.0	$0.0	$7.5	1,879	0
11	Monroe - Bayshore	($3.8)	($12.9)	($2.5)	$6.6	($0.1)	($0.8)	($0.1)	$0.5	$7.1	572	215
12	Crete - St Johns Tap	($0.2)	($5.7)	$1.0	$6.5	$0.0	$0.0	$0.0	$0.0	$6.5	724	0
13	Braidwood - East Frankfurt	($0.1)	($5.1)	($0.0)	$5.0	$0.0	$0.0	$0.0	$0.0	$5.0	54	0
14	Byron - Cherry Valley	($0.5)	($4.8)	$0.5	$4.9	$0.0	$0.0	$0.0	$0.0	$4.9	233	0
15	Mercer IP - Galesburg	($3.7)	($10.9)	($1.6)	$5.6	($0.0)	$0.5	($0.6)	($1.1)	$4.5	816	206
16	Marysville - Tangy	($0.4)	($5.1)	($0.2)	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	118	0
17	Cherry Valley - Silver Lake	($1.0)	($4.9)	$0.1	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	224	0
18	Benton Harbor - Palisades	($0.1)	($3.8)	($0.5)	$3.3	$0.0	$0.0	$0.0	$0.0	$3.3	283	0
19	Maryland	($2.3)	($4.6)	$0.8	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	434	0
20	Klondcin - Purdue	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.4	($2.5)	($2.9)	($2.8)	40	53

Congestion-Event Summary for NYISO Flowgates

PJM and NYISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes a structure and framework for the reliable operation of the interconnected PJM and NYISO transmission systems and efficient market operation through M2M coordination.[23] Only a subset of all transmission constraints that exist in either market are eligible for coordinated congestion management. This subset of transmission constraints is identified as M2M flowgates. Flowgates eligible for the M2M coordination process are called M2M flowgates.[24]

Table 11-28 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during 2016, and which had the greatest congestion cost impact on PJM.

Table 11-28 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 2016

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central East	Flowgate	NYISO	($0.1)	($0.4)	$0.0	$0.3	$0.6	$1.7	($0.2)	($1.3)	($1.0)	64	1,074
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	2

Table 11-29 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 2015

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.4	$1.1	($0.0)	($0.7)	($0.7)	0	419
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	$0.2	$0.2	0	25

23 See "New York Independent System Operator, Inc. NYISO Tariffs" (May 26, 2016) Section 35.3.1, Effective Date: January 15, 2013. <http://www.pjm.com/documents/agreements.aspx>.
24 See "New York Independent System Operator, Inc. NYISO Tariffs" (May 26, 2016) Section 35.23, Effective Date: June 11, 2014. <http://www.pjm.com/documents/agreements.aspx>.

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-30 and Table 11-31 show the 500 kV constraints affecting congestion costs in PJM for 2016 and 2015. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints affecting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Table 11-30 Regional constraints summary (By facility): 2016

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Conastone - Peach Bottom	Line	500	$27.9	($0.2)	$0.8	$28.9	$1.3	$0.9	$0.0	$0.4	$29.3	2,407	699
2	AP South	Interface	500	$13.8	($4.9)	($1.9)	$16.8	$0.1	$0.1	$0.0	$0.0	$16.8	1,076	14
3	Bedington - Black Oak	Interface	500	$9.5	($6.2)	($0.6)	$15.2	$0.2	$0.2	$0.1	$0.1	$15.3	1,515	105
4	Loudoun	Transformer	500	$1.1	($9.8)	($0.2)	$10.6	$1.5	$2.2	$3.4	$2.7	$13.3	222	69
5	AEP - DOM	Interface	500	$3.5	($4.5)	$0.2	$8.2	$0.3	($0.0)	$0.1	$0.3	$8.5	1,604	5
6	502 Junction	Transformer	500	$0.3	($3.3)	$0.1	$3.7	$0.0	$0.1	($0.0)	($0.1)	$3.6	321	2
7	Three Mile Island	Transformer	500	$1.2	($1.5)	$0.3	$3.0	$0.1	($0.0)	$0.1	$0.2	$3.2	298	47
8	Brambleton - Mosby	Line	500	($0.5)	($3.5)	$0.1	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	151	0
9	West	Interface	500	($0.9)	($3.1)	($0.1)	$2.1	$0.2	($0.1)	($0.0)	$0.3	$2.4	165	8

Table 11-31 Regional constraints summary (By facility): 2015

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	($23.0)	($134.8)	($9.2)	$102.6	$7.0	$22.5	$1.9	($13.6)	$89.0	678	321
2	Bedington - Black Oak	Interface	500	$46.1	($45.2)	($7.2)	$84.1	$2.4	$2.2	$3.2	$3.5	$87.6	2,933	344
3	AP South	Interface	500	$38.1	($22.8)	($5.5)	$55.4	$0.3	$0.2	$0.6	$0.7	$56.2	1,285	42
4	AEP - DOM	Interface	500	$28.1	($28.0)	($1.1)	$55.0	$0.9	$1.6	($1.9)	($2.6)	$52.4	1,328	44
5	East	Interface	500	($13.0)	($37.6)	($2.1)	$22.4	($0.1)	$0.3	$0.5	$0.1	$22.6	540	16
6	Valley	Transformer	500	$17.4	($0.2)	$0.0	$17.7	$0.0	$0.0	$0.0	$0.0	$17.7	624	0
7	Central	Interface	500	($15.5)	($32.7)	($3.9)	$13.3	$0.1	$1.0	$0.3	($0.7)	$12.6	291	41
8	West	Interface	500	($1.8)	($15.6)	($0.9)	$12.9	$0.2	$1.0	$0.1	($0.6)	$12.3	319	49
9	502 Junction	Transformer	500	($0.3)	($3.0)	($0.2)	$2.5	$0.2	($0.2)	($0.0)	$0.4	$3.0	41	8

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

In 2016, financial entities as a group were net recipients of congestion credits and physical entities were net payers of congestion charges. Explicit costs are the primary source of congestion credits to financial entities. Total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In 2016, the total explicit cost is -$2.9 million, comprised of $41.0 million day-ahead explicit cost and -$43.9 million balancing explicit cost. UTCs are in the explicit congestion cost category and comprise most of that category. UTCs contributed 79.8 percent of day-ahead explicit cost and 107.1 percent of balancing explicit cost. In 2015, the total explicit cost was -$127.3 million, of which -$155.9 million (122.4 percent) was credited to UTCs. In 2016, financial entities received $9.4 million in net congestion charges, and received $132.1 million in net congestion credits 2015. In 2016, physical entities paid $1,033.0 million in congestion charges, a decrease of $484.3 million or 31.9 percent compared to 2015.

Table 11-32 Congestion cost by type of participant: 2016

Congestion Costs (Millions)										
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$25.5	($2.0)	$10.3	$37.8	($34.2)	($11.4)	($24.3)	($47.1)	$0.0	($9.4)
Physical	$379.8	($652.1)	$30.7	$1,062.7	$29.7	$39.7	($19.6)	($29.6)	$0.0	$1,033.0
Total	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	$0.0	$1,023.7

Table 11-33 Congestion cost by type of participant: 2015

Congestion Costs (Millions)										
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$81.0	$39.8	($2.9)	$38.2	($46.7)	($6.9)	($130.5)	($170.3)	$0.0	($132.1)
Physical	$533.3	($1,007.5)	$53.2	$1,593.9	$47.3	$76.7	($47.1)	($76.6)	$0.0	$1,517.3
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3

Congestion-Event Summary: Impact of Changes in UTC Volumes

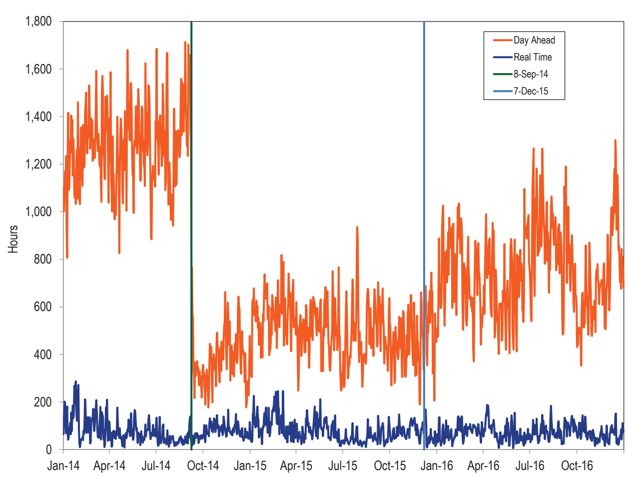
FERC issued a notice, effective September 8, 2014, that UTCs could be liable on a retroactive basis for paying uplift charges.[25] That potential refund period ended, after 15 months, on December 7, 2015.[26]

Day-ahead congestion event hours decreased significantly after September 8, 2014, when UTC activity declined. In 2015, the average hourly UTC submitted MW decreased 49.9 percent and UTC cleared MW decreased 61.1 percent compared to 2014. Day-ahead congestion event hours decreased by 49.2 percent from 363,463 congestion event hours in 2014 to 184,713 congestion event hours in 2015.

Day-ahead congestion event hours increased significantly after December 7, 2015 when UTC activity increased. In 2016, the average hourly UTC submitted MW increased 70.3 percent and UTC cleared MW increased 78.6 percent, compared to 2015. Day-ahead congestion event hours increased by 48.9 percent from 184,851 congestion event hours in 2015 to 275,298 congestion event hours in 2016.

Figure 11-5 shows the daily day-ahead and real-time congestion event hours for 2014 through 2016.

Figure 11-5 Daily congestion event hours: 2014 through 2016



Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the Day-Ahead and Real-Time Energy Markets. PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Each PJM member is charged for the cost of losses on the transmission system. Total marginal loss costs, analogous to total congestion costs, are equal to the net of the load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point-to-point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[27] 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.[28] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

Marginal loss costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. Total loss costs, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Load loss payments, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Generation loss credits, when negative, measure the total loss payment by a PJM member and when positive, measure the total loss credit paid to a PJM member.

25 See 18 CFR § 385.213 (2014).
26 *See* FERC Docket No. EL14-37.
27 OA. Schedule 1 (PJM Interchange Energy Market) §3.7
28 *Id.*

The loss component of LMP is calculated with respect to the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the Day-Ahead and Real-Time Energy Markets priced at the marginal loss price component of LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

The total loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total energy costs and net residual market adjustments that is allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[29]

- **Day-Ahead Load Loss Payments.** Day-ahead load loss payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead, load loss payments are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Generation Loss Credits.** Day-ahead generation loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead, generation loss credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Load Loss Payments.** Balancing load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Generation Loss Credits.** Balancing generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Costs.** Explicit loss costs are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs,

29 See PJM. "Manual 28: Operating Agreement Accounting," Revision 75 (November 18, 2016), p.70.

not directly attributable to specific participants, that are distributed on a load ratio basis.[30]

Total Marginal Loss Cost

The total marginal loss cost in PJM for 2016 was $696.5 million, which was comprised of load loss payments of -$55.0 million, generation loss credits of -$782.1 million, explicit loss costs of -$30.6 million and inadvertent loss charges of $0.0 million. Monthly marginal loss costs in 2016 ranged from $36.6 million in May to $86.4 million in July. Total marginal loss surplus decreased in 2016 by $109.2 million or 32.5 percent from 2015, from $336.3 million to $227.2 million in 2016.

Table 11-34 shows the total marginal loss costs as a component of total energy related costs for 2009 through 2016.

Table 11-34 Total component costs (Dollars (Millions)): 2009 through 2016[31]

	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$1,268	NA	$26,550	4.8%
2010	$1,635	29.0%	$34,771	4.7%
2011	$1,380	(15.6%)	$35,887	3.8%
2012	$982	(28.8%)	$29,181	3.4%
2013	$1,035	5.5%	$33,862	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%

Table 11-35 shows PJM total marginal loss costs by accounting category for 2009 through 2016. Table 11-36 shows PJM total marginal loss costs by accounting category by market for 2009 through 2016.

Table 11-35 Total PJM marginal loss costs by accounting category (Dollars (Millions)): 2009 through 2016

	Marginal Loss Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
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

30 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.
31 The loss costs include net inadvertent charges.

Table 11-36 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): 2009 through 2016

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
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

Table 11-37 and Table 11-38 show the total loss costs for each transaction type in 2016 and 2015. In 2016, generation paid loss costs of $727.1 million, 104.4 percent of total loss costs. In 2015, generation paid loss costs of $940.7 million, 97.1 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 2016, DECs were paid $5.2 million in loss costs in the day-ahead market, paid $2.2 million in congestion credits in the balancing energy market and received $3.0 million in net payment for losses. In 2016, INCs paid $11.9 million in loss costs in the day-ahead market, were paid $11.1 million in congestion credits in the balancing energy market and paid $0.7 million in net payment for losses. In 2016, up to congestion paid $51.6 million in the day-ahead market, were paid $84.8 million in loss credits in the balancing energy market and received $33.1 million in net payment for losses.

Table 11-37 Total PJM loss costs by transaction type by market (Dollars (Millions)): 2016

	Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	($5.2)	$0.0	$0.0	($5.2)	$2.2	$0.0	$0.0	$2.2	$0.0	($3.0)
Demand	($5.6)	$0.0	$0.0	($5.6)	$9.3	$0.0	$0.0	$9.3	$0.0	$3.7
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($18.9)	$0.0	$0.3	($18.6)	($6.2)	$0.0	$0.7	($5.5)	$0.0	($24.1)
Generation	$0.0	($732.6)	$0.0	$732.6	$0.0	$5.4	$0.0	($5.4)	$0.0	$727.1
Grandfathered Overuse	$0.0	$0.0	($0.7)	($0.7)	$0.0	$0.0	($0.4)	($0.4)	$0.0	($1.1)
Import	$0.0	($5.3)	$0.7	$6.1	$0.0	($18.5)	$0.5	$19.0	$0.0	$25.0
INC	$0.0	($11.9)	$0.0	$11.9	$0.0	$11.1	$0.0	($11.1)	$0.0	$0.7
Internal Bilateral	($32.1)	($31.8)	$0.3	($0.0)	$1.4	$1.4	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$51.6	$51.6	$0.0	$0.0	($84.8)	($84.8)	$0.0	($33.1)
Wheel In	$0.0	$0.0	$1.2	$1.2	$0.0	$0.0	($0.0)	($0.0)	$0.0	$1.2
Total	($61.7)	($781.6)	$53.4	$773.2	$6.8	($0.5)	($84.0)	($76.7)	$0.0	$696.5

Table 11-38 Total PJM loss costs by transaction type by market (Dollars (Millions)): 2015

	Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	($1.3)	$0.0	$0.0	($1.3)	($4.0)	$0.0	$0.0	($4.0)	$0.0	($5.3)
Demand	($10.2)	$0.0	$0.0	($10.2)	$22.2	$0.0	$0.0	$22.2	$0.0	$12.0
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0
Export	($17.8)	$0.0	$0.4	($17.4)	($2.5)	$0.0	$1.6	($1.0)	$0.0	($18.3)
Generation	$0.0	($980.0)	$0.0	$980.0	$0.0	$39.3	$0.0	($39.3)	$0.0	$940.7
Grandfathered Overuse	$0.0	$0.0	($1.5)	($1.5)	$0.0	$0.0	$0.0	$0.0	$0.0	($1.5)
Import	$0.0	($14.2)	$3.8	$18.0	$0.0	($48.2)	$1.6	$49.7	$0.0	$67.8
INC	$0.0	($13.9)	$0.0	$13.9	$0.0	$14.2	$0.0	($14.2)	$0.0	($0.2)
Internal Bilateral	($24.1)	($24.1)	$0.0	$0.0	$6.0	$6.0	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$29.1	$29.1	$0.0	$0.0	($57.3)	($57.3)	$0.0	($28.2)
Wheel In	$0.0	$0.0	$1.9	$1.9	$0.0	$0.0	($0.1)	($0.1)	$0.0	$1.8
Total	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7

Monthly Marginal Loss Costs

Table 11-39 shows a monthly summary of marginal loss costs by market type for 2015 and 2016.

Table 11-39 Monthly marginal loss costs by market (Millions): 2015 and 2016

	Marginal Loss Costs (Millions)							
	2015				2016			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$115.9	($4.2)	$0.0	$111.7	$78.2	($6.2)	$0.0	$72.0
Feb	$218.2	$2.0	$0.0	$220.3	$61.3	($3.8)	$0.0	$57.5
Mar	$97.9	($4.7)	($0.0)	$93.2	$43.8	($3.2)	($0.0)	$40.6
Apr	$54.0	($2.0)	($0.0)	$52.0	$52.1	($6.0)	$0.0	$46.1
May	$66.2	($3.6)	$0.0	$62.6	$40.4	($3.9)	($0.0)	$36.6
Jun	$73.2	($4.6)	($0.0)	$68.6	$59.6	($6.5)	($0.0)	$53.1
Jul	$89.3	($5.7)	$0.0	$83.6	$93.8	($7.5)	($0.0)	$86.4
Aug	$77.3	($4.4)	$0.0	$72.9	$95.6	($9.8)	($0.0)	$85.8
Sep	$68.8	($3.8)	($0.0)	$65.0	$70.6	($6.6)	($0.0)	$64.0
Oct	$53.8	($4.3)	($0.0)	$49.5	$51.6	($6.6)	($0.0)	$45.0
Nov	$48.5	($3.6)	$0.0	$44.9	$49.0	($6.9)	($0.0)	$42.1
Dec	$49.6	($5.0)	($0.0)	$44.6	$77.2	($9.7)	($0.0)	$67.5
Total	$1,012.6	($43.9)	$0.0	$968.7	$773.2	($76.7)	($0.0)	$696.5

Figure 11-6 shows PJM monthly marginal loss costs for 2009 through 2016.

Figure 11-6 PJM monthly marginal loss costs (Dollars (Millions)): 2009 through 2016

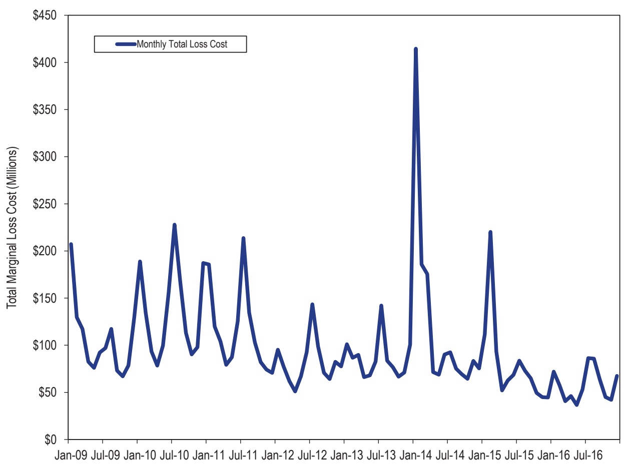


Table 11-40 and Table 11-41 show the monthly total loss costs for each virtual transaction type in 2015 and 2016.

Table 11-40 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2016

	Loss Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$0.3	$1.2	$3.7	$5.1	($0.6)	($1.1)	($6.8)	($8.5)	($3.3)
Feb	$0.1	$0.8	$1.9	$2.8	($0.0)	($0.8)	($4.3)	($5.2)	($2.4)
Mar	($0.0)	$1.1	$1.3	$2.4	($0.1)	($1.0)	($3.4)	($4.5)	($2.0)
Apr	($0.1)	$1.0	$3.9	$4.8	($0.1)	($0.8)	($6.3)	($7.3)	($2.5)
May	($0.3)	$0.7	$2.1	$2.4	$0.0	($0.5)	($4.7)	($5.2)	($2.8)
Jun	($0.7)	$1.0	$4.8	$5.1	$0.7	($1.0)	($7.6)	($7.9)	($2.8)
Jul	($1.0)	$1.4	$5.8	$6.2	$0.7	($1.2)	($8.5)	($9.0)	($2.7)
Aug	($0.5)	$1.0	$7.7	$8.2	$0.4	($1.3)	($11.6)	($12.5)	($4.3)
Sep	($0.7)	$0.8	$5.0	$5.1	$0.5	($1.1)	($7.0)	($7.6)	($2.5)
Oct	($0.8)	$0.9	$4.6	$4.7	$0.5	($0.7)	($6.3)	($6.5)	($1.8)
Nov	($0.3)	$0.8	$4.6	$5.1	($0.3)	($0.7)	($6.9)	($7.9)	($2.8)
Dec	($1.1)	$1.1	$6.3	$6.3	$0.5	($0.9)	($11.3)	($11.7)	($5.3)
Total	($5.2)	$11.9	$51.6	$58.3	$2.2	($11.1)	($84.8)	($93.7)	($35.4)

Table 11-41 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2015

	Loss Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$0.2	$0.8	$2.9	$3.8	($1.1)	($0.7)	($4.9)	($6.7)	($2.9)
Feb	($0.6)	$1.8	($0.4)	$0.7	($0.8)	($2.0)	($3.4)	($6.2)	($5.5)
Mar	$0.5	$1.3	$3.5	$5.2	($1.1)	($2.3)	($6.0)	($9.4)	($4.2)
Apr	($0.3)	$0.9	$1.2	$1.7	($0.5)	($0.6)	($3.6)	($4.7)	($2.9)
May	($1.9)	$2.3	$1.2	$1.7	$0.4	($1.7)	($6.0)	($7.3)	($5.7)
Jun	($0.6)	$1.7	$4.3	$5.4	$0.2	($1.4)	($5.6)	($6.7)	($1.3)
Jul	$0.2	$1.1	$4.0	$5.3	($0.3)	($1.0)	($6.1)	($7.3)	($2.0)
Aug	$0.3	$0.9	$1.4	$2.6	($0.2)	($1.0)	($3.9)	($5.1)	($2.5)
Sep	$0.1	$1.0	$2.6	$3.7	($0.1)	($1.2)	($4.6)	($5.9)	($2.2)
Oct	$0.6	$0.5	$2.9	$4.0	($0.4)	($0.6)	($4.1)	($5.2)	($1.1)
Nov	($0.1)	$1.0	$2.4	$3.3	$0.2	($1.1)	($3.8)	($4.7)	($1.4)
Dec	$0.3	$0.7	$3.2	$4.3	($0.3)	($0.8)	($5.3)	($6.3)	($2.0)
Total	($1.3)	$13.9	$29.1	$41.8	($4.0)	($14.2)	($57.3)	($75.5)	($33.8)

Marginal Loss Costs and Loss Credits

Total loss surplus are calculated by adding the total energy costs, the total marginal loss costs and net residual market adjustments. The total energy costs are equal to the net implicit energy costs (load energy payments minus generation energy credits) plus net explicit energy costs plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (generation loss credits less load loss payments) plus net explicit loss costs plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. Total energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-42 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for 2009 through 2016. The total marginal loss surplus decreased $109.2 million in 2016 from 2015.

Table 11-42 Marginal loss credits (Dollars (Millions)): 2009 through 2016[32]

	Loss Credit Accounting (Millions)					
			Net Residual Market Adjustment			
	Total Energy Charges	Total Marginal Loss Charges	Known Day-ahead Error	Day-ahead Loss MW Congestion	Balancing Loss MW Congestion	Total Loss Surplus
2009	($628.8)	$1,267.7	$0.0	($0.7)	($0.0)	$639.7
2010	($797.9)	$1,634.8	$0.1	$0.7	($0.0)	$836.4
2011	($793.8)	$1,379.5	$0.1	($1.0)	$0.1	$586.7
2012	($593.0)	$981.7	$0.0	$2.0	($0.0)	$386.7
2013	($687.6)	$1,035.3	$0.1	$3.0	($0.0)	$344.8
2014	($977.7)	$1,466.1	($0.0)	$6.3	$0.1	$482.1
2015	($627.4)	$968.7	($0.0)	$5.1	($0.1)	$336.3
2016	($466.3)	$696.5	($0.0)	$3.2	($0.2)	$227.2

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP. Total energy costs, analogous to total congestion costs or total loss costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the balancing energy market, plus net inadvertent energy charges. Total energy costs can by more accurately thought of as net energy costs.

Total Energy Costs

The total energy cost for 2016 was -$466.3 million, which was comprised of load energy payments of $34,053.6 million, generation energy credits of $34,510.1 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$9.8 million. The monthly energy costs for 2016 ranged from -$57.8 million in July to -$26.1 million in May.

Table 11-43 shows total energy component costs and total PJM billing, for 2009 through 2016. The total energy component costs are net energy costs.

Table 11-43 Total PJM costs by energy component (Dollars (Millions)): 2009 through 2016[33]

	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($629)	NA	$26,550	(2.4%)
2010	($798)	26.9%	$34,771	(2.3%)
2011	($794)	(0.5%)	$35,887	(2.2%)
2012	($593)	(25.3%)	$29,181	(2.0%)
2013	($688)	15.9%	$33,862	(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%)

Energy costs for 2009 through 2016 are shown in Table 11-44 and Table 11-45. Table 11-44 shows PJM energy costs by accounting category for 2009 through 2016 and Table 11-45 shows PJM energy costs by market category for 2009 through 2016.

Table 11-44 Total PJM energy costs by accounting category (Dollars (Millions)): 2009 through 2016

	Energy Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
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)

32 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.

33 The energy costs include net inadvertent charges.

Table 11-45 Total PJM energy costs by market category (Dollars (Millions)): 2009 through 2016

	Energy Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
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)

Table 11-46 and Table 11-47 show the total energy costs for each transaction type in 2016 and 2015. In 2016, generation was paid $23,752.0 million and demand paid $23,099.8 million in net energy payment. In 2015, generation was paid $28,339.7 million and demand paid $28,497.4 million in net energy payment.

Table 11-46 Total PJM energy costs by transaction type by market (Dollars (Millions)): 2016

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$1,254.0	$0.0	$0.0	$1,254.0	($1,239.3)	$0.0	$0.0	($1,239.3)	$14.7
Demand	$22,886.5	$0.0	$0.0	$22,886.5	$213.3	$0.0	$0.0	$213.3	$23,099.8
Demand Response	($1.0)	$0.0	$0.0	($1.0)	$1.0	$0.0	$0.0	$1.0	($0.1)
Export	$653.2	$0.0	$0.0	$653.2	$308.0	$0.0	$0.0	$308.0	$961.2
Generation	$0.0	$23,956.2	$0.0	($23,956.2)	$0.0	($204.2)	$0.0	$204.2	($23,752.0)
Import	$0.0	$201.8	$0.0	($201.8)	$0.0	$553.5	$0.0	($553.5)	($755.3)
INC	$0.0	$1,275.2	$0.0	($1,275.2)	$0.0	($1,250.4)	$0.0	$1,250.4	($24.8)
Internal Bilateral	$9,452.4	$9,452.4	$0.0	$0.0	$525.5	$525.5	$0.0	$0.0	$0.0
Total	$34,245.1	$34,885.7	$0.0	($640.6)	($191.5)	($375.6)	$0.0	$184.0	($456.6)

Table 11-47 Total PJM energy costs by transaction type by market (Dollars (Millions)): 2015

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$1,303.1	$0.0	$0.0	$1,303.1	($1,297.8)	$0.0	$0.0	($1,297.8)	$5.3
Demand	$28,243.8	$0.0	$0.0	$28,243.8	$253.5	$0.0	$0.0	$253.5	$28,497.4
Demand Response	($1.9)	$0.0	$0.0	($1.9)	$1.8	$0.0	$0.0	$1.8	($0.1)
Export	$708.1	$0.0	$0.0	$708.1	$182.0	$0.0	$0.0	$182.0	$890.1
Generation	$0.0	$29,150.1	$0.0	($29,150.1)	$0.0	($810.4)	$0.0	$810.4	($28,339.7)
Import	$0.0	$451.9	$0.0	($451.9)	$0.0	$1,194.6	$0.0	($1,194.6)	($1,646.6)
INC	$0.0	$1,409.0	$0.0	($1,409.0)	$0.0	($1,372.5)	$0.0	$1,372.5	($36.5)
Internal Bilateral	$10,584.7	$10,584.7	$0.0	($0.0)	$624.5	$624.5	$0.0	$0.0	($0.0)
Total	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	($630.1)

Monthly Energy Costs

Table 11-48 shows a monthly summary of energy costs by market type for 2015 and 2016. Marginal total energy costs in 2016 increased from 2015. Monthly total energy costs in 2016 ranged from -$57.8 million in July to -$26.1 million in May.

Table 11-48 Monthly energy costs by market type (Dollars (Millions)): 2015 and 2016

	Energy Costs (Millions)							
	2015				2016			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($84.6)	$13.3	$0.9	($70.5)	($63.8)	$15.4	$0.6	($47.7)
Feb	($150.5)	$6.2	$2.8	($141.5)	($50.0)	$11.1	$0.4	($38.5)
Mar	($77.6)	$19.0	($1.0)	($59.6)	($36.6)	$9.3	($0.1)	($27.4)
Apr	($45.4)	$9.5	($0.1)	($36.0)	($43.6)	$12.7	$0.3	($30.6)
May	($57.1)	$12.2	$0.2	($44.7)	($37.4)	$11.5	($0.3)	($26.1)
Jun	($53.8)	$8.7	($0.1)	($45.2)	($50.9)	$17.6	($0.6)	($33.8)
Jul	($64.7)	$12.5	$0.1	($52.0)	($74.3)	$17.5	($0.9)	($57.8)
Aug	($55.5)	$9.6	$0.1	($45.8)	($72.9)	$18.2	($1.2)	($55.9)
Sep	($49.9)	$8.9	($0.0)	($41.1)	($54.0)	$14.8	($1.2)	($40.5)
Oct	($41.8)	$9.1	($0.1)	($32.8)	($42.7)	$16.4	($3.5)	($29.9)
Nov	($37.0)	$7.7	$0.1	($29.1)	($43.9)	$16.7	($1.5)	($28.8)
Dec	($40.1)	$11.2	($0.0)	($28.9)	($70.4)	$22.9	($1.8)	($49.4)
Total	($757.9)	$127.8	$2.7	($627.4)	($640.6)	$184.0	($9.8)	($466.3)

Figure 11-7 shows PJM monthly energy costs for 2009 through 2016.

Figure 11-7 PJM monthly energy costs (Millions): 2009 through 2016

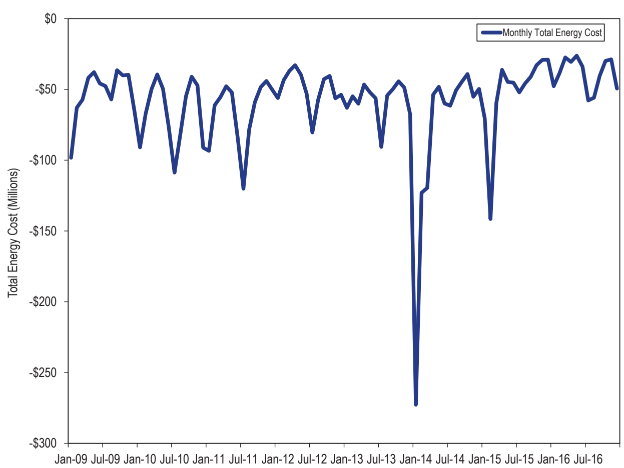


Table 11-49 and Table 11-50 show the monthly total energy costs for each virtual transaction type in 2016 and 2015. In 2016, DECs paid $1,254.0 million in energy costs in the day-ahead market, were paid $1,239.3 million in energy credits in the balancing energy market and paid $14.7 million in net payment for energy. In 2016, INCs were paid $1,275.2 million in energy credits in the day-ahead market, paid $1,250.4 million in energy cost in the balancing market and received $24.8 million in net payment for energy. In 2015, DECs paid $1,303.1 million in energy costs in the day-ahead market, were paid $1,297.8 million in energy credits in the balancing energy market and paid $5.3 million in net payment for energy. In 2015, INCs were paid $1,409.0 million in energy credits in the day-ahead market, paid $1,372.5 million in energy cost in the balancing energy market and received $36.5 million in net payment for energy.

Table 11-49 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2016

	Energy Costs (Millions)						
	Day-Ahead			Balancing			
	DEC	INC	Virtual Total	DEC	INC	Virtual Total	Virtual Grand Total
Jan	$102.0	($109.3)	($7.2)	($101.0)	$106.1	$5.1	($2.1)
Feb	$85.5	($87.5)	($2.1)	($81.3)	$84.3	$3.0	$1.0
Mar	$68.6	($100.2)	($31.6)	($63.8)	$93.0	$29.2	($2.4)
Apr	$84.9	($109.3)	($24.3)	($86.5)	$112.0	$25.6	$1.2
May	$78.3	($87.2)	($8.9)	($79.4)	$86.1	$6.8	($2.1)
Jun	$105.0	($91.0)	$14.0	($110.0)	$94.5	($15.5)	($1.5)
Jul	$139.7	($130.5)	$9.2	($128.9)	$119.4	($9.6)	($0.3)
Aug	$138.1	($119.8)	$18.3	($145.6)	$123.4	($22.2)	($3.8)
Sep	$124.7	($104.7)	$20.0	($124.3)	$104.0	($20.4)	($0.3)
Oct	$111.4	($110.5)	$1.0	($107.4)	$106.9	($0.5)	$0.5
Nov	$84.6	($100.7)	($16.1)	($82.9)	$98.5	$15.6	($0.6)
Dec	$131.2	($124.7)	$6.5	($128.2)	$122.2	($6.1)	$0.4
Total	$1,254.0	($1,275.2)	($21.2)	($1,239.3)	$1,250.4	$11.1	($10.2)

Table 11-50 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2015

	Energy Costs (Millions)						
	Day-Ahead			Balancing			
	DEC	INC	Virtual Total	DEC	INC	Virtual Total	Virtual Grand Total
Jan	$152.0	($122.5)	$29.5	($152.0)	$120.6	($31.3)	($1.8)
Feb	$224.2	($243.8)	($19.5)	($217.0)	$223.6	$6.6	($13.0)
Mar	$126.3	($140.1)	($13.8)	($137.0)	$148.6	$11.6	($2.2)
Apr	$78.8	($98.9)	($20.1)	($78.3)	$96.3	$18.0	($2.1)
May	$114.4	($128.4)	($14.0)	($108.5)	$119.8	$11.2	($2.8)
Jun	$98.2	($99.5)	($1.3)	($97.7)	$97.7	($0.0)	($1.4)
Jul	$88.8	($100.4)	($11.6)	($86.8)	$97.2	$10.4	($1.2)
Aug	$79.8	($95.8)	($16.0)	($76.7)	$92.2	$15.4	($0.6)
Sep	$99.1	($97.1)	$2.0	($107.4)	$102.0	($5.3)	($3.3)
Oct	$90.7	($98.1)	($7.4)	($85.6)	$92.7	$7.1	($0.3)
Nov	$74.2	($94.5)	($20.3)	($72.8)	$91.9	$19.2	($1.1)
Dec	$76.5	($89.9)	($13.4)	($77.9)	$89.9	$12.0	($1.4)
Total	$1,303.1	($1,409.0)	($105.9)	($1,297.8)	$1,372.5	$74.7	($31.1)

Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2016, 101,473.5 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 193,407.0 MW as of December 31, 2016. Of the capacity in queues, 13,110.5 MW, or 12.9 percent, are uprates and the rest are new generation. Wind projects account for 14,656.8 MW of nameplate capacity or 14.4 percent of the capacity in the queues. Combined cycle projects account for 69,264.4 MW of capacity or 68.3 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-5, 29,057.5 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 4,965.3 MW are planned to retire after 2016. In 2016, 395.5 MW were retired. Of the 4,965.3 MW pending retirement, 3,649.0 MW are coal units. The coal unit retirements were a result of low gas prices, low capacity prices and the investments required for compliance with the EPA's Mercury and Air Toxics Standards (MATS) for some units.
- **Generation Mix.** A significant shift in the distribution of unit types within the PJM footprint continues as natural gas fired units enter the queue and steam units retire. There are 277.0 MW of coal fired steam capacity and 69,264.4 MW of gas fired capacity in the queue. The replacement of coal steam units by units burning natural gas will significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Generation and Transmission Interconnection Planning Process

- 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.[1] 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 queue contains a substantial number of projects that are not likely to be built. Excluding currently active projects and projects currently under construction, 3,293 projects, representing 453,810.1 MW, have entered the queue process since its inception. Of those, 687 projects, 46,436.0 MW, went into service. Of the projects that entered the queue process, 67.4 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.
- Feasibility, impact and facilities studies may be delayed for reasons including disputes with developers, circuit and network issues and retooling as a result of projects being withdrawn. The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015 to address delays.[2] On May 12, 2016, The EQSTF presented proposed rule changes to the interconnection process. These changes were filed with FERC, and FERC approved the changes, and the PJM Open Access Transmission Tariff was modified effective October 31, 2016.
- 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."[3] Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of the parent company and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a merchant transmission developer which is a competitor of the transmission owner.

1 See PJM, OATT Parts IV & VI.

2 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/task-forces/eqstf.aspx>.

