Q3

State of the Market Report for PJM

January through September

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

11.15.2012

2012

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 *2012 Quarterly State of the Market Report for PJM: January through September.*

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).

Introduction

Q3 2012 In Review

The state of the PJM markets in the first three quarters of 2012 was good. The results of the energy market and the results of the capacity market were competitive.

The goal of a competitive power market is to provide power at the lowest possible price, consistent with cost. PJM markets met that goal in the first nine months of 2012. The test of a competitive power market is how it reacts to change. PJM markets have passed that test so far, but that test continues. The significant changes in the economic environment of PJM markets in 2011 continued in the first three quarters of 2012.

Continued success requires that market participants have access to all the information about the economic fundamentals of PJM markets necessary to make rational decisions. There are still areas where more transparency is required in order to permit markets to function effectively. The provision of clear, understandable information about market fundamentals matters.

Continued success requires markets that are flexible and adaptive. However, wholesale power markets are defined by complex rules. Markets do not automatically provide competitive and efficient outcomes. There are still areas of market design that need further improvement in order to ensure that the PJM markets continue to adapt successfully to changing conditions. The details of market design matter.

Both coal and natural gas prices decreased in the first nine months of 2012, although the decline in gas prices was substantially larger than the decline in coal prices. PJM LMPs were also substantially lower. The load-weighted average LMP was 29.2 percent lower in the first three quarters of 2012 than in the first three quarters of 2011, resulting in the lowest prices in the first nine months of a year since 2002.

The results of the energy market dynamics in January through September of 2012 were positive for new gas fired combined cycle units in some areas. The result of the changes in gas prices compared to coal prices was that the fuel cost of a new entrant combined cycle unit remained below the fuel cost of a new entrant coal plant in the first six months of 2012, but greater than the fuel cost of a coal plant for the months of July through September. The combination of lower energy prices, lower gas prices and lower coal prices resulted in lower energy net revenues for new entrant CC units in thirteen of seventeen zones and lower energy net revenues for the new entrant CT and CP unit in all zones in 2012.

Markets need accurate and understandable information about fundamental market parameters in order to function effectively. For example, the markets need better information about unit retirements in order to permit new entrants to address reliability issues. For example, the markets need better information about the reasons for operating reserve charges in order to permit market responses to persistent high payments of operating reserve credits.

The market design should permit market prices to reflect underlying supply and demand fundamentals. Significant factors that result in capacity market prices failing to reflect fundamentals should be addressed, including better LDA definitions, the effectiveness of the transmission interconnection queue process, the 2.5 percent reduction in demand that suppresses market prices and the continued inclusion of inferior demand side products that also suppress market prices.

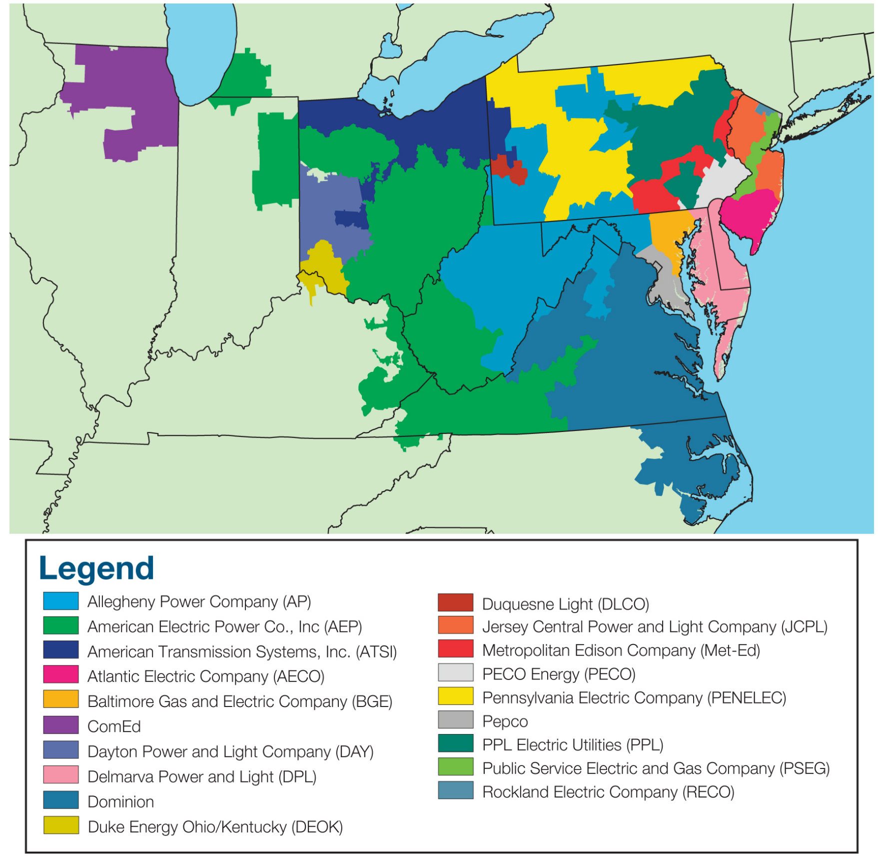
The PJM markets and PJM market participants from all sectors face significant challenges as a result of the changing economic environment. PJM and its market participants will need to continue to work constructively to address these challenges to ensure the continued effectiveness of PJM markets.

