State of the Market Report for PJM

Volume 1: Introduction

Monitoring Analytics, LLC

Independent Market Monitor for PJM

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Preface

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2012 State of the Market Report for PJM.*

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).

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Introduction

2012 In Review

The state of the PJM markets in 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 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 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 2012 compared to 2011. PJM LMPs were substantially lower. The load-weighted average LMP was $35.23 per MWh, 23.3 percent lower in 2012 than in 2011, the lowest average annual energy prices since 2002.

The results of the energy market dynamics in 2012 were generally positive for new gas fired combined cycle units. New combined cycle units continued to be cheaper than existing coal units. The result of the changes in gas prices compared to coal prices was that the fuel cost to produce a MWh from a new entrant combined cycle unit was below that of a new entrant coal plant for February through June but greater for January and July through December. However, the fuel cost of a new entrant combined cycle unit was below that of existing coal plants given that nearly all coal plants in PJM are 20 years or older. The combination of lower energy prices, mixed gas prices and lower coal prices resulted in lower energy revenues for the new entrant CC unit in all but four zones and lower energy net revenues for the new entrant CT and coal unit in all zones in 2012. With lower capacity prices, net revenues from energy and capacity markets decreased in 2012 for a new entrant combined cycle energy, a new entrant combustion turbine and a new entrant coal plant in PJM 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. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2012, had installed generating capacity of 181,990 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,

1 See PJM's "Company Overview," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.

2 *Id.*

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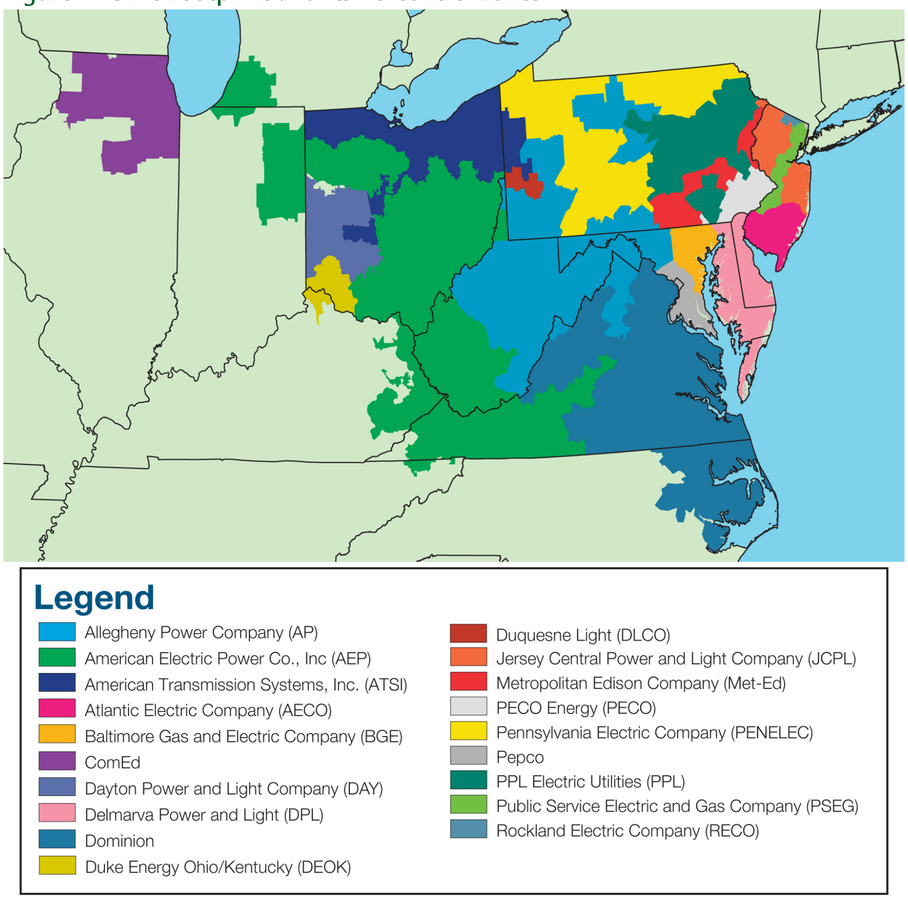
Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1).[3] In 2012, PJM had total billings of $29.18 billion, down from $35.89 billion in 2011. As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1 PJM's footprint and its 19 control zones[4]



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).