3 See PJM, OATT, Part I, § 1 "Definitions."

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek in the PSEG Zone. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues and operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. On July 30, 2015, the PJM Board of Managers accepted PJM's recommendation to assign the project to LS Power, a merchant developer, PSEG, and PHI with a total cost estimate between $263M and $283M.[4] [5] On August 5, 2016, PJM announced that the Artificial Island project was to be suspended immediately due to unanticipated project complexities and significant cost overruns. The PJM Board of Managers called for a new review of the project to be completed by PJM by February 2017 in order to assess how to proceed with the project.[6]
- On October 25, 2012, Schedule 12 of the tariff and Schedule 6 of the OA were changed to address FERC Order No. 1000 reforms to the cost allocation requirements for local and regional transmission planning projects that were formerly defined in Order No. 890. The new approach was applied for the first time to the 2013 RTEP. The allocation process has been upheld by the FERC despite repeated challenges.[7]

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects, which are intended to resolve multiple reliability criteria violations and congestion issues and which may have substantial impacts on energy and capacity markets. There are currently three backbone projects under development, Surry Skiffes Creek 500kV, the Northern New Jersey 345 kV Upgrades, and Byron Wayne 345 kV.[8]

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.[9]
- There were 20,214 transmission outage requests submitted in 2016. Of the requested outages, 77.5 percent were planned for five days or shorter and 6.6 percent were planned for longer than 30 days. Of the requested outages, 51.7 percent were late according to the rules in PJM's Manual 3.

Recommendations

The MMU recommends improvements to the planning process.

- 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.)

4 See "Artificial Island Recommendations," presented at the TEAC meeting on April 28, 2015 at <http://www.pjm.com/~/media/committees-groups/committees/teac/20150428-ai/20150428-artificial-island-recommendations.ashx>.

5 See letter from Terry Boston concerning the Artificial Island Project at <http://www.pjm.com/~/media/documents/reports/board-statement-on-artificial-island-project.ashx>.

6 See "PJM Board Statement on Artificial Island Project Suspension." <http://pjm.com/~/media/documents/reports/20160805-artificial-island-update.ashx> Accessed November 7, 2016.

7 *See Delaware PSC v. PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,090 (2016); PJM Interconnection, L.L.C., 155 FERC ¶ 61,089 (2016); *Consolidated Edison Company of New York, Inc. v. PJM Interconnection*, 155 FERC ¶ 61,088 (2016); *see also Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom.* S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41, 412 (D.C. Cir. 2014); *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,074 (2013) (accepting the proposed PJM cost allocation method, effective February 1, 2013, subject to the outcome of PJM's Order No. 1000 regional compliance filing proceeding); *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance*, 150 FERC ¶ 61,038 (2015), *order on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).

8 See "2016 RTEP Process Scope and Input Assumptions White Paper," P 23. <http://www.pjm.com/~/media/documents/reports/2016-rtep-process-scope-and-input-assumptions.ashx> Accessed November 7, 2016.

9 PJM. "Manual 03: Transmission Operations," Revision 50 (Dec. 1, 2016), Section 4.

- 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: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants 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 that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[10] (Priority: Low. First reported 2013. Status: Not 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.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends 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. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)
- 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.)

10 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

- The MMU recommends an 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.)

Conclusion

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

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

The PJM queue evaluation process should be improved to 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.

The PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and merchant transmission providers. PJM should enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

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.

Planned Generation and Retirements

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, 2016, 101,402.4 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 193,407.9 MW as of December 31,

2016. Although it is clear that not all generation in the queues will be built, PJM has added capacity.[11] In 2016, 5,414.1 MW of nameplate capacity went into service in PJM.

PJM Generation Queues

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. The duration of the queue period has varied. Queues A and B were open for a year. Queues C-T were open for six months. Starting in February 2008, Queues U-Y1 were open for three months. Starting in May 2012, the duration of the queue period was reset to six months, starting with Queue Y2. Queue AC2 is currently open.

All projects that have been entered in a queue 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. Withdrawn projects are removed from the queue and listed separately. 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.[12] 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.[13]

Table 12-1 shows MW in queues by expected completion date and MW changes in the queues between December 31, 2015 and December 31, 2016, for ongoing projects, i.e. projects with the status active, under construction or suspended.[14] Projects that are already in service are not included here. The total MW in queues increased by 16,079.3 MW, or 18.8 percent, from 85,323.1 MW at the end of 2015.

Table 12-1 Queue comparison by expected completion year (MW): December 31, 2015 to December 31, 2016[15]

			Twelve Month Change	
Year	As of 12/31/2015	As of 12/31/2016	MW	Percent
2015	9,641.9	0.0	NA	NA
2016	15,085.7	7,973.5	(7,112.2)	(89.2%)
2017	12,442.3	14,533.3	2,091.0	14.4%
2018	13,403.6	24,468.5	11,064.9	45.2%
2019	21,461.3	25,844.9	4,383.6	17.0%
2020	11,444.3	17,355.1	5,910.8	34.1%
2021	0.0	9,133.1	9,133.1	NA
2022	250.0	1,480.0	1,230.0	83.1%
2023	0.0	614.0	614.0	100.0%
2024	1,594.0	0.0	(1,594.0)	0.0%
Total	85,323.1	101,402.4	16,079.3	18.8%

Table 12-2 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between December 31, 2015, and December 31, 2016. For example, 22,800.7 MW entered the queue in 2016 and 568.6 of these MW have been withdrawn in 2016. Of the total 52,350.1 MW marked as active at the beginning of 2016, 1,129.9 MW were withdrawn, 69.1 MW were suspended, 1,050.9 MW started construction, and 10.0 MW went into service by the end of the quarter. The Under Construction column shows that 16.9 MW came out of suspension and 1,050.9 MW began construction 2016, in addition to the 22,957.7 MW of capacity that maintained the status under construction from the previous year.

11 See Monitoring Analytics, "New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019," <http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf>.

12 See PJM. Manual 14C "Generation and Transmission Interconnection Process," Revision 10 (October 1, 2016) Section 3.7 <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.

13 PJM does not track the duration of suspensions or PJM termination of projects.

14 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

15 Wind and solar capacity in Table 12-2 through Table 12-5 have not been adjusted to reflect derating.

Table 12-2 Change in project status (MW): December 31, 2015 to December 31, 2016

		Status at 12/31/2016				
Status at 12/31/2015	Total at 12/31/2015	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in 2016)		22,800.7	0.0	0.0	0.0	568.6
Active	52,350.1	48,766.3	69.1	1,050.9	10.0	1,129.9
Suspended	4,698.9	0.0	5,040.9	16.9	0.0	261.8
Under Construction	28,274.1	0.0	680.0	22,957.7	399.7	1,988.6
In Service	41,021.9	0.0	0.0	0.0	46,026.3	0.0
Withdrawn	286,258.0	0.0	0.0	19.9	0.0	301,951.7
Total at 12/31/2016		71,567.0	5,790.0	24,045.3	46,436.0	305,900.6

Table 12-3 shows the amount of capacity active, in service, under construction, suspended, or withdrawn for each queue since the beginning of the RTEP process and the total amount of capacity that had been included in each queue. All items in queues A-M are either in service or have been withdrawn. As of December 31, 2016, there are 101,402.4 MW of capacity in queues that are not yet in service, of which 5.7 percent are suspended, 23.7 percent are under construction and 70.6 percent have not begun construction.

Table 12-3 Capacity in PJM queues (MW): At December 31, 2016[16]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	8,103.0	0.0	0.0	17,252.0	25,355.0
B Expired 31-Jan-99	0.0	4,645.5	0.0	0.0	15,656.7	20,302.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,474.8	4,005.8
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,369.0	8,219.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,033.8	8,829.0
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	17,980.8	19,170.4
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	3,738.3	3,841.3
J Expired 31-Jan-03	0.0	40.0	0.0	0.0	846.0	886.0
K Expired 31-Jul-03	0.0	98.9	0.0	0.0	485.3	584.2
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	4,210.4
N Expired 31-Jan-05	0.0	2,398.8	38.0	0.0	8,090.3	10,527.0
O Expired 31-Jul-05	0.0	1,668.2	437.0	0.0	5,466.8	7,572.0
P Expired 31-Jan-06	0.0	3,064.7	253.0	0.0	5,320.5	8,638.2
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	1,886.4	600.0	848.3	19,420.6	22,755.3
S Expired 31-Jul-07	0.0	3,549.5	120.0	70.0	12,396.5	16,136.0
T Expired 31-Jan-08	0.0	2,814.0	1,408.0	300.0	23,013.3	27,535.3
U Expired 31-Jan-09	200.0	837.3	849.9	620.0	30,829.6	33,336.8
V Expired 31-Jan-10	590.0	2,020.6	770.1	555.0	12,877.6	16,813.3
W Expired 31-Jan-11	944.0	2,102.5	1,121.8	814.8	19,097.2	24,080.3
X Expired 31-Jan-12	1,689.0	3,738.2	5,622.4	878.0	18,416.8	30,344.5
Y Expired 30-Apr-13	833.5	719.1	4,381.3	1,336.5	18,469.3	25,739.5
Z Expired 30-Apr-14	1,114.0	430.3	5,823.4	82.2	6,860.8	14,310.7
AA1 Expired 31-Oct-14	5,226.3	115.7	1,416.1	141.4	5,102.4	12,001.9
AA2 Expired 30-Apr-15	8,393.4	36.1	358.4	94.0	7,184.4	16,066.3
AB1 Expired 31-Oct-15	12,839.1	24.2	701.0	49.9	6,684.3	20,298.5
AB2 Expired 31-Mar-16	12,422.6	10.0	145.0	0.0	625.6	13,203.2
AC1 Through 30-Sep-16	26,936.0	0.0	0.0	0.0	11.0	26,946.9
AC2 Through 30-Apr-17	379.2	0.0	0.0	0.0	557.6	936.8
Total	71,567.0	46,436.0	24,045.3	5,790.0	305,900.6	453,739.0

16 Projects listed as partially in service are counted as in service for the purposes of this analysis.

Distribution of Units in the Queues

Table 12-4 shows the projects under construction, suspended, or active, by unit type, and control zone.[17] As of December 31, 2016, 101,402.4 MW of capacity were in generation request queues for construction through 2024, compared to 85,323.1 MW at December 31, 2015.[18] Table 12-4 also shows the planned retirements for each zone.

Table 12-4 Queue capacity by LDA, control zone and fuel (MW): At December 31, 2016[19]

LDA	Zone	BioMass	CC	CT	Diesel	Fuel Cell	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	0.0	1,667.0	469.0	0.0	1.7	0.0	0.0	85.0	0.0	20.0	175.0	2,417.7	303.0
	DPL	25.8	742.0	0.0	2.0	0.0	0.0	0.0	1,412.5	0.0	26.0	599.6	2,807.9	34.0
	JCPL	0.0	2,047.2	0.0	0.0	0.4	0.0	0.0	304.8	0.0	103.0	0.0	2,455.4	614.5
	PECO	0.0	1,256.0	0.0	6.6	0.0	0.0	94.0	20.0	0.0	0.0	0.0	1,376.6	50.8
	PSEG	0.0	2,659.5	788.0	10.6	0.0	0.0	0.0	92.0	24.0	3.8	0.0	3,577.9	1,863.0
	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
	EMAAC Total	25.8	8,371.7	1,257.0	19.2	2.2	0.0	94.0	1,914.3	24.0	152.8	774.6	12,635.5	2,865.3
SWMAAC	BGE	0.0	0.0	0.0	1.3	0.0	0.4	19.2	44.1	0.0	0.1	0.0	65.1	135.0
	Pepco	0.0	2,498.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,498.5	0.0
	SWMAAC Total	0.0	2,498.5	0.0	1.3	0.0	0.4	19.2	44.1	0.0	0.1	0.0	2,563.6	135.0
WMAAC	Met-Ed	0.0	497.0	34.1	0.0	0.0	0.0	0.0	138.0	30.0	0.0	0.0	699.1	6.0
	PENELEC	0.0	1,333.0	560.9	139.0	0.0	17.0	0.0	13.5	590.0	0.0	575.8	3,229.2	0.0
	PPL	16.0	5,940.0	19.9	0.0	0.0	0.0	0.0	36.0	0.0	30.0	266.2	6,308.1	0.0
	WMAAC Total	16.0	7,770.0	614.9	139.0	0.0	17.0	0.0	187.5	620.0	30.0	842.0	10,236.4	6.0
Non-MAAC	AEP	0.0	15,077.0	394.0	9.4	0.0	146.5	102.0	2,400.1	504.0	120.0	6,953.5	25,706.5	0.0
	AP	0.0	5,730.4	30.0	122.8	0.0	0.0	0.0	666.1	10.0	162.5	1,001.7	7,723.4	0.0
	ATSI	0.0	5,153.0	0.0	4.0	0.0	0.0	0.0	326.0	0.0	12.5	518.0	6,013.5	776.0
	ComEd	0.0	8,733.3	1,114.0	32.1	0.0	22.7	0.0	27.0	64.0	89.1	3,446.5	13,528.7	510.0
	DAY	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0	223.0	12.0	39.9	300.0	1,724.9	0.0
	DEOK	0.0	0.0	0.0	4.8	0.0	0.0	0.0	125.0	20.0	19.8	0.0	169.6	0.0
	DLCO	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	225.0	0.0
	Dominion	62.5	9,166.9	114.0	12.0	0.0	0.0	0.0	9,855.5	0.0	134.0	820.5	20,165.4	621.0
	EKPC	0.0	614.0	0.0	0.0	0.0	0.0	0.0	80.0	0.0	0.0	0.0	694.0	0.0
	Non-MAAC Total	62.5	45,829.6	1,652.0	185.0	0.0	169.2	102.0	13,702.6	610.0	597.8	13,040.2	75,950.9	1,907.0
Total in PJM		104.3	64,469.8	3,523.9	344.5	2.2	186.6	215.2	15,848.5	1,254.0	780.7	14,656.8	101,386.4	4,913.3

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and steam units retire. As of December 31, 2016, there were 18,070.3 MW of gas fired capacity under construction in PJM. As of December 31, 2016, there were only 200.0 MW of coal fired steam capacity under construction in PJM. There is only one coal project classified as new under construction in PJM. With respect to retirements, 3,649.0 MW of coal fired steam capacity and 208.8 MW of natural gas capacity are slated for deactivation between now and 2020. The replacement of coal steam units by natural gas units could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Planned Retirements

As shown in Table 12-5, 29,057.5 MW have been, or are planned to be, retired between 2011 and 2020.[20] Of that, 4,965.3 MW are planned to retire after 2016. In 2016, 395.5 MW were retired. Of the 4,965.3MW pending retirement, 3,649.0 MW are coal units. The coal unit retirements were a result of low gas prices, low capacity prices and the investments required for compliance with the EPA's Mercury and Air Toxics Standards (MATS) for some units.

17 Unit types designated as reciprocating engines are classified as diesel.

18 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 namplate capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of nameplate capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of nameplate capacity. Based on the derating of 14,505.3 MW of wind resources and 7,7335 MW of solar resources, the 82,741.7 MW currently active in the queue would be reduced to 65,327.3 MW.

19 This data includes only projects with a status of active, under-construction, or suspended.

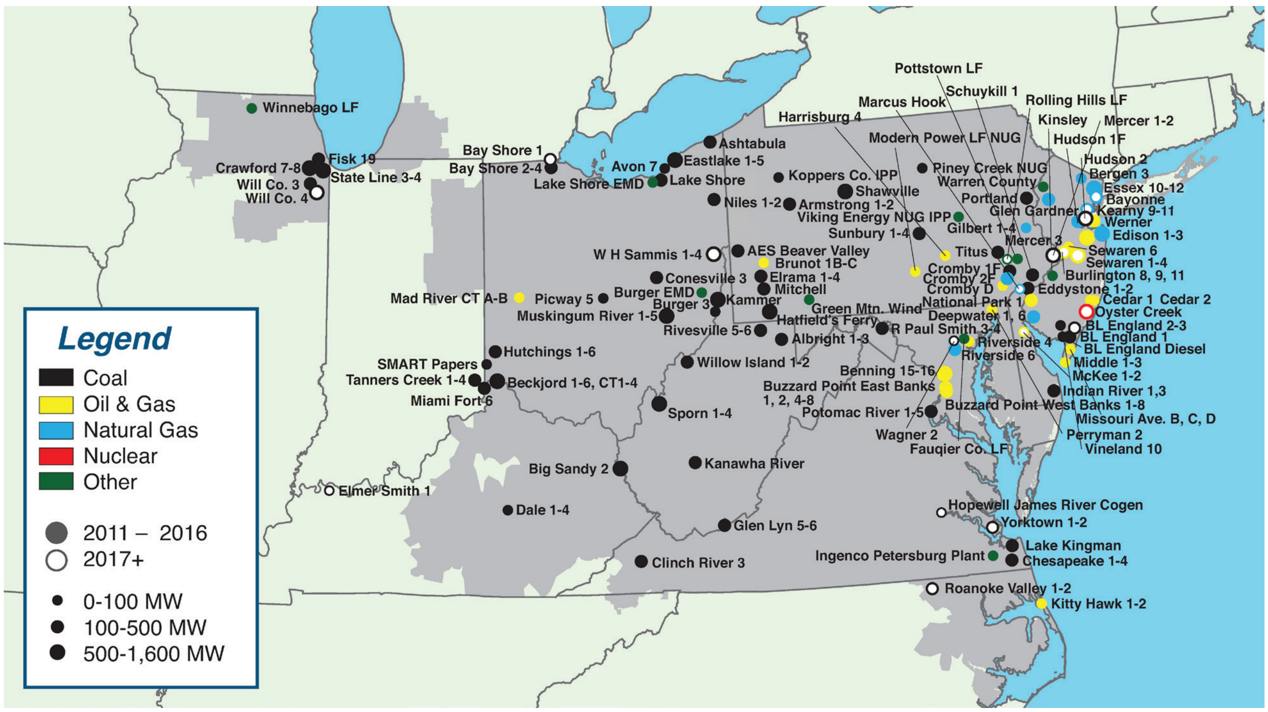
20 See PJM "Generator Deactivation Summary Sheets," at <http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx> (June 2, 2016).

Table 12-5 Summary of PJM unit retirements by fuel (MW): 2011 through 2020

	Coal	Diesel	Heavy Oil	Hydro	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wind	Wood Waste	Total
Retirements 2011	543.0	0.0	0.0	0.0	0.0	0.0	63.7	522.5	0.0	0.0	0.0	1,129.2
Retirements 2012	5,907.9	0.0	0.0	0.0	0.0	0.0	788.0	250.0	0.0	0.0	16.0	6,961.9
Retirements 2013	2,589.9	2.9	166.0	0.0	0.0	3.8	85.0	0.0	0.0	0.0	8.0	2,855.6
Retirements 2014	2,427.0	50.0	0.0	0.0	184.0	15.3	0.0	294.0	0.0	0.0	0.0	2,970.3
Retirements 2015	7,661.8	10.3	0.0	0.0	644.2	2.0	212.0	1,239.0	0.0	10.4	0.0	9,779.7
Retirements 2016	243.0	59.0	74.0	0.5	0.0	5.0	14.0	0.0	0.0	0.0	0.0	395.5
Planned Retirements Post-2016	3,501.0	0.0	182.0	0.0	0.0	6.0	0.0	661.8	614.5	0.0	0.0	4,965.3
Total	22,873.6	122.2	422.0	0.5	828.2	32.1	1,162.7	2,967.3	614.5	10.4	24.0	29,057.5

A map of the retirements between 2011 and 2020 is shown in Figure 12-1.

Figure 12-1 Map of PJM unit retirements: 2011 through 2020



The list of pending retirements is shown in Table 12-6.

Table 12-6 Planned retirement of PJM units: as of December 31, 2016

Unit	Zone	ICAP (MW)	Fuel	Unit Type	Projected Deactivation Date
Rolling Hills Landfill Generator	Met-Ed	6.0	LFG	Diesel	07-Dec-16
Roanoke Valley 1-2	Dominion	209.0	Coal	Steam	01-Mar-17
Yorktown 1-2	Dominion	323.0	Coal	Steam	15-Apr-17
BL England 2-3	AECO	303.0	Coal	Steam	30-Apr-17
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
Hopewell James River Cogen	Dominion	89.0	Coal	Steam	31-May-17
Hudson 2	PSEG	620.0	Coal	Steam	01-Jun-17
Mercer 1-2	PSEG	632.0	Coal	Steam	01-Jun-17
Sewaren 1-4	PSEG	453.0	Kerosene	Combustion Turbine	01-Jun-18
Bayonne Cogen Plant (CC)	PSEG	158.0	Natural gas	Steam	01-Nov-18
MH50 Marcus Hook Co-gen	PECO	50.8	Natural gas	Steam	13-May-19
Elmer Smith U1	External	52.0	Coal	Steam	01-Jun-19
Oyster Creek	JCPL	614.5	Nuclear	Nuclear	31-Dec-19
Will County 4	ComEd	510.0	Coal	Steam	31-May-20
W H Sammis 1-4	ATSI	640.0	Coal	Steam	31-May-20
Wagner 2	BGE	135.0	Coal	Steam	01-Jun-20
Bay Shore 1	ATSI	136.0	Coal	Steam	01-Oct-20
Total		4,965.3			

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2020, while Table 12-8 shows these retirements by state. The majority, 78.7 percent, of all MW retiring during this period are coal steam units. These units have an average age of 55.4 years and an average size of 167.0 MW. Over half of them, 51.0 percent, are located in either Ohio or Pennsylvania. Retirements have generally consisted of smaller subcritical coal steam units and those without adequate environmental controls to remain viable beyond 2016.

Table 12-7 Retirements by fuel type: 2011 through 2020

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	137	167.0	55.4	22,873.6	78.7%
Diesel	7	17.5	42.7	122.2	0.4%
Heavy Oil	5	84.4	54.6	422.0	1.5%
Hydro	1	0.5	100.0	0.5	0.0%
Kerosene	20	41.4	45.5	828.2	2.9%
Landfill Gas	9	3.6	14.0	32.1	0.1%
Light Oil	16	72.7	44.1	1,162.7	4.0%
Natural Gas	47	63.1	46.6	2,967.3	10.2%
Nuclear	1	614.5	51.0	614.5	2.1%
Wind	1	10.4	15.0	10.4	0.0%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	246	118.1	50.0	29,057.5	100.0%

Table 12-8 Retirements (MW) by fuel type and state: 2011 through 2020

State	Coal	Diesel	Hydro	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wind	Wood Waste	Total
DC	0.0	0.0	0.0	0.0	0.0	0.0	788.0	0.0	0.0	0.0	0.0	788.0
DE	254.0	0.0	34.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	288.0
IL	2,134.0	0.0	0.0	0.0	0.0	6.4	0.0	0.0	0.0	0.0	0.0	2,140.4
IN	982.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0
KY	1,047.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,047.0
MD	250.0	51.0	74.0	0.0	0.0	0.0	0.0	115.0	0.0	0.0	0.0	490.0
NC	209.0	0.0	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	240.0
NJ	1,543.0	8.0	148.0	0.5	828.2	7.7	212.0	2,600.5	614.5	0.0	0.0	5,962.4
OH	6,528.6	60.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,588.9
PA	5,145.0	0.0	166.0	0.0	0.0	16.0	131.7	251.8	0.0	10.4	24.0	5,744.9
VA	2,140.0	2.9	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	2,144.9
WV	2,641.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,641.0
Total	22,873.6	122.2	422.0	0.5	828.2	32.1	1,162.7	2,967.3	614.5	10.4	24.0	29,057.5

Actual Generation Deactivations in 2016

Table 12-9 shows the units that were deactivated in 2016.

Table 12-9 Unit deactivations in 2016

Company	Unit Name	ICAP (MW)	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
Exelon Corporation	Fauquier County Landfill	2.0	Diesel	Dominion	12	31-Jan-16
Exelon Corporation	Perryman 2	51.0	Diesel	BGE	44	01-Feb-16
NRG Energy Inc.	Avon Lake 7	94.0	Coal	ATSI	67	16-Apr-16
Eastern Kentucky Power Cooperative, Inc.	Dale 3	74.0	Coal	EKPC	59	16-Apr-16
Eastern Kentucky Power Cooperative, Inc.	Dale 4	75.0	Coal	EKPC	56	16-Apr-16
Rockland Capital Energy Investments, LLC	BL England Diesel Units 1-4	8.0	Diesel	AECO	55	31-May-16
Exelon Corporation	Riverside 4	74.0	Heavy Oil	BGE	65	01-Jun-16
South Jersey Industries, Inc.	Warren County Landfill Generator	3.0	LFG	JCPL	10	02-Jun-16
Great Bear Hydropower, Inc.	Columbia Dam Hydro	0.5	Hydro	JCPL	0	03-Oct-16
Talen Energy Corporation	Harrisburg 4 CT	14.0	Light Oil	PPL	49	17-Nov-16
Total		395.5				

Generation Mix

As of December 31, 2016, PJM had an installed capacity of 193,407.9 MW (Table 12-10). This measure 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.

Table 12-10 Existing PJM capacity: At December 31, 2016 (By zone and unit type (MW))[21]

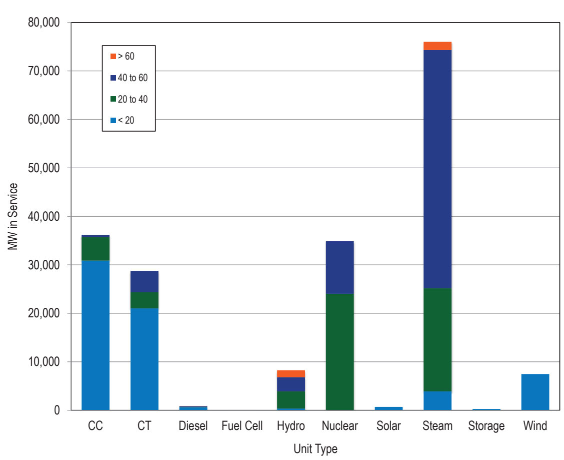
Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	901.9	570.7	14.6	0.0	0.0	0.0	41.7	815.9	0.0	7.5	2,352.3
AEP	6,100.0	3,682.2	80.3	0.0	1,071.9	3,211.0	10.1	18,897.8	4.0	2,204.0	35,261.3
APS	1,129.0	1,226.9	47.9	0.0	129.2	0.0	36.1	5,409.0	47.4	1,088.5	9,114.0
ATSI	685.0	1,618.3	67.7	0.0	0.0	2,134.0	0.0	5,719.0	0.0	0.0	10,224.0
BGE	0.0	789.0	18.4	0.0	0.0	1,716.0	0.0	2,921.5	0.0	0.0	5,444.9
ComEd	3,146.1	7,244.0	109.1	0.0	0.0	10,473.5	9.0	5,166.1	107.5	2,781.9	29,037.2
DAY	0.0	1,368.5	47.5	0.0	0.0	0.0	1.1	2,908.0	40.0	0.0	4,365.1
DEOK	47.2	654.0	0.0	0.0	112.0	0.0	0.0	3,567.0	20.0	0.0	4,400.2
DLCO	244.0	15.0	0.0	0.0	6.3	1,777.0	0.0	660.0	0.0	0.0	2,702.3
Dominion	6,851.6	3,761.7	151.8	0.0	3,589.3	3,581.3	157.8	7,775.0	0.0	208.0	26,076.5
DPL	1,498.5	1,820.4	96.1	30.0	0.0	0.0	100.0	1,620.0	0.0	0.0	5,165.0
EKPC	0.0	774.0	0.0	0.0	70.0	0.0	0.0	1,687.0	0.0	0.0	2,531.0
JCPL	2,682.5	763.1	16.1	0.0	400.0	614.5	154.2	10.0	0.0	0.0	4,640.4
Met-Ed	2,111.0	406.5	41.4	0.0	19.0	805.0	0.0	200.0	0.0	0.0	3,582.9
PECO	3,209.0	834.0	2.9	0.0	1,642.0	4,546.8	3.0	979.1	1.0	0.0	11,217.8
PENELEC	850.0	407.5	110.2	0.0	512.8	0.0	0.0	6,793.5	10.4	969.2	9,653.6
Pepco	230.0	1,091.7	9.9	0.0	0.0	0.0	0.0	3,649.1	0.0	0.0	4,980.7
PPL	2,657.9	602.2	55.5	0.0	706.6	2,520.0	15.0	5,169.9	20.0	219.7	11,966.8
PSEG	3,846.3	1,132.0	11.1	0.0	5.0	3,493.0	152.4	2,050.1	2.0	0.0	10,691.9
RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	36,190.0	28,761.7	880.5	30.0	8,264.1	34,872.1	680.4	75,998.0	252.3	7,478.8	193,407.9

Figure 12-2 and Table 12-11 show the age of PJM generators by unit type. Units older than 40 years comprise 71,090.4 MW, or 36.8 percent, of the total capacity of 193,407.9 MW.

Table 12-11 PJM capacity (MW) by age (years): At December 31, 2016

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 20	30,893.5	21,016.2	624.1	30.0	344.8	0.0	680.4	3,905.5	252.3	7,478.8	65,225.6
20 to 40	4,854.5	3,315.5	98.8	0.0	3,557.2	24,033.9	0.0	21,232.0	0.0	0.0	57,091.9
40 to 60	442.0	4,430.0	155.6	0.0	2,915.0	10,838.2	0.0	49,188.5	0.0	0.0	67,969.3
More than 60	0.0	0.0	2.0	0.0	1,447.1	0.0	0.0	1,672.0	0.0	0.0	3,121.1
Total	36,190.0	28,774.8	873.8	30.0	8,264.1	33,732.1	561.4	76,072.0	242.3	6,956.7	193,407.9

Figure 12-2 PJM capacity (MW) by age (years): At December 31, 2016



21 The capacity described in this section refers to all capacity in PJM at nameplate ratings, regardless of whether the capacity entered the RPM auction. This table previously included external units.

Generation and Transmission Interconnection Planning Process

PJM made changes to the queue process in May 2012.[22] These changes included reducing the length of the queues, creating an alternate queue for some small projects, and adjustments to the rules regarding suspension rights and Capacity Interconnection Rights (CIR). PJM staff reported on June 11, 2015, that due to these and other process improvements, the study backlog has been significantly reduced.[23] The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015, to further address the issue.[24]

The Earlier Queue Submittal Task Force

In 2015 and 2016, participants of the Earlier Queue Submittal Task Force (EQSTF) drafted rule changes to the Interconnection Queue process meant to address high levels of deficient project applications being submitted to PJM for review.

To discourage incomplete interconnection project requests, the EQSTF proposed to only assign queue positions for project applications that had submitted all required project elements including site control. In addition, all project applications would be required to remedy any deficiencies by the end of the queue window in order to be considered in feasibility studies or be terminated and withdrawn. Queue positions had historically been assigned to project developers that paid the study deposit and submitted a project application by the appropriate submission deadline. Project applications with missing information were assigned queue numbers so long as these two criteria were met.

The EQSTF also proposed rule changes to interconnection study fee structures that would discourage the submission of speculative or incomplete queue projects. Under the old rules, deposits provided by developers for interconnection studies could not be charged until after a queue position was accepted. Under the new rules, these deposits would be available for charging before a queue position is assigned.

In addition, rather than socializing the study costs for deficient applications from project developers, the EQSTF proposed that these project costs be assigned directly to the developer that submitted the project. This would significantly increase the cost burden that developers would experience if a project is found to be deficient in the review process.

The EQSTF proposed to change the timing of queue windows and Feasibility Study dates to enable more generation projects to participate in the PJM Base Residual Auction. The EQSTF proposed shifting start dates for the queue windows back a month from May 1 to April 1 and Nov 1 to October 1. The EQSTF also proposed shifting feasibility study dates from Dec 1 to Nov 1 and June 1 to May 1.

The EQSTF presented these proposed tariff changes to the PJM Planning Committee on May 12, 2016, where they were endorsed. The Markets and Reliability Committee and PJM Members Committee endorsed the same changes. FERC approved these changes and they were added into the PJM Open Access Transmission Tariff effective October 31, 2016.

Interconnection Study Phase

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.

22 See letter from PJM to Secretary Kimberly Bose, Docket No. ER12-1177-000 <http://www.pjm.com/~/media/documents/ferc/2012-filings/20120229-er12-1177-000.ashx>.

23 See presentation by Dave Egan to the PJM Planning Committee, at <http://www.pjm.com/~/media/committees-groups/committees/pc/20150611/20150611-item-09-queue-status-update.ashx>.

24 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/task-forces/eqstf.aspx>.

Table 12-12 PJM generation planning process

Process Step	Start on	Financial Obligation	Days for PJM to Complete	Days for Applicant to Decide Whether to Continue
Feasibility Study	Close of current queue	Cost of study (partially refundable deposit)	90	30
System Impact Study	Upon acceptance of the System Impact Study Agreement	Cost of study (partially refundable deposit)	120	30
Facilities Study	Upon acceptance of the Facilities Study Agreement	Cost of study (refundable deposit)	Varies	60
Schedule of Work	Upon acceptance of Interconnection Service Agreement (ISA)	Letter of credit for upgrade costs	Varies	37
Construction (only for new generation)	Upon acceptance of Interconnection Construction Service Agreement (ICSA)	None	Varies	NA

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.[25] 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 12-13 and Table 12-14.

Table 12-13 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the projects withdrawn, 49.6 percent were withdrawn before the system impact study was completed. Once an Interconnection Service Agreement (ISA) or a Wholesale Market Participation Agreement (WMPA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted.[26] [27] Withdrawing at or beyond this point is uncommon; only 235 projects, or 12.8 percent, of all projects withdrawn were withdrawn after reaching this milestone.

Table 12-13 Last milestone at time of withdrawal: January 1, 1997 through December 31, 2016

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	101	5.5%	171	1,235
Feasibility Study	810	44.1%	320	3,238
System Impact Study	439	23.9%	593	3,174
Facilities Study	250	13.6%	1,281	4,210
Construction Service Agreement (CSA) or beyond	235	12.8%	1,341	4,249
Total	1,835	100.0%		

Table 12-14 and Table 12-15 show 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 983 days, or 2.7 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 639 days, or 1.8 years, between entering a queue and withdrawing.

Table 12-14 Average project queue times (days): At December 31, 2016

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	907	570	65	3,745
In-Service	983	709	1	4,024
Suspended	2,031	1,091	610	5,108
Under Construction	1,678	1,010	426	4,652
Withdrawn	639	668	1	4,249

Table 12-15 presents information on the time in the stages of the queue for those projects not yet in service. Of the 765 projects in the queue as of December 31, 2016, 88 had a completed feasibility study and 183 were under construction.

25 See PJM Manual 14B. "PJM Region Transmission Planning Process," Revision 33 (May 5, 2016), p.70.

26 "Generators planning to connect to the local distribution systems at locations that are not under FERC jurisdiction and wish to participate in PJM's market need to execute a PJM Wholesale Market Participation Agreement (WMPA)…" instead of an ISA. See PJM Manual 14C. "Generation and Transmission Interconnection Facility Construction," Revision 10 (October 1, 2016), p.8.

27 See PJM. "Manual 14C: Generation and Transmission Interconnection Facility Construction," Revision 10 (October 1, 2016), p.22.

Table 12-15 PJM generation planning summary: At December 31, 2016

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	314	41.0%	745	2,540
Feasibility Study	88	11.5%	866	1,828
System Impact Study	89	11.6%	1,104	3,651
Facilities Study	91	11.9%	1,809	4,260
Construction Service Agreement (CSA) or beyond	183	23.9%	1,979	5,108
Total	765	100.0%		

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 12-16 shows the number of projects that entered the queue by year. The number of queue entries has increased during the past three years, primarily by renewable projects (solar, hydro, storage, biomass, wind). Of the 844 projects entered in 2014, 2015, and 2016, 594, 70.3 percent, were renewable. Of the 349 projects entered 2016, 281, 80.5 percent, were renewable.

Table 12-16 Number of projects entered in the queue as of December 31, 2016

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	Grand Total
1997	2	0	11	13
1998	0	0	18	18
1999	1	5	85	91
2000	2	3	79	84
2001	4	6	83	93
2002	3	14	33	50
2003	1	35	17	53
2004	4	17	32	53
2005	3	78	51	132
2006	9	78	70	157
2007	9	68	142	219
2008	3	114	99	216
2009	10	113	50	173
2010	5	381	55	441
2011	6	265	78	349
2012	2	73	80	155
2013	1	78	73	152
2014	0	122	68	190
2015	0	191	114	305
2016	3	281	65	349
Total	68	1,922	1,303	3,293

Even though renewable projects comprise the majority of projects entered in the queue, as well as what is currently active in the queue, renewable projects only account for 31.2 percent of the nameplate MW currently active in the queue (Table 12-17).