PJM Market Background

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2012, had installed generating capacity of 182,874 megawatts (MW) and about 800 market buyers, sellers and traders of electricity[1] in a region including more than 60 million people[2] 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] In the first nine months of 2012, PJM had total billings of $22.12 billion, down from $28.84 billion in the first three quarters of 2011. 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 See "Company Overview." PJM.com. PJM Interconnection L.L.C. (Accessed November 13, 2012). <http://pjm.com/about-pjm/member-services/member-list.aspx>.
2 See "Company Overview." PJM.com. PJM Interconnection L.L.C. (Accessed November 13, 2012). <http://pjm.com/about-pjm/who-we-are.aspx>.
3 See the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2011.

Figure 1-1 PJM's footprint and its 19 control zones[4] (See 2011 SOM, Figure 1-1)



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 Markets, the Day Ahead Scheduling Reserve (DASR) Market and the Long Term, Annual and Monthly Balance of Planning Period Auction Markets in Financial Transmission Rights (FTRs).

4 On January 1, 2012, the Duke Energy Ohio/Kentucky (DEOK) Control Zone joined the PJM footprint.

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 an auction-based FTR Market 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 spinning 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.[5,6]

On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone.

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine months of 2012, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the independent Market Monitoring Unit (MMU) for PJM.

For each PJM market, 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 test is the most relevant measure of market structure because it accounts for both the ownership of assets and the relationship between ownership among multiple entities and the market demand and it does so using actual market conditions reflecting 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 referenced 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 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 performance, 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.

5 See also the *2011 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."
6 Analysis of 2012 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. 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 2012, see the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

The MMU concludes the following for the first nine months of 2012:

Table 1-1 The Energy Market results were competitive (See 2011 SOM, Table 1-1)

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 because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1234 with a minimum of 927 and a maximum of 1657 in the first nine months of 2012.
- 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 mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

  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.[7] 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 only 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.[8]

7 OATT Attachment M

Table 1-2 The Capacity Market results were competitive (See 2011 SOM, Table 1-2)

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

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction (BRA), for every planning year for which a BRA has been run to date. 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.[9]
- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the PMSS, which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which a BRA has been run to date. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[10]
- 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

8 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.
9 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
10 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.

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, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and the definition of DR which permits inferior products to substitute for capacity.

Table 1-3 The Regulation Market results were not competitive[11] (See 2011 SOM, Table 1-3)

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

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 44 percent of the hours in January through September 2012.[12]
- Participant behavior was evaluated as competitive 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 anti-competitive behavior.
- Market performance was evaluated as not competitive, despite competitive participant behavior, because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.[13]
- Market design was evaluated as flawed because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

Table 1-4 The Synchronized Reserve Markets results were competitive (See 2011 SOM, Table 1-4)

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

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 24 percent of the hours in January through September of 2012.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.

11 As Table 1-3 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

12 These TPS results reflect MMU estimates for the period between May 6 and July 21, 2012, when the TPS test was not correctly applied by PJM.

13 PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in prices that reflect marginal costs.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 1-5 The Day-Ahead Scheduling Reserve Market results were competitive (See 2011 SOM, Table 1-5)

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

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because the market did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), about 17 percent of offers reflected economic withholding, with offer prices above $5.00.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Table 1-6 The FTR Auction Markets results were competitive (see 2011 SOM, Table 1-6)

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

- The 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.
- 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.
- Market design was evaluated as effective because the market design provides a wide range of options for market participants to acquire FTRs and a competitive auction mechanism.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[14] 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.[15]

14 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).