3 See the Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2012.

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 2012, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

For each PJM market, market structure is evaluated as competitive or not competitive, and participant

5 See also 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 Appendix A, "PJM Geography."

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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 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.

The MMU concludes the following for 2012:

Table 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 because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1240 with a minimum of 931 and a maximum of 1657 in 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.
- 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.
- 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.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design

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provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes.

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]

Table 2 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. 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 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.

7 OATT Attachment M.

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.

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Table 3 The Regulation Market results were not competitive for the first three quarters and were indeterminate for the fourth quarter[11]

	January through September, 2012		October through December, 2012	
Market Element	Evaluation	Market Design	Evaluation	Market Design
Market Structure	Not Competitive		Not Competitive	
Participant Behavior	Competitive		Competitive	
Market Performance	Not Competitive	Flawed	To Be Determined	To Be Determined

- The Regulation Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 43 percent of the hours in 2012.[12]
- Participant behavior in the Regulation Market was evaluated as competitive for the year 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 for the first three quarters, despite competitive participant behavior, because prior 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 performance was evaluated as indeterminate for the fourth quarter, after the introduction of the new market design. It is too early to reach a definitive conclusion about performance under the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information on performance.
- Market design was evaluated as flawed for the first three quarters 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 were additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.
- Market design was evaluated as indeterminate for the fourth quarter, after the introduction of the new market design. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. It is too early to reach a definitive conclusion about the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information about actual implementation of the design.

Table 4 The Synchronized Reserve Markets results were competitive

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.
- The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 22 percent of the hours in 2012.
- 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 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.

11 As Table 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 market rules, in particular 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 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.

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

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 market participants 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 12 percent of offers reflected economic withholding.
- 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 6 The FTR Auction Markets results were competitive

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. Nonetheless there is a growing issue with FTR revenue sufficiency.

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]

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

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.

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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. 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]

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.*
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.

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]

Prioritized Summary Recommendations

Table 7 includes a brief description and a priority ranking of the MMU's recommendations.

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.

The reference number links to a detailed description of the recommendation in "Detailed Recommendations."

32 OATT Attachment M § IV.D.
33 *Id.*
34 *Id.*
35 *Id.*
36 OATT Attachment M § VI.A.

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Table 7 Prioritized summary recommendations