Table 12-17 Queue details by fuel group: At December 31, 2016

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	8	1.0%	226.3	0.2%
Renewable	518	67.4%	31,636.8	31.2%
Traditional	243	31.6%	69,610.4	68.6%
Total	769	100.0%	101,473.5	100.0%

Table 12-18 shows the current status of all generation queue projects by fuel type and project classification from January 1, 1997, through December 31, 2016. For example, between January 1, 1997 and December 31, 2016, 138 nameplate capacity upgrades at natural gas fired facilities have completed the queue process and are in service.

Since 1997, there have been a total of 3,293 projects in PJM generation queues. A total of 2,681 projects have been classified as new generation and 612 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 2,540 projects, or 77.1 percent, of all 3,293 generation queue projects. A total of 361 new projects from either project classification entered the generation queue in 2016.

Table 12-18 Status of all generation queue projects: January 1, 1997 through December 31, 2016

		Number of Projects												
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel	TOTAL
In Service	New Generation	87	61	9	102	1	9	4	7	15	3	71	6	375
	Upgrade	138	15	45	15	41	16	14	5	3	4	14	2	312
Under Construction	New Generation	34	25	1	65	0	4	0	0	30	0	9	0	168
	Upgrade	34	1	5	3	1	1	0	2	3	0	1	0	51
Suspended	New Generation	15	15	0	22	0	0	0	1	4	0	1	0	58
	Upgrade	3	2	0	0	0	0	0	0	2	0	0	0	7
Withdrawn	New Generation	403	368	54	621	9	40	9	32	63	10	74	12	1695
	Upgrade	65	14	12	8	9	2	13	1	7	2	7	2	142
Active	New Generation	68	43	0	236	0	1	0	4	31	0	2	0	385
	Upgrade	60	7	4	10	7	1	0	1	4	3	0	3	100
Total Projects	New Generation	607	512	64	1046	10	54	13	44	143	13	157	18	2681
	Upgrade	300	39	66	36	58	20	27	9	19	9	22	7	612

Table 12-19 shows the MW in Table 12-18 by share by classification as new generation or upgrade. Within a fuel type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 80.0 percent of all hydro projects classified as upgrades are currently in service in PJM, 10.0 percent of hydro upgrades were withdrawn, 5.0 percent of hydro upgrades are under construction, and 5.0 percent of hydro upgrades are active in the queue. From January 1, 1997, through December 31, 2016, solar projects have had the lowest completion rate across all technology types for projects classified as new generation and storage projects have had the lowest completion rate across all technology types for projects classified as upgrades. Landfill gas projects have had the highest completion rate across all technology types for projects classified as new generation and hydro projects have had the highest completion rate across all technology types for projects classified as upgrades.

Table 12-20 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 368 new generation wind projects that have been withdrawn from the queue as of December 31, 2016 listed in Table 12-18 constitute 57,889.6 MW of nameplate capacity. The 468 new generation and upgrade natural gas projects that have been withdrawn in the same time period constitute 188,595.9 MW of nameplate capacity.

Table 12-19 Status of all generation queue projects as percent of total projects by classification: January 1, 1997 through December 31, 2016

		Percent of Total Projects by Classification											
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel
In Service	New Generation	14.3%	11.9%	14.1%	9.8%	10.0%	16.7%	30.8%	15.9%	10.5%	23.1%	45.2%	33.3%
	Upgrade	46.0%	38.5%	68.2%	41.7%	70.7%	80.0%	51.9%	55.6%	15.8%	44.4%	63.6%	28.6%
Under Construction	New Generation	5.6%	4.9%	1.6%	6.2%	0.0%	7.4%	0.0%	0.0%	21.0%	0.0%	5.7%	0.0%
	Upgrade	11.3%	2.6%	7.6%	8.3%	1.7%	5.0%	0.0%	22.2%	15.8%	0.0%	4.5%	0.0%
Suspended	New Generation	2.5%	2.9%	0.0%	2.1%	0.0%	0.0%	0.0%	2.3%	2.8%	0.0%	0.6%	0.0%
	Upgrade	1.0%	5.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.5%	0.0%	0.0%	0.0%
Withdrawn	New Generation	66.4%	71.9%	84.4%	59.4%	90.0%	74.1%	69.2%	72.7%	44.1%	76.9%	47.1%	66.7%
	Upgrade	21.7%	35.9%	18.2%	22.2%	15.5%	10.0%	48.1%	11.1%	36.8%	22.2%	31.8%	28.6%
Active	New Generation	11.2%	8.4%	0.0%	22.6%	0.0%	1.9%	0.0%	9.1%	21.7%	0.0%	1.3%	0.0%
	Upgrade	20.0%	17.9%	6.1%	27.8%	12.1%	5.0%	0.0%	11.1%	21.1%	33.3%	0.0%	42.9%

Table 12-20 Status of all generation capacity (MW) in the PJM generation queue: January 1, 1997 through December 31, 2016

		Project MW												
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel	TOTAL
In Service	New Generation	22,626.3	6,698.6	1,378.0	792.2	9.0	465.6	607.0	225.7	149.0	50.0	382.7	69.5	33,453.5
	Upgrade	6,914.4	33.7	755.5	19.4	3,810.8	605.6	125.8	58.8	36.4	547.5	49.3	25.3	12,982.4
Under Construction	New Generation	16,196.1	4,191.1	80.0	965.2	0.0	123.1	0.0	0.0	83.9	0.0	49.8	0.0	21,689.1
	Upgrade	1,874.2	100.0	120.0	4.5	102.0	17.0	0.0	62.5	72.0	0.0	4.0	0.0	2,356.2
Suspended	New Generation	2,616.2	2,547.4	0.0	249.0	0.0	0.0	0.0	16.0	54.0	0.0	0.9	0.0	5,483.4
	Upgrade	221.6	75.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	0.0	306.6
Withdrawn	New Generation	180,004.5	57,889.5	33,431.6	8,085.8	8,161.0	1,988.0	1,721.0	1,027.7	688.8	843.8	416.2	63.9	294,321.8
	Upgrade	8,591.4	367.0	815.0	47.8	916.0	56.0	589.0	12.1	92.1	24.0	39.4	29.0	11,578.8
Active	New Generation	39,177.9	7,482.5	0.0	14,099.3	0.0	12.5	0.0	21.8	388.3	0.0	8.2	0.0	61,190.5
	Upgrade	9,178.4	260.8	77.0	590.6	124.3	34.0	0.0	4.0	172.5	0.0	0.0	6.1	10,447.7
Total Projects	New Generation	260,621.0	78,809.2	34,889.6	24,191.4	8,170.0	2,589.2	2,328.0	1,291.2	1,363.9	893.8	857.7	133.4	416,138.4
	Upgrade	26,780.0	836.4	1,767.5	662.3	4,953.1	712.6	714.8	137.4	383.0	571.5	92.7	60.4	37,671.7

Figure 12-3 shows the project MW that have entered the PJM generation queue by fuel type and year of entry. In 2015 and 2016, natural gas, wind, and solar projects accounted for the majority of all new projects entering the generation queue. The increase in solar projects entering the queue in 2016 from 2015 was primarily a result of new projects in Dominion.

Figure 12-3 Queue Project MW by Fuel Type and queue entry year: January 1, 1997 through December 31, 2016

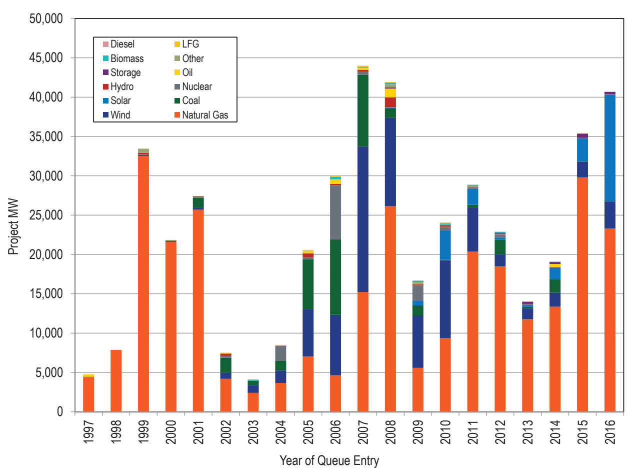


Table 12-21 shows the MW in Table 12-20 by share by classification as new generation or upgrade. Within a fuel type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 73.5 percent of wind projects classified as new generation have been withdrawn from the queue between January 1, 1997, and December 31, 2016.

Table 12-21 Status of all generation queue projects as percent of total MW in project classification: January 1, 1997 through December 31, 2016

		Percent of Total Project MW by Classification											
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel
In Service	New Generation	8.7%	8.5%	3.9%	3.3%	0.1%	18.0%	26.1%	17.5%	10.9%	5.6%	44.6%	52.1%
	Upgrade	25.8%	4.0%	42.7%	2.9%	76.9%	85.0%	17.6%	42.8%	9.5%	95.8%	53.2%	41.9%
Under Construction	New Generation	6.2%	5.3%	0.2%	4.0%	0.0%	4.8%	0.0%	0.0%	6.2%	0.0%	5.8%	0.0%
	Upgrade	7.0%	12.0%	6.8%	0.7%	2.1%	2.4%	0.0%	45.5%	18.8%	0.0%	4.3%	0.0%
Suspended	New Generation	1.0%	3.2%	0.0%	1.0%	0.0%	0.0%	0.0%	1.2%	4.0%	0.0%	0.1%	0.0%
	Upgrade	0.8%	9.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	0.0%	0.0%	0.0%
Withdrawn	New Generation	69.1%	73.5%	95.8%	33.4%	99.9%	76.8%	73.9%	79.6%	50.5%	94.4%	48.5%	47.9%
	Upgrade	32.1%	43.9%	46.1%	7.2%	18.5%	7.9%	82.4%	8.8%	24.0%	4.2%	42.5%	48.0%
Active	New Generation	15.0%	9.5%	0.0%	58.3%	0.0%	0.5%	0.0%	1.7%	28.5%	0.0%	1.0%	0.0%
	Upgrade	34.3%	31.2%	4.4%	89.2%	2.5%	4.8%	0.0%	2.9%	45.0%	0.0%	0.0%	10.1%

Table 12-22 shows the status of all natural gas projects by number of projects that entered PJM generation queues from January 1, 1997 through December 31, 2016, by zone. Of the 128 natural gas projects classified either as new generation or upgrade currently active in the PJM generation queue, 63 projects, 49.2 percent, are located within AEP, ComEd and PENELEC.

Table 12-22 Status of all natural gas generation queue projects: January 1, 1997 through December 31, 2016

		Number of Projects																				
Project Status	Project Classification	AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	7	2	7	1	6	2	0	1	4	7	0	0	8	3	7	6	6	9	11	0	87
	Upgrade	7	9	7	1	3	9	6	0	29	13	0	0	5	2	8	6	3	6	24	0	138
Under Construction	New Generation	2	4	1	1	1	0	0	0	4	0	1	0	2	0	2	4	4	5	3	0	34
	Upgrade	2	3	3	1	0	6	0	0	5	0	0	0	1	0	3	0	2	4	4	0	34
Suspended	New Generation	3	2	5	0	0	0	0	0	0	1	0	0	0	0	0	4	0	0	0	0	15
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0	1	0	0	0	0	3
Withdrawn	New Generation	23	11	37	13	11	9	0	1	17	18	2	2	23	25	41	47	32	34	55	2	403
	Upgrade	5	1	4	3	0	1	0	1	7	4	0	0	5	7	2	4	3	4	14	0	65
Active	New Generation	4	11	8	4	0	11	1	0	4	1	0	1	2	1	1	9	0	5	5	0	68
	Upgrade	1	16	6	2	0	14	0	0	4	0	0	0	1	4	3	2	0	3	4	0	60
Total Projects	New Generation	39	30	58	19	18	22	1	2	29	27	3	3	35	29	51	70	42	53	74	2	607
	Upgrade	15	30	20	7	3	30	6	1	45	17	0	0	13	13	16	13	8	17	46	0	300

Table 12-23 shows the status of all gas projects by MW that entered PJM generation queues from January 1, 1997 through December 31, 2016, by zone. Of the 48,356.3 MW of natural gas projects classified either as new generation or upgrade currently active in the PJM generation queue, 26,968.0 MW, 55.8 percent, are located within AEP, ComEd and Dominion.

Table 12-23 Status of all natural gas generation capacity (MW) in the PJM generation queue: January 1, 1997 through December 31, 2016

Project Status	Project Classification	Project MW											
		AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC
In Service	New Generation	1,016.2	1,615.0	1,701.0	16.5	390.0	629.0	0.0	20.0	3,211.0	1,122.2	0.0	0.0
	Upgrade	265.7	244.0	796.7	40.0	6.5	849.5	60.0	0.0	1,418.7	189.0	0.0	0.0
Under Construction	New Generation	1.5	2,729.0	930.0	800.0	1.3	0.0	0.0	0.0	3,655.1	0.0	205.0	0.0
	Upgrade	41.0	21.0	61.0	161.0	0.0	112.6	0.0	0.0	369.1	0.0	0.0	0.0
Suspended	New Generation	1,058.0	1,110.0	70.1	0.0	0.0	0.0	0.0	0.0	0.0	291.0	0.0	0.0
	Upgrade	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	6,932.0	5,535.0	15,915.1	5,420.7	4,792.1	3,958.0	0.0	134.5	11,066.0	5,651.4	665.0	377.8
	Upgrade	122.8	610.0	567.0	86.0	0.0	10.0	0.0	36.0	305.3	668.0	0.0	0.0
Active	New Generation	963.2	8,224.0	4,495.9	4,047.0	0.0	7,343.3	1,150.0	0.0	3,598.5	451.0	0.0	614.0
	Upgrade	74.0	3,660.0	315.0	145.0	0.0	2,484.0	0.0	0.0	1,658.2	0.0	0.0	0.0
Total Projects	New Generation	9,970.9	19,213.0	23,112.1	10,284.2	5,183.4	11,930.3	1,150.0	154.5	21,530.6	7,515.6	870.0	991.8
	Upgrade	503.5	4,555.0	1,739.7	432.0	6.5	3,456.1	60.0	36.0	3,751.3	857.0	0.0	0.0

Project Status	Project Classification	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	2,070.3	1,397.0	2,464.3	1,227.3	115.0	3,576.6	2,054.9	0.0	22,626.3
	Upgrade	224.0	665.0	715.0	103.0	45.1	327.3	964.9	0.0	6,914.4
Under Construction	New Generation	440.4	0.0	760.5	649.7	2,374.0	3,074.0	575.6	0.0	16,196.1
	Upgrade	0.0	0.0	206.0	0.0	124.5	524.0	254.0	0.0	1,874.2
Suspended	New Generation	0.0	0.0	0.0	87.1	0.0	0.0	0.0	0.0	2,616.2
	Upgrade	200.0	0.0	0.0	1.6	0.0	0.0	0.0	0.0	221.6
Withdrawn	New Generation	11,286.0	12,486.5	23,270.0	16,557.0	19,769.2	13,576.7	22,604.7	6.9	180,004.5
	Upgrade	253.0	1,730.0	205.0	1,040.6	85.0	480.0	2,392.7	0.0	8,591.4
Active	New Generation	1,267.2	450.0	220.0	1,793.5	0.0	2,058.9	2,501.4	0.0	39,177.9
	Upgrade	140.0	111.1	70.0	91.0	0.0	303.0	127.1	0.0	9,178.4
Total Projects	New Generation	15,063.9	14,333.5	26,714.8	20,314.6	22,258.2	22,286.2	27,736.6	6.9	260,621.0
	Upgrade	817.0	2,506.1	1,196.0	1,236.2	254.6	1,634.3	3,738.7	0.0	26,780.0

Table 12-24 shows the status of all wind generation projects that entered PJM generation queues from January 1, 1997 through December 31, 2016, by zone. Of the 76 wind projects to achieve in service status, 65 projects, 87.8 percent are located within ComEd, AEP, AP and PENELEC. Of the 50 wind projects currently active in the PJM generation queue, 37 projects, 74.0 percent are located within AEP, ComEd and AP.

Table 12-24 Status of all wind generation queue projects: January 1, 1997 December 31, 2016

Project Status	Project Classification	Number of Projects																				
		AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	1	8	11	0	0	17	0	0	0	0	0	0	1	1	0	18	0	4	0	0	61
	Upgrade	0	0	3	0	0	2	0	0	0	0	0	0	0	0	0	6	0	4	0	0	15
Under Construction	New Generation	1	9	6	1	0	4	0	0	3	1	0	0	0	0	0	0	0	0	0	0	25
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	1	7	2	0	0	1	2	0	0	0	0	0	0	0	0	1	0	1	0	0	15
	Upgrade	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Withdrawn	New Generation	15	80	40	6	0	92	13	0	13	8	0	1	1	0	0	59	0	39	1	0	368
	Upgrade	1	0	7	0	0	1	0	0	1	0	0	0	0	0	0	2	0	2	0	0	14
Active	New Generation	0	19	1	1	0	12	0	0	2	2	0	0	0	0	0	4	0	2	0	0	43
	Upgrade	0	0	3	0	0	2	0	0	0	0	0	0	0	0	0	2	0	0	0	0	7
Total Projects	New Generation	18	123	60	8	0	126	15	0	18	11	0	1	2	1	0	82	0	46	1	0	512
	Upgrade	2	1	14	0	0	5	0	0	1	0	0	0	0	0	0	10	0	6	0	0	39

Table 12-25 shows the wind project capacity in MW of all wind generation projects that have entered the PJM generation queue from January 1, 1997 through December 31, 2016, by zone.. Of the 6,732.3 MW of wind generation capacity to achieve in service status, 6,397.7 MW, or 95.0 percent of nameplate capacity is located within ComEd, AEP, AP and PENELEC. Of the 7,743.3 MW of wind generation capacity currently active in the PJM generation queue, 6,375.5 MW of generation capacity or 82.3 percent is located within AEP, ComEd and AP.

Table 12-25 Status of all wind generation capacity (MW) in the PJM generation queue: January 1, 1997 through December 31, 2016

Project Status	Project Classification	AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC
In Service	New Generation	7.5	2,052.0	1,031.4	0.0	0.0	2,413.5	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Under Construction	New Generation	150.0	1,118.3	732.0	500.0	0.0	978.5	0.0	0.0	612.3	100.0	0.0	0.0
	Upgrade	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	20.0	1,398.3	129.1	0.0	0.0	500.0	300.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	5.0	0.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	3,626.4	15,123.0	2,950.1	645.6	0.0	21,515.8	1,828.0	0.0	2,156.5	2,210.0	0.0	150.3
	Upgrade	0.0	0.0	199.0	0.0	0.0	4.0	0.0	0.0	78.0	0.0	0.0	0.0
Active	New Generation	0.0	4,336.9	50.6	18.0	0.0	1,798.0	0.0	0.0	208.2	499.6	0.0	0.0
	Upgrade	0.0	0.0	20.0	0.0	0.0	170.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Projects	New Generation	3,803.9	24,028.5	4,893.2	1,163.6	0.0	27,205.8	2,128.0	0.0	2,977.0	2,809.6	0.0	150.3
	Upgrade	5.0	100.0	289.0	0.0	0.0	174.0	0.0	0.0	78.0	0.0	0.0	0.0

Project Status	Project Classification	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	30.6	70.0	0.0	894.4	0.0	199.2	0.0	0.0	6,698.6
	Upgrade	0.0	0.0	0.0	6.4	0.0	27.3	0.0	0.0	33.7
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,191.1
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0
Suspended	New Generation	0.0	0.0	0.0	100.0	0.0	100.0	0.0	0.0	2,547.4
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0
Withdrawn	New Generation	60.0	0.0	0.0	4,897.6	0.0	2,706.3	20.0	0.0	57,889.6
	Upgrade	0.0	0.0	0.0	80.0	0.0	6.0	0.0	0.0	367.0
Active	New Generation	0.0	0.0	0.0	405.0	0.0	166.2	0.0	0.0	7,482.5
	Upgrade	0.0	0.0	0.0	70.8	0.0	0.0	0.0	0.0	260.8
Total Projects	New Generation	90.6	70.0	0.0	6,297.0	0.0	3,171.7	20.0	0.0	78,809.2
	Upgrade	0.0	0.0	0.0	157.1	0.0	33.3	0.0	0.0	836.4

Table 12-26 shows the status of all solar generation projects that have entered the PJM generation queue from January 1, 1997 through December 31, 2016, by zone. Out of a total of 1,082 solar projects in the PJM generation queue, 500 projects or 46.2 percent have been located in JCPL, AECO and PSEG, all zones in New Jersey. Of these three zones, AECO has the lowest completion rates for new generation and upgrade solar projects. Excluding currently active projects, only 5.1 percent of solar projects classified as new generation or upgrades in AECO are either in service or under construction. Of these three zones, PSEG has the highest completion rates. Excluding currently active projects, 43.6 percent of solar projects classified as either new generation or upgrades in PSEG are either in service or under construction.

The number of currently active new generation solar projects is also highly concentrated in several zones. Out of 200 active new generation projects, 108 projects, or 43.9 percent of all currently active new generation solar projects are located in Dominion.

Table 12-26 Status of all solar generation queue projects: January 1, 1997 through December 31, 2016

Project Status	Project Classification	Number of Projects																				
		AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	5	4	2	0	1	1	1	0	6	9	0	0	34	0	1	0	0	2	36	0	102
	Upgrade	0	0	0	0	0	0	0	0	2	8	0	0	5	0	0	0	0	0	0	0	15
Under Construction	New Generation	3	4	9	0	2	0	2	0	12	9	0	0	14	0	0	0	0	2	8	0	65
	Upgrade	0	0	0	0	0	0	0	0	1	1	0	0	1	0	0	0	0	0	0	0	3
Suspended	New Generation	0	3	9	0	0	0	0	0	1	0	0	0	5	1	0	1	0	0	2	0	22
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	147	17	44	6	4	7	4	4	47	78	0	0	151	11	5	10	6	25	55	0	621
	Upgrade	1	1	0	0	0	0	0	0	1	0	0	0	5	0	0	0	0	0	0	0	8
Active	New Generation	10	28	10	2	6	3	4	1	100	48	0	1	8	2	1	0	2	2	8	0	236
	Upgrade	0	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	2	0	10
Total Projects	New Generation	165	56	74	8	13	11	11	5	166	144	0	1	212	14	7	11	8	31	109	0	1,046
	Upgrade	1	1	0	0	0	0	0	0	12	9	0	0	11	0	0	0	0	0	2	0	36

Table 12-27 shows the status of all solar generation project MW that have entered the PJM generation queue from January 1, 1997 through December 31, 2016, by zone. Out of a total of 42,191.4 MW of solar nameplate capacity in the PJM generation queue, 4,232.0 MW or 17.0 percent have been located in JCPL, AECO and PSEG, all of which are zones in New Jersey. Solar projects in Dominion have accounted for 11,559.9 MW or 46.5percent of all solar project nameplate capacity in the PJM queue from January 1, 1997 through December 31, 2016. Solar projects in DPL have accounted for 2,679.4 MW or 10.8 percent of all solar project nameplate capacity in the PJM queue from January 1, 1997 through December 31, 2016.

Table 12-27 Current status of all solar generation capacity (MW) in the PJM generation queue: January 1, 1997 through December 31, 2016

Project Status	Project Classification	Project MW											
		AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC
In Service	New Generation	38.5	14.7	34.0	0.0	1.1	9.0	2.5	0.0	157.0	118.4	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	0.0	0.0	0.0
Under Construction	New Generation	20.8	40.0	105.8	0.0	22.0	0.0	23.4	0.0	438.0	80.5	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	0.0	0.0	0.0
Suspended	New Generation	0.0	49.9	108.9	0.0	0.0	0.0	0.0	0.0	5.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	1,628.8	332.3	750.1	60.1	9.2	84.8	51.5	63.0	1,536.2	1,148.5	0.0	0.0
	Upgrade	10.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0	0.0	0.0	0.0
Active	New Generation	64.2	2,310.2	451.4	326.0	22.1	27.0	199.6	125.0	8,819.1	1,332.0	0.0	80.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	588.9	0.0	0.0	0.0
Total Projects	New Generation	1,752.3	2,747.1	1,450.2	386.1	54.4	120.8	277.0	188.0	10,955.3	2,679.4	0.0	80.0
	Upgrade	10.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	604.5	0.0	0.0	0.0

Project Status	Project Classification	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	217.3	0.0	3.3	0.0	0.0	15.0	181.4	0.0	792.2
	Upgrade	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.4
Under Construction	New Generation	187.5	0.0	0.0	0.0	0.0	6.0	41.2	0.0	965.2
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5
Suspended	New Generation	59.0	3.0	0.0	13.5	0.0	0.0	9.7	0.0	249.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	1,243.4	367.0	50.1	34.3	58.1	277.7	390.6	0.0	8,085.8
	Upgrade	23.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	47.8
Active	New Generation	58.3	135.0	20.0	0.0	60.0	30.0	39.4	0.0	14,099.3
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	590.6
Total Projects	New Generation	1,765.5	505.0	73.4	47.8	118.1	328.7	662.4	0.0	24,191.4
	Upgrade	40.1	0.0	0.0	0.0	0.0	0.0	1.7	0.0	662.3

Table 12-28 shows the relationship between the project developer and Transmission Owner for every project that has entered the PJM generation queue from January 1, 1997 through December 31, 2016 by zone and technology 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 natural gas fired generation projects that have entered the PJM generation queue in DEOK were projects submitted by Duke Energy or subsidiaries of Duke Energy, the Transmission Owner for DEOK. There have been 154.5 MW of natural gas fired projects that have entered the PJM generation queue in DEOK by developers unrelated to Duke Energy.

Table 12-28 Relationship between project developer and Transmission Owner for all interconnection queue projects MW by fuel type: January 1, 1997 through December 31, 2016

				MW by Fuel Type										
Parent Company	Transmission Owner	Related To Developer	Number of Projects	Biomass	Coal	Diesel	Hydro	Landfill Gas	Natural Gas	Nuclear	Other	Solar	Wind	Total MW
AEP	AEP	Related	47	0.0	3,965.0	0.0	34.0	3.0	3,010.0	186.0	0.0	74.7	0.0	7,272.7
		Unrelated	316	501.1	10,292.0	7.5	448.4	83.8	22,338.0	0.0	66.0	2,588.0	23,749.9	60,074.6
AES	DAY	Related	15	0.0	1,347.5	0.0	0.0	0.0	51.0	0.0	0.0	4.0	0.0	1,402.5
		Unrelated	28	1.9	0.0	0.0	0.0	10.0	9.0	0.0	0.0	223.1	2,128.0	2,372.0
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
		Unrelated	20	0.0	2,810.0	0.0	106.0	19.2	870.0	1,879.0	0.0	0.0	0.0	5,684.2
Dominion	Dominion	Related	73	64.0	287.0	0.0	340.0	0.0	13,075.0	1,944.0	0.0	101.4	142.0	15,953.4
		Unrelated	259	343.7	20.0	10.0	29.5	184.0	12,033.8	0.0	156.3	11,283.5	3,063.0	27,123.8
Duke	DEOK	Related	4	0.0	0.0	0.0	0.0	0.0	36.0	0.0	0.0	0.0	0.0	36.0
		Unrelated	14	0.0	70.0	0.0	112.0	4.8	154.5	0.0	0.0	188.0	0.0	529.3
EKPC	EKPC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	6	0.0	0.0	0.0	0.0	0.0	2,141.8	0.0	0.0	80.0	150.3	2,372.1
Exelon	AECO	Related	3	0.0	0.0	0.0	0.0	0.0	730.0	0.0	0.0	0.0	0.0	730.0
		Unrelated	265	29.8	15.0	13.0	0.0	31.0	9,782.8	0.0	0.0	1,772.1	3,808.9	15,452.6
	BGE	Related	13	0.0	10.0	0.0	0.0	0.0	1,037.0	3,362.2	0.0	20.0	0.0	4,429.2
		Unrelated	58	0.0	0.0	29.0	140.4	9.5	4,152.9	0.0	132.0	34.4	0.0	4,498.2
	ComEd	Related	18	0.0	0.0	0.0	0.0	0.0	0.0	1,185.0	0.0	9.0	396.0	1,590.0
		Unrelated	239	90.0	1,926.0	42.0	22.7	112.9	15,386.4	0.0	20.0	91.8	27,359.8	45,051.6
	DPL	Related	10	0.0	0.0	0.0	0.0	0.0	1,716.0	0.0	0.0	31.4	0.0	1,747.4
		Unrelated	232	66.0	653.0	0.0	0.0	27.6	6,656.6	0.0	30.0	2,644.2	2,809.6	12,887.0
	PECO	Related	29	0.0	7.0	0.0	45.0	0.0	6,420.0	437.8	0.0	0.0	0.0	6,909.8
		Unrelated	78	0.0	0.0	12.1	220.0	18.7	21,490.8	0.0	0.0	73.4	0.0	21,815.0
	Pepco	Related	1	0.0	0.0	0.0	0.0	0.0	0.0	1,640.0	0.0	0.0	0.0	1,640.0
		Unrelated	63	0.0	0.0	0.0	0.0	12.5	22,623.9	0.0	0.0	58.1	0.0	22,694.5
First Energy	AP	Related	14	0.0	1,745.0	0.0	252.0	0.0	4,790.0	0.0	0.0	0.0	0.0	6,787.0
		Unrelated	295	177.2	4,057.0	53.8	356.3	125.8	18,938.3	0.0	96.0	1,463.9	5,182.7	30,450.9
	ATSI	Related	8	0.0	0.0	0.0	0.0	0.0	1,678.0	16.0	0.0	0.6	0.0	1,694.6
		Unrelated	47	0.0	0.0	0.0	0.0	35.3	9,021.7	0.0	135.0	385.5	1,163.6	10,741.1
	JCPL	Related	2	0.0	0.0	0.0	20.0	0.0	100.0	0.0	0.0	0.0	0.0	120.0
		Unrelated	303	30.0	0.0	0.0	1.6	24.4	15,780.9	0.0	0.0	1,815.0	90.6	17,742.4
	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
		Unrelated	88	90.4	0.0	8.0	0.0	57.9	16,839.6	93.0	11.0	505.0	70.0	17,674.9
	PENELEC	Related	8	0.0	1,860.0	0.0	32.0	0.0	1,174.0	0.0	0.0	0.0	0.0	3,066.0
		Unrelated	211	0.0	561.0	8.0	53.3	50.9	19,387.8	0.0	621.0	47.8	6,454.1	27,183.8
PPL	PPL	Related	36	0.0	139.0	0.0	0.0	7.7	2,294.0	1,988.0	0.0	0.0	0.0	4,428.7
		Unrelated	186	28.5	6,868.6	10.4	2.6	95.4	21,626.5	0.0	152.5	328.7	3,205.0	32,318.1
PSEG	PSEG	Related	100	0.0	24.0	0.0	0.0	11.7	12,802.1	381.0	0.0	124.0	0.0	13,342.8
		Unrelated	163	0.0	0.0	0.0	1,000.0	24.4	18,516.8	0.0	45.5	544.8	20.0	20,151.5
Consolidated Edison, Inc.	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
		Unrelated	1	0.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	6.0
Total		Related	381	64.0	9,384.5	0.0	723.0	22.4	48,913.1	11,140.0	0.0	365.1	538.0	71,150.1
		Unrelated	2,872	1,358.6	27,272.6	193.8	2,492.8	928.0	237,758.0	1,972.0	1,465.3	24,127.1	79,255.5	376,823.7

Table 12-29 shows the relationship between the project developer and Transmission Owner for every solar project that has entered the PJM generation queue from January 1, 1997 through December 31, 2016 by zone and project status. 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. PSEG is the zone that has had the most solar MW built by the incumbent Transmission Owner.

Table 12-29 Relationship between project developer and Transmission Owner for all solar project MW in PJM interconnection queue: January 1, 1997 through December 31, 2016

Parent Company	Transmission Owner	Related To Developer	MW by Project Status IS	UC	Suspended	W	Active
AEP	AEP	Related	2.5	12.2	0.0	0.0	60.0
		Unrelated	0.0	20.0	51.7	336.5	2,310.2
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	2.5	23.4	0.0	51.5	199.6
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0
Dominion	Dominion	Related	20.0	0.0	0.0	7.0	74.4
		Unrelated	140.1	122.9	205.0	1,511.2	9,762.3
Duke	DEOK	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	63.0	125.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	80.0
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	38.5	20.8	0.0	1,638.8	74.0
	BGE	Related	0.0	20.0	0.0	0.0	0.0
		Unrelated	1.1	2.0	0.0	9.2	22.1
	ComEd	Related	9.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	84.8	27.0
	DPL	Related	7.4	0.0	0.0	24.0	0.0
		Unrelated	21.0	159.5	0.0	1,094.5	1,541.2
	PECO	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	3.3	0.0	0.0	50.1	20.0
	Pepco	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	58.1	60.0
First Energy	AP	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	34.0	32.5	38.9	692.2	666.3
	ATSI	Related	0.0	0.0	0.0	0.6	0.0
		Unrelated	0.0	0.0	0.0	59.5	326.0
	JCPL	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	204.1	175.5	92.9	1,235.2	111.7
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	3.0	367.0	135.0
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	13.5	34.3	0.0
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	15.0	16.0	0.0	267.7	30.0
PSEG	PSEG	Related	105.8	10.0	0.0	8.2	0.0
		Unrelated	53.8	46.2	9.7	382.5	53.0
Consolidated Edison, Inc.	RECO	Related	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0
Total		Related	144.7	42.2	0.0	39.8	134.4
		Unrelated	513.4	618.8	414.7	7,935.9	15,543.4

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.[28] When one of the reportable transmission facilities needs to be taken out of service, the TO is required to submit an outage request as early as possible. The specific timeline is shown in Table 12-31.[29]

Transmission outages have significant impacts on PJM markets. There are impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. It is important for the efficient functioning of the markets that there be clear, enforceable rules governing transmission outages.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days and greater than five calendar days; or less than or equal to five calendar days.[30] Table 12-30 shows that 77.5 percent of the requested outages were planned for less than or equal to five days and 6.6 percent of requested outages were planned for greater than 30 days in 2016. All of the outage data in this section except in the analysis for the FTR market are for outages scheduled to occur in 2015 and 2016, regardless of when they were initially submitted.[31] The outage data in the analysis for the FTR market are for outages scheduled to occur in the planning periods 2015 to 2016 and 2016 to 2017.

28 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 3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Revision 12 (September 30, 2016).

29 See PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p.68.

30 See PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p.70.

31 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. We only included all the transmission outage tickets submitted by PJM internal companies which are currently active.

Table 12-30 Transmission facility outage request summary by planned duration: 2015 and 2016

	2015		2016	
Planned Duration (Days)	Outage Requests	Percent	Outage Requests	Percent
<=5	15,527	77.3%	15,670	77.5%
>5 & <=30	3,177	15.8%	3,212	15.9%
>30	1,388	6.9%	1,332	6.6%
Total	20,092	100.0%	20,214	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-31.[32]

The purpose of the rules defined in Table 12-31 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 so that PJM can accurately model market conditions.[33]

Table 12-31 PJM transmission facility outage request received status definition

Planned Duration (Calendar Days)	Request Submitted	Received Status
<=5	Before the 1st of the month one month prior to the starting month of the outage	On Time
	After or on the 1st of the month one month prior to the starting month of the outage	Late
> 5 & <=30	Before the 1st of the month six months prior to the starting month of the outage	On Time
	After or on the 1st of the month six months prior to the starting month of the outage	Late
>30	The earlier of 1) February 1st, 2) the 1st of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of 1) February 1st, 2) the 1st of the month six months prior to the starting month of the outage	Late

Table 12-32 shows a summary of requests by received status. In 2016, 51.7 percent of outage requests received were late.

Table 12-32 Transmission facility outage request summary by received status: 2015 and 2016

	2015				2016			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	8,077	7,450	15,527	48.0%	7,798	7,872	15,670	50.2%
>5 & <=30	1,551	1,626	3,177	51.2%	1,521	1,691	3,212	52.6%
>30	518	870	1,388	62.7%	451	881	1,332	66.1%
Total	10,146	9,946	20,092	49.5%	9,770	10,444	20,214	51.7%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage requests submitted on time; and transmission outage request submitted late. PJM retains the right to deny all transmission outage requests that are submitted late unless the request is an emergency.

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.[34] Table 12-33 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in 2016, 13.7 percent were for emergency outages. Of all outage requests scheduled to occur in 2015, 13.4 percent were for emergency outages.

32 See PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p.69 and p.70.
33 *See* "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).
34 PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p. 80.

Table 12-33 Transmission facility outage request summary by emergency: 2015 and 2016

	2015				2016			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	2,104	13,423	15,527	13.6%	2,183	13,487	15,670	13.9%
>5 & <=30	418	2,759	3,177	13.2%	415	2,797	3,212	12.9%
>30	177	1,211	1,388	12.8%	172	1,160	1,332	12.9%
Total	2,699	17,393	20,092	13.4%	2,770	17,444	20,214	13.7%

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."[35]

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 12-34 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in 2016, 8.7 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.2 percent (73 out of 1,757) were denied by PJM in 2016 and 20.5 percent (361 out of 1,757) were cancelled (Table 12-36).