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

Reporting

The MMU performs its reporting function by issuing and filing annual and quarterly state of the market reports, and reports on market issues. The state of the market reports provide a comprehensive analysis of the structure, behavior and performance of PJM markets. The reports evaluate whether the market structure of each PJM Market is competitive or not competitive; whether participant behavior is competitive or not competitive; and, most importantly, whether the outcome of each market, the market performance, is competitive or not competitive. The MMU also evaluates the market design for each market. Market design translates participant behavior within the market structure into market performance. The MMU evaluates whether the market design of each PJM market provides the framework and incentives for competitive results. 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's quarterly state of the market reports supplement the annual state of the market report for the prior year, and extend the analysis into the current year. Readers of the quarterly state of the market reports should refer to the prior annual report for detailed explanation of reported metrics and market design.

The MMU's reports on market issues cover specific topics in depth. For example, the MMU issues reports on RPM auctions. In addition, the MMU's reports frequently respond to the needs of FERC, state regulators, or other authorities, in order to assist policy development, decision making in regulatory proceedings, and in support of investigations.

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.[16] The MMU has direct, confidential access to the FERC.[17] The MMU may also refer matters to the attention of State commissions.[18]

The MMU monitors market behavior for violations of FERC Market Rules.[19] 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,[20] or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[21] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[22]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[23] 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[24] and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[25] 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.

16 OATT Attachment M § IV.
17 OATT Attachment M § IV.K.3.
18 OATT Attachment M § IV.H.
19 OATT Attachment M § II(d)&(q) ("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.").
20 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.
21 OATT Attachment M § II(h-1).
22 OATT Attachment M § IV.C.
23 OATT Attachment M § IV.I.1.
24 *Id.*
25 *Id.*

The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

Another 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. Cost based offers for the energy market and the regulation market are based on incremental costs as defined in the PJM Cost Development Guidelines (PJM Manual 15).[26] 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.[27]

The MMU also reviews operational parameter limits included with unit offers,[28] evaluates compliance with the requirement to offer into the energy and capacity markets,[29] evaluates the economic basis for unit retirement requests,[30] and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[31]

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.[32] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[33] 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.[34] 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.[35] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[36]

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,"[37] 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 *2012 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2011 State of the Market Report for PJM* and subsequent 2012 quarterly state of the market reports remain MMU recommendations.

The following are new recommendations since the last quarterly report.

From Section 3, "Operating Reserve":

- 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.

26 *See* OATT Attachment M–Appendix § II.A.
27 OATT Attachment M–Appendix § II.E.
28 OATT Attachment M–Appendix § II.B.
29 OATT Attachment M–Appendix § II.C.
30 OATT Attachment M–Appendix § IV.
31 OATT Attachment M–Appendix § VII.
32 OATT Attachment M § IV.D.
33 *Id.*
34 *Id.*
35 *Id.*
36 OATT Attachment M § VI.A.
37 18 CFR § 35.28(g)(3)(ii)(A); *see also* OATT Attachment M § IV.D.

- The MMU recommends that this stakeholder process address three areas of incorrect allocation that are directly related to and part of the current issue. These areas are related to reactive service costs, black start service costs and the inclusion of no load costs in the lost opportunity cost calculation.[38,39,40] As part of the stakeholder process, the MMU recommends that PJM clearly identify and classify the reasons for operating reserve credits in the Day-Ahead and the Real-Time Energy Markets in order to ensure the correct allocation of the corresponding charges.

From Section 4, "Capacity":

- 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. The MMU also 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. The currently proposed related deadline of 120 days prior to an RPM Auction for requesting exemption to the RPM Must Offer Obligation is a step in the right direction.[41] All notification recommendations assume that the generation owner has the required knowledge in the defined time frame.
- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.[42]
- 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. All revenues should be at risk under the peak hour availability charge.
- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.
- The MMU recommends that all generation types face the same performance incentives.
- The MMU recommends elimination of the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.
- The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during the RPM peak period.
- The MMU recommends that PJM eliminate all Out of Management Control (OMC) outages from use in planning or capacity markets.

From Section 8, "Interchange Transactions":

- The MMU recommends the termination of the existing PJM/PEC (Progress Energy Carolinas) JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet, and its dispatch. Those assumptions are no longer correct, as is evident by the Progress/DUK joint dispatch agreement, and thus the PJM/PEC JOA should be terminated.

From Section 9, "Ancillary Services":

- The MMU recommends that PJM reevaluate its use of the Tier 1 bias factor and define explicit and transparent rules for calculating available Tier 1 MW and calculating required Tier 2 MW.