Priority	Section	Description	Reference Number
Medium	2 - Energy Market	Eliminate FMU and AU adders	2-1
Medium	2 - Energy Market	The definition of maximum emergency status for generating units should apply at all times rather than just during Maximum Emergency Events	2-2
Medium	3 - Operating Reserve	Improve classification of operating reserve credits to ensure correct allocation.	3-1
Medium	3 - Operating Reserve	The allocation of operating reserve charges should be carefully reexamined.	3-2
Medium	3 - Operating Reserve	Require all up-to congestion transactions to pay day-ahead and balancing O.R. charges.	3-3
High	3 - Operating Reserve	Energy LOC should be based on the schedule on which units are scheduled/committed, not the higher of cost or price.	3-4
Medium	3 - Operating Reserve	Energy LOC paid to CTs and diesels scheduled in DA and not called in RT should include the avoided no load and startup costs.	3-5
Medium	3 - Operating Reserve	Energy LOC paid to CTs and diesels scheduled in DA and not called in RT should not use the DA LMP in the calculation.	3-6
Medium	3 - Operating Reserve	Energy LOC should be calculated using entire offer curve, not a single point on the curve.	3-7
Low	3 - Operating Reserve	PJM should analyze why some CTs and diesels scheduled in DA are not being called in RT while being economic.	3-8
Low	3 - Operating Reserve	Include LOC for CTs and diesels scheduled in DA not called in RT in calculation of Perfect Dispatch.	3-9
Low	3 - Operating Reserve	Compensate wind units on the lesser of desired output, forecasted output, or Capacity Injection Rights.	3-10
Medium	3 - Operating Reserve	The total cost of providing reactive support should be categorized and allocated as reactive services.	3-11
Low	3 - Operating Reserve	Reactive services credits should be calculated on segments which include all hours for which unit provides reactive service.	3-12
High	4 - Capacity	Eliminate the Short-Term Resource Procurement Target (2.5 percent demand offset).	4-1
High	4 - Capacity	Modify definition of Demand Side resources; eliminate Limited and Extended Summer DR so DR has same year round capacity obligation as generation.	4-2
Low	4 - Capacity	PJM should procure the maximum amount of Annual and Extended Summer capacity resources available during an RPM auction, without impacting the clearing price.	4-3
Low	4 - Capacity	Address barriers to entry in capacity market; capture the uncertainty and risk in cost of new entry when developing capacity market demand curve.	4-4
Low	4 - Capacity	Redefine the test for determining modeled Locational Deliverability Areas in RPM, including reliability analysis of units at risk.	4-5
Low	4 - Capacity	Modifications to existing resources should not be treated as new resources for purposes of market power related offer caps or MOPR offer floors	4-6
Low	4 - Capacity	Requirement should exist that capacity unit offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.	4-7
Low	4 - Capacity	Define rules for recalling energy output of capacity resources in emergency condition.	4-8
Low	4 - Capacity	Generation capacity resources should be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.	4-9
Medium	4 - Capacity	Unit offer not consistent with DA offer should reflect outage, not offer energy on an emergency basis	4-10
High	4 - Capacity	All generation types should face the same performance incentives.	4-11
High	4 - Capacity	Eliminate OMC outages from use in planning or capacity markets, develop transparent rules for OMC, and review all OMC outage requests carefully.	4-12
Low	4 - Capacity	Eliminate lack of fuel as an acceptable basis for an OMC outage.	4-13
Low	4 - Capacity	Eliminate lack of gas exception during winter for single-fuel, natural gas-fired units.	4-14
Low	4 - Capacity	Unit not capable of fulfilling DA offer should reflect outage, not emergency availability.	4-15
Low	4 - Capacity	Eliminate the exception for units that run less than 50 hours during RPM peak period.	4-16
Low	4 - Capacity	Extend deactivation notification requirement from 90 days to 12 months prior to retirement, and extend duration of PJM and MMU analysis.	4-17
Medium	4 - Capacity	Extend deactivation notification requirement to 6 to 12 months prior to RPM auction.	4-18
Low	4 - Capacity	Emphasize costs in RMR filings; customers should bear incremental costs, generation should bear all other costs.	4-19
High	4 - Capacity	All MOPR projects should be required to use the same basic modeling assumptions.	4-20
High	5 - Demand Response	DR should be classified as an economic program and not an emergency program.	5-1
Medium	5 - Demand Response	Actual meter load data should be provided in order to measure and verify actual demand resource behavior.	5-2
Medium	5 - Demand Response	M & V should reflect compliance. Testing should have limited warning to CSPs.	5-3
Low	5 - Demand Response	Demand resources should be required to provide their nodal location.	5-4
Medium	5 - Demand Response	Compliance rules should be revised to include submittal of hourly load data, and negative values when calculating compliance across hours and registrations.	5-5
Low	5 - Demand Response	Shutdown cost should be defined as the cost to curtail load for a given period that does not vary with the measured reduction.	5-6
Low	5 - Demand Response	Modify the testing program to require verification of test methods and results.	5-7
Medium	5 - Demand Response	Refine baseline methods used to calculate compliance in LM for GLD customers.	5-8
Medium	8 - Interchange Transactions	PJM should permit unlimited spot market imports and exports at all PJM Interfaces.	8-1
Medium	8 - Interchange Transactions	PJM should continue to work with both MISO and NYISO to improve the ways in which interface flows and prices are established.	8-2
Medium	8 - Interchange Transactions	Market participants should be required to submit transactions on market paths that reflect the expected actual flow.	8-3
High	8 - Interchange Transactions	PJM and the MMU should perform a comprehensive evaluation of the up-to congestion product and provide a joint report to PJM stakeholders.	8-4
High	8 - Interchange Transactions	During the period of study, up-to congestion transactions should be required to pay a fee in lieu of operating reserve charges.	8-5
Low	8 - Interchange Transactions	Terminate the existing PJM/PEC JOA.	8-6
High	8 - Interchange Transactions	Implement rules to prevent sham scheduling.	8-7
Low	9 - Ancillary Services	Incorporate the three pivotal supplier test in the DASR Market.	9-1
Medium	9 - Ancillary Services	Definition of LOC should be based on the offer schedule accepted in the market.	9-2
High	9 - Ancillary Services	Regulation Market should have consistent implementation of the marginal benefit factor in optimization, pricing and settlement for RegA and RegD.	9-3
Low	9 - Ancillary Services	Reevaluate Synchronized Reserve compliance rules.	9-4
Medium	11 - Planning	Projects should be removed from the queue, if they are no longer viable and no longer planning to complete the project.	11-1
High	12 - FTRs	The reported FTR payout ratio should consider negative target allocations as a source of revenue to fund FTRs.	12-1
High	12 - FTRs	Netting of positive and negative target allocations within portfolios should be eliminated.	12-2
High	12 - FTRs	Counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.	12-3
Medium	12 - FTRs	The difference between day ahead and balancing congestion should be reviewed.	12-4