Table 12-34 Transmission facility outage request summary by congestion: 2015 and 2016

	2015				2016			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,426	14,101	15,527	9.2%	1,301	14,369	15,670	8.3%
>5 & <=30	363	2,814	3,177	11.4%	344	2,868	3,212	10.7%
>30	132	1,256	1,388	9.5%	112	1,220	1,332	8.4%
Total	1,921	18,171	20,092	9.6%	1,757	18,457	20,214	8.7%

Table 12-35 shows the outage requests summary by received status, congestion status and emergency status. In 2016, 38.0 percent of requests were submitted late and were nonemergency while 1.8 (367 out of 20,214) percent of requests were late, nonemergency, and expected to cause congestion.

Table 12-35 Transmission facility outage requests that by received status, congestion and emergency: 2015 and 2016

		2015				2016			
Submission Status		Congestion Expected	No Congestion Expected	Total	Percent	Congestion Expected	No Congestion Expected	Total	Percent
Late	Emergency	113	2,569	2,682	13.3%	100	2,654	2,754	13.6%
	Non Emergency	346	6,918	7,264	36.2%	367	7,323	7,690	38.0%
On Time	Emergency	3	14	17	0.1%	1	15	16	0.1%
	Non Emergency	1,459	8,670	10,129	50.4%	1,289	8,465	9,754	48.3%
Total		1,921	18,171	20,092	100.0%	1,757	18,457	20,214	100.0%

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.[36] Table 12-36 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 12-36. Table 12-36 shows that of all the outage requests that were expected to cause congestion, 4.2 percent (73 out of 1,757) were denied by PJM in 2016, 75.0 percent were complete and 20.5 percent (361 out of 1,757) were cancelled.

35 PJM added this definition to Manual 38 in February 2017. PJM. "Manual 38: Operations Planning," Revision 10 (February 1, 2017), p. 17.

36 See PJM. "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (November 1, 2015).

Table 12-36 Transmission facility outage requests that might cause congestion status summary: 2015 and 2016

		2015						2016					
Submission Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	12	100	0	1	113	88.5%	4	94	1	1	100	94.0%
	Non Emergency	66	252	2	26	346	72.8%	67	253	4	43	367	68.9%
On Time	Emergency	0	3	0	0	3	100.0%	0	1	0	0	1	100.0%
	Non Emergency	387	1,020	2	50	1,459	69.9%	290	969	1	29	1,289	75.2%
Total		465	1,375	4	77	1,921	71.6%	361	1,317	6	73	1,757	75.0%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[37] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Many (68.9 percent or 253 out of 367) outages that were nonemergency, expected to cause congestion, and late transmission outages were approved and completed. 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 12-37 is a summary of all the outage requests planned for 2015 and 2016 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 2016, 1.7 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 1.9 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.

Table 12-37 Rescheduled and cancelled transmission outage request summary: 2015 and 2016

	2015					2016				
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	102,667	2,003	2.0%	2,465	2.4%	95,754	1,695	1.8%	2,000	2.1%
>5 & <=30	18,170	278	1.5%	211	1.2%	16,499	204	1.2%	180	1.1%
>30	8,052	126	1.6%	74	0.9%	6,345	76	1.2%	51	0.8%
Total	128,889	2,407	1.9%	2,750	2.1%	118,598	1,975	1.7%	2,231	1.9%

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 a 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.[38] 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.[39] 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

37 OATT Attachment K Appendix § 1.9.2 (Planned Outages).
38 PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p. 70.
39 PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p. 70.

a duration exceeding five days needs to be submitted before the first of the month nine months prior to the month in which the outage was expected to occur.

The 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 12-31) 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. Table 12-38 shows that there were 12,141 transmission equipment planned outages in 2016, of which 1,375 were planned outages longer than 30 days, and of which 205 or 1.7 percent were scheduled longer than 30 days if the duration of the outages were combined for the same equipment. The duration of those outages could potentially be longer than 30 days, however were divided into shorter periods by transmission owners.

Table 12-38 Transmission outage summary: 2015 and 2016

		2015		2016	
Duration	Divided into Shorter Periods	Number of Outages	Percent	Number of Outages	Percent
> 30 Days	No	1,207	10.5%	1,170	9.6%
	Yes	181	1.6%	205	1.7%
<= 30 Days		10,108	87.9%	10,766	88.7%
Total		11,496	100.0%	12,141	100.0%

Table 12-39 shows the details of potentially long duration (> 30 days) outages when combining the duration of the outages for the same equipment. The actual duration of scheduled outages would be longer than 30 days if the duration of the outages were combined for the same equipment within a period of days. In 2016, there would have been two outages with a combined duration longer than 30 days that were instead scheduled to occur as shorter outages within a period of less than or equal to 31 days. In 2016, there would have been 32 outages with a combined duration longer than 30 days that were instead scheduled to occur as shorter outages within a period of more than 31 days and less than 62 days.

Table 12-39 Summary of potentially long duration (> 30 days) outages: 2015 and 2016

	2015		2016	
Days	Number of Outages	Percent	Number of Outages	Percent
<=31	4	2.2%	2	1.0%
>31 & <=62	12	6.6%	32	15.6%
>62 and <=93	18	9.9%	19	9.3%
>93	147	81.2%	152	74.1%
Total	181	100.0%	205	100.0%

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR auctions. The purpose of the rules is to ensure that outages are known with enough lead time prior to FTR auctions so that market participants can understand market conditions and so that PJM can accurately model market conditions. Outage requests must be submitted according to rules based on planned outage duration (Table 12-31). The rules defining when an outage is late are based on the timing of FTR auctions. When an outage request is submitted late, the outage will be marked as Late and may be denied if it is expected to cause congestion. Table 12-43 shows that 792 outage requests with a duration of two weeks or longer but shorter than two months were late, and only one of them were denied by PJM and 9.0 percent were cancelled. Table 12-43 also shows that 399 outage requests with a duration of two months or longer were late and only one of them were denied by PJM and 9.5 percent were cancelled in the 2016 to 2017 planning year.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR market. When determining transmission outages to be modeled in the annual ARR allocation and FTR auction, PJM does not consider outages with planned durations shorter than two weeks, does consider some outages with planned duration longer than two weeks but shorter than two months, and does consider all outages with planned duration longer than or equal to two months. PJM may exercise significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[40]

Table 12-40 shows that 85.5 percent of the outage requests for outages expected to occur during the planning period 2016 to 2017 had a planned duration of less than two weeks and that 46.0 (7,031 out of 15,274) percent of all outage requests for the planning period were submitted late according to outage submission rules.

Table 12-40 Transmission facility outage requests by received status: Planning periods 2015 to 2016 and 2016 to 2017

	2015/2016				2016/2017			
Planned Duration	On Time	Late	Total	Percent	On Time	Late	Total	Percent
<2 weeks	8,797	8,814	17,611	87.0%	7,216	5,840	13,056	85.5%
>=2 weeks & <2 months	853	1,022	1,875	9.3%	827	792	1,619	10.6%
>=2 months	225	523	748	3.7%	200	399	599	3.9%
Total	9,875	10,359	20,234	100.0%	8,243	7,031	15,274	100.0%

Table 12-41 shows outage requests summary by emergency status. Of all outage requests for outages expected to occur in the 2016 to 2017 planning year and submitted late, 73.8 percent were for nonemergency outages.

Table 12-41 Transmission facility outage requests by received status and emergency: Planning periods 2015 to 2016 and 2016 to 2017

		2015/2016				2016/2017			
	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	16	8,781	8,797	99.8%	10	7,206	7,216	99.9%
	>=2 weeks & <2 months	4	849	853	99.5%	2	825	827	99.8%
	>=2 months	0	225	225	100.0%	0	200	200	100.0%
	Total	20	9,855	9,875	99.8%	12	8,231	8,243	99.9%
Late	<2 weeks	2,399	6,415	8,814	72.8%	1,630	4,210	5,840	72.1%
	>=2 weeks & <2 months	174	848	1,022	83.0%	138	654	792	82.6%
	>=2 months	102	421	523	80.5%	75	324	399	81.2%
	Total	2,675	7,684	10,359	74.2%	1,843	5,188	7,031	73.8%

PJM analyzes 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 12-42 shows a summary of requests by expected congestion and received status. Overall, 5.1 percent of all outage requests for outages expected to occur in the 2016 to 2017 planning year and submitted late were requests that were expected to cause congestion.

Table 12-42 Transmission facility outage requests by submission status and congestion: Planning periods 2015 to 2016 and 2016 to 2017

		2015/2016				2016/2017			
	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	1,151	7,646	8,797	13.1%	885	6,331	7,216	12.3%
	>=2 weeks & <2 months	172	681	853	20.2%	132	695	827	16.0%
	>=2 months	46	179	225	20.4%	34	166	200	17.0%
	Total	1,369	8,506	9,875	13.9%	1,051	7,192	8,243	12.8%
Late	<2 weeks	371	8,443	8,814	4.2%	296	5,544	5,840	5.1%
	>=2 weeks & <2 months	49	973	1,022	4.8%	47	745	792	5.9%
	>=2 months	18	505	523	3.4%	14	385	399	3.5%
	Total	438	9,921	10,359	4.2%	357	6,674	7,031	5.1%

40 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission outage Modeling," <http://www.pjm.com/~/media/markets-ops/ftr/annual-ftr-auction/2015-2016/2015-2016-annual-outage-modeling.ashx> (April 1, 2015).

Table 12-43 shows that 69.2 percent of late outage requests with a duration of two weeks or longer but shorter than two months were active or completed, one was denied by PJM and 9.0 percent were cancelled in the 2016 to 2017 planning year. Table 12-43 also shows that 56.6 percent of late outage requests with duration of two months or longer were active or completed, one of them was denied, and 9.5 percent were cancelled in the 2016 to 2017 planning year.

Table 12-43 Transmission facility outage requests by received status and processed status: Planning periods 2015 to 2016 and 2016 to 2017

		2015/2016				2016/2017			
Planned Duration	Processed Status	On Time	Percent	Late	Percent	On Time	Percent	Late	Percent
<2 weeks	In Progress	16	0.2%	144	1.6%	2,025	28.1%	299	5.1%
	Denied	39	0.4%	36	0.4%	26	0.4%	44	0.8%
	Approved	0	0.0%	0	0.0%	36	0.5%	44	0.8%
	Cancelled	2,416	27.5%	1,062	12.0%	1,477	20.5%	658	11.3%
	Revised	0	0.0%	0	0.0%	14	0.2%	3	0.1%
	Active	0	0.0%	1	0.0%	12	0.2%	17	0.3%
	Completed	6,326	71.9%	7,571	85.9%	3,626	50.2%	4,775	81.8%
Total Submission		8,797	100.0%	8,814	100.0%	7,216	100.0%	5,840	100.0%
>=2 weeks & <2 months	In Progress	0	0.0%	13	1.3%	301	36.4%	115	14.5%
	Denied	0	0.0%	0	0.0%	1	0.1%	1	0.1%
	Approved	0	0.0%	0	0.0%	1	0.1%	2	0.3%
	Cancelled	236	27.7%	92	9.0%	164	19.8%	71	9.0%
	Revised	0	0.0%	0	0.0%	0	0.0%	0	0.0%
	Active	0	0.0%	0	0.0%	10	1.2%	55	6.9%
	Completed	617	72.3%	917	89.7%	350	42.3%	548	69.2%
Total Submission		853	100.0%	1,022	100.0%	827	100.0%	792	100.0%
>=2 months	In Progress	0	0.0%	9	1.7%	30	15.0%	39	9.8%
	Denied	0	0.0%	0	0.0%	0	0.0%	1	0.3%
	Approved	0	0.0%	0	0.0%	0	0.0%	2	0.5%
	Cancelled	45	20.0%	46	8.8%	50	25.0%	38	9.5%
	Revised	0	0.0%	0	0.0%	0	0.0%	0	0.0%
	Active	4	1.8%	30	5.7%	35	17.5%	93	23.3%
	Completed	176	78.2%	438	83.7%	85	42.5%	226	56.6%
Total Submission		225	100.0%	523	100.0%	200	100.0%	399	100.0%

Table 12-44 shows that there were 792 outage requests with a duration of two weeks or longer but shorter than two months submitted late, of which 45 were nonemergency and expected to cause congestion in the 2016 to 2017 planning year. Of the 45 such requests, 9 were in process, one was denied, four were cancelled, and 30 were active or complete. For the outages planned for two months or longer, there were 399 total outages submitted late, of which 13 requests were nonemergency. Of those requests, three were in process, three were cancelled and six were active or complete.

Table 12-44 Transmission facility outage requests by received status, processed status, emergency and congestion: Planning periods 2015 to 2016 and 2016 to 2017

		2015/2016						2016/2017					
		On Time			Late			On Time			Late		
Planned Duration	Processed Status	Non Emergency and Congestion Expected	Total	Percent	Non Emergency and Congestion Expected	Total	Percent	Non Emergency and Congestion Expected	Total	Percent	Non Emergency and Congestion Expected	Total	Percent
<2 weeks	In Progress	0	16	0.0%	1	144	0.7%	184	2,025	9.1%	12	299	4.0%
	Denied	32	39	82.1%	18	36	50.0%	20	26	76.9%	31	44	70.5%
	Approved	0	0	0.0%	0	0	0.0%	6	36	16.7%	3	44	6.8%
	Cancelled	305	2,416	12.6%	61	1,062	5.7%	167	1,477	11.3%	37	658	5.6%
	Revised	0	0	0.0%	0	0	0.0%	2	14	14.3%	0	3	0.0%
	Active	0	0	0.0%	0	1	0.0%	2	12	16.7%	0	17	0.0%
	Completed	811	6,326	12.8%	205	7,571	2.7%	503	3,626	13.9%	136	4,775	2.8%
Total Submission		1,148	8,797	13.0%	285	8,814	3.2%	884	7,216	12.3%	219	5,840	3.8%
>=2 weeks & <2 months	In Progress	0	0	0.0%	1	13	7.7%	49	301	16.3%	9	115	7.8%
	Denied	0	0	0.0%	0	0	0.0%	1	1	100.0%	1	1	100.0%
	Approved	0	0	0.0%	0	0	0.0%	0	1	0.0%	1	2	50.0%
	Cancelled	31	236	13.1%	5	92	5.4%	13	164	7.9%	4	71	5.6%
	Revised	0	0	0.0%	0	0	0.0%	0	0	0.0%	0	0	0.0%
	Active	0	0	0.0%	0	0	0.0%	1	10	10.0%	5	55	9.1%
	Completed	141	617	22.9%	39	917	4.3%	68	350	19.4%	25	548	4.6%
Total Submission		172	853	20.2%	45	1,022	4.4%	132	827	16.0%	45	792	5.7%
>=2 months	In Progress	0	0	0.0%	0	9	0.0%	5	30	16.7%	3	39	7.7%
	Denied	0	0	0.0%	0	0	0.0%	0	0	0.0%	1	1	100.0%
	Approved	0	0	0.0%	0	0	0.0%	0	0	0.0%	0	2	0.0%
	Cancelled	3	45	6.7%	2	46	4.3%	6	50	12.0%	3	38	7.9%
	Revised	0	0	0.0%	0	0	0.0%	0	0	0.0%	0	0	0.0%
	Active	0	4	0.0%	0	30	0.0%	3	35	8.6%	1	93	1.1%
	Completed	43	176	24.4%	15	438	3.4%	20	85	23.5%	5	226	2.2%
Total Submission		46	225	20.4%	17	523	3.3%	34	200	17.0%	13	399	3.3%

Even if an outage were submitted on time according to the transmission outage rules, it would not be modeled in the FTR model if it were submitted after the Annual FTR Auction bidding opening date. Table 12-45 shows that 62.5 percent of outage requests with duration longer than two weeks and shorter than two months labelled on time according to rules were submitted or rescheduled after the Annual FTR Auction bidding opening date in the 2016 to 2017 planning year. It also shows that 34.0 percent of outage requests with duration longer than or equal to two months labelled on time according to rules were submitted or rescheduled after the Annual FTR Auction bidding opening date in the 2016 to 2017 planning year.

Table 12-45 Transmission facility outage requests by received status and bidding opening date: Planning periods 2015 to 2016 and 2016 to 2017

	2015/2016						2016/2017					
	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	766	8,031	91.3%	181	8,633	97.9%	830	6,386	88.5%	134	5,706	97.7%
>=2 weeks & <2 months	316	537	63.0%	126	896	87.7%	310	517	62.5%	68	724	91.4%
>=2 months	131	94	41.8%	189	334	63.9%	132	68	34.0%	166	233	58.4%
Total	1,213	8,662	87.7%	496	9,863	95.2%	1,272	6,971	84.6%	368	6,663	94.8%

Table 12-46 shows that 78.9 percent of late outage requests which were submitted or rescheduled after the Annual FTR Auction bidding opening date were approved and complete in the 2016 to 2017 planning.

Table 12-46 Late transmission facility outage requests that are submitted after annual bidding opening date: Planning periods 2015 to 2016 and 2016 to 2017

	2015/2016			2016/2017		
Planned Duration	Completed Outages	Total	Percent	Completed Outages	Total	Percent
<2 weeks	7,407	8,633	85.8%	4,653	5,706	81.5%
>=2 weeks & <2 months	799	896	89.2%	497	724	68.6%
>=2 months	282	334	84.4%	110	233	47.2%
Total	8,488	9,863	86.1%	5,260	6,663	78.9%

Thus, although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the Annual FTR Auction bidding opening date, the rules have not worked to prevent this since the rule has no direct connection to the Annual FTR Auction opening date. 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. 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 but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent long-duration transmission outages submitted late. The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the Annual FTR Auction bidding opening date.

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 so that 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.[41]

In order to analyze the market impact, the outage requests that affect the operating day are compared: 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 the view of outages available to market participants. The day-ahead market model uses a list of outages as an input. The list of 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 impact on markets.

For example for the operating day of November 23, 2016, Figure 12-4 shows that: there were 421 approved or active outages seen by market participants before the day-ahead market was closed; there were 282 outage requests included in the day-ahead market model; there were 273 outage request included in both sets of outage; there were 148 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 9 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

41 PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p. 74

Figure 12-4 Illustration of day-ahead market analysis on November 22, 2016

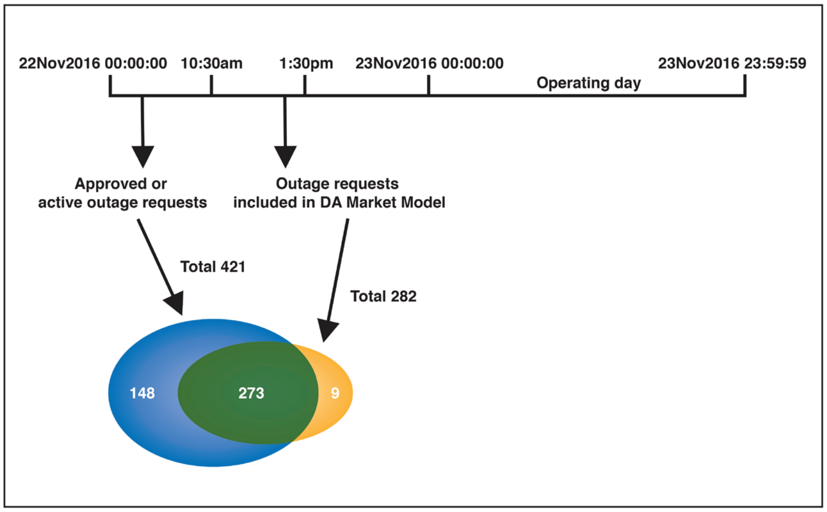


Figure 12-5 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

Figure 12-5 Weekly average number of approved or active outage requests comparing day-ahead market model outages: 2015 and 2016

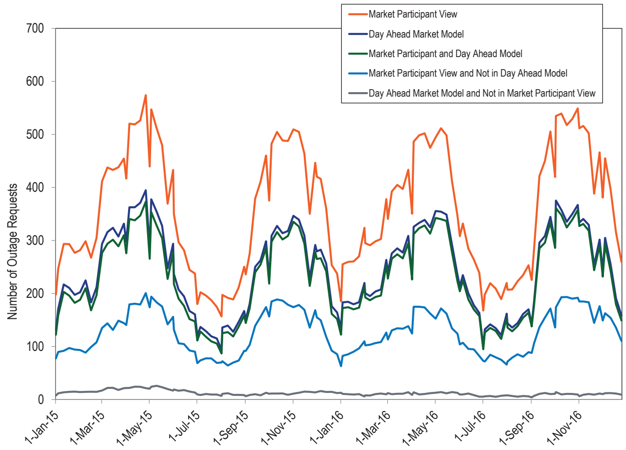


Figure 12-6 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-6 Weekly average number of day-ahead market model outages comparing outages occurred on operating day: 2015 and 2016

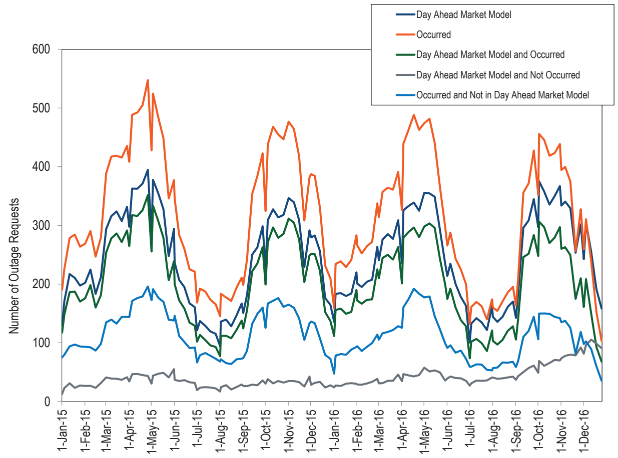


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-7 Weekly average number of approved or active outage requests comparing outages occurred on operating day: 2015 and 2016

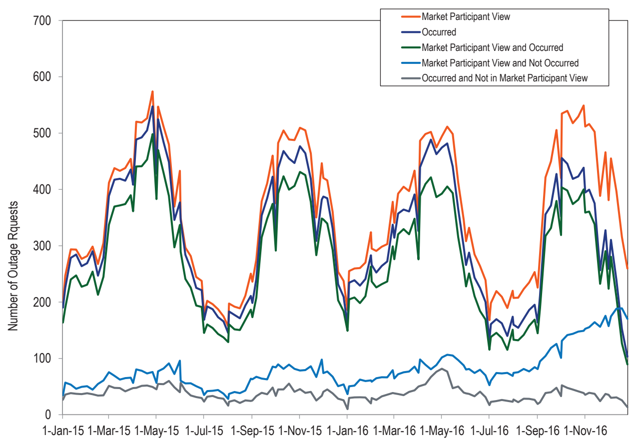


Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or approved outages available to day-ahead market participants are more consistent with the outages that actually occurred in real time than with the outages included in the day-ahead market model.

Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, subject to the ability of the transmission system to deliver that energy. When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. Prior to the introduction of LMP markets, contracts based on the physical rights associated with the transmission system were the mechanism used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through rates received the low cost generation.

After the introduction of LMP markets, financial transmission rights (FTRs) were introduced to permit the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system.[1] Financial transmission rights and the associated revenues were directly provided to loads in recognition of the facts that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated congestion revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source of the funds available to offset congestion costs in an LMP market.[2] Congestion is defined to be load payments in excess of generation revenues. Congestion revenues are the source of the funds to pay 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. 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. Congestion revenues are defined to be equal to the sum of day ahead and balancing congestion. FTRs are one way to do that.

Effective April 1, 1999, FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and balancing congestion to load. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). The load still owns the rights to congestion collected under this system, but the ARR construct allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights in the FTR auction in exchange for a revenue stream based on the prices of the FTRs. Under the ARR construct, all of the FTR auction revenues should belong to the load and all of the congestion revenues should belong to those that purchase or self schedule the FTRs.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 86.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2015 to 2016 planning period. One of the reasons for this inefficiency is the link, established by PJM member companies in their initial FTR filings, between congestion revenues and specific generation to load transmission paths. The original filings, made before PJM members had any experience with LMP markets, retained the view of congestion rooted in physical transmission rights. In an effort to protect themselves, the PJM utilities linked the payment of FTRs to specific, physical contract paths from specific generating units to specific load zones. That linkage was inconsistent with the appropriate functioning of FTRs in a nodal, network system with locational marginal pricing. The ARR allocation in 2015 continued to be based on those original physical generation to load paths, an illustration of the inadequacy of that approach and a source of the issues with the FTR model in 2015.

On September 15, 2016, FERC ordered PJM to address the allocation of congestion credits in the FTR market,

1 *See* 81 FERC ¶ 61,257, at 62,241 (1997).
2 *See Id.* at 62, 259–62,260 & n. 123.

portfolio netting within the FTR market and the use of historical resources for the Annual ARR allocation process.[3] PJM made a compliance filing on November 14, 2016, outlining their plans to address these issues.[4] Under the order, PJM will allocate the costs of balancing congestion and market-to-market payments to load and exports. PJM will allocate all excess congestion revenue from the day-ahead market to FTR holders. PJM will allocate excess auction revenue, which is what FTR holders were willing to pay for FTRs in excess of what is provided to ARR holders, to FTR holders. FERC ordered the continued use of portfolio netting with the corresponding cross subsidies among participants in the FTR market. FERC directed PJM to replace generation to load paths based on retired generation with generation to load paths based on existing generation resources.

If the original PJM FTR design had been designed to return congestion revenues to load without use of the generation to load paths, many of the subsequent issues with the FTR design would have been avoided. 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 *2016 State of the Market Report for PJM* focuses on the 2016 to 2017 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions for the 2014 to 2015 and 2015 to 2016 planning periods, covering January 1, 2016, through December 31, 2016.

Table 13-1 The FTR Auction Markets results were competitive

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

- Market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility. But it is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable.
- Market design was evaluated as flawed because there are significant flaws with the basic ARR/FTR design. The market design is not an efficient way to ensure that all congestion revenues are returned to load.

Overview

Auction Revenue Rights

Market Structure

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

  In the first seven months of the 2016 to 2017 planning period, PJM allocated a total of 39,233.4 MW of residual ARRs, up from 26,845.4 MW in the first seven months of the 2015 to 2016 planning period, with a total target allocation of $7.0 million for the first seven months of the 2016 to 2017 planning period, down from $7.5 million for the first seven months of the 2015 to 2016 planning period.
- **ARR Reassignment for Retail Load Switching.** There were 43,089 MW of ARRs associated with $504,600 of revenue that were reassigned in the first seven months of the 2015 to 2016 planning period. There were 27,920 MW of ARRs associated with $315,900 of revenue that were reassigned for the first seven months of the 2016 to 2017 planning period.

3 *See* 156 FERC ¶ 61,180 (2016).

4 *See* "Compliance Filing concerning Modifications to ARR and FTR Provisions," Docket No. EL16-6 (November 14, 2016).

Market Performance

- **Revenue Adequacy.** For the 2016 to 2017 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $911.4 million, while PJM collected $935.7 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2015 to 2016 planning period, the ARR target allocations were $931.6 million while PJM collected $968.1 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. The year over year decrease in ARR target allocations and auction revenue is a result of decreased prices from the previous planning period resulting from continued reduced allocation of Stage 1B and Stage 2 ARRs. ARR revenue adequacy is also affected by PJM's clearing of additional counter flow FTRs to alleviate infeasibilities from Stage 1A.
- **ARRs as an Offset to Congestion.** ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenue offset only 63.8 percent of total congestion costs, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2014 to 2015 planning period. In the first seven months of the 2016 to 2017 planning period, total ARR and self scheduled FTR revenues offset 82.3 percent of total congestion costs. The total offset for the last six planning periods is 70.9 percent. The goal of the design should be to return 100 percent of the congestion revenues to the load.

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2017 to 2020 Long Term FTR Auction include the St. John's transformer in Dominion and the Elliott-Rosewood Line in AEP. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2016 to 2017 planning period include the Rockwell-Congress Line in AEP and the Graves Mills-Reusens Line in AEP.

  Market participants can sell FTRs. In the 2017 to 2020 Long Term FTR Auction, total participant FTR sell offers were 208,405 MW, down from 327,980 in the 2016 to 2017 Long Term FTR Auction. In the 2016 to 2017 Annual FTR Auction, total participant sell offers were 378, 431 MW, down from 378,744 MW in the 2015 to 2016 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2016 to 2017 planning period, total participant FTR sell offers were 3,173,126 MW, up from 2,078,673 MW for the same period during the 2015 to 2016 planning period.
- **Demand.** In the 2017 to 2020 Long Term FTR Auction, total FTR buy bids were 2,176,871 MW, down 11.5 percent from 2,459,946 MW the previous planning period. There were 2,592,183 MW of buy and self-scheduled bids in the 2016 to 2017 Annual FTR Auction, up 5.3 percent from 2,461,662 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2016 to 2017 planning period increased 51.9 percent from 1,081,644 MW for the same time period of the prior planning period, to 1,642,735 MW.
- **Patterns of Ownership.** For the 2017 to 2020 Long Term FTR Auction, financial entities purchased 77.5 percent of prevailing flow FTRs and 84.9 percent of counter flow FTRs. For the 2016 to 2017 Annual FTR Auction, financial participants purchased 56.9 percent of all prevailing flow FTRs and 79.7 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 71.3 percent of prevailing flow and 74.6 percent of counter flow FTRs for January through December of 2016. Financial entities owned 64.2 percent of all prevailing and counter flow FTRs, including 55.8 percent of all prevailing flow FTRs and 76.0 percent of all counter flow FTRs during the period from January through December 2016.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first seven months of the 2016 to 2017 planning period were $0.4 million for Increment Offers, Decrement Bids and UTC Transactions using PJM's method. Using the proposed MMU approach, total FTR forfeitures would have been $0.6 million.

- **Credit Issues.** There was one collateral default in 2016 which was promptly resolved.

Market Performance

- **Volume.** The 2017 to 2020 Long Term FTR Auction cleared 297,083 MW (13.6 percent) of demand of FTR buy bids, up 7.1 percent from 277,397 MW (11.3 percent) in the 2016 to 2019 Long Term FTR Auction. The Long Term FTR Auction also cleared 36,782 MW (17.6 percent) of FTR sell offers, compared to 61,210 (18.7 percent), a 40.0 percent decrease.

  In the Annual FTR Auction for the 2016 to 2017 planning period 420,198 MW (16.2 percent) of buy and self-schedule bids cleared, up 11.1 percent from 378,328 MW (15.4 percent) for the previous planning period. In the first seven months of the 2016 to 2017 planning period Monthly Balance of Planning Period FTR Auctions 1,642,735 MW (11.0 percent) of FTR buy bids and 707,646 MW (22.3 percent) of FTR sell offers cleared.

- **Price.** The weighted-average buy-bid FTR price in the 2017 to 2020 Long Term FTR Auction was $0.04 per MW, down from $0.05 per MW for the 2016 to 2019 planning period. The weighted-average buy-bid FTR price in the Annual FTR Auction for the 2016 to 2017 planning period was $0.49 per MW, up from $0.31 per MW in the 2015 to 2016 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2016 to 2017 planning period was $0.13, down from $0.25 per MW for the same period in the 2015 to 2016 planning period.

- **Revenue.** The 2017 to 2020 Long Term FTR Auction generated $26.7 million of net revenue for all FTRs, up from $23.2 million for the 2016 to 2019 Long Term FTR Auction. The 2016 to 2017 Annual FTR Auction generated $909.0 million in net revenue, down from $936.3 million for the 2015 to 2016 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $26.7 million in net revenue for all FTRs for the first seven months of the 2016 to 2017 planning period, up from $17.3 million for the same time period in the 2015 to 2016 planning period.

- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first seven months of the 2016 to 2017 planning period. This high level of revenue adequacy was primarily a result of actions taken by PJM to reduce the level of available ARRs and FTRs. PJM's actions included PJM's decision to include more outages and PJM's decision to include additional constraints (closed loop interfaces) in the model, both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In 2016, FTRs were profitable overall, with $244.1 million in profits for physical entities, of which $207.0 million was gross revenue from self-scheduled FTRs, and $47.5 million for financial entities.

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
2017/2020 Long Term	6/1/2016	12/5/2016
2016/2017 ARR	2/29/2016	3/29/2016
2016/2017 Annual	4/5/2016	4/28/2016

Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the

purpose of improving FTR payout ratios.[5] (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2012. Status: Not adopted.)
- 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 implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Pending before FERC.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013. Status: Adopted partially, 14/15 planning period.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Adopted partially, 14/15 planning period.)
- 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. Status: Adopted 2016.)

Conclusion

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to firm transmission service customers, without requiring contract path physical transmission rights that are impossible to define and enforce in LMP markets. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service which results in load paying congestion revenues.

After the introduction of LMP markets, financial transmission rights (FTRs) permitted the loads which pay for the transmission system to continue to receive the benefits of firm low cost generation delivered using the transmission system in the form of revenues which offset congestion. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load and loads pay congestion. Another way of describing the result is that FTRs and the associated revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source congestion revenues in an LMP market. In other words, load payments in excess of generation revenues are the source of the funds to pay 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 to pay back to load the difference between the total load payments and the total generation revenues, which equals total congestion revenues.

With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm

5 See PJM. "Manual 6: Financial Transmission Rights" Revision 17 (June 1, 2016), p. 55.

transmission service and FTR holders do not have the right to revenue adequacy.

As a result of the creation of ARRs and other changes to the design, the current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all the congestion revenues and has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 63.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period. For the 2015 to 2016 planning period, ARRs and self scheduled FTRs offset 86.5 percent of total congestion costs. For the first seven months of the 2016 to 2017 planning period ARRs and self scheduled FTRs offset 82.3 percent of total congestion costs.

Load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[6] One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach would ignore the fact that loads must pay both day-ahead and balancing congestion and that congestion is defined, in an accounting sense, to equal the sum of day ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system, would have to continue paying in excess of generator revenues and not have balancing congestion included in the calculation of congestion in order to increase the payout to holders of FTRs who are not loads and who therefore did not receive an allocation of ARRs. In other words, load would have to continue providing all the funding of FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths and result in profits to FTR holders.

The Commission's order will shift substantial revenue from load to the holders of FTRs and reduce the ability of load to offset congestion. If these rules had been in place for the first seven months of the 2016 to 2017 planning period, and ARR/FTR allocations had remained constant, ARR holders would have gone from an offset of 82.3 percent under the current rule, to 77.4 percent under the new rule, a loss of $43.8 million for the first seven months. FTR holders would have received a corresponding windfall and revenues to FTR holder would have exceeded target allocations by $130.7 million.

If these rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received $996.7 million less in congestion offsets from the 2011/2012 through the 2016/2017 planning period. The total overpayment to FTR holders for the 2011/2012 through 2016/2017 planning period would have been $896.1 million. The underpayment to load and the overpayment to FTR holders is a result of several factors in the new rules all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is now required to pay for balancing congestion, which significantly increases costs to load and significantly increases revenues paid to FTR holders. PJM will continue to clear counter flow FTRs using excess auction revenues in order to make it possible to sell more prevailing flow FTRs. FTR holders will receive excess day-ahead congestion revenues in excess of target allocations. FTR holders will receive excess auction revenue, which is what FTR holders were willing to pay for FTRs in excess of what is provided to ARR holders.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reporting, distribution of and quantity of funding in the FTR market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy even when defined correctly. Load does have those rights based on load's payment for the transmission system and load's payment of total congestion.

Reported FTR revenue adequacy uses target allocations as the relevant benchmark. But target allocations are not the relevant benchmark. Target allocations are based on day-ahead congestion only, ignoring balancing congestion which is the other part of total congestion. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and balancing markets.

6 See "FirstEnergy Solutions Corp. Allegheny Energy Supply Company, LLC v PJM Interconnection, LLC," Docket No. EL13-47-000 (February 15, 2013).

When day-ahead congestion differs significantly from balancing congestion, as has occurred only in recent years, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences between the day-ahead and real-time markets. Such differences are not an indication that FTR holders are under paid.

PJM used a more conservative approach to modeling the transmission capability for the 2014 to 2015 through 2016 to 2017 planning periods compared to the 2013 to 2014 planning period. PJM simply used higher outage levels and included additional constraints, both of which reduced system capability in the FTR auction model. The result was a significant reduction in Stage 1B and Stage 2 ARR allocations, and a corresponding reduction in the available quantity of FTRs, an increase in FTR prices and an increase in ARR target allocations. The market response to the reduced supply of FTRs was increased bid prices, increased clearing prices and reduced clearing quantities.