38 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Black Start and Voltage Support Units".
39 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Reactive Service Credits and Operating Reserve Credits".
40 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Lost Opportunity Cost Calculation".
41 In order to make an offer in a BRA, planned generation must be in a generation queue, have completed a Feasibility Study and have a signed Impact Study Agreement. Planned generation must be in the queue at least six months prior to the month of the BRA, or by October 31 of the calendar year preceding the auction, in order to ensure timely completion of the Feasibility Study and Impact Study Agreement. Given these requirements of the queue process, a notification period of nine months prior to the BRA would be required to allow planned generation time to enter the queue in response to a notice of deactivation.
42 For more details on the reasons for these recommendations, see the IMM'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)

Highlights

The following presents highlights of each of the sections of the *2012 Quarterly State of the Market Report for PJM: January through September:*

Section 2, Energy Market

- Average offered supply increased by 10,571, or 6.6 percent, from 159,826 MW in the first nine months of 2011 to 170,397 MW in the first nine months of 2012. The increase in offered supply was in part the result of the integration of the Duke Energy Ohio/Kentucky (DEOK) Transmission Zone in the first quarter of 2012 and the integration of the American Transmission Systems, Inc. (ATSI) Transmission Zone in the second quarter of 2011. In addition, 1,898 MW of nameplate capacity were added to PJM in the first nine months of 2012. The increases in supply were partially offset by the deactivation of 43 units (6,722 MW) since January 1, 2012. (See page 20)
- In January through September 2012, coal units provided 41.8 percent, nuclear units 34.1 percent and gas units 19.6 percent of total generation. Compared to January through September 2011, generation from coal units decreased 10.0 percent, generation from nuclear units increased 5.3 percent, while generation from natural gas units increased 45.4 percent, and generation from oil units increased 96.5 percent. (See page 21)
- The PJM system peak load for the first nine months of 2012 was 154,344 MW, which was 3,672 MW, or 2.3 percent, lower than the PJM peak load for the first nine months of 2011.[43] The DEOK Transmission Zone accounted for 5,360 MW in the peak hour of the first nine months of 2012. The peak load in 2012 excluding the DEOK Transmission Zone was 148,984 MW, a decrease of 9,032 MW, or 5.7 percent, from the peak load for the first nine months 2011. (See page 23)
- PJM average real-time load increased in the first nine months of 2012 by 5.9 percent from the first nine months of 2011, from 83,762 MW to 88,680 MW. The PJM average real-time load would have decreased in the first nine months of 2012 by 0.9 percent from the first nine months of 2011, from 83,762 MW to 82,970 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM.[44] (See page 35)
- PJM average day-ahead load, including DECs and up-to congestion transactions, increased in the first nine months of 2012 by 16.5 percent from the first nine months of 2011, from 113,724 MW to 132,494 MW. PJM average day-ahead load would have increased in the first nine months of 2012 by 10.7 percent from the first nine months of 2011, from 113,724 MW to 125,917 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM. The day-ahead load growth was 179.7 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions. (See page 40)
- PJM average real-time generation increased in the first nine months of 2012 by 3.9 percent from the first nine months of 2011, from 86,966 MW to 90,367 MW. PJM average real-time generation would have decreased in the first nine months of 2012 by 1.6 percent from the first nine months of 2011, from 86,966 MW to 85,532 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM. (See page 43)
- PJM average day-ahead generation, including INCs and up-to congestion transactions, increased in the first nine months of 2012 by 15.6 percent from the first nine months of 2011, from 116,988 MW to 135,213 MW. PJM average day-ahead generation would have increased 11.5 percent from the first nine months of 2011, from 116,988 MW to 135,213 MW if the DEOK and ATSI transmission zones were excluded from the comparison for the months in 2011 when they were not part of PJM. The day-ahead generation growth was 300.0 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions. (See page 44)
- PJM Real-Time Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The load-weighted

43 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2011 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

44 The ATSI Transmission Zone was excluded from this comparison and similar comparisons for the first 5 months of 2012 because it did not join PJM until June 1, 2011. The DEOK Transmission Zone was excluded from this comparison for all of the months of 2012 because it did not join PJM until January 1, 2012.

average LMP was 29.2 percent lower in the first nine months of 2012 than in the first nine months of 2011, $35.02 per MWh versus $49.48 per MWh. (See page 47)