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Detailed 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 State of the Market Report for PJM*, the MMU makes the following recommendations.

From Section 2, "Energy Market":

- 2-1) The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and significant changes to the scarcity pricing rules in 2012. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.
- 2-2) The MMU recommends that the definition of maximum emergency status for generating units apply at all times rather than just during Maximum Emergency Events.

From Section 3, "Operating Reserve":

- 3-1) The MMU recommends PJM clearly identify and classify all reasons for incurring operating reserves in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.
- 3-2) The MMU recommends that the allocation of operating reserve charges to participants be carefully reexamined to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.
  - 3-3) The MMU recommends, that in the absence of the elimination of the up-to congestion transaction product and the absence of a reexamination of the allocation of all operating reserve charges, PJM should require all up-to congestion transactions to pay day-ahead and balancing operating reserve charges.
- The MMU recommends four modifications to the energy lost opportunity cost calculations.
  - 3-4) The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market.
  - 3-5) 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 called in real time.
  - 3-6) The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
  - 3-7) The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.
- 3-8) The MMU recommends PJM initiate an analysis on the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not being called in real time while being economic.
- 3-9) The MMU recommends including the lost opportunity costs paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market and not called in real time in the calculation of PJM's Perfect Dispatch metric.
- 3-10) 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 PJM allow and wind units submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time.

37 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

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- 3-11) The MMU recommends the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be equal to the positive difference between total offer (including no load and startup costs) and energy revenues.
- 3-12) The MMU recommends that reactive services credits be calculated on segments which include all hours for which unit provides reactive service. Segments should be the higher of hours needed for reactive support and minimum run time

From Section 4, "Capacity":

- 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.
  - 4-1) The MMU recommends that the Short-Term Resource Procurement Target (2.5 percent demand offset) be eliminated.
  - 4-2) The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources provide the same value in the Capacity Market as generation 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.
  - 4-3) 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.
  - 4-4) 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.
  - 4-5) The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model.
  - 4-6) 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.
- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.
  - 4-7) The MMU recommends that there be an explicit requirement that capacity unit offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.
  - 4-8) The MMU recommends that protocols be defined for recalling the energy output of capacity resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details.
- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.
  - 4-9) 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.
  - 4-10) 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.
  - 4-11) The MMU recommends that all generation types face the same performance incentives.
- The MMU recommends that the treatment of outages be made consistent with appropriate market incentives.
  - 4-12) The MMU recommends elimination of all Out of Management Control (OMC) outages from use in planning or capacity markets.

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MMU recommends that pending elimination of OMC outages, that PJM review all requests for Out of Management Control (OMC) carefully, implement a transparent set of rules governing the designation of outages as OMC and post those guidelines.

  - 4-13) The MMU recommends immediate elimination of lack of fuel as an acceptable basis for an OMC outage.
  - 4-14) The MMU recommends elimination of the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.
  - 4-15) 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.
  - 4-16) 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 the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized.
  - 4-17) 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.
  - 4-18) 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.
  - 4-19) 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.
- 4-20) 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.

From Section 5, “Demand Response”:

- 5-1) The MMU recommends that the DR program be classified as an economic program and not an emergency program.
- 5-2) The MMU recommends that actual meter load data should be provided in order to measure and verify actual demand resource behavior.
- 5-3) The MMU recommends that demand side measurement and verification should be modified to accurately reflect compliance. Increases in load during event hours should not be considered zero response, but should be included for reporting and determining compliance.
- 5-4) The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation
- 5-5) The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations.
- 5-6) The MMU recommends that shutdown cost should 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, should be equivalent to the start cost defined in Manual 15.
- 5-7) The MMU recommends that the testing program be modified to require verification of test methods and results. Tests should be initiated by PJM without prior scheduling by CSPs, in order to more accurately model demand response during an emergency event.
- 5-8) The MMU recommends refinement of the baseline methods used to calculate compliance in Load Management for GLD customers.