Clearing prices fell and cleared quantities increased from the 2010 to 2011 planning period through the 2013 to 2014 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid volumes and offer volumes. In the 2014 to 2015 and 2015 to 2016 planning periods, due to reduced ARR allocations, FTR volume decreased relative to the 2013 to 2014 planning period. The reduction in ARR allocations and resulting FTR volume caused, by definition, an improvement in revenue adequacy, and also resulted in an increase in the prices of FTRs. Increased FTR prices resulted in increased ARR target allocations, because ARR target allocations are based on the Annual FTR Auction nodal prices.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge. The FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the portfolio subsidy would be a good first step in that direction.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2013 to 2014 planning period would have been 87.5 percent instead of the reported 72.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the impact of lower payouts among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. The FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the counter flow subsidy would be another good step in that direction.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would have increased the calculated payout ratio in the 2013 to 2014 planning period from the reported 72.8 percent to 91.0 percent. For the 2014 to 2015 and 2015 to 2016 planning period the payout ratio was 100 percent. The MMU recommends that counter flow and prevailing flow FTRs be treated symmetrically with respect to the application of a payout ratio.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. Stage 1A ARR overallocation is a source of revenue inadequacy and cross subsidy. The origin and basis for the requirement to assign Stage 1A ARRs needs further investigation. The issues associated with over allocation are based on the use of out of date generation to load ARR paths and on whether PJM has appropriately built transmission to meet the requirement.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit, that the role of out of date generation to load paths be reviewed and that the building of the transmission capability required to provide all defined Stage 1A allocations be reviewed. There is a reason that transmission is not built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR overallocation in the 2013 to 2014 planning period would have increased the payout ratio to 94.6 percent without reducing ARR allocations in Stage 1B and Stage 2.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. These reasons include the inadequate transmission outage modeling in the FTR auction model which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day-ahead and real-time markets, including reactive interfaces, which directly results in differences in congestion between day-ahead and real-time markets; differences in day-ahead and real-time modeling including different line ratings, the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load, which directly results in differences in congestion between day-ahead and real-time markets; the overallocation of ARRs which directly results in a difference between congestion revenue and the payment obligation; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up to congestion transactions to the differences between day-ahead and balancing congestion and thus to FTR payout ratios; the payment of congestion revenues to UTCs; and the continued sale of FTR capability on pathways with a persistent difference between FTRs and total congestion revenue. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion.

It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed away.

For the 2014 to 2015 and 2015 to 2016 planning periods FTRs have been revenue adequate. This is not because the underlying problems have been fixed. Revenue adequacy has been accomplished by limiting the amount of available ARRs and FTRs by arbitrarily decreasing the ARR allocations for Stage 1B and Stage 2 which also results in a redistribution of ARRs based on differences in allocations between Stage 1A and Stage 1B ARRs.

Auction Revenue Rights

ARRs are the financial instruments through which the proceeds from FTR Auctions are allocated to load based on load's payment for the transmission system and for load's payment of congestion. ARR values are based on nodal price differences between the ARR source and sink points.[7] These price differences are based on the bid prices of participants in the Annual FTR Auction. The auction clears the set of feasible FTR bids which produce the highest net revenue. ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences and the associated level of revenue adequacy.

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 sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the price difference between sink and source, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than the sum of all ARR target allocations, ARRs are fully funded. If these revenues are less than the sum of all ARR target allocations, available revenue is proportionally allocated among all ARR holders. If there are excess ARR revenues, the excess revenue is given pro rata to FTR holders.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives the rights to all the congestion revenues, and has the ability to receive the auction revenues associated with all the potential congestion revenues. The MMU recommends that all FTR auction revenues be allocated to ARR holders.

When a new control zone is integrated into PJM, firm transmission customers in that control zone may choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are not eligible for directly allocated FTRs. Network service users and firm transmission customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the new control zone. During this transitional period, the directly allocated FTRs are reallocated, as load shifts between LSEs within the transmission zone.

Incremental ARRs (IARRs) are allocated to customers that have been assigned cost responsibility for certain upgrades included in the PJM's Regional Transmission Expansion Plan (RTEP). These customers as defined in Schedule 12 of the Tariff are network service customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each regionally assigned facility and allocates the IARRs, if any are created by the upgrade, to eligible customers based on their percentage of cost responsibility. The customers may choose to decline the IARR allocation during the annual ARR allocation process.[8] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone.

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 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 to 2008 and subsequent planning periods through the present, all eligible market participants were allocated ARRs.

Supply and Demand

ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible. The top ten binding transmission constraints for the 2014 to 2015 planning period are shown in Table 13-3.

7 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

8 PJM. "Manual 6: Financial Transmission Rights," Revision 17 (June 1, 2016), pp. 31 and "IARRs for RTEP Upgrades Allocated for 2016/2017 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2016-2017/2016-2017-iarrs-for-rtep-upgrades-allocated.ashx>.

ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[9] Long Term ARRs can give LSEs the ability to offset their congestion costs on a long-term basis. Long Term ARR holders can self schedule their Long Term ARRs as FTRs for any planning period during the 10 planning period timeline.

Each March, PJM allocates ARRs to eligible customers in a three-stage process:

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain ARRs, up to their share of zonal base load, based on generation to load paths that reflect generation resources that had served load prior to markets in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[10] While transmission upgrades are being implemented, Stage 1A ARRs, and therefore FTRs, are overallocated.
- **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation for the following planning period. Network transmission service customers can obtain ARRs, up to their share of zonal peak load, based on generation to load paths that reflect generation resources that had served load prior to markets in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. 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. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.
- **Stage 2.** Stage 2 of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. 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 for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[11] Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015 to 2016 planning period, when residual zone pricing was introduced, an ARR will default to sinking at the load settlement point, but the ARR holder may elect to sink their ARR at the physical zone instead.[12]

ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on assumptions about the configuration and availability of transmission capability during the planning period.[13] PJM may also adjust the outages modeled, adjust line limits and account for potential closed loop interfaces

9 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.
10 See PJM. "Manual 6: Financial Transmission Rights" Revision 17 (June 1, 2016), p. 22.
11 See PJM. "Manual 6: Financial Transmission Rights," Revision 17 (June 1, 2016), pp. 21.
12 *See* "Residual Zone Pricing," PJM Presentation to the Members Committee (February 23, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mc/20120223/20120223-item-03-residual-zone-pricing-presentation.ashx>.
13 PJM. "Manual 6: Financial Transmission Rights," Revision 17 (June 1, 2016), pp. 55-56.

to address expected revenue issues. The simultaneous feasibility requirement is necessary to ensure that there are adequate revenues from congestion charges to satisfy all resulting ARR obligations. If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints, except Stage 1A ARRs:

Equation 13- 1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) X (Individual requested MW / Total requested MW) X (1 / MW effect on line).[14]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power flow on the binding constraint. The PJM methodology prorates ARR requests in proportion to their MW value and the impact on the binding constraint. PJM's method results in the prorating only of ARRs that cause the greatest flows on the binding constraint. Were all ARR requests prorated equally, regardless of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs.

Table 13-3 shows the top 10 principal binding transmission constraints that limited the 2015 to 2016 ARR Stage 1A allocation. PJM was required to increase capability limits for several facilities in order to make the ARR allocation feasible.[15]

Table 13-3 Top 10 principal binding transmission constraints limiting the Annual ARR Allocation: Planning period 2015 to 2016

Constraint	Type	Control Zone
Breed - Wheatland	Flowgate	MISO
Wheatland - Petersburg	Flowgate	MISO
Wempletown	Transformer	ComEd
Nelson - Electric Junction	Flowgate	MISO
Cherry Valley - Silverlake	Flowgate	MISO
Pana North	Flowgate	MISO
Nelson - Cordova	Line	ComEd
Pana North	Flowgate	MISO
Cherry Valley	Transformer	ComEd
Pontiac Midpoint - Wilton Ctr.	Flowgate	ComEd

14 See the *MMU Technical Reference for PJM Markets*, at "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

15 It is a requirement of Section 7.4.2 (i) in the OATT that any ARR request made in Stage 1A must be feasible and transmission capability must be raised if an ARR request is found to be infeasible.

FERC Order on EL16-121: Stage 1A ARR Allocation

FERC ordered PJM to more accurately represent system usage when allocating Stage 1A ARRs by removing retired resources from their allocation methodology.[16] PJM made a compliance filing, accepted by FERC, stating that retired units would be replaced with qualified replacement resources (QRRs).[17] PJM proposed to categorize QRRs as built under a rate base approach or a non-rate base (market) approach. PJM proposed to give priority to load delivery from their own rate based units in deciding between competing ARR claims.

Under the new allocation methodology, PJM will replace retired units or units whose ICAP is less than their historical capacity with QRRs. A QRR will be a unit, or combination of units, whose ICAP value can meet the historically allocated MW quantity that was allocated based on the retired resource. QRRs will be classified as rate base or non-rate base units and ranked by rate base/non-rate base and by economics within each category. Participants will have to provide evidence that a unit is a rate-base unit to qualify for the designation in the Stage 1A ARR allocation. PJM will assign the historical MW to rate base QRRs within the zone, and then intra zonally to all generation units to replace retired resource capacity. These reassignments must all pass the simultaneous feasibility test.

The method PJM has proposed continues to rely on a contract path based approach. PJM is not applying this method to all Stage 1A units, so over allocations may persist. Existing, non-retired, Stage 1A resources will still be given their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources will be prorated based on the feasibility of these of ARRs after existing resources are allocated. As a result of this proration, the new ARRs will have lower priority than the non-retired Stage 1A resources, which could affect the value of the newly assigned ARRs.

16 156 FERC ¶ 61,180 (2016).

17 See FERC Docket No. EL16-6-003.

FTR Revenue Adequacy and Stage 1B/Stage 2 ARR Allocations

For the 2014 to 2015 and 2015 to 2016 planning periods, FTR revenue adequacy was over 100 percent. Not every month was revenue adequate, but there was excess revenue from other months to ensure that the planning period was revenue adequate. The last time there were four months of consecutive funding of 100 percent or more was in the 2009 to 2010 planning period.

This high level of revenue adequacy was primarily due to actions taken by PJM to address prior low levels of revenue adequacy. PJM's actions included PJM's arbitrary use of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs.

While PJM's approach to outages in the Annual FTR Auction reduces revenue inadequacy, which was caused in part by Stage 1A ARR overallocations, it does not address the Stage 1A ARR overallocation issue directly, and has resulted in decreased Stage 1B ARR allocations through proration, decreased Stage 2 ARR allocations through proration and decreased FTR capability. Stage 1A ARRs were not affected by PJM's assumption of increased outages because they cannot be prorated.

Figure 13-1 shows the historic allocations for Stage 1B and Stage 2 ARRs from the 2011 to 2012 to 2016 to 2017 planning periods. There was an 84.9 percent decrease in Stage 1B ARRs allocated and an 88.1 percent decrease in total Stage 2 ARR allocations from the 2013 to 2014 planning period to the 2014 to 2015 planning period. Total Stage 1B and Stage 2 ARR allocations increased slightly in the 2015 to 2016 planning year over the 2014-2015 planning year allocations, from 3,497.6 MW to 5,219.6 MW. But the ARR allocations for the 2015-2016 planning year were still 78.8 percent below 2013 to 2014 planning period volumes of 34,444.0 MW. For the 2016 to 2017 planning period there was another relatively small increase in available Stage 1B and Stage 2 capacity from 5,319.6 MW to 12,821.6 MW, but available ARRs were still 48.9 percent below 2013 to 2014 planning period volumes.

Figure 13-1 Historic Stage 1B and Stage 2 ARR Allocations from the 2011 to 2012 through 2016 to 2017 planning periods

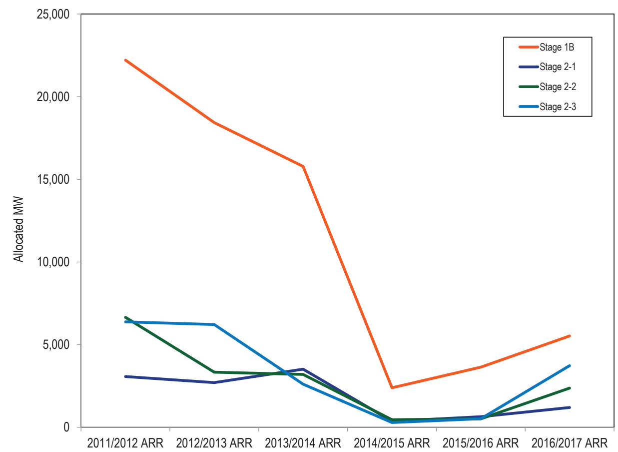


Table 13-4 shows the ARR allocations for the 2011 to 2012 through 2016 to 2017 planning periods. Stage 1A allocations cannot be prorated and have been slowly increasing. Stage 1B and Stage 2 allocations can be prorated. Stage 1B and Stage 2 allocations were steadily declining over the 2011 to 2012 through 2013 to 2014 planning periods, but were very significantly reduced in the 2014 to 2015 planning period as a result of PJM's arbitrary increase in modeled outages designed to increase revenue adequacy. There was a small increase in Stage 1B and Stage 2 ARR volume from the 2014 to 2015 planning period to the 2015 to 2016 planning period and a small increase for the 2016 to 2017 planning period. These incremental increases are the result of PJM making more ARRs available based on excess revenue in the previous planning period.

Table 13-4 Historic Stage 1B and Stage 2 ARR Allocations from the 2011 to 2012 through 2016 to 2017 planning periods

Stage	2011/2012 ARR	2012/2013 ARR	2013/2014 ARR	2014/2015 ARR	2015/2016 ARR	2016/2017 ARR
Stage 1A	64,159.9	67,299.6	67,861.4	68,837.7	71,874.0	68,729.1
Stage 1B	22,208.3	18,431.7	15,782.0	2,389.6	3,643.1	5,525.7
Stage 2-1	3,072.5	2,700.6	3,519.2	360.9	643.8	1,197.1
Stage 2-2	6,652.6	3,334.3	3,200.0	455.9	511.2	2,368.8
Stage 2-3	6,382.6	6,218.7	2,611.8	291.2	521.5	3,730.0
Total Stage 2	16,107.7	12,253.6	9,331.0	1,108.0	1,676.5	7,295.9

Table 13-5 shows the top 10 principal binding transmission constraints that limited the 2016 to 2017 ARR Stage 1A allocation. PJM was required to increase capability limits for several facilities in order to make the ARR allocation feasible.[18]

Table 13-5 Top 10 principal binding transmission constraints limiting the Annual ARR Allocation: Planning period 2016 to 2017

Constraint	Type	Control Zone
Nucore - Whitestown	Flowgate	MISO
Monroe - Bayshore	Flowgate	MISO
Pana North	Flowgate	MISO
Nelson - Electric Junction	Flowgate	MISO
Cherry Valley - Silverlake	Flowgate	MISO
Nelson - Electric Junction	Flowgate	MISO
Churchtown	Transformer	AECO
Pierce - Foster	Flowgate	MISO
Byron - Cherry Valley	Flowgate	MISO
Pana North	Flowgate	MISO

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned to follow that load.[19] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying 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 55,638 MW of ARRs associated with $659,000 of revenue that were reassigned in the 2015 to 2016 planning period. There were 27,920 MW of ARRs associated with $315,900 of revenue that were reassigned for the first seven months of the 2016 to 2017 planning period.

Table 13-6 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2015 and December 2016.

Table 13-6 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2015, through December 31, 2016

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2015/2016 (12 months)	2016/2017 (7 months)	2015/2016 (12 months)	2016/2017 (7 months)
AECO	594	274	$4.5	$2.6
AEP	7,145	1,381	$72.0	$8.4
AP	2,171	936	$51.8	$19.5
ATSI	7,077	3,773	$66.7	$20.6
BGE	3,044	1,673	$95.7	$98.9
ComEd	5,433	2,005	$133.0	$66.8
DAY	624	473	$1.3	$1.4
DEOK	6,489	1,428	$31.5	$8.4
DLCO	6,179	4,117	$13.1	$10.0
DPL	1,628	1,155	$55.2	$23.0
Dominion	20	55	$0.3	$0.2
EKPC	0	0	$0.0	$0.0
JCPL	1,629	655	$12.4	$2.1
Met-Ed	1,081	474	$9.4	$4.1
PECO	4,189	2,735	$23.8	$6.2
PENELEC	1,277	848	$21.8	$12.7
PPL	3,341	3,320	$18.6	$3.7
PSEG	1,569	965	$37.5	$13.4
Pepco	2,098	1,619	$10.4	$13.9
RECO	52	35	$0.0	$0.0
Total	55,638	27,920	$659.0	$315.9

18 It is a requirement of Section 7.4.2 (i) in the OATT that any ARR request made in Stage 1A must be feasible and transmission capability must be raised if an ARR request is found to be infeasible.

19 See PJM. "Manual 6: Financial Transmission Rights," Revision 17 (June 1, 2016), p. 28.

Incremental ARRs (IARRs) for RTEP Upgrades

Table 13-7 lists the IARR allocation MW for the planning periods from the 2008 to 2009 planning period through the 2016 to 2017 planning period. This table includes IARRs from RTEP projects and IARRs from other projects.

Table 13-7 IARR allocation volume: Planning periods 2008 to 2009 through 2016 to 2017

Planning Period	Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	890.5	890.5	100%	0	0%
2009/2010	14	530.5	530.5	100%	0	0%
2010/2011	14	530.5	530.5	100%	0	0%
2011/2012	15	595.0	595.0	100%	0	0%
2012/2013	15	687.4	687.4	100%	0	0%
2013/2014	17	1,087.4	1,087.4	100%	0	0%
2014/2015	18	1,447.4	1,447.4	100%	0	0%
2015/2016	17	1,290.5	1,290.5	100%	0	0%
2016/2017	18	1,447.4	1,447.4	100%	0	0%

Table 13-8 lists the three RTEP upgrade projects that were allocated a total of 678.2 MW of IARRs for the 2016 to 2017 planning period.

Table 13-8 IARRs allocated for the 2015 to 2016 Annual ARR Allocation for RTEP upgrades

		IARR Parameters		
Project #	Project Description	Source	Sink	Total MW
B0287	Install 600 MVAR Dynamic Reactive Device at Elroy 500kV	RTEP B0287 Source	DPL	190.6
B0328	TrAIL Project: 502 JCT - Loudoun 500kV	RTEP B0328 Source	Pepco	391.2
B0329	Cason-Suffolk 500 kV	RTEP B0329 Source	Dominion	96.4

Residual ARRs

Residual ARRs are available if transmission system capability is added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs are effective on the first day of the month in which the additional transmission system capability is included in FTR auctions and exist until the end of the planning period. For the following planning period, any Residual ARRs are available as ARRs in the annual ARR allocation. Residual ARRs are a separate product from incremental ARRs.

Only ARR holders that had their Stage 1 ARRs prorated are eligible to receive Residual ARRs which cannot be declined, with positive or negative target allocations. Stage 1 ARR holders have a priority right to ARRs. Effective August 1, 2012, Residual ARRs are also available for eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility becomes available during the modeled year. Residual ARRs awarded due to outages are effective for single, whole months and cannot be self scheduled. ARR target allocations are based on the clearing prices from FTR obligations in the effective 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.

Table 13-9 shows the Residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month. In the first seven months of the 2016 to 2017 planning period planning period, PJM allocated a total of 21,600.4 MW of residual ARRs, down from 34,537.6 MW for the first seven months of the 2015 to 2016 planning period. Residual ARRs had a total target allocation of $4.2 million for the first seven months of the 2016 to 2017 planning period, down from $5.9 million for the first seven months of the 2015 to 2016 planning period. Some ARRs that were previously allocated in Stage 1B are now being allocated as Residual ARRs on a month to month basis without the option to self schedule.

Table 13-9 Residual ARR allocation volume and target allocation: 2016

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-16	6,710.0	2,992.7	44.6%	$1,732,883
Feb-16	4,317.0	3,781.0	87.6%	($669,918)
Mar-16	6,422.8	3,935.0	61.3%	$746,442
Apr-16	5,490.3	3,769.5	68.7%	$44,884
May-16	4,329.3	3,154.8	72.9%	$897,905
Jun-16	4,596.8	2,978.5	64.8%	$501,311
Jul-16	5,802.8	3,084.0	53.1%	$394,249
Aug-16	6,355.5	3,658.1	57.6%	$353,280
Sep-16	3,932.2	3,277.5	83.4%	$780,618
Oct-16	8,784.6	3,643.7	41.5%	$562,507
Nov-16	3,690.4	2,553.8	69.2%	$651,587
Dec-16	4,748.3	2,404.8	50.6%	$999,086
Total	65,180.0	39,233.4	60.2%	$6,994,833

Market Performance

Volume

Table 13-10 shows the MW of ARR allocations for each round of the 2015 to 2016 and 2016 to 2017 planning periods. The percent cleared for the 2016 to 2017 planning period increased 2.7 percentage points from the previous planning period.

Table 13-10 Annual ARR Allocation volume: planning periods 2015 to 2016 and 2016 to 2017

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2015/2016	1A	0	21,508	71,874	71,874	100.0%	0	0.0%
	1B	1	14,915	38,848	3,643	9.4%	35,205	90.6%
	2	2	5,849	26,710	644	2.4%	26,066	97.6%
		3	4,773	25,900	511	2.0%	25,389	98.0%
		4	4,326	25,986	522	2.0%	25,464	98.0%
		Total	14,948	78,596	1,677	2.1%	76,919	97.9%
	Total		51,371	189,318	77,194	40.8%	112,124	59.2%
2016/2017	1A	0	21,824	68,729	68,729	100.0%	0	0.0%
	1B	1	15,508	36,569	5,526	15.1%	31,043	84.9%
	2	2	5,784	27,942	1,197	4.3%	26,745	95.7%
		3	5,203	27,118	2,369	8.7%	24,749	91.3%
		4	5,070	27,080	3,730	13.8%	23,350	86.2%
		Total	16,057	82,140	7,296	8.9%	74,844	91.1%
	Total		53,389	187,438	81,551	43.5%	105,887	56.5%

For the 2016 to 2017 planning period, Stage 1A of the Annual ARR Allocation was infeasible. 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 PJM 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.

The result of this required increased capability in the models is an overallocation of both ARRs and FTRs for the entire planning period and an associated reduction in ARR and FTR funding. Table 13-11 shows the MW quantity and count of overloaded facilities and the reasons for the modeled overload.

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required to ensure that the long term ARRs can remain feasible. 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.[20]

There is a reason that transmission is not actually built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

Table 13-11 Overloaded facility type and reason: 2016/2017 planning period

Reason	Type	MW	Count
Network Load	M2M Flowgate	5,106	75
Network Load	Pseudo Tie Flowgate	2,238	64
Internal PJM	Transmission Outage	751	20

In order to eliminate the infeasibilities for the requested Stage 1A ARR allocations, PJM was required to raise the modeled capacity limits on 159 facilities, 20 of which were internal to PJM and the rest were in MISO, a total of 8,095 MW.[21]

Figure 13-2 shows the predicted and estimated impact of Stage 1A infeasibilities on funding for the 2012 to 2013 through 2015 to 2016 planning periods, as well as the predicted impact on funding for the 2016 to 2017 planning period. The predicted funding is based on the infeasible ARR MW and the nodal price of the source and sink in the Annual FTR Auction. The estimated funding is calculated assuming every infeasible ARR MW is self scheduled, and uses the hourly congestion

20 PJM. "Manual 6: Financial Transmission Rights," Revision 17 (June 1, 2016), p22.

21 PJM 2016/2017 Stage 1A Over allocation notice, PJM FTRs, <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2016-2017/2016-2017-stage-1a-over-allocation-notice.ashx> (January 25, 2017).

LMP values. In the 2015 to 2016 planning period, Stage 1A ARR infeasibilities accounted for $304.7 million in over allocation.

Figure 13-2 Stage 1A Infeasibility Funding Impact

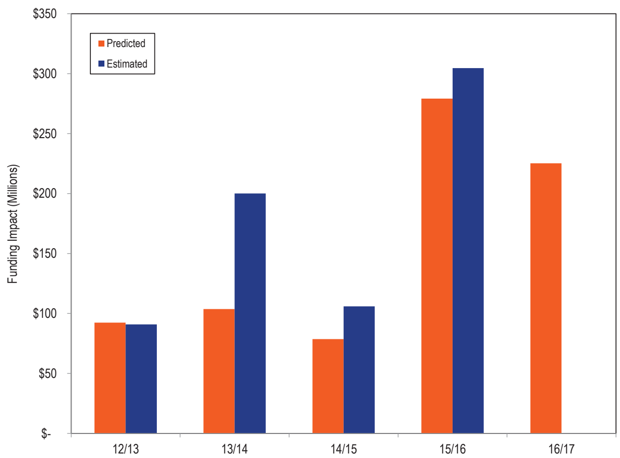
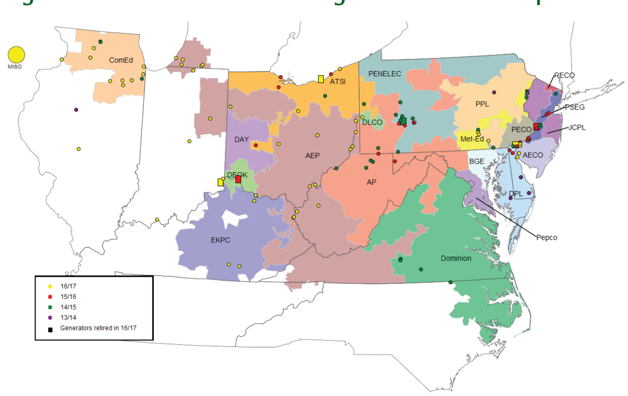


Figure 13-3 shows a map of over allocated ARR source points in Stage 1A, regardless of reason, for the 2013 to 2014 through 2016 to 2017 planning periods. The year indicated for each source point is the latest year that source was announced as over allocated in the Stage 1A process. Generators retired as of the 2016 to 2017 planning period are indicated by a square marker to show Stage 1A source points that are no longer in service for the most recent Stage 1A allocation period.

Figure 13-3 Overallocated Stage 1A ARR source points



Revenue

ARRs are allocated to qualifying customers rather than sold, so there is no ARR revenue comparable to the revenue that results from the FTR auctions.

Revenue Adequacy

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as an offset to total congestion. Revenue adequacy is a narrower concept that compares the revenues available to ARR holders to the value of ARRs as determined in the Annual FTR Auction. ARRs have been revenue adequate for every auction to date. Customers that self schedule ARRs as FTRs have the same revenue adequacy characteristics as all other FTRs.

ARR holders received $968.1 million in credits from the FTR auctions during the 2015 to 2016 planning period before accounting for self scheduling, load shifts or residual ARRs. The FTR auction revenue collected pays ARR holders' credits. During the first seven months of the 2016 to 2017 planning period, ARR holders received $935.7 million in ARR credits.

Table 13-12 lists projected ARR target allocations from the Annual ARR Allocation and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2015 to 2016 planning period and the first seven months of the 2016 to 2017 planning periods.

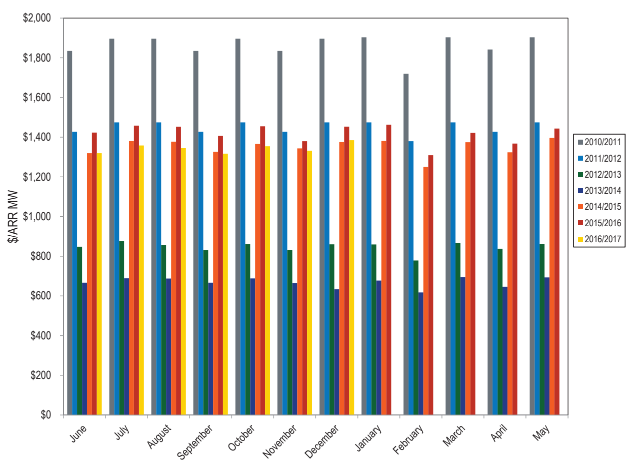
Table 13-12 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 2015 to 2016 and 2016 to 2017

	2015/ 2016	2016/ 2017
Total FTR auction net revenue	$968.1	$935.7
Annual FTR Auction net revenue	$936.3	$909.0
Monthly Balance of Planning Period FTR Auction net revenue*	$31.8	$26.7
ARR target allocations	$931.6	$911.4
ARR credits	$931.6	$911.4
Surplus auction revenue	$36.5	$24.3
ARR payout ratio	100%	100%
FTR payout ratio*	100%	100%

* Shows twelve months for 2015/2016 and seven months for 2016/2017.

Figure 13-4 shows the dollars per ARR MW held for each month of the 2010 to 2011 planning period through the first seven months of the 2016 to 2017 planning periods. The ARR MW held do not include self-scheduled FTRs and do include Residual ARRs starting in August 2012. FTR prices increased in the 2014 to 2015 Annual FTR Auction as a result of reduced supply caused by PJM's assumption of more outages in the model used to allocate Stage 1B and Stage 2 ARRs. The increased FTR prices resulted in an increase in dollars paid per ARR MW. For the 2014 to 2015 planning period, the total dollars per MW of ARR allocation was $11,279, while the previous planning period resulted in a dollars per MW of $6,692, a 68.5 percent increase in payment per allocated ARR MW. Some of the ARR MW lost from proration were provided in the Residual ARR process, but the residual allocations are not comparable to the ARRs awarded in the annual process because residual ARR allocations change each month and cannot be self scheduled as FTRs. For the 2015 to 2016 planning period, the dollars per MW of ARR allocation was $10,641.54. For the first seven months of the 2016 to 2017 planning period, the dollars per MW of ARR allocation were $7,180.49 down from $7,739.36 in the first seven months of the 2015 to 2016 planning period. Total dollars per MW were down slightly in the 2016 to 2017 planning period due to increased Stage 1B and Stage 2 ARR volume.

Figure 13-4 Dollars per ARR MW paid to ARR holders: Planning periods 2010 to 2011 through 2016 to 2017



Excess Auction Revenue

Figure 13-5 shows the monthly excess auction revenue from the 2011 to 2012 through 2015 to 2016 planning periods. Excess auction revenue is the revenue collected each month from FTR auctions in excess of ARR target allocations.

Beginning with the 2014 to 2015 planning period, market rules allow PJM to decrease prevailing flow target allocations by clearing counter flow FTRs, without making the opposite prevailing flow FTR available, as long as ARRs remain revenue adequate.[22] This allows PJM to use the excess auction revenue to pay prevailing flow FTRs without increasing prevailing flow obligations. The result is to increase FTR funding. This action removes money from the ARR revenue stream and caused the decrease in excess ARR revenue beginning in June 2014. Excess auction revenue is allocated pro rata to FTR holders at the end of the planning period, instead of being distributed to ARR holders.

Figure 13-5 Monthly excess ARR revenue: Planning periods 2011 to 2012 through 2016 to 2017

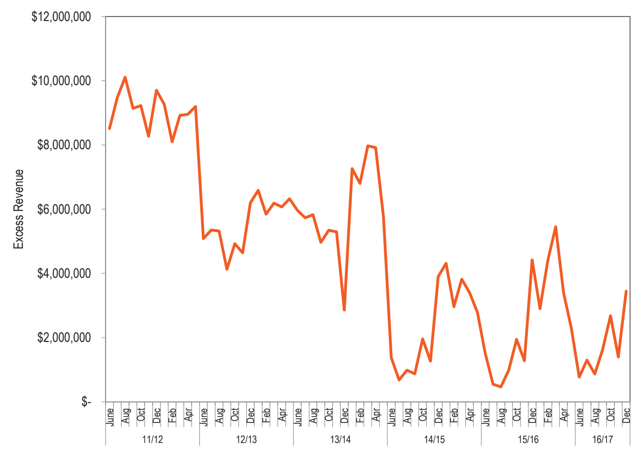


Table 13-13 shows the excess auction revenue, by planning period, for planning periods 2010 to 2011 through 2016 to 2017.

Table 13-13 Excess Auction Revenue: Planning periods 2010 to 2011 through 2016 to 2017

Planning Period	Excess Auction Revenue
2010/2011	$29,704,562
2011/2012	$80,083,695
2012/2013	$66,652,822
2013/2014	$71,687,937
2014/2015*	$29,045,590
2015/2016	$29,612,591
2016/2017**	$12,093,742
Total	$318,880,939

*Start of counter flow "buy back"

**Through December 31, 2016

22 *See* PJM. "Manual 6: Financial Transmission Rights" Revision 17 (June 1, 2016), p. 55.

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, subject to total congestion revenue including day-ahead and balancing congestion. The value of the day-ahead congestion price differences, termed the FTR target allocation, defines the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in day-ahead congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses.

Auction market participants are free to request FTRs between any eligible pricing nodes on the system. For the Long Term FTR Auction a list of available hubs, control zones, aggregates, generator buses and interface pricing points is available. For the Annual FTR Auction and FTRs bought for a quarterly period in the monthly auction the available FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. An FTR bought in the Monthly FTR Auction for the single calendar month following the auction may include any bus for which an LMP is calculated in the FTR model used. Effective August 5, 2011, PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The target allocation of an FTR can be positive or negative depending on the sink minus source congestion price difference, with a negative difference resulting in a liability for the holder. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. Revenues above that level on individual FTR paths are used to fund FTRs on paths which received less than their target allocations.

Available revenue to pay FTR holders is based on the amount of day-ahead and balancing congestion collected, payments by holders of negatively valued FTRs, Market to Market payments, excess ARR revenues available at the end of a month and any charges made to day-ahead operating reserves. Depending on the amount of revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations.

FTR funding is not on a path specific basis or on a time specific basis. There are widespread cross subsidies paid to equalize payments across paths and across time periods within a planning period. All paths receive the same proportional level of target revenue at the end of the planning period. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year.

FTRs can be bought, sold and self scheduled. Buy bids are bids to buy FTRs in the auctions; sell offers are offers to sell existing FTRs in the auctions; and self-scheduled bids are FTRs that have been directly converted from ARRs in the Annual FTR Auction.

There are two types of FTR products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three classes of FTR products: 24-hour, on peak and off peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

PJM operates an Annual FTR Auction for all participants. In addition, PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period. PJM also runs a Long Term FTR Auction for the following three consecutive planning years. FTR options are not available in the Long Term FTR Auction. A secondary bilateral market is also administered by PJM to allow participants to buy and sell existing FTRs. FTRs can also be exchanged bilaterally outside PJM markets.

The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

FTR buy bids and sell offers may be made as obligations or options and as any of the three classes. FTR self-scheduled bids by ARR holders are available only as obligations and 24-hour product class, consistent with the associated ARRs, and only in the Annual FTR Auction.

Market Structure

Supply and Demand

PJM oversees the process of selling and buying FTRs through ARR Allocations and FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[23] FTRs can also be traded between market participants through bilateral transactions. ARRs may be self scheduled as FTRs for participation only in the Annual FTR Auction.

Total FTR supply is limited by the capability of the transmission system, as modeled in the Annual ARR Allocation. Stage 1A ARR requests must be granted, which artificially increases the transmission capacity in the model on the affected facilities. The capacity modeled in the Annual ARR Allocation is used as the capacity for the Annual FTR Auction to simultaneously accommodate the various combinations of requested FTRs. Depending on assumptions used in the auction transmission model, the total FTR supply can be greater than or less than system capability in aggregate and/or on an element by element basis. When FTR supply is greater than system capability, FTR target allocations will be greater than congestion revenues, contributing to FTR revenue inadequacy. Where FTR supply is less than system capability, FTR target allocations will be less than congestion revenues, contributing to FTR revenue surplus.

PJM can also make further adjustments to the auction model to address expected revenue inadequacies. PJM can assume higher outage levels and PJM can decide to include additional constraints (closed loop interfaces) both of which reduce system capability in the auction model. These PJM actions reduce the supply of available Stage 1B and Stage 2 ARRs, which in turn reduce the number of FTRs available for purchase. PJM made such adjustments starting in the 2014 to 2015 planning year auction model.

For the Annual FTR Auction, known transmission outages that are expected to last for two months or more may be included in the model, while known outages of five days or more may be included in the model for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[24] The full list of outages selected is publicly posted, but the process by which these outages are selected is not fully explained and PJM exercises significant discretion in selecting outages to accomplish FTR revenue adequacy goals.

The auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages. In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model may have significant distributional consequences. The fact that outages are modeled at significantly lower than historical levels results in selling too many FTRs which creates downward pressure on revenues paid to each FTR. To address this issue, the MMU has recommended that PJM use probabilistic outage modeling and seasonal ARR/FTR markets to better align the supply of ARRs and FTRs with actual system capabilities.