- PJM Day-Ahead Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The load-weighted average LMP was 29.1 percent lower in the first nine months of 2012 than in the first nine months of 2011, $34.29 per MWh versus $48.34 per MWh. (See page 51)
- Based on average spot fuel prices, the fuel cost of a new entrant combined cycle unit ($19.54/MWh) was lower than the fuel cost of a new entrant coal plant ($19.83/MWh) in the first nine months of 2012. (See page 48)
- Levels of offer capping for local market power remained low. In the first nine months of 2012, 1.6 percent of unit hours and 1.0 percent of MW were offer capped in the Real-Time Energy Market and 0.2 percent of unit hours and 0.2 percent of MW were offer capped in the Day-Ahead Energy Market. (See page 25)
- Of the 131 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first nine months of 2012, 44 (33.6 percent) qualified in all months, and 26 (19.9 percent) qualified in only one month of the first nine months of 2012. (See page 34)

Section 3, Operating Reserve

- Operating reserve charges decreased $42.8 million, or 8.9 percent, from $479.8 million in the first nine months of 2011, to $437.0 million in the first nine months of 2012. Day-ahead operating reserve charges increased $17.8 million, or 26.3 percent to $85.3 million and balancing operating reserve charges decreased $59.9 million, or 14.5 percent to $351.7 million. (See page 67)
- Balancing operating reserve charges for reliability decreased by $5.3 million, or 7.1 percent compared to the first nine months of 2011. Balancing operating reserve charges for deviations decreased by $47.4 million, or 27.6 percent. (See page 68)
- The reduction in balancing operating reserve charges was comprised of a decrease of $52.7 million in generator and real-time import transactions balancing operating reserve charges, a decrease of $9.8 million in lost opportunity costs, a decrease of $2.6 million in canceled resources and an increase of $5.2 million in charges to participants requesting resources to control local constraints. (See page 69)
- Generators and real-time transactions balancing operating reserve charges were $194.2 million, 55.2 percent of all balancing operating reserve charges. Balancing operating reserve charges were allocated 35.8 percent as reliability charges and 64.2 percent as deviation charges. Lost opportunity cost charges were $146.5 million or 41.7 percent of all balancing charges. The remaining 3.1 percent of balancing operating reserve charges were comprised of 0.9 percent canceled resources charges and 2.2 percent of local constraints control charges. (See page 69)
- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 21.1 percent of total operating reserve credits in the first nine months of 2012, compared to 29.7 percent in the first nine months of 2011. HHI for day-ahead operating reserve credits was 3868, for balancing operating reserve credits was 2847 and for lost opportunity cost credits was 3832. (See page 83)
- The regional concentration of operating reserves remained high in the first nine months of 2012. In the first nine months of 2012, 47.1 percent of all operating reserve credits were paid to resources in the top three zones, a decrease of 13.5 percentage points from the first nine months of 2011. (See page 79)

Section 4, Capacity

- During the period January 1, through September 30, 2012, PJM installed capacity increased 4,019.4 MW or 2.2 percent from 178,854.1 MW on January 1 to 182,873.5 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis. (See page 98)

- The 2013/2014 RPM Second Incremental Auction and the 2014/2015 RPM First Incremental Auction were conducted in the third quarter of 2012. In the 2013/2014 RPM Second Incremental Auction, the rest of RTO clearing price was $7.01 per MW-day. In the 2014/2015 RPM First Incremental Auction, the rest of RTO clearing price for Annual and Extended Summer Resources was $5.54 per MW-day. (See page 105)
- Capacity in the RPM load management programs was 7,118.5 MW for June 1, 2012 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2012/2013 Delivery Year (9,407.0 MW) less replacement capacity (2,288.5 MW). (See page 102)
- Annual weighted average capacity prices increased from a Capacity Credit Market (CCM) weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $148.33 per MW-day in 2015. (See page 107)
- Combined cycle units ran more often in January through September 2012, than in the same period in 2011, increasing from a 47.1 percent capacity factor in 2011 to a 63.8 percent capacity factor in 2012. Combined cycle units had a higher capacity factor than steam units, for which the capacity factor decreased from 54.0 percent in 2011 to 45.5 percent in January through September 2012. (See page 108)
- The average PJM equivalent demand forced outage rate (EFORd) decreased from 7.6 percent in the first nine months of 2011 to 6.8 percent in the first nine months of 2012. (See page 109)
- The PJM aggregate equivalent availability factor (EAF) increased from 84.9 percent in January through September 2011 to 85.5 percent for the same period in 2012. The equivalent maintenance outage factor (EMOF) increased from 2.8 percent to 3.5 percent, the equivalent planned outage factor (EPOF) decreased from 7.1 percent to 6.3 percent, and the equivalent forced outage factor (EFOF) decreased from 5.3 percent to 4.7 percent. (See page 104)

Section 5, Demand Response

- In January through September 2012, the total MWh of load reduction under the Economic Load Response Program increased by 84,620 MWh compared to the same period in 2011, from 15,376 MWh in 2011 to 99,996 MWh in 2012, a 550 percent increase. Total payments under the Economic Program increased by $4,896,597, from $1,943,507 in the first nine months of 2011 to $6,840,104 in 2012, a 252 percent increase, as a result of the implementation of Order 745 on April 1, 2012. The increased payments were concentrated in the summer months of 2012. (See page 120)
- In January through September 2012, total capacity payments to demand response resources under the PJM Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, decreased by $118.2 million, or 31.0 percent, compared to the same period in 2011, from $381 million in 2011 to $263 million in 2012. The decrease in capacity credits in 2012 was the result of a decrease in RPM clearing prices in the rest of RTO region. While prices increased for MAAC zones, the rest of the PJM RTO cleared at $16.46 in the 2012/2013 delivery year, an 85 percent decrease from the RTO wide $110.04 clearing price in the 2011/2012 delivery year. (See page 126)

Section 6, Net Revenue

- Average real time LMP decreased by 29.1 percent in the first nine months of 2012 over the first nine months of 2011. (See page 47)
- Natural gas prices decreased by more than coal prices in the first nine months of 2012 compared to the first nine months of 2011. The price of Northern Appalachian coal was 15.5 percent lower; the price of Central Appalachian coal was 19.4 percent lower; and the price of Powder River Basin coal was 34.1 percent lower. The price of eastern natural gas was 40.5 percent lower; and the price of western natural gas was 37.1 percent lower.[45] (See page 48)

45 Eastern natural gas and Western natural gas prices are the average of daily fuel price indices in the PJM footprint. 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.

- While average net revenues for all three technologies declined, only new entrant combined cycle units had net revenue increases in some zones. Comparing the first nine months of 2012 to the first nine months of 2011, energy net revenues for the new entrant combustion turbine unit were down 36.8 percent, energy net revenues for the new entrant combined cycle unit were down 8.7 percent, and energy net revenues for the new entrant coal unit were down 69.1 percent.[46] (See page 129)

Section 7, Environmental and Renewables

- In a decision dated August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated the Cross State Air Pollution Rule (CSAPR).[47] The court had found "fatal flaws" in the prior rule, the Clean Air Interstate Rule (CAIR), but allowed it to remain in effect until replaced.[48] The EPA filed a petition for review en banc with the court on October 5, 2012. CAIR remains in place, as does the requirement to replace it. (See page 134)
- On March 27, 2012, the EPA proposed a Carbon Pollution Standard for new fossil-fired electric utility generating units. The proposed standard would limit emissions from new electric generating units to 1,000 pounds of CO_2 per MWh. In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the GHG rule, rejecting challenges brought by industry groups and a number of states.[49] (See page 134)
- The EPA proposed to exempt certain small reciprocating engines participating in DR programs as behind-the-meter generation from otherwise applicable run time restrictions. On May 22, 2012, the EPA proposed to increase the existing 15-hour exemption to 100 hours. EPA justified this exemption based on concerns about the impact on reliability and efficient operation of the wholesale energy markets.[50] The Market Monitor testified on this issue explaining that such concerns are unwarranted, and that, by providing a special exemption to units participating in demand response programs, the exemption would harm efficiency and reliability.[51] (See page 135)
- NO_x and SO_2 emission prices declined in January through September 2012, compared to 2011, while RGGI CO_2 prices increased. NO_x prices declined 75.9 percent in 2012 compared to 2011, and SO_2 prices declined 55.2 percent in 2012 compared to 2011. Spot average RGGI CO_2 prices increased by 2.6 percent in 2012 compared to 2011, partially as a result of the increase in the price floor for RGGI CO_2 allowances. (See page 136)
- The auction price of RGGI CO_2 allowances remained at the floor price of $1.93 during January through September 2012, and as of January 1, 2012, the state of New Jersey no longer participates in the RGGI program. (See page 136)
- Generation from wind units increased from 7,924.5 GWh in January through September 2011 to 8,944.7 GWh in January through September 2012, an increase of 12.9 percent. Generation from solar units increased from 37.9 GWh in January through September 2011 to 192.7 GWh in January through September 2012, an increase of 408.7 percent. (See page 141)