23 See PJM. "Manual 6: Financial Transmission Rights," Revision 17 (June 1, 2016), p. 38.

24 See PJM. "Manual 6: Financial Transmission Rights," Revision 17 (June 1, 2016), p. 55.

Long Term FTR Auctions

PJM conducts a Long Term FTR Auction for the next three consecutive planning periods. The capacity offered for sale in Long Term FTR Auctions is the residual system capability assuming that all ARRs allocated in the prior annual ARR allocation process are self scheduled as FTRs. These ARRs are modeled as fixed injections and withdrawals in the Long Term FTR Auction. Future transmission upgrades are not included in the model. The 2009 to 2012 and 2010 to 2013 Long Term FTR Auctions consisted of two rounds.[25] Subsequent Long Term FTR Auctions consist of three rounds. FTRs purchased in prior rounds may be offered for sale in subsequent rounds. FTRs obtained in the Long Term Auctions may have terms of any one year or a single term of all three years. FTR products available in the Long Term Auction include 24-hour, on peak and off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- Round 1. The first round is conducted in the June prior to the start of the term covered by the Long Term FTR Auction. Market participants make offers for FTRs between any source and sink.
- Round 2. The second round is conducted approximately three months after the first round and follows the same rules as Round 1.
- Round 3. The third round is conducted approximately six months after the first round and follows the same rules as Round 1.

Table 13-14 shows the top 10 binding constraints for the 2017 to 2020 Long Term FTR Auction and the 2015 to 2016 Annual FTR Auction based on the marginal value of on peak hours. The severity ranking is based on the marginal value of the constraint in the simultaneous feasibility test.

Table 13-14 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2017 to 2020

			Severity Ranking by Auction Round		
Constraint	Type	Control Zone	1	2	3
St. Johns	Transformer	Dominion	1	NA	5
Elliott - Rosewood	Line	AEP	NA	1	NA
Brown Jct. - Gates Hill	Line	AP	NA	NA	1
Mercer IP - Galesburg	Flowgate	MISO	2	NA	NA
Gore Jct. - Rolling Meadow	Line	Penelec	3	NA	6
Greenfield - Visteaon-Ford	Line	ATSI	NA	2	NA
Erie South - French Road	Line	Penelec	NA	3	NA
Worcester - Ocean Pines	Line	DPL	27	4	13
Gainesville	Transformer	Dominion	NA	5	NA

Annual FTR Auctions

After the Long Term FTR Auction, residual capability on the PJM transmission system is auctioned in the Annual FTR Auction. Annual FTRs are effective beginning June 1 of the planning period through May 31. Outages expected to last two or more months are included in the determination of the simultaneous feasibility for the Annual FTR Auction. ARR holders who wish to self schedule must inform PJM prior to round one of this auction. Any self-scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. This auction consists of four rounds that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24-hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

Table 13-15 shows the top 10 binding constraints for the 2016 to 2017 Annual FTR Auction based on the marginal value of on peak hours.

25 FERC approved, on December 7, 2009, the addition of a third round to the Long Term FTR Auction. FERC letter order accepting PJM Interconnection, L.L.C.'s revisions to Long-Term Financial Transmission Rights Auctions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff, Docket No. ER10-82-000 (December 7, 2009).

Table 13-15 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2016 to 2017

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Rockwell - Congress	Line	AEP	2	1	1	1
Graves Mills - Reusens	Line	AEP	1	3	28	NA
Mercer IP - Galesburg	Flowgate	MISO	5	2	2	2
Rantoul Jct - Paxton East	Flowgate	MISO	7	4	3	3
Davenport - East Calamus	Flowgate	MISO	3	18	41	37
St. Johns	Transformer	Dominion	4	27	24	111
Waterman - Sandwich	Line	ComEd	10	7	4	4
New Hope - Ocean Pines	Line	DPL	6	NA	NA	NA
Wempletown	Transformer	ComEd	8	88	17	122
Electric Junction - Waterman	Line	ComEd	9	8	7	8

Monthly Balance of Planning Period FTR Auctions

The residual capability of the PJM transmission system, after the Long Term and Annual FTR Auctions are concluded, is offered in the Monthly Balance of Planning Period FTR Auctions. Existing FTRs are modeled as fixed injections and withdrawals. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the planning period. FTRs in the auctions include obligations and options and 24-hour, on peak and off peak products.[26]

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but 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.

Buy Bids

The total FTR buy bids in the Monthly Balance of Planning Period FTR Auctions for the entire 2015 to 2016 planning period and the first seven months of the 2016 to 2017 planning period were 9,386,860 MW and 10,167,078 MW.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions.

In order to evaluate the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks 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 13-16 presents the 2017 to 2020 Long Term FTR Auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 77.5 percent of prevailing flow buy bid FTRs and 84.9 percent of counter flow buy bid FTRs with the result that financial entities purchased 80.8 percent of all Long Term FTR Auction cleared buy bids for the 2017 to 2020 Long Term FTR Auction.

26 See PJM. "Manual 6: Financial Transmission Rights," Revision 17 (June 1, 2016), p. 39.

Table 13-16 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2017 to 2020

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	22.5%	15.1%	19.2%
	Financial	77.5%	84.9%	80.8%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	36.9%	26.6%	33.3%
	Financial	63.1%	73.4%	66.7%
	Total	100.0%	100.0%	100.0%

Table 13-17 presents the Annual FTR Auction cleared FTRs for the 2016 to 2017 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2016 to 2017 planning period, financial entities purchased 56.9 percent of prevailing flow FTRs, up 0.6 percentage points, and 79.7 percent of counter flow FTRs, up 4.7 percentage points, with the results that financial entities purchased 65.6 percent, up 3.3 percentage points, of all Annual FTR Auction cleared buy bids for the 2016 to 2017 planning period.

Table 13-17 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2016 to 2017

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	10.0%	0.4%	6.4%
		No	33.0%	19.9%	28.0%
		Total	43.1%	20.3%	34.4%
	Financial	No	56.9%	79.7%	65.6%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		26.6%	24.7%	25.9%
	Financial		73.4%	75.3%	74.1%
	Total		100.0%	100.0%	100.0%

Table 13-18 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for 2016 by trade type, organization type and FTR direction. Financial entities purchased 71.3 percent of prevailing flow FTRs, down 3.6 percent, and 74.6 percent of counter flow FTRs, down 2.2 percent, for the year, with the result that financial entities purchased 72.8 percent, down 2.9 percent, of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for 2016.

Table 13-18 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: 2016

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	28.7%	25.4%	27.2%
	Financial	71.3%	74.6%	72.8%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	30.7%	35.1%	32.1%
	Financial	69.3%	64.9%	67.9%
	Total	100.0%	100.0%	100.0%

Table 13-19 presents the average daily net position ownership for all FTRs for 2016, by FTR direction.

Table 13-19 Daily FTR net position ownership by FTR direction: 2016

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	44.2%	24.0%	35.8%
Financial	55.8%	76.0%	64.2%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

In an effort to address reduced FTR payout ratios, PJM may use normal transmission limits in the FTR auction model. These capability limits may be reduced if ARR funding is not impacted, all requested self-scheduled FTRs clear and net FTR Auction revenue is positive. If the normal capability limit cannot be reached due to infeasibilities then FTR Auction capability reductions are undertaken pro rata based on the MW of Stage 1A infeasibility and the availability of appropriate auction bids for counter flow FTRs.[27]

In another effort to reduce FTR funding issues, PJM implemented a new rule stating that PJM may model normal capability limits on facilities which are infeasible due to modeled transmission outages in Monthly Balance of Planning Period FTR Auctions. The capability of these facilities may be reduced if ARR target allocations are fully funded and net auction revenues are greater than zero. This reduction may only take place when there are counter flow auction bids available to reduce the infeasibilities.[28]

In the 2017 to 2020 Long Term FTR Auction 133,153 MW (26.8 percent of demand; 44.8 percent of total FTR

27 See PJM. "Manual 6: Financial Transmission Rights," Revision 17 (June 1, 2016) p. 56.
28 See PJM. "Manual 6: Financial Transmission Rights," Revision 17 (June 1, 2016) p. 56.

volume) of counter flow FTR buy bids cleared, an increase from 120,650 MW and 43.5 percent of total FTR volume. In the same auction, prevailing flow FTR buy bids cleared 163,931 MW (9.8 percent of demand; 55.2 percent of total FTR volume) an increase from 156,746 MW and 55.2 percent of total FTR volume. In the 2017 to 2020 Long Term FTR Auction, there were 12,853 MW (13.5 percent) of counter flow sell offers and 23,929 MW (21.1 percent) of prevailing flow sell offers cleared.

Table 13-20 Long Term FTR Auction market volume: Planning period 2017 to 2020

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	71,013	188,872	48,984	25.9%	139,887	74.1%
		Year 2	55,813	167,917	47,150	28.1%	120,767	71.9%
		Year 3	49,332	137,540	36,330	26.4%	101,210	73.6%
		Year All	266	1,627	688	42.3%	938	57.7%
		Total	176,424	495,955	133,153	26.8%	362,802	73.2%
	Prevailing Flow	Year 1	167,750	646,060	58,233	9.0%	587,826	91.0%
		Year 2	129,840	510,387	61,768	12.1%	448,618	87.9%
		Year 3	127,220	508,133	43,709	8.6%	464,425	91.4%
		Year All	2,760	16,336	220	1.3%	16,116	98.7%
		Total	427,570	1,680,916	163,931	9.8%	1,516,986	90.2%
	Total		603,994	2,176,871	297,083	13.6%	1,879,788	86.4%
Sell offers	Counter Flow	Year 1	26,109	59,201	8,744	14.8%	50,457	85.2%
		Year 2	12,347	28,722	3,582	12.5%	25,140	87.5%
		Year 3	3,192	7,167	527	7.3%	6,640	92.7%
		Year All	NA	NA	NA	NA	NA	NA
		Total	41,648	95,089	12,853	13.5%	82,237	86.5%
	Prevailing Flow	Year 1	29,991	62,737	14,093	22.5%	48,644	77.5%
		Year 2	17,866	40,390	8,575	21.2%	31,814	78.8%
		Year 3	4,555	10,189	1,261	12.4%	8,928	87.6%
		Year All	NA	NA	NA	NA	NA	NA
		Total	52,412	113,316	23,929	21.1%	89,386	78.9%
	Total		94,060	208,405	36,782	17.6%	171,623	82.4%

Table 13-21 provides the Annual FTR Auction market volume for the 2016 to 2017 planning period. Total FTR buy bids were 2,592,183 MW, up 5.3 percent from 2,461,662 MW for the previous planning period. For the 2016 to 2017 planning period 393,509 MW (15.3 percent) of buy bids cleared, up 11.0 percent from 354,630 MW for the previous planning period. There were 378,431 MW of sell offers with 69,451 MW (18.4 percent) clearing for the 2016 to 2017 planning period. The total volume of cleared buy and self-scheduled bids was 420,198 MW, up 11.1 percent from 378,328 in the previous Annual FTR Auction.

Table 13-21 Annual FTR Auction market volume: Planning period 2016 to 2017

Trade Type	Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	169,985	651,973	159,684	24.5%	492,289	75.5%
		Prevailing Flow	318,673	1,397,127	210,885	15.1%	1,186,243	84.9%
		Total	488,658	2,049,100	370,569	18.1%	1,678,532	81.9%
	Options	Counter Flow	1,150	25,255	33	0.1%	25,222	99.9%
		Prevailing Flow	50,862	491,138	22,908	4.7%	468,231	95.3%
		Total	52,012	516,393	22,940	4.4%	493,453	95.6%
	Total	Counter Flow	171,135	677,228	159,717	23.6%	517,511	76.4%
		Prevailing Flow	369,535	1,888,266	233,792	12.4%	1,654,474	87.6%
		Total	540,670	2,565,494	393,509	15.3%	2,171,985	84.7%
Self-scheduled bids	Obligations	Counter Flow	75	591	591	100.0%	0	0.0%
		Prevailing Flow	3,585	26,099	26,099	100.0%	0	0.0%
		Total	3,660	26,689	26,689	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	170,060	652,564	160,275	24.6%	492,289	75.4%
		Prevailing Flow	322,258	1,423,226	236,983	16.7%	1,186,243	83.3%
		Total	492,318	2,075,790	397,258	19.1%	1,678,532	80.9%
	Options	Counter Flow	1,150	25,255	33	0.1%	25,222	99.9%
		Prevailing Flow	50,862	491,138	22,908	4.7%	468,231	95.3%
		Total	52,012	516,393	22,940	4.4%	493,453	95.6%
	Total	Counter Flow	171,210	677,818	160,307	23.7%	517,511	76.3%
		Prevailing Flow	373,120	1,914,365	259,891	13.6%	1,654,474	86.4%
		Total	544,330	2,592,183	420,198	16.2%	2,171,985	83.8%
Sell offers	Obligations	Counter Flow	74,701	176,389	28,577	16.2%	147,811	83.8%
		Prevailing Flow	86,565	186,695	39,895	21.4%	146,801	78.6%
		Total	161,266	363,084	68,472	18.9%	294,612	81.1%
	Options	Counter Flow	24	120	0	0.0%	120	100.0%
		Prevailing Flow	2,889	15,227	979	6.4%	14,248	93.6%
		Total	2,913	15,347	979	6.4%	14,368	93.6%
	Total	Counter Flow	74,725	176,509	28,577	16.2%	147,931	83.8%
		Prevailing Flow	89,454	201,922	40,874	20.2%	161,049	79.8%
		Total	164,179	378,431	69,451	18.4%	308,980	81.6%

Figure 13-6 Annual Bid FTR Auction volume: Planning period 2009 to 2010 through 2016 to 2017

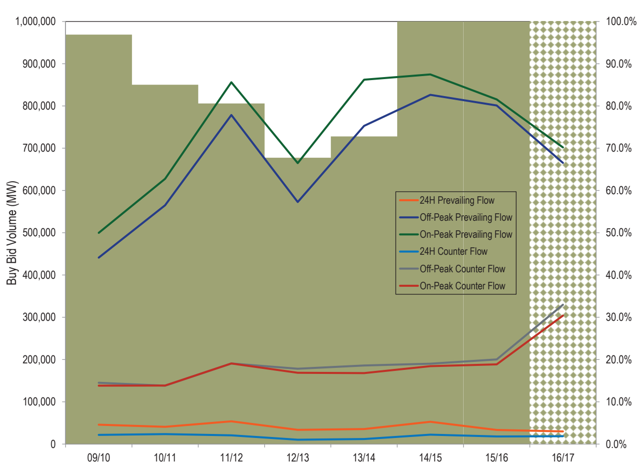


Figure 13-6 shows the bid volumes of the Annual FTR Auctions from the 2009 to 2010 planning period through the 2016 to 2017 planning period and the associated planning period payout ratios, represented by the background bars. The payout ratio for the current planning period is shown as dotted background because it is not yet final. Bid volume has not changed significantly with payout ratio, with the exception of on and off peak prevailing flow products. For on and off peak prevailing flow products, the 2012 to 2013 planning period the bid volume decreased 24.3 percent from the 2011 to 2012 planning period, but then increased 30.5 percent for the 2013 to 2014 planning period despite an only slightly improved payout ratio. Bid volume for the 2016 to 2017 planning period was down 15.4 percent from the 2015 to 2016 planning period.

Figure 13-7 shows the cleared volumes of the Annual FTR Auctions from planning period 2009 to 2010 through the 2016 to 2017 planning period and the associated planning period payout ratios, represented by the background bars. The payout ratio for the current planning period is shown as dotted background because it is not yet final. The cleared MW increased from the 2009 to 2010 planning period through the 2013 to the 2014 planning period, as a market response to lower payout ratios compared to target allocations. The 2014 to 2015, 2015 to 2016 and 2016 to 2017 planning period volumes were 19.1 percent, 16.3 percent and 7.0 percent lower than the 2013 to 2014 volume, as a result of PJM's more restrictive modeling of Stage 1B and Stage

2 ARRs starting in the 2014 to 2015 planning period and leading to fewer available FTRs in the Annual FTR Auction and higher prices. In the planning periods since the inception of this policy, PJM has been allowing more Stage 1B and Stage 2 ARRs to clear resulting in higher slightly higher cleared volume, but increasing prices in the Annual FTR Auction.

Figure 13-7 Annual Cleared FTR Auction volume: Planning period 2009 to 2010 through 2016 to 2017

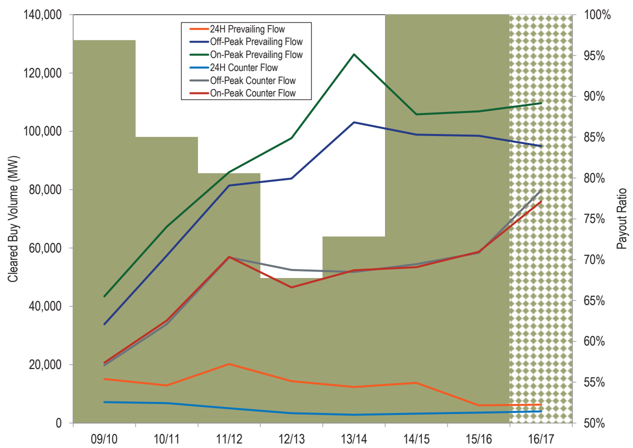


Table 13-22 shows the proportion of ARRs self-scheduled as FTRs for the last seven planning periods. The maximum possible level of self-scheduled FTRs includes all ARRs. Eligible participants self-scheduled 26,689 MW (32.5 percent) of ARRs as FTRs for the 2016 to 2017 planning period, up from 26,689 MW (30.4 percent) in the previous planning period.

Table 13-22 Comparison of self-scheduled FTRs: Planning periods 2009 to 2010 through 2016 to 2017

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2009/2010	68,589	109,613	62.6%
2010/2011	55,669	102,046	54.6%
2011/2012	46,017	103,660	44.4%
2012/2013	41,351	99,115	41.7%
2013/2014	29,289	94,097	31.1%
2014/2015	26,964	73,504	36.7%
2015/2016	23,699	77,872	30.4%
2016/2017	26,689	82,229	32.5%

Table 13-23 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 2015 to 2016 planning period and the first seven months of the 2016 to 2017 planning period. There were 11,947,294 MW of FTR obligation buy bids and 2,802,202 MW of FTR obligation sell offers for all bidding periods in the first seven months of the 2016 to 2017 planning period. The Monthly Balance of Planning Period FTR Auction cleared 1,595,935 MW (13.4 percent) of FTR obligation buy bids and 593,901 MW (21.2 percent) of FTR obligation sell offers.

There were 3,023,974 MW of FTR option buy bids and 370,924 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 2016 to 2017 planning period. The monthly auctions cleared 46,800 MW (1.5 percent) of FTR option buy bids, and 113,745 MW (30.7 percent) of FTR option sell offers.

Table 13-23 Monthly Balance of Planning Period FTR Auction market volume: 2016

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-16	Obligations	Buy bids	341,467	2,106,004	235,561	11.2%	1,870,443	88.8%
		Sell offers	120,657	303,271	81,934	27.0%	221,338	73.0%
	Options	Buy bids	9,175	268,381	7,783	2.9%	260,598	97.1%
		Sell offers	8,075	37,712	10,212	27.1%	27,500	72.9%
Feb-16	Obligations	Buy bids	310,044	2,122,942	168,574	7.9%	1,954,368	92.1%
		Sell offers	99,043	267,534	79,992	29.9%	187,543	70.1%
	Options	Buy bids	24,657	487,736	9,869	2.0%	477,867	98.0%
		Sell offers	7,835	37,179	9,297	25.0%	27,881	75.0%
Mar-16	Obligations	Buy bids	328,233	2,040,401	256,731	12.6%	1,783,670	87.4%
		Sell offers	120,625	314,628	102,897	32.7%	211,731	67.3%
	Options	Buy bids	19,431	404,511	9,082	2.2%	395,429	97.8%
		Sell offers	9,806	44,757	11,080	24.8%	33,677	75.2%
Apr-16	Obligations	Buy bids	247,410	1,484,893	191,218	12.9%	1,293,674	87.1%
		Sell offers	87,100	233,733	69,280	29.6%	164,453	70.4%
	Options	Buy bids	8,938	178,209	5,291	3.0%	172,918	97.0%
		Sell offers	6,820	35,740	9,938	27.8%	25,802	72.2%
May-16	Obligations	Buy bids	149,322	689,190	106,669	15.5%	582,521	84.5%
		Sell offers	42,621	103,346	40,823	39.5%	62,522	60.5%
	Options	Buy bids	2,882	91,075	2,055	2.3%	89,020	97.7%
		Sell offers	3,654	18,069	7,924	43.9%	10,145	56.1%
Jun-16	Obligations	Buy bids	492,145	1,988,712	261,393	13.1%	1,727,319	86.9%
		Sell offers	262,228	487,524	116,314	23.9%	371,210	76.1%
	Options	Buy bids	15,453	435,374	11,296	2.6%	424,078	97.4%
		Sell offers	21,679	74,214	22,222	29.9%	51,992	70.1%
Jul-16	Obligations	Buy bids	509,577	2,131,823	284,246	13.3%	1,847,577	86.7%
		Sell offers	271,006	466,772	112,440	24.1%	354,332	75.9%
	Options	Buy bids	16,677	619,864	8,552	1.4%	611,312	98.6%
		Sell offers	14,562	65,749	19,229	29.2%	46,520	70.8%
Aug-16	Obligations	Buy bids	456,681	2,224,197	257,093	11.6%	1,967,104	88.4%
		Sell offers	232,423	422,754	83,265	19.7%	339,489	80.3%
	Options	Buy bids	13,398	387,403	6,451	1.7%	380,953	98.3%
		Sell offers	14,808	58,654	13,962	23.8%	44,692	76.2%
Sep-16	Obligations	Buy bids	402,909	1,772,262	244,301	13.8%	1,527,961	86.2%
		Sell offers	240,198	441,114	83,618	19.0%	357,497	81.0%
	Options	Buy bids	9,461	607,443	8,313	1.4%	599,130	98.6%
		Sell offers	14,471	61,891	17,458	28.2%	44,433	71.8%
Oct-16	Obligations	Buy bids	355,949	1,486,644	222,742	15.0%	1,263,902	85.0%
		Sell offers	148,613	352,652	62,772	17.8%	289,880	82.2%
	Options	Buy bids	6,254	433,810	4,378	1.0%	429,432	99.0%
		Sell offers	10,027	45,230	15,242	33.7%	29,988	66.3%
Nov-16	Obligations	Buy bids	304,708	1,231,314	176,846	14.4%	1,054,468	85.6%
		Sell offers	126,001	318,875	62,972	19.7%	255,902	80.3%
	Options	Buy bids	6,759	311,130	4,848	1.6%	306,282	98.4%
		Sell offers	7,529	32,355	12,373	38.2%	19,983	61.8%
Dec-16	Obligations	Buy bids	267,390	1,112,342	149,314	13.4%	963,028	86.6%
		Sell offers	131,826	312,511	72,521	23.2%	239,989	76.8%
	Options	Buy bids	3,496	228,950	2,963	1.3%	225,987	98.7%
		Sell offers	8,435	32,831	13,259	40.4%	19,571	59.6%
2015/2016*	Obligations	Buy bids	4,076,728	21,836,340	2,366,860	10.8%	19,469,480	89.2%
		Sell offers	1,582,528	4,385,972	1,088,967	24.8%	3,297,005	75.2%
	Options	Buy bids	157,638	3,850,526	92,957	2.4%	3,757,569	97.6%
		Sell offers	112,395	505,471	137,873	27.3%	367,598	72.7%
2016/2017**	Obligations	Buy bids	2,789,359	11,947,294	1,595,935	13.4%	10,351,359	86.6%
		Sell offers	1,412,295	2,802,202	593,901	21.2%	2,208,300	78.8%
	Options	Buy bids	71,498	3,023,974	46,800	1.5%	2,977,173	98.5%
		Sell offers	91,511	370,924	113,745	30.7%	257,179	69.3%

* Shows twelve months for 2015/2016; ** Shows seven months ended December 31 for 2016/2017

Table 13-24 presents the buy-bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume. The average monthly cleared volume for 2016 was 219,630.6 MW. The average monthly cleared volume for 2015 was180,531.0 MW.

Table 13-24 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): 2016

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-16	Bid	1,330,456	389,271	264,547				390,110	2,374,385
	Cleared	126,983	33,997	17,849				64,514	243,344
Feb-16	Bid	1,612,886	305,237	352,140				340,415	2,610,677
	Cleared	114,428	24,775	21,204				18,035	178,442
Mar-16	Bid	1,476,838	381,466	372,548				214,060	2,444,912
	Cleared	155,020	44,575	37,508				28,710	265,813
Apr-16	Bid	1,244,258	418,843						1,663,101
	Cleared	131,099	65,411						196,509
May-16	Bid	780,265							780,265
	Cleared	108,724							108,724
Jun-16	Bid	681,521	288,949	273,138	204,684	335,252	331,270	309,273	2,424,086
	Cleared	101,097	28,610	26,583	24,752	35,094	31,969	24,584	272,688
Jul-16	Bid	998,701	420,705	308,767		341,395	358,352	323,766	2,751,687
	Cleared	119,303	47,520	24,596		35,155	36,548	29,676	292,798
Aug-16	Bid	1,180,580	289,291	241,822		266,319	316,435	317,152	2,611,600
	Cleared	128,158	32,177	19,141		26,069	29,079	28,921	263,544
Sep-16	Bid	838,551	343,803	323,119		198,258	351,139	324,834	2,379,704
	Cleared	106,735	39,188	30,410		12,664	36,463	27,154	252,614
Oct-16	Bid	791,635	322,827	244,616			280,907	280,468	1,920,453
	Cleared	112,738	33,781	19,665			33,161	27,775	227,120
Nov-16	Bid	682,928	228,572	185,778			205,536	239,630	1,542,444
	Cleared	97,144	24,934	13,547			22,869	23,199	181,694
Dec-16	Bid	590,623	208,416	203,619			117,437	221,197	1,341,292
	Cleared	80,302	20,754	18,552			10,493	22,177	152,277

Figure 13-8 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through December 2016, by type of auction. FTR volumes are included in the calendar month they are effective, with Long Term and Annual FTR auction volume spread equally to each month in the relevant planning period. This figure shows the share of FTRs purchased in each auction type by month. Over the course of the planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, making them a greater portion of active FTRs. When the Annual FTR Auction occurs, FTRs purchased in any previous Monthly Balance of Planning Period Auction, other than the current June auction, are no longer in effect, so there is a reduction in their share of total FTRs with a corresponding increase in the share of Annual FTRs.

Figure 13-8 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through December 2016

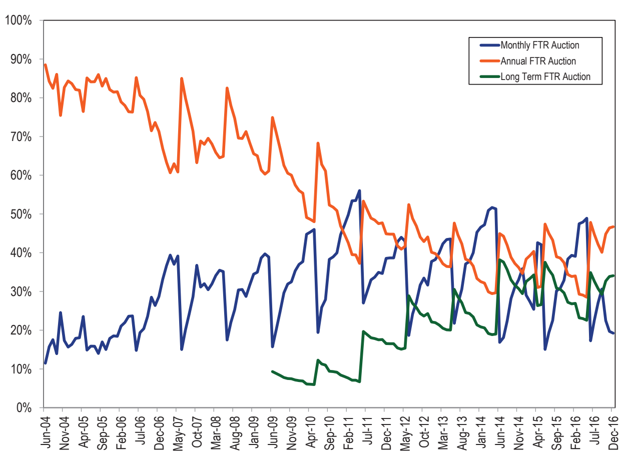


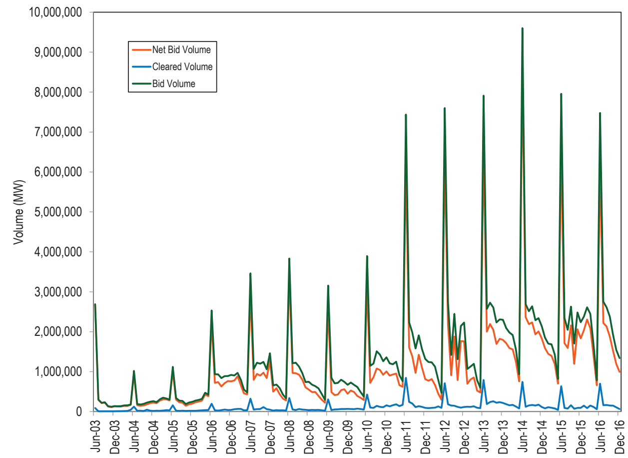
Table 13-25 provides the secondary bilateral FTR market volume for the entire 2015 to 2016 and 2016 to 2017 planning periods.

Table 13-25 Secondary bilateral FTR market volume: Planning periods 2015 to 2016 and 2016 to 2017[29]

Planning Period	Type	Class Type	Volume (MW)
2015/2016	Obligation	24-Hour	667.6
		On Peak	40,207.5
		Off Peak	27,652.4
		Total	68,527.5
	Option	24-Hour	0.0
		On Peak	8,765.5
		Off Peak	6,157.1
		Total	14,922.6
2016/2017	Obligation	24-Hour	538.5
		On Peak	11,699.0
		Off Peak	6,384.5
		Total	18,622.0
	Option	24-Hour	0.0
		On Peak	678.0
		Off Peak	104.5
		Total	782.5

Figure 13-9 shows the FTR bid, cleared and net bid volume from June 2003 through December 2016 for Long Term, Annual and Monthly Balance of Planning Period Auctions.[30] Cleared volume is the volume of 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. Bid volumes and net bid volumes have increased since 2003. Cleared volume was relatively steady until 2010, with an increase in 2011 followed by a slight decrease in 2012. In 2013, cleared volume increased, and there was a larger increase in 2014. The demand for FTRs has increased.

Figure 13-9 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2016



Price

Table 13-26 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2017 to 2020 Long Term FTR Auction. Only FTR obligation products are available in the Long Term FTR Auctions. In this auction, weighted-average buy bid counter flow and prevailing flow FTR prices were -$0.42 and $0.41, compared to -$0.47 and $0.45 from the 2016 to 2019 Long Term FTR Auction. Weighted-average sell bid counter flow and prevailing flow FTR prices were -$0.43 and $0.44, compared to -$0.37 for counter flow FTRs and $0.43 for prevailing flow FTRs.

29 The 2014 to 2015 planning period covers bilateral FTRs that are effective for any time between June 1, 2014 through June 1, 2015, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

30 The data for this table are available in *2016 State of the Market Report for PJM*, Volume 2, Appendix H.

Table 13-26 Long Term FTR Auction weighted-average cleared prices (Dollars per MW): Planning periods 2017 to 2020

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($1.55)	($0.33)	($0.55)	($0.47)
		Year 2	($1.19)	($0.31)	($0.52)	($0.42)
		Year 3	($0.71)	($0.27)	($0.44)	($0.36)
		Year All	NA	($0.03)	($0.09)	($0.05)
		Total	($1.18)	($0.30)	($0.50)	($0.42)
	Prevailing Flow	Year 1	$0.81	$0.35	$0.55	$0.46
		Year 2	$0.78	$0.32	$0.50	$0.41
		Year 3	$0.61	$0.27	$0.44	$0.35
		Year All	NA	$0.01	$0.01	$0.01
		Total	$0.75	$0.32	$0.50	$0.41
	Total		($0.26)	$0.03	$0.06	$0.04
Sell offers	Counter Flow	Year 1	($1.46)	($0.35)	($0.50)	($0.46)
		Year 2	NA	($0.32)	($0.45)	($0.40)
		Year 3	NA	($0.10)	($0.18)	($0.13)
		Year All	NA	NA	NA	NA
		Total	($1.17)	($0.33)	($0.48)	($0.43)
	Prevailing Flow	Year 1	$0.55	$0.27	$0.48	$0.38
		Year 2	$0.62	$0.47	$0.65	$0.55
		Year 3	NA	$0.26	$0.49	$0.36
		Year All	NA	NA	NA	NA
		Total	$0.57	$0.34	$0.54	$0.44
	Total		($0.26)	$0.11	$0.19	$0.13

Figure 13-10 shows the volume-weighted average buy bid price for the Annual FTR Auctions from the 2009 to 2010 through the 2016 to 2017 planning periods and the associated planning period payout ratios, represented by the background bars. The payout ratio for the 2016 to 2017 planning period is shown as dotted background because it is not yet final. From the 2010 to 2011 planning period to the 2013 to 2014 planning period FTR prices decreased. The 2014 to 2015, 2015 to 2016 and 2016 to 2017 planning periods 24 hour obligation prices increased 142.5 percent, 210.8 and 260.8 percent from the 2013 to 2014 planning period. This large price increase was driven by the significant decrease in FTR supply volume during the Annual FTR Auction which was a result of PJM's decisions to use a more constrained model and its impact on Stage 1B and Stage 2 ARR allocations. The increased price due to decreased volume has led to an increase in ARR target allocations for the planning period.

Figure 13-10 Annual FTR Auction volume-weighted average buy bid price: Planning period 2009 to 2010 through 2016 to 2017

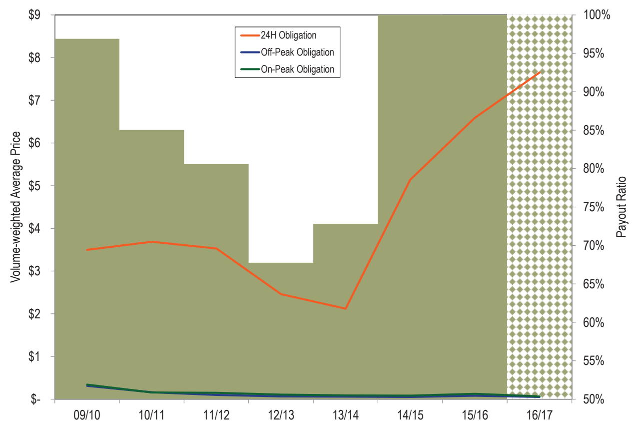


Table 13-27 shows the weighted-average cleared buy-bid prices by trade type, FTR product, FTR direction and class type for the Annual FTR Auction for the 2016 to 2017 planning period. The weighted-average cleared buy bid price in the 2016 to 2017 Annual FTR Auction was $0.35 per MW, up from $0.31 per MW in the 2015 to 2016 planning period.

Table 13-27 Annual FTR Auction weighted-average cleared prices (Dollars per MW): Planning period 2016 to 2017

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.95)	($0.54)	($0.33)	($0.45)
		Prevailing Flow	$1.79	$1.03	$0.73	$0.94
		Total	$0.72	$0.39	$0.25	$0.34
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.05	$0.64	$0.38	$0.49
		Total	$0.05	$0.64	$0.38	$0.49
Self-scheduled bids	Obligations	Counter Flow	($0.11)	NA	NA	($0.11)
		Prevailing Flow	$1.32	NA	NA	$1.32
		Total	$1.29	NA	NA	$1.29
Buy and self-scheduled bids	Obligations	Counter Flow	($0.84)	($0.54)	($0.33)	($0.45)
		Prevailing Flow	$1.41	$1.03	$0.73	$1.01
		Total	$1.13	$0.39	$0.25	$0.46
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.05	$0.64	$0.38	$0.49
		Total	$0.05	$0.64	$0.38	$0.49
Sell offers	Obligations	Counter Flow	($2.07)	($0.58)	($0.40)	($0.59)
		Prevailing Flow	$0.68	$0.50	$0.30	$0.41
		Total	($0.47)	$0.10	$0.02	$0.02
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$0.47	$0.30	$0.35
		Total	$0.00	$0.47	$0.30	$0.35

Table 13-28 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2016 through December 2016. For example, for the January 2016 Monthly Balance of Planning Period FTR Auction, the current month column is January, the second month column is February and the third month column is March. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the January 2016 Monthly Balance of Planning Period FTR Auction.

Table 13-28 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through December, 2016

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-16	$0.13	$0.29	($0.00)				$0.07	$0.11
Feb-16	$0.13	$0.20	$0.12				$0.20	$0.16
Mar-16	$0.15	$0.11	$0.07				$0.07	$0.12
Apr-16	$0.11	$0.11					$0.00	$0.11
May-16	$0.11						$0.00	$0.11
Jun-16	$0.09	$0.07	$0.03	$0.20	$0.19	$0.30	$0.16	$0.17
Jul-16	$0.11	$0.15	$0.04		$0.12	$0.23	$0.12	$0.14
Aug-16	$0.08	$0.10	$0.12		$0.07	$0.19	$0.09	$0.10
Sep-16	$0.11	$0.09	$0.09		$0.12	$0.14	$0.09	$0.11
Oct-16	$0.13	$0.11	$0.02			$0.12	$0.10	$0.11
Nov-16	$0.10	$0.14	$0.13			$0.18	$0.11	$0.13
Dec-16	$0.15	$0.19	$0.27			$0.24	$0.14	$0.17

The cleared weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions for January through December 2016 was $0.13 per MW, down from $0.24 per MW in the same time last year, a 45.8 percent decrease in FTR prices. The cleared weighted-average price for the current planning period was $0.13, down 48.0 percent from $0.25 for the same time period during the previous planning period.

Profitability

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. For a prevailing flow FTR, the FTR credits are the actual revenue that an FTR holder receives and the auction price is the cost. For a counter flow FTR, the auction price is the revenue that an FTR holder is paid and the FTR credits are the cost to the FTR holder, which the FTR holder must pay. The cost of self-scheduled FTRs is zero. ARR holders that self schedule FTRs purchase the FTRs in the Annual FTR Auction, but the ARR holders receive offsetting ARR credits that equal the purchase price of the FTRs.