Section 8, Interchange Transactions

- During the first nine months of 2012, PJM was a net exporter of energy in the Real-Time Energy Market in January, August and September, and a net importer of energy in the remaining months. During the first nine months of 2011, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in the remaining months. (See page 147)
- During the first nine months of 2012, PJM was a net exporter of energy in the Day-Ahead Energy Market in January through April and July through September, and a net importer of energy in May and June. During the first nine months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market in January through May, and a net exporter of energy in July through September. (See page 147)

46 Changes are simple zonal averages.
47 EME Homer City Generation, L.P. v. EPA, et al., No. 11-1302.
48 State of North Carolina, et al. v. EPA, 531 F.3d 896 (D.C. Cir. 2008), *order on reh'g*, 550 F.3d 1176 (2008).
49 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
50 *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, 77 Fed. Reg. 33812 (June 7, 2012).
51 Comments of the Independent Market Monitor for PJM, filed in EPA Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).

- The direction of power flows was not consistent with real-time energy market price differences in 55 percent of hours at the border between PJM and MISO and in 48 percent of hours at the border between PJM and NYISO during the first nine months of 2012. (See page 165)
- During the first nine months of 2012, net scheduled interchange was 1,051 GWh and net actual interchange was 801 GWh, a difference of 251 GWh. During the first nine months of 2011, net scheduled interchange was -4,176 GWh and net actual interchange was -4,524 GWh, a difference of 348 GWh. (See page 169)
- PJM initiated 29 TLRs during the first nine months of 2012, a reduction from the 58 TLRs initiated during the first nine months of 2011. (See Page 170)
- The average daily volume of up-to congestion bids increased from 26,553 bids per day, during the first nine months of 2011, to 58,273 bids per day during the first nine months of 2012. (See page 171)
- During the first nine months of 2012, there were no balancing operating reserve credits paid to dispatchable transactions, a decrease from $1.3 million for the first nine months of 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that dispatchable schedules were only submitted on three days during the first nine months of 2012. (See page 179)

Section 9, Ancillary Services

- The weighted average Regulation Market clearing price, including opportunity cost, for January through September 2012 was $14.92 per MW.[52] This was a decrease of $2.11, or 12.4 percent, from the average price for regulation in January through September 2011. The total cost of regulation decreased by $12.13 from $32.71 per MW in January through September 2011, to $20.58, or 37.1 percent. In January through September 2012, the weighted Regulation Market clearing price was 72 percent of the total regulation cost per MW, compared to 52 percent of the total regulation cost per MW in January through September 2011. (See page 188)

52 The term "weighted" when applied to clearing prices in the Regulation Market means clearing prices weighted by the MW of cleared regulation.

- The weighted average Tier 2 Synchronized Reserve Market clearing price in the Mid-Atlantic Subzone was $7.06 per MW in January through September 2012, a $4.94 per MW decrease from January through September 2011.[53] The total cost of synchronized reserves per MW in January through September 2012, was $10.96, a 23 percent decrease from the total cost of synchronized reserves ($14.21) during January through September 2011. The weighted average Synchronized Reserve Market clearing price was 64 percent of the weighted average total cost per MW of synchronized reserve in January through September 2012. The price to cost ratio was 84 percent in January through September 2011. (See page 196)
- The weighted DASR market clearing price was $0.91 per MW in January through September 2012. In January through September 2011, the weighted price of DASR was $1.04 per MW. The average hourly purchased DASR was 7,042 MW, an increase from 6,622 MW during the same period of 2011, reflecting PJM's larger footprint with the integration of DEOK on January 1, 2012. (See page 200)
- Black start zonal charges in January through September 2012 ranged from $0.02 per MW in the ATSI zone to $1.80 per MW in the BGE zone. (See page 202)

Section 10, Congestion and Marginal Losses

- Marginal loss costs decreased by $395.0 million or 34.3 percent, from $1,152.6 million in the first nine months of 2011 to $757.6 million in the first nine months of 2012 (Table 10-10). (See page 208)
- Day-ahead marginal loss costs decreased by $415.0 million or 34.8 percent, from $1,191.1 million in the first nine months of 2011 to $776.0 million in the first nine months of 2012 (Table 10-12). (See page 209)
- Balancing marginal loss costs increased by $20.0 million or 52.0 percent, from $38.5 million in the first nine months of 2011 to -$18.5 million in the first nine months of 2012 (Table 10-12). (See page 209)
- The marginal loss credits (loss surplus) decreased by $188.7 million or 37.6 percent, from $502.1 million in the first nine months of 2011 to $313.4 million in the first nine months of 2012. (Table 10-13). (See page 209)

53 The term "weighted" when applied to clearing prices in the Synchronized Reserve Market means clearing prices weighted by the MW of cleared synchronized reserve.