The fact that FTRs have been consistently profitable regardless of the payout ratio raises questions about the competitiveness of the market. It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed to zero or a de mimimis level.

Table 13-29 lists FTR profits by organization type and FTR direction for the period from January through December, 2016. Some participants classified as physical, such as a company that holds one generator, are not eligible for ARRs but do have a physical presence on the PJM system. Such entities would be under the Physical category, while any entity that holds an ARR will be under the Physical ARR Holder category. Separating physical into those participants with and without FTRs allows a better view into the profits ARR holders are making through the FTR market. FTR profits are the sum of the daily FTR target allocations, including for self-scheduled FTRs, adjusted by the payout ratio minus the daily FTR auction costs for each FTR held by an organization. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source in the Day-Ahead Energy Market. The FTR credits do not include after the fact adjustments which are very small and do not occur in every month. The FTR credits also do not include any excess congestion revenue distributions made at the end of the planning period. The daily FTR auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in days. Self-scheduled FTRs have zero cost. FTRs were profitable overall, with $244.2 million in profits for all physical entities, of which $207.4 million was from self-scheduled FTRs, and $47.5 million for financial entities.

Table 13-29 FTR profits by organization type and FTR direction: 2016

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Financial	($108,757,022.37)	NA	$156,294,514	NA	$47,537,492
Physical	($26,934,571.67)	NA	$26,856,705	NA	($77,867)
Physical ARR Holder	$29,022,758.28	$206,994,377	$7,822,186	$378,265	$244,217,586
Total	($106,668,835.76)	$206,994,377	$190,973,404	$378,265	$291,677,210

Table 13-30 lists the monthly FTR profits in 2016 by organization type.

Table 13-30 Monthly FTR profits by organization type: 2016

	Organization Type			
Month	Physical	Physical ARR Holders	Financial	Total
Jan	$68,003	$18,722,463	$25,562,897	$44,353,362
Feb	$539,063	$30,173,609	$19,619,306	$50,331,977
Mar	($2,765,117)	$22,529,897	$1,230,244	$20,995,025
Apr	($2,156,157)	$22,549,475	$7,422,799	$27,816,117
May	($7,016,575)	$8,108,304	($5,728,428)	($4,636,700)
Jun	($2,369,364)	$10,987,038	($6,163,265)	$2,454,408
Jul	$666,260	$31,092,695	$570,363	$32,329,318
Aug	$3,423,455	$14,534,611	$9,898,169	$27,856,234
Sep	$6,634,340	$47,173,377	$12,909,228	$66,716,944
Oct	$5,640,273	$52,627,609	($3,486,077)	$54,781,805
Nov	($1,876,298)	($4,683,570)	($8,477,147)	($15,037,015)
Dec	($865,749)	($9,597,922)	($5,820,596)	($16,284,267)
Total	($77,867)	$244,217,586	$47,537,492	$291,677,210

Table 13-31 lists the historical profits by calendar year by organization type beginning January 2011.

Table 13-31 Yearly FTR profits by organization type: 2011 through 2016

Calendar Year	Physical	Financial	Total
2011	$340,260,261	$125,697,493	$465,957,753
2012	($7,634,041)	$78,762,923	$71,128,882
2013	$170,180,569	$177,494,506	$347,675,076
2014	$873,909,275	$543,642,102	$1,417,551,377
2015	$453,547,398	$182,282,134	$635,829,532
2016	$244,139,718	$47,537,492	$291,677,210

Revenue

Long Term FTR Auction Revenue

Table 13-32 shows the Long Term FTR Auction revenue data by trade type, FTR direction, period type and class type. The 2017 to 2020 Long Term FTR Auction netted $26.7 million in revenue, $3.5 million more than the previous Long Term FTR Auction. Buyers paid $48.4 million and sellers received $21.7 million, down $12.0 million and $15.4 million over the previous Long Term FTR Auction. In general, revenue increased $3.5 million over the previous Long Term FTR Auction, with counter flow buy bid revenue decreasing 3.9 percent and prevailing flow buy bid revenue decreasing 6.9 percent.

Table 13-32 Long Term FTR Auction Revenue: Planning periods 2017 to 2020

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($13,865,196)	($52,361,573)	($37,364,286)	($103,591,055)
		Year 2	($7,761,389)	($43,553,743)	($37,548,472)	($88,863,605)
		Year 3	($5,005,407)	($28,000,602)	($25,397,031)	($58,403,039)
		Year All	$0	($319,141)	($176,332)	($495,473)
		Total	($26,631,992)	($124,235,058)	($100,486,121)	($251,353,171)
	Prevailing Flow	Year 1	$6,795,665	$67,652,677	$44,562,449	$119,010,791
		Year 2	$5,662,333	$57,741,990	$49,101,454	$112,505,777
		Year 3	$2,860,593	$35,206,352	$30,170,444	$68,237,390
		Year All	$6,961	$10,816	$15,524	$33,301
		Total	$15,325,553	$160,611,835	$123,849,872	$299,787,259
	Total		($11,306,439)	$36,376,777	$23,363,751	$48,434,088
Sell offers	Counter Flow	Year 1	($2,553,051)	($8,658,617)	($7,007,072)	($18,218,739)
		Year 2	($666,560)	($3,101,121)	($2,656,749)	($6,424,429)
		Year 3	0	($158,053)	($142,046)	($300,099)
		Year All	NA	NA	NA	NA
		Total	($3,219,610)	($11,917,790)	($9,805,868)	($24,943,268)
	Prevailing Flow	Year 1	$1,026,067	$14,286,980	$8,408,061	$23,721,107
		Year 2	$699,642	$10,531,252	$9,695,363	$20,926,257
		Year 3	11,648	$1,206,188	$792,342	$2,010,177
		Year All	NA	NA	NA	NA
		Total	$1,737,356	$26,024,420	$18,895,765	$46,657,541
	Total		($1,482,254)	$14,106,630	$9,089,897	$21,714,273
Total			($9,824,185)	$22,270,147	$14,273,853	$26,719,815

Annual FTR Auction Revenue

Table 13-33 shows the Annual FTR Auction revenue by trade type, type, FTR direction and class type. The Annual FTR Auction for the 2016 to 2017 planning period generated $909.0 million, down 2.9 percent from $936.3 million in the 2015 to 2016 planning period, and up 21.4 percent from $748.6 in the 2014 to 2015 planning period. Counter flow FTR holders received $255.7 million, up 62.8 percent from the previous planning period and prevailing flow FTR holders paid $1,164.7 million, up 6.5 percent from the previous planning period.

Table 13-33 Annual FTR Auction revenue: Planning period 2015 to 2016

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($33,376,334)	($171,543,694)	($120,897,348)	($325,817,376)
		Prevailing Flow	$98,648,009	$473,996,780	$319,439,439	$892,084,228
		Total	$65,271,675	$302,453,086	$198,542,091	$566,266,853
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$122,422	$29,281,256	$20,105,845	$49,509,523
		Total	$122,422	$29,281,256	$20,105,845	$49,509,523
	Total	Counter Flow	($33,376,334)	($171,543,694)	($120,897,348)	($325,817,376)
		Prevailing Flow	$98,770,431	$503,278,036	$339,545,284	$941,593,751
		Total	$65,394,098	$331,734,342	$218,647,936	$615,776,376
Self-scheduled bids	Obligations	Counter Flow	($554,976)	NA	NA	($554,976)
		Prevailing Flow	$302,732,687	NA	NA	$302,732,687
		Total	$302,177,711	NA	NA	$302,177,711
Buy and self-scheduled bids	Obligations	Counter Flow	($33,931,309)	($171,543,694)	($120,897,348)	($326,372,351)
		Prevailing Flow	$401,380,696	$473,996,780	$319,439,439	$1,194,816,915
		Total	$367,449,387	$302,453,086	$198,542,091	$868,444,564
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$122,422	$29,281,256	$20,105,845	$49,509,523
		Total	$122,422	$29,281,256	$20,105,845	$49,509,523
	Total	Counter Flow	($33,931,309)	($171,543,694)	($120,897,348)	($326,372,351)
		Prevailing Flow	$401,503,118	$503,278,036	$339,545,284	$1,244,326,438
		Total	$367,571,809	$331,734,342	$218,647,936	$917,954,087
Sell offers	Obligations	Counter Flow	($16,305,297)	($29,281,811)	($25,092,182)	($70,679,290)
		Prevailing Flow	$7,442,064	$42,620,672	$28,029,936	$78,092,673
		Total	($8,863,233)	$13,338,861	$2,937,754	$7,413,382
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$691,623	$847,523	$1,539,146
		Total	$0	$691,623	$847,523	$1,539,146
	Total	Counter Flow	($16,305,297)	($29,281,811)	($25,092,182)	($70,679,290)
		Prevailing Flow	$7,442,064	$43,312,295	$28,877,459	$79,631,819
		Total	($8,863,233)	$14,030,484	$3,785,277	$8,952,528
Total			$376,435,042	$317,703,858	$214,862,658	$909,001,559

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-34 shows Monthly Balance of Planning Period FTR Auction revenue by trade type, type and class type for January through December 2016. The Monthly Balance of Planning Period FTR Auctions for the 2016 to 2017 planning period netted $26.7 million in revenue, the difference between buyers paying $133.0 million and sellers receiving $106.3 million for the first seven months of the 2016 to 2017 planning period. For the entire 2015 to 2016 planning period, the Monthly Balance of Planning Period FTR Auctions netted $31.8 million in revenue with buyers paying $263.5 million and sellers receiving $231.7 million.

Table 13-34 Monthly Balance of Planning Period FTR Auction revenue: 2016

			Class Type			
Monthly Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-16	Obligations	Buy bids	$2,767,129	$6,642,066	$5,322,646	$14,731,841
		Sell offers	($1,527,329)	$6,009,617	$4,867,971	$9,350,259
	Options	Buy bids	$7,749	$433,485	$222,655	$663,889
		Sell offers	$4,548	$2,013,776	$1,952,220	$3,970,544
Feb-16	Obligations	Buy bids	$2,484,838	$5,046,424	$3,565,515	$11,096,777
		Sell offers	($566,504)	$4,516,965	$3,621,103	$7,571,565
	Options	Buy bids	$4,254	$586,461	$407,158	$997,873
		Sell offers	$8,038	$1,653,043	$1,337,798	$2,998,879
Mar-16	Obligations	Buy bids	$3,613,801	$5,764,687	$3,975,010	$13,353,498
		Sell offers	$316,238	$5,416,263	$3,820,100	$9,552,601
	Options	Buy bids	$16,807	$431,121	$223,272	$671,200
		Sell offers	$5,536	$1,528,874	$1,167,147	$2,701,557
Apr-16	Obligations	Buy bids	$2,617,134	$2,986,782	$1,654,425	$7,258,340
		Sell offers	$115,458	$3,448,354	$2,223,777	$5,787,589
	Options	Buy bids	$47	$407,910	$179,795	$587,752
		Sell offers	$7,609	$1,089,056	$777,074	$1,873,738
May-16	Obligations	Buy bids	$95,103	$2,444,319	$1,923,140	$4,462,562
		Sell offers	$40,269	$1,316,756	$1,072,812	$2,429,838
	Options	Buy bids	$206	$144,053	$79,575	$223,834
		Sell offers	$3,556	$983,572	$781,069	$1,768,197
Jun-16	Obligations	Buy bids	$16,456,472	$10,330,600	$2,578,829	$29,365,901
		Sell offers	$1,081,144	$13,005,246	$6,209,015	$20,295,405
	Options	Buy bids	$14,434	$2,077,626	$1,341,275	$3,433,336
		Sell offers	$42,161	$5,547,550	$3,732,866	$9,322,577
Jul-16	Obligations	Buy bids	$3,291,958	$12,811,711	$6,309,992	$22,413,662
		Sell offers	$708,924	$9,454,234	$3,919,893	$14,083,051
	Options	Buy bids	$4,188	$2,108,948	$1,148,228	$3,261,364
		Sell offers	$17,838	$3,859,285	$2,239,573	$6,116,695
Aug-16	Obligations	Buy bids	$3,203,792	$7,741,721	$2,321,385	$13,266,898
		Sell offers	$136,920	$5,656,728	$1,783,234	$7,576,882
	Options	Buy bids	$211,177	$1,772,385	$1,093,625	$3,077,187
		Sell offers	$11,798	$3,019,930	$1,524,192	$4,555,920
Sep-16	Obligations	Buy bids	$558,863	$9,639,403	$4,685,818	$14,884,083
		Sell offers	$295,989	$5,168,545	$1,776,746	$7,241,280
	Options	Buy bids	$111,025	$887,738	$559,749	$1,558,512
		Sell offers	$35,188	$2,965,495	$1,747,988	$4,748,671
Oct-16	Obligations	Buy bids	$2,451,829	$7,507,347	$3,747,301	$13,706,477
		Sell offers	$200,638	$4,545,291	$2,182,012	$6,927,941
	Options	Buy bids	$164	$473,752	$346,490	$820,406
		Sell offers	$201,432	$2,563,593	$1,496,728	$4,261,752
Nov-16	Obligations	Buy bids	$2,213,524	$6,285,598	$3,465,184	$11,964,306
		Sell offers	$56,338	$4,230,107	$1,970,692	$6,257,137
	Options	Buy bids	$27,276	$613,392	$388,626	$1,029,294
		Sell offers	$211,502	$2,076,710	$1,337,854	$3,626,066
Dec-16	Obligations	Buy bids	$4,064,286	$6,207,922	$3,281,636	$13,553,844
		Sell offers	$284,607	$4,211,838	$1,844,002	$6,340,448
	Options	Buy bids	$1,927	$437,616	$259,429	$698,971
		Sell offers	$30,617	$3,114,447	$1,833,947	$4,979,011
2015/2016*	Obligations	Buy bids	$19,822,319	$132,789,349	$90,651,090	$243,262,758
		Sell offers	($3,279,132)	$105,708,110	$76,816,631	$179,245,609
	Options	Buy bids	$34,213	$12,353,013	$7,822,858	$20,210,083
		Sell offers	$237,496	$30,375,844	$21,799,523	$52,412,863
	Net Total		$22,898,168	$9,058,407	($142,207)	$31,814,368
2016/2017**	Obligations	Buy bids	$32,240,723	$60,524,301	$26,390,146	$119,155,170
		Sell offers	$2,764,559	$46,271,990	$19,685,595	$68,722,145
	Options	Buy bids	$370,191	$8,371,455	$5,137,423	$13,879,070
		Sell offers	$550,536	$23,147,010	$13,913,146	$37,610,692
	Net Total		$29,295,819	($523,244)	($2,071,173)	$26,701,403

* Shows Twelve Months; ** Shows Seven Months

FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the first four months of the 2016 to 2017 planning period. Figure 13-11 shows the ten largest positive and negative FTR target allocations, summed by sink, for the first seven months of the 2016 to 2017 planning period. The top 10 sinks that produced financial benefit accounted for 50.6 percent of total positive target allocations during the first seven months of the 2016 to 2017 planning period with the Northern Illinois Hub accounting for 16.1 percent of all positive target allocations. The top 10 sinks that created liability accounted for 17.8 percent of total negative target allocations with the PSEG Zone accounting for 3.2 percent of all negative target allocations.

Figure 13-11 Ten largest positive and negative FTR target allocations summed by sink: 2016 to 2017 planning period

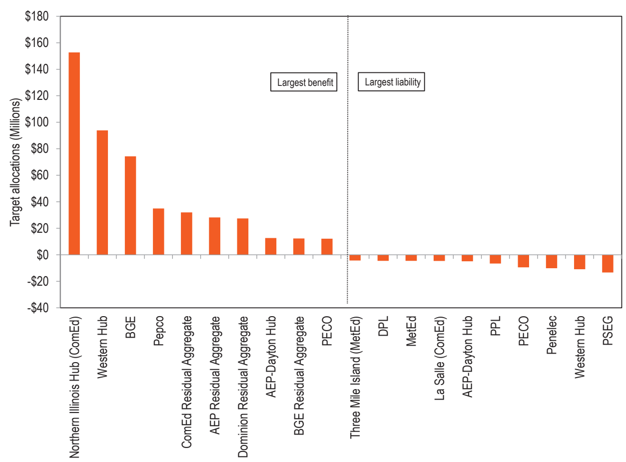
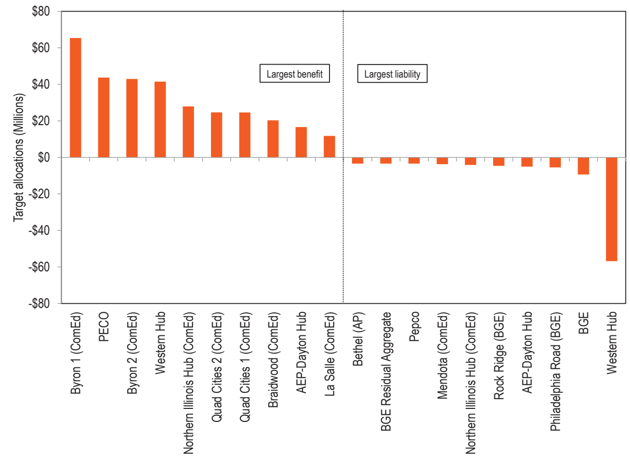


Figure 13-12 shows the ten largest positive and negative FTR target allocations, summed by source, for the first seven months of the 2016 to 2017 planning period. The top 10 sources with a positive target allocation accounted for 33.6 percent of total positive target allocations with Byron accounting for 6.9 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 24.1 percent of all negative target allocations, with the Western Hub accounting for 13.8 percent.

Figure 13-12 Ten largest positive and negative FTR target allocations summed by source: 2016 to 2017 planning period



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load in a constrained area pays more than the amount that generators receive, excluding losses, positive congestion revenue exists. The load MW exceed the generation MW in constrained areas because part of the load is served by imports using transmission capability into the constrained areas. That is why load, which pays for the transmission capability, is assigned ARRs to offset congestion in the constrained areas. Generating units that are the source of such imports are paid the price at their own bus, which does not reflect congestion in constrained areas. Generation in constrained areas receives the congestion price and all load in constrained areas pays the congestion price. As a result, load congestion payments are greater than the congestion-related payments to generation.[31] That is the source of the congestion revenue to pay holders of ARRs and FTRs. If PJM allocated FTRs equal to the transmission capability into constrained areas, FTR payouts would equal the sum of congestion.

Revenue adequacy must be distinguished from the adequacy of ARRs/FTRs as an offset against total congestion. Revenue adequacy is a narrower concept that compares total congestion revenues, including

31 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *MMU Technical Reference for PJM Markets*, at "Financial Transmission and Auction Revenue Rights."

day-ahead and balancing congestion, to the total target allocations, based only on day-ahead congestion, across the specific paths for which FTRs were available and purchased. A path specific target allocation is not a guarantee of payment. The adequacy of ARRs/FTRs as an offset for load against congestion compares ARR and self-scheduled FTR revenues to total congestion on the system.

FTRs are paid each month from congestion revenues, both day-ahead and balancing. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. For example, in June 2014, there was $2.9 million in excess congestion revenue, to be used to fund months later in the planning period that may have a revenue shortfall. 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 during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For example, the 2013 to 2014 planning period was not revenue adequate, and thus this uplift charge was collected from FTR participants. There was excess congestion revenue at the end of the 2014 to 2015 planning period, which was distributed to FTR participants in the same manner that the FTR uplift is applied.

FTR revenues are primarily comprised of hourly congestion revenue, from the day-ahead and balancing markets.[32] FTR revenues also include ARR excess revenues, which equal the difference between ARR target allocations and FTR auction revenues, and negative FTR target allocations, which are a source of revenue from FTRs with a negative target allocation. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 13-35 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates (M2M flowgates) in MISO and NYISO whose operating limits are respected by PJM.[33]

Market to market operations resulted in NYISO, MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each reciprocally coordinated flowgate (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 nonmonitoring 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 non-monitoring RTO based on the difference between the nonmonitoring RTO's market flow and their FFE.

For the 2014 to 2015, 2015 to 2016 and the first seven months of the 2016 to 2017 planning periods, PJM paid MISO and NYISO a combined $33.2 million, $41.5 million and $13.6 million for redispatch on the designated M2M flowgates. The timing of the addition of new M2M flowgates may reduce FTR funding levels. MISO's ability to add flowgates dynamically throughout the planning period, which were not modeled in any previous PJM FTR auction, may result in oversold FTRs in PJM, and as a direct consequence, reduce FTR funding.

FTRs were paid at 100 percent of the target allocation level for the 2014 to 2015 and 2015 to 2016 planning periods. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,457.1 million, $1,003.3 million and $613.2 million of FTR revenues during the 2014 to 2015, 2015 to 2016 and first seven months of the 2016 to 2017 planning periods. Congestion in January 2014 was extremely high due to

32 When hourly congestion revenues are negative, it is defined as a net negative congestion hour.

33 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 6.1 <http://pjm.com/media/documents/merged-tariffs/miso-joa.pdf>. (Accessed February 23, 2016)

cold weather events, resulting in target allocations and congestion revenues that were unusually high for 2014. For the 2015 to 2016 planning period, the top sink and top source with the highest positive FTR target allocations were the Northern Illinois Hub and Western Hub. The top sink and top source with the largest negative FTR target allocation was the Western Hub.

This high level of revenue adequacy was primarily due to actions taken by PJM to address prior low levels of revenue adequacy. PJM's actions included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs. For the 2014 to 2015 planning period, Stage 1B and Stage 2 ARR allocations were reduced by 84.9 percent and 88.1 percent from the 2013 to 2014 planning period. For the 2015 to 2016 planning period, Stage 1B and Stage 2 ARR allocations were reduced by 76.9 percent and 82.0 percent from the 2013 to 2014 planning period. The result of this change in modeling was also that available FTR capacity decreased for the planning period. This decrease resulted in an increase in FTR nodal prices for the Annual FTR Auction. The result was fewer available ARRs, but an increased dollar per MW value for those ARRs. The impact on total ARR target allocations is shown in Table 13-35 and on dollars per MW in Figure 13-4.

Table 13-35 presents the PJM FTR revenue detail for the 2015 to 2016 planning period and the first seven months of the 2016 to 2017 planning period.

Table 13-35 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2015 to 2016 and 2016 to 2017

Accounting Element	2015/2016	2016/2017
ARR information		
ARR target allocations	$963.5	$547.9
FTR auction revenue	$993.1	$560.0
ARR excess	$29.6	$12.1
FTR targets		
Positive target allocations	$1,148.8	$669.5
Negative target allocations	($209.1)	($133.0)
FTR target allocations	$939.7	$536.5
Adjustments:		
Adjustments to FTR target allocations	($0.3)	($0.4)
Total FTR targets	$939.4	$536.1
FTR revenues		
ARR excess	$29.6	$12.1
Congestion		
Net Negative Congestion (enter as negative)	($25.2)	($7.7)
Hourly congestion revenue	$1,021.0	$613.9
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($41.5)	($13.6)
Adjustments:		
Excess revenues carried forward into future months	$21.5	$8.7
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	$0.0	$0.0
Total FTR revenues		
Excess revenues distributed to other months	$21.5	$8.7
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$1,003.3	$613.2
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,003.3	$613.2
Remaining deficiency	($39.2)	($68.4)

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for FTR paths and are defined to be the revenue required to compensate FTR holders for day-ahead congestion on those paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 13-36 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies.

The total row in Table 13-36 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 2016 and October 2016 had revenue shortfalls totaling $2.6 million and $6.1 million, but were fully funded using excess revenue from previous months.

Table 13-36 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2015 to 2016 and 2016 to 2017

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Excess/Deficiency (with adjustments)
Jun-15	$103.8	$83.8	100.0%	$103.8	100.0%	$20.0
Jul-15	$88.0	$67.5	100.0%	$88.0	100.0%	$20.5
Aug-15	$57.3	$47.6	100.0%	$57.3	100.0%	$9.7
Sep-15	$77.5	$76.6	100.0%	$77.5	100.0%	$0.9
Oct-15	$84.8	$82.6	100.0%	$82.6	100.0%	$2.2
Nov-15	$91.9	$92.3	99.5%	$92.3	100.0%	($0.4)
Dec-15	$66.1	$69.1	95.6%	$69.1	100.0%	($3.0)
Jan-16	$105.7	$102.1	100.0%	$102.1	100.0%	($3.7)
Feb-16	$110.5	$103.7	100.0%	$103.7	100.0%	($6.8)
Mar-16	$75.4	$80.2	94.1%	$80.2	100.0%	$4.7
Apr-16	$71.4	$82.6	86.4%	$82.6	100.0%	$11.3
May-16	$49.2	$51.6	95.4%	$51.6	100.0%	$2.4
Summary for Planning Period 2015 to 2016						
Total	$981.6	$939.6		$990.8	100.0%	$57.7
Jun-16	$60.5	$55.1	100.0%	$60.5	100.0%	($5.4)
Jul-16	$112.1	$87.1	100.0%	$112.1	100.0%	($24.9)
Aug-16	$110.9	$82.2	100.0%	$110.9	100.0%	($28.7)
Sep-16	$117.7	$120.4	97.7%	$120.4	100.0%	$2.6
Oct-16	$104.9	$110.9	94.5%	$110.9	100.0%	$6.1
Nov-16	$45.7	$38.2	100.0%	$45.7	100.0%	($7.4)
Dec-16	$52.9	$42.3	100.0%	$52.9	100.0%	($10.7)
Summary for Planning Period 2016 to 2017						
Total	$604.7	$536.1		$613.3		($68.4)

Figure 13-13 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through December 2015. The months with payout ratios above 100 percent have excess congestion revenue and the months with payout ratios under 100 percent are revenue inadequate. Figure 13-13 also shows the payout ratio after distributing excess revenue across months within the planning period. If there are excess revenues in a given month, the excess is distributed to other months within the planning period that were revenue deficient. The payout ratio for revenue inadequate months in the current planning period may change if excess revenue is collected in the remainder of the planning period. March 2015 had high levels of negative balancing congestion that resulted in a payout ratio of 64.6 percent. However, there was enough excess from previous months to bring the payout ratio to 100 percent.

Figure 13-13 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through December 2016

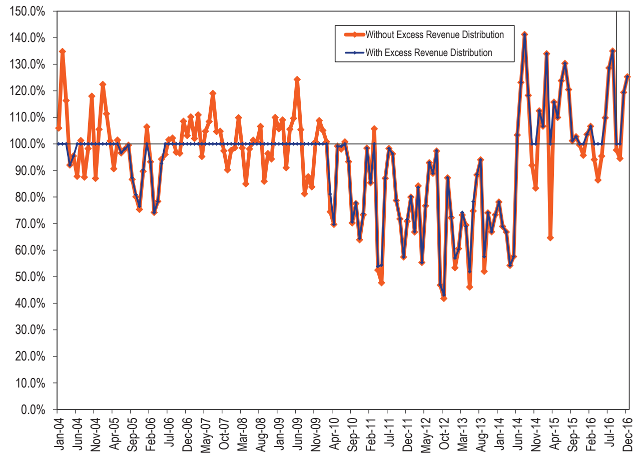


Table 13-37 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward. Planning period 2013 to 2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For the 2014 to 2015 and 2015 to 2016 planning periods, there was excess congestion revenue to pay target allocations resulting in a payout ratio of 116.2 percent and 106.8 percent for the planning periods. This excess will be distributed to all FTR participants, pro rata, based on their net positive target allocations.

Table 13-37 PJM reported FTR payout ratio by planning period

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	72.8%
2014/2015	100.0%
2015/2016	100.0%
2016/2017	100.0%

FTR Uplift Charge

At the end of the planning period, an uplift charge is applied to FTR holders. This charge is to cover the net of the monthly deficiencies in the target allocations calculated for individual participants. An individual participant's uplift charge is a pro rata charge, to cover this deficiency, based on their net target allocation with respect to the total net target allocation of all participants with net positive target allocations for the planning period. Participants pay an uplift charge that is a ratio of their share of net positive target allocations to the total net positive target allocations.

The uplift charge is only applied to, and calculated from, members with a net positive target allocation at the end of the planning period. Members with a net negative target allocation have their year-end target allocation set to zero for all uplift calculations. Since participants in the FTR Market with net positive target allocations are paying the uplift charge to fully fund FTRs, their payout ratio cannot be 100 percent. The end of planning period payout ratio is calculated as the participant's target allocations minus the uplift charge applied to them divided by their target allocations. The calculations of uplift are structured so that, at the end of the planning period, every participant in the FTR Market with a positive net target allocation receives payments based on the same payout ratio. At the end of the planning period and the end of a given month no payout ratio is actually applied to a participant's target allocations. The payout ratio is simply used as a reporting mechanism to demonstrate the amount of revenue available to pay target allocations and represent the percentage of target allocations a participant with a net positive portfolio has been paid for the planning period. However, this same calculation is not accurate when calculating a single month's payout ratio as currently reported, where the calculation of available revenue is not the same.

The total planning period target allocation deficiency is the sum of the monthly deficiencies throughout the planning period. The monthly deficiency is the difference in the net target allocation of all participants and the total revenue collected for that month. The total revenue paid to FTR holders is based on the hourly congestion revenue collected, which includes hourly M2M, wheel payments and unallocated congestion credits.

Table 13-38 provides a demonstration of how the FTR uplift charge is calculated. In this example it is important to note that the sum of the net positive target allocations is $32 and the total monthly deficiency is $10. The uplift charge is structured so that those with higher target allocations pay more of the deficit, which ultimately impacts their net payout. Also, in this example, and in the PJM settlement process, the monthly payout ratio varies for all participants, but the uplift charge is structured so that once the uplift charge is applied the end of planning period payout ratio is the same for all participants.

For the 2012 to 2013 planning period, the total deficiency was $291.8 million. The top ten participants with the highest target allocations paid 53.6 percent of the total deficiency for the planning period. All of the uplift money is collected from individual participants, and distributed so that every participant experiences the same payout ratio. This means that some participants subsidize others and receive less payout from their FTRs after the uplift is applied, while others receive a subsidy and get a higher payout after the uplift is applied. In this example, participants 1 and 5 are paid less after the uplift charge is applied, while participants 3 and 4 are paid more.

Table 13-38 End of planning period FTR uplift charge example

Participant	Net Target Allocation	Total Monthly Payment	Monthly Deficiency	Uplift Charge	Net Payout	Payout Change	Monthly Payout Ratio	EOPP Payout Ratio
1	$10.00	$8.00	$2.00	$3.13	$6.88	($1.13)	80.0%	68.8%
2	($4.00)	$0.00	$0.00	$0.00	($4.00)	$0.00	100.0%	100.0%
3	$15.00	$10.00	$5.00	$4.69	$10.31	$0.31	66.7%	68.8%
4	$3.00	$1.00	$2.00	$0.94	$2.06	$1.06	33.3%	68.8%
5	$4.00	$3.00	$1.00	$1.25	$2.75	($0.25)	75.0%	68.8%
Total	$28.00	$22.00	$10.00	$10.00	$18.00	$0.00		

Revenue Adequacy Issues and Solutions

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues. The reasons include unavoidable modeling differences, avoidable modeling differences, such as outage modeling decisions, cross subsidies among and between FTR participants ARR holders and the construction of the Stage 1A ARR system which is based on historical, rather than physical, pathways.

The issuance of the September 15, 2016 FERC order increases the gap between congestion revenue and ARR/FTR revenue collected. Allocating balancing congestion and M2M payments, along with allocating excess congestion revenue to FTR holders solely, increases revenue adequacy for FTRs, but reduces payments to load and increases costs to load, undermining the ability of load to offset their congestion costs. Supporting FTR portfolio netting leads to cross subsidies among FTR participants. Restructuring Stage 1A allocations using QRRs for retired resources is an attempt to fix a flawed system, but retains the core problem which is reliance on contract path congestion revenue rights. The accepted rule change does not address the problem with using contract paths, does not address the deficiencies for active units and gives priority to units based on financial, not physical, determinations. The purpose of the FTR/ARR system is to return congestion revenue to load. The current and newly accepted rules do not meet this goal.

Netting Target Allocations within Portfolios

Currently, FTR target allocations are netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. Elimination of portfolio netting would correctly account for negative target allocations as a source of revenue to pay positive target allocations. It would also apply the payout ratio directly to a participant's positive target allocations before subtracting negative target allocations, rather than applying the payout ratio to a participant's net portfolio. Applying the payout ratio to a participant's net portfolio, results in unequal payout ratios depending on a participant's portfolio construction.

The current method requires those with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. But all FTRs with positive target allocations should be treated in exactly the same way, which would eliminate this form of cross subsidy.

For example, a participant has $200 of positive target allocation FTRs and $100 of negative target allocation FTRs and the payout ratio is 80 percent. Under the current method, the positive and negative positions are first netted to $100 and then the payout ratio is applied. In this example, the holder of the portfolio would receive 80 percent of $100, or $80.

The correct method would first apply the payout ratio to FTRs with positive target allocations and then net FTRs with negative target allocations. In the example, the 80 percent payout ratio would first be applied to the positive target allocation FTRs, 80 percent of $200 is $160. Then the negative target allocation FTRs would be netted against the positive target allocation FTRs, $160 minus $100, so that the holder of the portfolio would receive $60.

If done correctly, the payout ratio would also change, although the total net payments made to or from participants would not change. The sum of all positive and negative target allocations is the same in both methods. The net result of this change would be that holders of portfolios with smaller shares of negative target allocation FTRs would no longer subsidize holders of portfolios with larger shares of negative target allocation FTRs.

Under the current method all participants with a net positive target allocation in a month are paid a payout ratio based on each participant's net portfolio position. The correct approach would calculate payouts to FTRs with positive target allocations, without netting in an hour. This would treat all FTRs the same, regardless of a participant's portfolio. This approach would also eliminate the requirement that participants with larger shares of positive target allocation FTRs subsidize participants with larger shares of negative target allocation FTRs.

Elimination of portfolio netting should also be applied to the end of planning period FTR uplift calculation. With this approach, negative target allocations would not offset positive target allocations at the end of the planning period when allocating uplift. The FTR uplift charge would be based on participants' share of the total positive target allocations paid for the planning period.

Table 13-39 shows an example of the effects of calculating FTR payouts on a per FTR basis rather than the current method of portfolio netting for four hypothetical organizations for an example hour. In this example, there was $45 in congestion revenue collected, which results in a payout ratio of 39.1 percent for positive target allocations when ignoring any contribution by negative or net negative target allocations. With portfolio netting, the total revenue available to pay positive target allocations is $50, which is the $45 in congestion collected plus the $5 generated by the net negative target allocation of Participant 4, which results in a payout ratio of 41.7 percent for net positive target allocations. Without portfolio netting there is $110 in total revenue available, which is the $45 in congestion collected plus the $65 in negative target allocations from all participants, which results in a payout ratio of 61.1 percent for positive target allocations.

The positive and negative TA columns show the total positive and negative target allocations, calculated separately, for each organization. The percent negative target allocations is the share of the portfolio which is negative target allocation FTRs. The net target allocation is the net of the positive and negative target allocations for the given hour. The FTR netting payout column shows what a participant would see on their bill, including payout ratio adjustments, under the current method. The per FTR payout column shows what a participant would see on their bill, including payout ratio adjustments, if FTR target allocations were done correctly. In this example, the actual monthly payout ratio is 41.7 percent. If portfolio netting were eliminated, the actual monthly payout ratio would rise to 61.1 percent.

This table shows the effects of a per FTR target allocation calculation on individual participants. The total payout does not change, but the allocation across individual participants does.

The largest change in payout is for participants 1 and 2. Participant 1, who has a large proportion of FTRs with negative target allocations, receives less payment. Participant 2, who has no negative target allocations, receives more payment.

Table 13-39 Example of FTR payouts from portfolio netting and without portfolio netting

Participant	Positive Target Allocation	Negative Target Allocation	Percent Negative Target Allocation	Net TA	FTR Netting Payout (Current)	No Netting Payout (Proposed)	Percent Change
1	$60.00	($40.00)	66.7%	$20.00	$8.33	($3.33)	(140.0%)
2	$30.00	$0.00	0.0%	$30.00	$12.50	$18.33	46.7%
3	$90.00	($20.00)	22.2%	$70.00	$29.17	$35.00	20.0%
4	$0.00	($5.00)	100.0%	($5.00)	($5.00)	($5.00)	0.0%
Total	$180.00	($65.00)	-	$115.00	$45.00	$45.00	-

Table 13-40 shows the total value for the 2014 to 2015 and 2015 to 2016 planning periods of FTRs with positive and negative target allocations. The Net Positive Target Allocation column shows the value of all portfolios with an hourly net positive value after negative target allocation FTRs are netted against positive target allocation FTRs. The Net Negative Target Allocation column shows the value of all portfolios with an hourly net negative value after negative target allocation FTRs are netted against positive target allocation FTRs. The Per FTR Positive Allocation column shows the total value of the hourly positive target allocation FTRs without netting. The Per Negative Allocation column shows the total value of the hourly negative target allocation FTRs without netting.

The Reported Payout Ratio column is the monthly payout ratio as currently reported by PJM, calculated as total revenue divided by the sum of the net positive and net negative target allocations. The No Netting FTR Payout Ratio column is the payout ratio that participants with positive target allocations would receive if FTR payouts were calculated without portfolio netting, calculated by dividing the total revenue minus the per FTR negative target allocation by the per FTR positive target allocations. The total revenue available to fund the holders of positive target allocation FTRs is calculated by adding any negative target allocations to the congestion credits for that month.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio for the 2013 to 2014 planning period would have been 87.5 percent instead of the reported 72.8. For the 2014 to 2015 and 2015 to 2016 planning periods there was no revenue inadequacy, so eliminating portfolio netting would have no effect. September 2016 experienced revenue inadequacy, but excess revenue was distributed from previous months to ensure full funding. For months with no revenue inadequacies there is no change in payout ratio.

Table 13-40 Monthly positive and negative target allocations and payout ratios with and without hourly netting: Planning period 2015 to 2016 and 2016 to 2017

	Net Positive Target Allocations	Net Negative Target Allocations	Per FTR Positive Target Allocations	Per FTR Negative Target Allocations	Total Congestion Revenue	Reported Payout Ratio (Current)	No Netting Payout Ratio (Proposed)
Jun-16	$66,890,503	($11,761,810)	$145,725,072	($90,578,663)	$60,547,574	100.0%	100.0%
Jul-16	$103,067,704	($15,947,225)	$234,908,328	($147,750,891)	$112,060,353	100.0%	100.0%
Aug-16	$106,463,071	($24,309,023)	$270,738,798	($188,528,046)	$110,872,528	100.0%	100.0%
Sep-16	$143,711,526	($23,349,848)	$334,869,805	($214,320,300)	$120,361,723	100.0%	100.0%
Oct-16	$140,704,976	($29,766,159)	$322,466,349	($211,484,113)	$110,938,816	100.0%	100.0%
Nov-16	$50,418,317	($12,156,919)	$124,242,433	($85,964,032)	$45,658,421	100.0%	100.0%
Dec-16	$58,101,556	($15,818,469)	$164,917,652	($122,634,566)	$52,937,720	100.0%	100.0%
2015/2016 Total	$1,148,845,079	($206,167,602)	$2,970,405,028	($2,030,832,071)	$1,003,307,668	100.0%	100.0%
2016/2017* Total	$669,357,653	($133,109,453)	$1,597,868,436	($1,061,260,610)	$613,377,135	100.0%	100.0%

*First seven months of 2016 to 2017 planning period

Portfolio Dependent Payout Ratio

Under the current portfolio netting rules, negative target allocations are first netted against positive, and then the payout ratio is applied. This results in two significant problems with the current method. First is that a participant can shield itself from both monthly revenue inadequacy and the end of planning period uplift charge by shrinking the size of their positive target allocations. This is advantageous because the participant can still be profiting from their negative target allocations if they are paid to take counter flow positions and pay back less than they received. Additionally, it results in positive target allocations receiving different payout ratios depending on the composition of the portfolio they are in. All positive target allocation FTR should be treated equally, regardless of the portfolio they are in, and this can only be accomplished by eliminating portfolio netting. Not treating all FTRs equally results in participants with more negative target allocations receiving a subsidy by reducing the effective payout ratio to participants with fewer negative target allocations. The reduced payouts to participants with fewer negative target allocations subsidize increased payout ratios to participants with larger negative target allocations, and is an unbalanced distribution of available congestion revenue collected.

Table 13-41 demonstrates the impact on the payout ratio to positive target allocation FTRs with and without portfolio netting. In the example the total congestion collected is $4,750 and the total net target allocation is $9,500, resulting in a reported payout ratio of 50.0 percent. With portfolio netting, the net target allocation is simply multiplied by the payout ratio to calculate the congestion revenue a participant receives. For Participant 1, this is $250 multiplied by 0.5 for a total revenue received of $125. The revenue to positive TA column is an indication of how much revenue the positive target allocations, which are the only part of a portfolio receiving available revenue, of a participant need to be paid in order to reach the congestion revenue received. For participant 1, they are effectively being paid $875 of their $1,000 so that the congestion revenue received can be $125. Another way to state this is the participant is effectively paying themselves their negative target allocations first, and then receiving revenue based on their net target allocation. The result of this is that Participant 1's positive target allocations are effectively granted a payout ratio of 87.5 percent simply because they hold negative target allocations, while Participant 3, who holds no negative target allocations, is only paid at a 50.0 percent payout ratio.

Without portfolio netting all participants are paid at the same effective payout ratio for their positive target allocations. Counting negative target allocations as a source of revenue raises the payout ratio to 54.5 percent. Without portfolio netting, the payout ratio is first applied to positive target allocations, then the participant's negative target allocations are added. The result of this calculation is that each participant is paid an equal 54.5 percent regardless of their portfolio's negative target allocations. In this example Participant 1 pays ends up paying $204.55 into the congestion pot, in net, while Participant 3 is paid 54.5 percent of the positive target allocations, resulting in a payment of $4,745.45. Eliminating portfolio netting is the only way to treat positive target allocations equally across all portfolios, and eliminates the subsidy positive target allocations holders are paying to negative target allocation holders.

Mathematically Equivalent FTRs

A single FTR can be broken into multiple FTRs. The newly formed set of multiple FTRs can have the same net target allocation as long as the start and end points of the constituent end points are, in net, the same as the original. Opponents of the elimination of FTR netting have claimed that without netting this would no longer be true. However, this assertion does not account for revenues from negative target allocation FTR paths in the mathematically equivalent set of FTRs. Appropriately including these revenues results in mathematical equivalence between the single FTR and that same FTR broken into a constituent set of FTRs with the same start and end point.

Table 13-43 shows the effects on a participant with and without portfolio netting under three distinct scenarios. Table 13-42 provides the day-ahead CLMP values for each node used in the example. In this example, a participant can either buy an FTR position directly from

Table 13-41 Change in positive target allocation payout ratio given portfolio construction

Congestion = $4,750 Net TA = $9,500					With Netting			Without Netting		
Participant	Positive Target Allocations	Negative Target Allocations	Net Target Allocations	Reported Payout Ratio	Congestion Revenue Received	Revenue to Positive TA	Calculated Positive TA Payout Ratio	Congestion Revenue Received	Revenue to Positive TA	Calculated Positive TA Payout Ratio
1	$1,000.00	($750.00)	$250.00	50.0%	$125.00	$875.00	87.5%	($204.55)	$545.45	54.5%
2	$750.00	($200.00)	$550.00	50.0%	$275.00	$475.00	63.3%	$209.09	$409.09	54.5%
3	$8,700.00	$0.00	$8,700.00	50.0%	$4,350.00	$4,350.00	50.0%	$4,745.45	$4,745.45	54.5%
Total	$10,450.00	($950.00)	$9,500.00	-	$4,750.00	$5,700.00	-	$4,750.00	$5,700.00	-

A to B or can break it into individual pieces with the net effect of an FTR from A to B with a net target allocation of $5. In this example, there was $3.60 in congestion collected, due to a payout ratio of 72.0 percent and a total payout in each of the three scenarios of $3.60. This payout amount is simply the payout ratio of 72.0 percent multiplied by the net target allocations of $5 in each scenario.

With the elimination of netting, if the additional revenue created by considering positive and negative target allocations separately is disregarded, it appears as if the payout for the same net FTR is drastically different depending on the composition of the FTR. The results of this mistake are payouts of $3.60, -$0.60 and -$25.80 for the same net FTR in each distinct scenario. However, if the negative target allocations are properly accounted for as a source of revenue when considering congestion collected, the total revenue available increases thereby increasing the payout ratio for each scenario's positive target allocations. The total revenue available is the $3.60 in congestion collected plus the negative target allocations, resulting in revenue available to pay positive target allocations of $3.60, $18.60 and $108.60 with payout ratios to positive target allocations of 72.0 percent (unchanged due to no negative target allocations), 93.0 percent and 98.7 percent. Multiplying these correct payout ratios by the scenario's positive target allocations, and then adding the scenario's negative target allocations results in a net payout of $3.60 for each scenario.

Table 13-42 Nodal day-ahead CLMPs

Node	DA CLMP
A	$20
B	$25
C	$40
D	$100
E	$10

Table 13-43 Mathematically equivalent FTR payments with and without portfolio netting

FTR Path(s)	Positive TA	Negative TA	Net TA	Available Revenue Netting	Netting Revenue Received	No Netting Revenue Received (Incorrect)	Available Revenue No Netting	Payout Ratio No Netting	Correct No Netting Revenue Received
A-B	$5.00	$0.00	$5.00	$3.60	$3.60	$3.60	$3.60	72.0%	$3.60
A-C, C-B	$20.00	($15.00)	$5.00	$3.60	$3.60	($0.60)	$18.60	93.0%	$3.60
A-C, C-E, E-D, D-B	$110.00	($105.00)	$5.00	$3.60	$3.60	($25.80)	$108.60	98.7%	$3.60

The results of this example demonstrate the mathematical fact that no matter how an FTR path is constructed, as a single FTR or a mathematically equivalent set of FTRs, the total payment the FTR path will be the same. Attempts to disprove this ignore the revenues from the constituent FTR counter flow positions and the resulting change in payout ratio that is experienced by positive target allocations. A net FTR may be constructed in any manner and the resultant total payout will be equivalent with and without portfolio netting.

FERC Order on FTRs: Portfolio Netting

On September 15, 2016, FERC decided that PJM's current practice of portfolio netting was just and reasonable.[34] FERC did not agree that portfolio netting led to subsidization of portfolios with counterflow positions. The Market Monitor and PJM demonstrated that eliminating portfolio netting would eliminate a cross subsidy among FTR portfolios without changing the amount of total revenue available revenue to pay to portfolios.

Counter Flow FTRs and Revenues

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. The payout to the holders of counter flow FTRs is not affected when the payout ratio is less than 100 percent. There is no reason for that asymmetric treatment.

For a prevailing flow FTR, the target allocation would be subject to a reduced payout ratio, while a counter flow FTR holder would not be subject to the reduced payout ratio. The profitability of the prevailing flow FTRs is affected by the payout ratio while the profitability of the counter flow FTRs is not affected by the payout ratio.

34 *See* 156 FERC ¶ 61,180 (2016).

Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocation FTRs are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

A counter flow FTR is profitable if the hourly negative target allocation is smaller than the hourly auction payment they received. A prevailing flow FTR is profitable if the hourly positive target allocation is larger than the auction payment they made.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount, parallel to the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide funding between counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations.

Table 13-44 provides an example of how the counter flow adjustment method would impact a two FTR system. In this example, there is $15 of total congestion revenue available, corresponding to a reported payout ratio of 75 percent and an actual payout ratio of 87.5 percent. In the example, the profit is shown with and without the counter flow adjustment. As the example shows, the profit of a counter flow FTR does not change when there is a payout ratio less than 100 percent, while the profit of a prevailing flow FTR is reduced. Applying the payout ratio to counter flow FTRs distributes the funding penalty evenly to both prevailing and counter flow FTR holders.

Table 13-44 Example implementation of counter flow adjustment method

	Prevailing A-B 10MW	Counter C-D 10MW
Auction Cost	$50.00	($30.00)
Target Allocation	$40.00	($20.00)
Payout	$30.00	($20.00)
Profit without revenue inadequacy	($10.00)	$10.00
Profit after revenue inadequacy	($20.00)	$10.00
Payout for Positive TA	$35.00	($20.00)
Profit for Positive TA	($15.00)	$10.00
Payout after CF Adjustment	$36.67	($21.67)
Profit after CF Adjustment	($13.33)	$8.33
Profit Difference	$1.67	($1.67)

Table 13-45 shows the monthly positive, negative and total target allocations.[35] Table 13-45 also shows the total congestion revenue available to fund FTRs, as well as the total revenue available to fund positive target allocation FTR holders on a per FTR basis and on a per FTR basis with counter flow payout adjustments. Implementing this change to the payout ratio for counter flow FTRs would result in an additional $188.4 million (27.8 percent of difference between revenues and total target allocations) in revenue available to fund positive target allocations for the 2013 to 2014 planning period. If this change were implemented after excess planning period revenue was distributed, it would not result in additional revenue for the 2014 to 2015, 2015 to 2016 or 2016 to 2017 planning periods. However, if this change were implemented before excess planning period revenues were distributed, there would be an increase in the revenue available each month to pay prevailing flow FTRs, resulting in a decrease in the amount of excess from previous months that needs to be used to achieve revenue adequacy. This can be seen as a slight difference in the total revenue and adjusted counter flow total revenue columns for March, April, May and September 2016 that were not revenue adequate. The result of this would be $4.3 million in additional revenue generated for the 2015 to 2016 planning period.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio for the 2013 to 2014 planning period from the reported 72.8 percent to 91.0 percent. For months with no revenue inadequacies there is no change in payout ratio.

35 Reported payout ratio may differ between Table 13-40 and Table 13-45 due to rounding differences when netting target allocations and considering each FTR individually.

Table 13-45 Counter flow FTR payout ratio adjustment impacts: Planning period 2015 to 2016 and 2016 to 2017

	Positive Target Allocations	Negative Target Allocations	Total Target Allocations	Total Congestion Revenue	Reported Payout Ratio*	Total Revenue Available	Adjusted Prevailing Flow Payout Ratio	Adjusted Counter Flow Payout Ratio	Adjusted Counter Flow Revenue Available	Additional Revenue Generated
Jan-16	$321,877,316	($219,805,629)	$102,071,687	$111,640,380	100.0%	$331,446,009	100.0%	100.0%	$331,446,009	$0
Feb-16	$315,314,260	($211,591,605)	$103,722,655	$116,388,192	100.0%	$327,979,798	100.0%	100.0%	$327,979,798	$0
Mar-16	$309,689,295	($229,412,325)	$80,276,969	$75,303,718	100.0%	$304,716,044	100.0%	100.0%	$306,379,919	$1,663,876
Apr-16	$286,739,441	($204,102,945)	$82,636,496	$79,920,761	100.0%	$284,023,706	100.0%	100.0%	$284,895,369	$871,662
May-16	$192,044,982	($140,414,905)	$51,630,077	$49,689,877	100.0%	$190,104,782	100.0%	100.0%	$190,780,714	$675,932
Jun-16	$145,725,072	($90,578,663)	$55,146,409	$60,547,574	100.0%	$151,126,237	100.0%	100.0%	$151,126,237	$0
Jul-16	$234,908,328	($147,750,891)	$87,157,436	$112,060,353	100.0%	$259,811,244	100.0%	100.0%	$259,811,244	$0
Aug-16	$270,738,798	($188,528,046)	$82,210,752	$110,872,528	100.0%	$299,400,574	100.0%	100.0%	$299,400,574	$0
Sep-16	$334,869,805	($214,320,300)	$120,549,505	$120,361,678	100.0%	$334,681,978	100.0%	100.0%	$334,742,412	$60,435
Oct-16	$322,466,349	($211,484,113)	$110,982,236	$110,938,816	100.0%	$322,422,929	100.0%	100.0%	$322,437,170	$14,241
Nov-16	$124,242,433	($85,964,032)	$38,278,401	$45,658,421	100.0%	$131,622,453	100.0%	100.0%	$131,622,453	$0
Dec-16	$164,917,652	($122,634,565)	$42,283,086	$52,937,720	100.0%	$175,572,286	100.0%	100.0%	$175,572,286	$0
Total 2015/2016	$2,970,404,365	($2,030,831,660)	$939,572,706	$1,002,235,633	100.0%	$3,033,067,292	100.0%	100.0%	$3,037,387,376	$4,320,084
Total 2016/2017	$1,597,868,436	($1,061,260,610)	$536,607,826	$613,377,090	100.0%	$1,674,637,700	100.0%	100.0%	$1,597,711,865	$74,676

* Reported payout ratios may vary due to rounding differences when netting

Figure 13-14 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through December 2016. May 2016 had positive total balancing congestion of $7.5 million. March 2015 had balancing congestion of -$70.0 million.

Figure 13-14 FTR surplus and the collected day-ahead, balancing and total congestion: January 2005 through December 2016

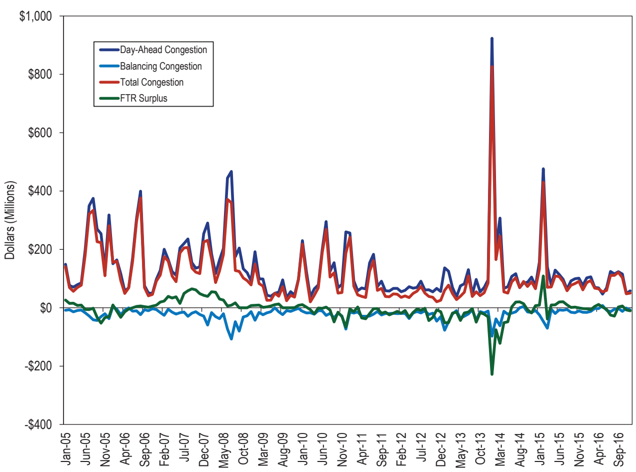
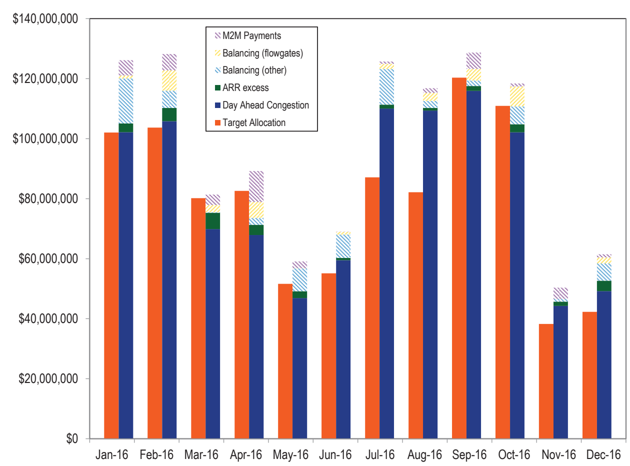


Figure 13-15 shows the relationship among monthly target allocations, balancing congestion, M2M payments and day-ahead congestion. The left column is the target allocations for all FTRs for the month. The total height of the right column is day-ahead congestion revenues and the stripes are reductions to total congestion revenues. When the total height of the solid segments in the right column exceeds the height of the left column, the month is revenue adequate. For example, February 2016 was revenue adequate by $6.8 million. March was revenue inadequate by $4.9 million, but there was enough excess revenue in other months in the planning period to fully fund the month.

Figure 13-15 FTR target allocation compared to sources of positive and negative congestion revenue



ARRs as an Offset to Congestion for Load

Load pays for the transmission system and contributes congestion revenues. FTRs and later ARRs were intended to return congestion revenues to load. With the implementation of the current FTR/ARR design, other participants are allowed to receive a portion of the congestion revenues.

Table 13-46 compares the revenue received by ARR holders and total congestion for the 2011 to 2012 through the first seven months of the 2016 to 2017 planning period. This compares the total offset provided to all ARR holders including all ARRs converted to self scheduled FTRs to the total congestion revenues. ARR credits are calculated as the product of the ARR MW and the cleared price of the ARR path from the Annual FTR Auction. The FTR credits represent the total self scheduled FTR target allocations for FTRs held by ARR holders, adjusted by the FTR payout ratio. ARR holders that elect to self schedule FTRs are paid the daily ARR credits for the ARR, and then pay the daily auction price of the self scheduled FTRs, netting the cost of the FTRs to zero. This is accounted for in the ARR credits column by subtracting the cost of the FTR from the ARR credits.

The total ARR/FTR offset is the sum of the ARR and self scheduled FTR credits. The congestion column shows the total amount of congestion collected in the Day-Ahead Energy Market and the balancing energy market. The percent offset is the percent of total, system wide, congestion offset by ARR and self scheduled FTR credits that ARR holders receive.

Table 13-46 shows the offset provided by ARRs and self scheduled FTRs for the entire 2011 to 2012 through the 2016 to 2017 planning period. This offset reflects the share of congestion revenues returned to loads. ARR and FTR revenues offset 44.7 percent of Day-Ahead Energy Market and the balancing energy market for the 2013 to 2014 planning period and 63.8 percent for the 2014 to 2015 planning period. For the 2015 to 2016 planning period ARRs and self scheduled FTRs offset 86.5 percent of total congestion costs. For the first seven months of the 2016 to 2017 planning period ARRs and self scheduled FTRs offset 82.3 percent of total congestion costs. Over the last six planning periods 70.9 percent of total congestion costs have been offset through ARRs and FTRs.

This demonstrates the inadequacies of the current ARR/FTR design. The goal of the design should be to return 100 percent of the congestion revenues to the load. But the actual results fall well short of that goal. The current allocation of congestion revenue resulted in a total of $1,780.6 million in unreturned congestion revenue to ARR holders, and a 70.9 percent congestion offset, over the last six planning periods.

Table 13-46 ARR and FTR total congestion offset (in millions) for ARR holders: Planning periods 2011 to 2012 through 2016 to 2017

Planning Period	ARR Credits	FTR Credits	Total Congestion	Total ARR/ FTR Offset	Percent Offset	Unreturned Revenue
2011/2012	$512.2	$249.8	$770.6	$762.0	98.9%	$8.5
2012/2013	$349.5	$181.9	$575.8	$531.4	92.3%	$44.4
2013/2014	$337.7	$456.4	$1,777.1	$794.0	44.7%	$983.1
2014/2015	$482.4	$404.4	$1,390.9	$886.8	63.8%	$504.1
2015/2016	$635.3	$223.4	$992.6	$858.8	86.5%	$133.8
2016/2017	$375.2	$122.2	$604.1	$497.5	82.3%	$106.7
Total	$2,692.4	$1,638.1	$6,111.0	$4,330.5	70.9%	$1,780.6

FERC Order on FTRs: Balancing Congestion and M2M Payment Allocation

On September 15, 2016, FERC issued an order removing balancing congestion and market to market (M2M) payments from the FTR funding equation and assigned them, on a load ratio basis, to load and exports.[36]

This order will go into effect on June 1, 2017, for the 2017 to 2018 planning period.

In its compliance filing PJM redefined balancing congestion as balancing congestion plus market to market (M2M) payments between MISO and NYISO. Under the order, load and exports will pay balancing congestion and M2M payments proportionally. On average from the 2011 to 2012 planning period on, load comprises 94.8 percent of all demand. From the 2011 to 2012 planning period onward, total balancing congestion and M2M payments were $1,496.3 million, so load would have been responsible for 94.8 percent, or an additional $1,418.4 million in charges to subsidize FTR holders.

36 *See* 156 FERC ¶ 61,180 (2016).

In addition, FERC ordered that all excess congestion revenue, which includes day-ahead congestion in excess of FTR target allocations and excess FTR auction revenue, belongs to FTR holders. PJM initially proposed returning excess day-ahead and excess FTR auction revenue to ARR holders, but that proposal was rejected by FERC. Under this new rule, for the 2011 to 2012 through 2016 to 2017 planning period FTR holders would have receive an additional $896.1 million over their target allocations.

The Market Monitor continues to propose that excess FTR auction revenue should be allocated to ARR holders and all congestion rents, including balancing congestion, should be allocated to FTRs.

The reallocation of balancing congestion and M2M payments from FTR holders to load, and the allocation of excess auction revenues to FTR holders subsidizes FTR holders at the expense of ARR holders. It is inconsistent with the logic that FTRs are a day-ahead only product because excess auction revenues are not day-ahead revenues.

Table 13-47 shows the share of total congestion that is offset by ARRs and FTRs for load for the 2011 to 2012 through 2016 to 2017 planning periods. Table 13-47 shows the congestion offset available to load under the current rules. Table 13-47 also shows what the congestion offset available to load would be under the new rules, the change in the congestion offset available to load and the overpayment to FTRs under the new rules. The new congestion offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total congestion and the load share of balancing and M2M payments. The proposed new revenue is the sum of the ARR credits, adjusted FTR credits and the load share of balancing congestion and M2M payments. The FTR over payment is the excess day-ahead congestion revenue and excess auction revenue FTR holders received over their FTR target allocations.

If these rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received $996.7 million less in congestion offsets from the 2011/2012 through the 2016/2017 planning period. The total overpayment to FTR holders for the 2011/2012 through 2016/2017 planning period would have been $896.1 million. The underpayment to load and the overpayment to FTR holders is a result of several factors in the new rules all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is now required to pay for balancing congestion, which significantly increases costs to load and significantly increases revenues paid to FTR holders. PJM will continue to clear counter flow FTRs using excess auction revenues in order to make it possible to sell more prevailing flow FTRs. FTR holders will receive excess day-ahead congestion revenues in excess of target allocations. FTR holders will receive excess auction revenue, which is what FTR holders were willing to pay for FTRs in excess of what is provided to ARR holders.

Table 13-47 ARR and FTR total congestion offset (in millions) for ARR holders under PJM's proposed FTR funding: Planning periods 2011 to 2012 through 2016 to 2017

	Old					Proposed				
Planning Period	ARR Credits	FTR Credits	Total Congestion	Total ARR/ FTR Offset	Percent Offset	New Offset	Old Revenue Received	New Revenue Received	ARR Holder Change	FTR Over Payment
2011/2012	$512.2	$249.8	$770.6	$762.0	98.9%	83.3%	$762.0	$598.6	($163.4)	$113.9
2012/2013	$349.5	$181.9	$575.8	$531.4	92.3%	68.0%	$531.4	$275.9	($255.5)	$62.1
2013/2014	$337.7	$456.4	$1,777.1	$794.0	44.7%	43.2%	$794.0	$574.1	($219.9)	$0.0
2014/2015	$482.4	$404.4	$1,390.9	$886.8	63.8%	57.2%	$886.8	$686.6	($200.2)	$400.6
2015/2016	$635.3	$223.4	$992.6	$858.8	86.5%	78.2%	$858.8	$744.8	($113.9)	$188.9
2016/2017	$375.2	$122.2	$604.1	$497.5	82.3%	77.4%	$497.5	$453.7	($43.8)	$130.7
Total	$2,692.4	$1,638.1	$6,111.0	$4,330.5	70.9%	63.1%	$4,330.5	$3,333.8	($996.7)	$896.1

Credit Issues

There was one collateral default in 2016 which was promptly resolved.

FTR Forfeitures

An FTR holder may be subject to forfeiture of any profits from an FTR if it meets the criteria defined in Section 5.2.1 (b) of Schedule 1 of the PJM Operating Agreement. If a participant has a cleared increment offer or decrement bid for an applicable hour at or near the source or sink of any FTR they own and the day-ahead congestion LMP difference is greater than the real-time congestion LMP difference the profits from that FTR may be subject to forfeiture for that hour. An increment offer or decrement bid is considered near the source or sink point if 75 percent or more of the energy injected or withdrawn, and which is withdrawn or injected at any other bus, is reflected on the constrained path between the FTR source or sink. This rule only applies to increment offers and decrement bids that would increase the price separation between the FTR source and sink points.

Figure 13-16 demonstrates the FTR forfeiture rule for INCs and DECs. The INC or DEC distribution factor (dfax) is compared to the largest impact withdrawal or injection dfax. If the absolute difference between the virtual bid and its counterpart is greater than or equal to 75 percent, the virtual bid is considered for forfeiture. This is the metric in the rule which defines the impact of the virtual bid on the constraint.

In the first part of the example in Figure 13-16, the INC has a dfax of 0.25 and the maximum withdrawal dfax on the constraint is -0.5. The difference between the two dfax values is -0.75 (0.25 minus -0.5). The absolute value is 0.75. In the second part of the example in, the DEC has dfax of 0.5 and the maximum injection dfax on the constraint is -0.25. The difference between the two dfax values is 0.75 (-0.25 minus 0.5). The absolute value is also 0.75.

Figure 13-16 Illustration of INC/DEC FTR forfeiture rule

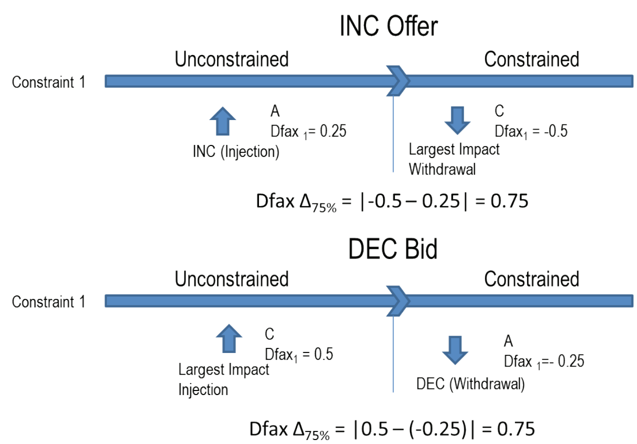


Figure 13-17 shows the FTR forfeiture values for both physical and financial participants for each month of June 2010 through December 2016. Currently, counter flow FTRs are not subject to forfeiture regardless of INC or DEC positions. Total forfeitures for the first seven months of the 2016 to 2017 planning period were $0.4 million (0.07 percent of total FTR target allocations).

Figure 13-17 Monthly FTR forfeitures for physical and financial participants: June 2010 through December 2016

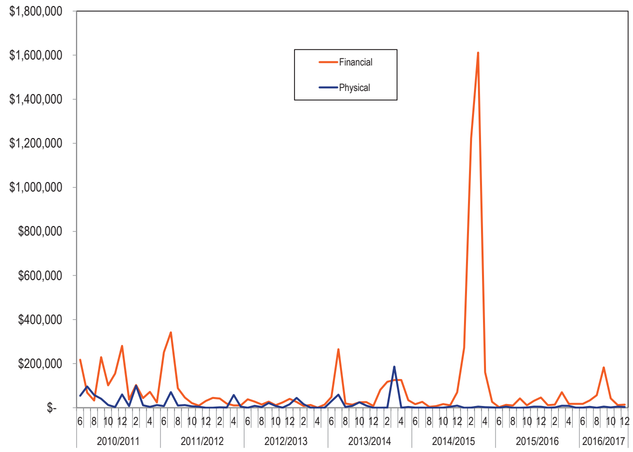


Figure 13-18 FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for both the PJM and MMU methods: January 2013 through December 2016

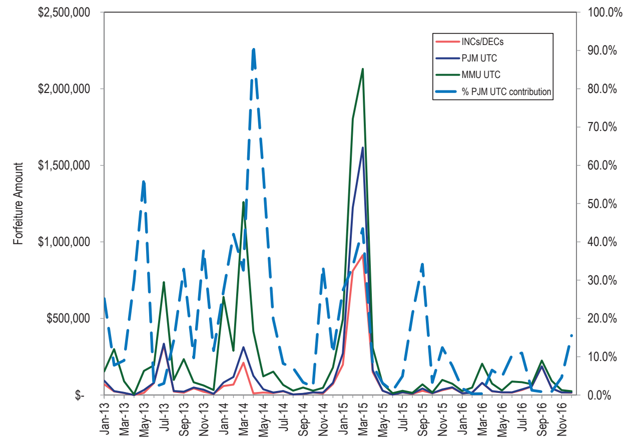


Figure 13-18 shows the FTR forfeitures on just INCs and DECs, FTR forfeitures on INCs, DECs and UTCs using the method proposed by PJM and FTR forfeitures on INCs, DECs and UTCs using the method proposed by the MMU from January 2013 through December 2016. The method proposed by PJM for calculating forfeitures associated with UTCs was implemented on September 1, 2013, and for each month thereafter. UTC forfeitures before September 2013 were not billed, but are included to illustrate the impact of the different methods of calculating forfeitures. The UTC curves include all forfeitures for the month associated with INCs, DECs and UTCs. The dotted line indicates the percentage of forfeitures caused by UTC transactions using PJM's method, excluding INCs and DECs.

Up-to-Congestion Transaction FTR Forfeitures

The current implementation of the FTR forfeiture rule submitted by PJM is not consistent with the application of the forfeiture rule for INCs and DECs. Under PJM's method the simple net dfax of the UTC transaction is the only consideration for forfeiture, representing the contract path of the UTC transaction. Under this method, the net dfax is the sink dfax of the UTC minus the source dfax of the UTC. The net dfax alone cannot be used as an indication of helping or hurting a constraint, rather, the direction of the constraint must also be considered. In addition, the PJM method only considers UTC transactions whose net dfax is positive. This logic not only passes transactions that should fail the forfeiture test, but fails transactions that should pass the forfeiture test.

PJM's logic also does not hold when one of the points of the UTC is far from the constraint. In this case, one side of the UTC would have a dfax of zero, indicating no connection to the constraint being considered. If a point of the UTC transaction has no connection to the constraint, there can be no power flow directly between the two UTC points, so the simple net dfax, cannot logically be used in this case to indicate whether a UTC is eligible for forfeiture. Under the MMU method this UTC would be treated as an INC or DEC and follow the same rules as the current INC/DEC FTR forfeiture rule.

Figure 13-19 shows an example of the two proposed FTR forfeiture rules for UTC transactions. In both cases, the net dfax of the UTC is taken. Under the PJM method the net dfax of the UTC is calculated by subtracting the dfax of the sink bus A (0.2) from the dfax of the source bus B (0.5) to get a net dfax of -0.3. If this net dfax value is greater than 0.75 the UTC is subject to forfeiture. Under the MMU method, the net dfax is calculated by subtracting the dfax of sink A (0.2) from the dfax of source bus B (0.5) to get a net dfax of 0.3. This net dfax is then compared to the withdrawal point with the largest impact on the constraint. The MMU method compares the net UTC dfax to a withdrawal because the UTC is a net injection on this constraint. In this example, the net dfax is 0.3 and it is compared to the largest withdrawal dfax at C (-0.5). The absolute value of the difference is calculated from these two points to determine if the UTC fails the FTR forfeiture rule. In this case, the absolute value of the difference is the dfax of bus C (-0.5) minus the net UTC dfax (0.3) for a total impact of 0.8, which is over the 0.75 threshold for the FTR forfeiture rule. The result is that this UTC fails the FTR forfeiture rule. The MMU proposes to apply the same rules to UTC transactions as is applied to INCs and DECs, treat the UTC as equivalent to an INC or a DEC depending on its net impact on a given constraint. A UTC transaction is essentially a paired INC/DEC, it has a net impact on the flow across a constraint, as an INC or DEC does. While total system power balance is maintained by a UTC, local flows may change based on the UTC's net impact on a constraint. The MMU method captures this impact.

Figure 13-19 Illustration of UTC FTR forfeiture rule

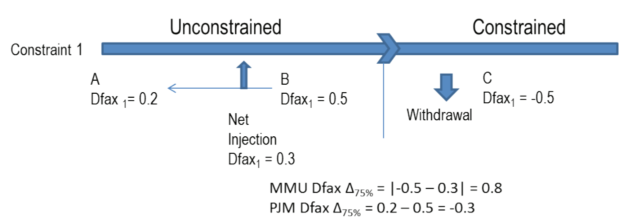
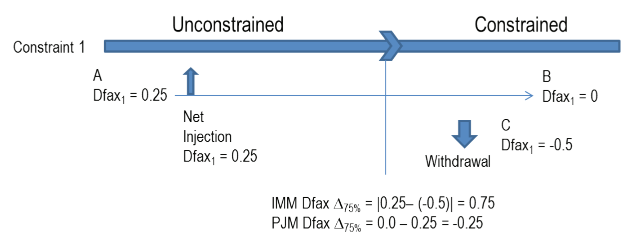


Figure 13-20 demonstrates where the assumption of contract path for UTCs in PJM's method does not hold with actual system conditions when either the source or sink of the UTC does not have any impact on the constraint being considered. In this case, the UTC is effectively an INC or a DEC relative to the constraint, as the other end of the UTC has no impact on the constraint. However, the PJM approach would not treat the UTC as an INC or DEC, despite the effective absence of the other end of the UTC. This is a flawed result.

As demonstrated in Figure 13-20, the UTC is no different than an INC on the constraint being considered. Using the PJM method this UTC would pass the FTR forfeiture rule. The net dfax would be calculated as the dfax of bus B (0) minus the dfax of bus A (0.25) for a net dfax of -0.25, with no comparison to any withdrawal bus. Since the dfax is negative, it would pass the PJM FTR forfeiture rule. Under the MMU's method, the net dfax is calculated as an injection with a dfax of 0.25, and then the absolute value of the difference is calculated between that injection and the dfax of the largest withdrawal on the constraint. In this example that is bus C, with a dfax of -0.5. The result is an absolute value of the dfax difference of 0.75, meaning that this UTC fails the FTR forfeiture test.

Figure 13-20 Illustration of UTC FTR Forfeiture rule with one point far from constraint



The MMU recommends that the FTR forfeiture rule be applied to UTCs in the same way it is applied to INCs and DECs.