- Congestion decreased by $449.7 million or 51.4 percent, from $874.9 million in the first nine months of 2011 to $425.2 million in the first nine months of 2012 (Table 10-15). (See page 212)
- Day-ahead congestion costs decreased by 460.0 million or 43.3 percent, from $1,063.2 million in the first nine months of 2011 to $603.2 million in the first nine months of 2012. (See page 212)
- Balancing congestion costs decreased by $10.3 million or 5.8 percent, from -$178.0 million in the first nine months of 2011 to -$188.3 million in the first nine months of 2012. (See page 212)

Section 11, Planning

- At September 30, 2012, 75,869 MW of capacity were in generation request queues to be in service through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for 26,495 MW, 34.9 percent of the capacity in the queues, and combined-cycle projects account for 38,806 MW, 51.1 percent of the capacity in the queues. (See page 226)
- A total of 6,722 MW of generation capacity retired between January and October 1, 2012, and it is expected that a total of 19,142.8 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Units that have retired through October 1, 2012, make up 35 percent of all retirements currently expected to occur from 2012 through 2019. (See page 225)

Section 12, Financial Transmission Rights and Auction Revenue Rights

- The total cleared FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2012 to 2013 planning period decreased by 15.2 percent from 1,067,015 MW to 904,797 MW compared to the first four months of the 2011 to 2012 planning period. (See page 240)
- FTRs were paid at 79.1 percent for the first four months of the 2012 to 2013 planning period. (See page 249)
- FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. FTRs were not profitable overall for physical entities but were profitable for financial entities in the period from January through September 2012. Total FTR profits were -$3.3 million for physical entities and $77.2 million for financial entities. Self-scheduled FTRs were the source of $134.0 million of the FTR profits for physical entities. (See page 251)

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 1-7 provides the average price and total revenues paid, by component, for the first nine months of 2011 and 2012.

Table 1-7 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 95.0 percent of the total price per MWh in the first nine months of 2012.

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 non firm point to point transmission service.[54]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[55]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[56]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[57]
- 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.[58]
- 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.[59]
- 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.[60]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[61]
- The Black Start component is the average cost per MWh of black start service.[62]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[63]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[64]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[65]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[66]

Table 1-7 Total price per MWh by category and total revenues by category: January through September 2011 and 2012 (See 2011 SOM, Table 1-7)

Category	Jan-Sep 2011 $/MWh	Jan-Sep 2012 $/MWh	Percent Change Totals	Jan-Sep 2011 Percent of Total	Jan-Sep 2012 Percent of Total
Load Weighted Energy	$49.47	$35.02	(29.2%)	74.3%	72.4%
Capacity	$10.19	$6.27	(38.5%)	15.3%	12.9%
Transmission Service Charges	$4.30	$4.69	9.0%	6.5%	9.7%
Operating Reserves (Uplift)	$0.90	$0.75	(15.8%)	1.3%	1.6%
Reactive	$0.38	$0.44	14.5%	0.6%	0.9%
PJM Administrative Fees	$0.38	$0.44	13.8%	0.6%	0.9%
Transmission Enhancement Cost Recovery	$0.28	$0.32	11.2%	0.4%	0.7%
Regulation	$0.36	$0.23	(34.8%)	0.5%	0.5%
Transmission Owner (Schedule 1A)	$0.09	$0.08	(7.4%)	0.1%	0.2%
Day Ahead Scheduling Reserve (DASR)	$0.07	$0.06	(11.0%)	0.1%	0.1%
Synchronized Reserves	$0.09	$0.03	(63.2%)	0.1%	0.1%
Black Start	$0.02	$0.02	26.7%	0.0%	0.1%
NERC/RFC	$0.02	$0.02	18.3%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(5.8%)	0.0%	0.0%
Load Response	$0.01	$0.01	44.3%	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	(20.1%)	0.0%	0.0%
Total	$66.58	$48.40	(27.3%)	100.0%	100.0%

54 OATT §§ 13.7, 14.5, 27A & 34.
55 OA Schedules 1 §§ 3.2.3 & 3.3.3.
56 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.
57 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
58 OATT Schedule 12.
59 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
60 OATT Schedule 1A.
61 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
62 OATT Schedule 6A. The Black Start charges do not include Operating Reserve charges required for units to provide Black Start Service under the ALR option.
63 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
64 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
65 OA Schedule 1 § 3.6.
66 OA Schedule 1 § 5.3b.