From Section 6, “Net Revenue”:

- There are no recommendations in Section 6.

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From Section 7, "Environmental and Renewables":

- There are no recommendations in Section 7.

From Section 8, "Interchange Transactions":

- 8-1) PJM and MISO have agreed to allow for unlimited spot market ATC on the NYISO Interface. These modifications are currently being evaluated by PJM. The MMU continues to recommend that PJM permit unlimited spot market imports and exports at all PJM Interfaces.

- 8-2) The MMU recommends that PJM continue to work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market.

- 8-3) The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices.

- 8-4) The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the charges and credits to market participants in all other areas of the PJM Energy Market.

- 8-5) The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges.

- 8-6) The MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

- 8-7) The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU also recommends that PJM, NYISO, MISO and Ontario work together to create business rules that prevent sham scheduling among and between the RTO/ISO markets.

From Section 9, "Ancillary Services":

- 9-1) The MMU recommends that the TPS test be incorporated in the DASR market.

- 9-2) The MMU recommends that the definition of opportunity cost 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.

- 9-3) The MMU recommends that the Regulation Market design evaluate and compensate RegA and RegD resources on an equivalent, non-discriminatory basis. This requires the consistent implementation of the marginal benefits factor in optimization, pricing and settlement.

- 9-4) The MMU recommends that PJM define explicit and transparent rules for calculating available Tier 1 synchronized reserve MW and for its use of biasing during any phase of the market solution. The MMU recommends that PJM publish these rules in Manual 11: Energy and Ancillary Services Market Operations, and associate each instance of biasing with a rule.

- 9-5) The MMU recommends that the rules for compliance with calls to respond to actual spinning events be reevaluated.

From Section 10, "Congestion and Marginal Losses":

- There are no recommendations in Section 10.

From Section 11, "Planning":

- 11-1) The MMU recommends that a review process be created to ensure that projects are removed from transmission queues, if they are no longer viable and no longer planning to complete the project.

From Section 12, "FTRs and ARRs":

- 12-1) The MMU recommends that the calculation of the reported payout ratio appropriately include negative target allocations as a source of revenue to fund FTRs, consistent with actual settlement payout.

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- 12-2) The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.
- 12-3) The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.
- 12-4) The MMU recommends that the difference between day ahead and balancing congestion be reviewed and modifications implemented where possible. Funding issues that persist as a result of modeling differences should be borne by FTR holders operating in the voluntary FTR market

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

Table 8 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.[38]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[39]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[40]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[41]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[42]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[43]
- 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.[44]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[45]
- The Black Start component is the average cost per MWh of black start service.[46]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[47]

38 OATT §§ 13.7, 14.5, 27A & 34.

39 OA Schedules 1 §§ 3.2.3 & 3.3.3.

40 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.

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

42 OATT Schedule 12.

43 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.

44 OATT Schedule 1A.

45 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.

46 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.

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

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Table 8 Total price per MWh by category and total revenues by category: 2011 and 2012

Category	2011 $/MWh	2012 $/MWh	Percent Change Totals	2011 Percent of Total	2012 Percent of Total
Load Weighted Energy	$45.94	$35.23	(23.3%)	73.4%	72.6%
Capacity	$9.72	$6.05	(37.7%)	15.5%	12.5%
Transmission Service Charges	$4.42	$4.78	8.3%	7.1%	9.9%
Operating Reserves (Uplift)	$0.79	$0.79	0.0%	1.3%	1.6%
Reactive	$0.42	$0.43	3.0%	0.7%	0.9%
PJM Administrative Fees	$0.37	$0.42	15.6%	0.6%	0.9%
Transmission Enhancement Cost Recovery	$0.29	$0.34	17.9%	0.5%	0.7%
Regulation	$0.32	$0.26	(20.2%)	0.5%	0.5%
Transmission Owner (Schedule 1A)	$0.09	$0.08	(11.0%)	0.1%	0.2%
Day Ahead Scheduling Reserve (DASR)	$0.05	$0.05	(10.3%)	0.1%	0.1%
Synchronized Reserves	$0.09	$0.04	(55.2%)	0.1%	0.1%
Black Start	$0.02	$0.03	28.3%	0.0%	0.1%
NERC/RFC	$0.02	$0.02	19.6%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(5.4%)	0.0%	0.0%
Load Response	$0.01	$0.01	43.0%	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	(17.1%)	0.0%	0.0%
Non-Synchronized Reserves		$0.00			0.0%
Total	$62.56	$48.55	(22.4%)	100.0%	100.0%

- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[49]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[50]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[51]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[52]

Table 9 Total price per MWh by category: Calendar years 2001 through 2012[48]

Category	Totals ($/MWh) 2001	Totals ($/MWh) 2002	Totals ($/MWh) 2003	Totals ($/MWh) 2004	Totals ($/MWh) 2005	Totals ($/MWh) 2006	Totals ($/MWh) 2007	Totals ($/MWh) 2008	Totals ($/MWh) 2009	Totals ($/MWh) 2010	Totals ($/MWh) 2011	Totals ($/MWh) 2012
Load Weighted Energy	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35	$45.94	$35.23
Capacity	$0.32	$0.12	$0.08	$0.09	$0.03	$0.03	$3.97	$8.33	$11.02	$12.15	$9.72	$6.05
Transmission Service Charges	$3.46	$3.37	$3.56	$3.26	$2.68	$3.15	$3.41	$3.65	$4.00	$4.00	$4.42	$4.78
Operating Reserves (Uplift)	$1.07	$0.69	$0.86	$0.93	$0.97	$0.45	$0.63	$0.61	$0.48	$0.79	$0.79	$0.79
Reactive	$0.22	$0.20	$0.24	$0.25	$0.26	$0.29	$0.31	$0.32	$0.36	$0.44	$0.42	$0.43
PJM Administrative Fees	$0.36	$0.43	$0.54	$0.50	$0.38	$0.40	$0.38	$0.24	$0.31	$0.36	$0.37	$0.42
Transmission Enhancement Cost Recovery									$0.09	$0.21	$0.29	$0.34
Regulation	$0.50	$0.42	$0.50	$0.50	$0.79	$0.53	$0.63	$0.70	$0.34	$0.35	$0.32	$0.26
Transmission Owner (Schedule 1A)	$0.08	$0.07	$0.07	$0.11	$0.09	$0.09	$0.09	$0.09	$0.08	$0.09	$0.09	$0.08
Day Ahead Scheduling Reserve (DASR)								$0.00	$0.00	$0.01	$0.05	$0.05
Synchronized Reserves		$0.11	$0.19	$0.16	$0.15	$0.10	$0.11	$0.09	$0.05	$0.06	$0.09	$0.04
Black Start		$0.00	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03
NERC/RFC							$0.01	$0.01	$0.01	$0.02	$0.02	$0.02
RTO Startup and Expansion		$0.04	$0.05	$0.10	$0.37	$0.15	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Load Response	-$0.00	$0.00	$0.02	$0.00	$0.00	$0.03	$0.07	$0.03	$0.00	$0.00	$0.01	$0.01
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Non-Synchronized Reserves												$0.00
Total	$42.66	$37.05	$47.36	$50.25	$69.20	$58.58	$71.30	$85.24	$55.85	$66.85	$62.55	$48.55

48 Data are missing for January of 2002.

49 OATT Schedule 10-NERC and OATT Schedule 10-RFC.

50 OA Schedule 1 § 3.6.

51 OA Schedule 1 § 5.3b.

52 OA Schedule 1 § 3.2.3A.001.

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Table 10 Percentage of total price per MWh by category: Calendar years 2001 through 2012[53]

Category	Percentage of Total Charges 2001	Percentage of Total Charges 2002	Percentage of Total Charges 2003	Percentage of Total Charges 2004	Percentage of Total Charges 2005	Percentage of Total Charges 2006	Percentage of Total Charges 2007	Percentage of Total Charges 2008	Percentage of Total Charges 2009	Percentage of Total Charges 2010	Percentage of Total Charges 2011	Percentage of Total Charges 2012
Load Weighted Energy	85.9%	85.3%	87.1%	88.2%	91.7%	91.1%	86.5%	83.4%	69.9%	72.3%	73.4%	72.6%
Capacity	0.7%	0.3%	0.2%	0.2%	0.0%	0.0%	5.6%	9.8%	19.7%	18.2%	15.5%	12.5%
Transmission Service Charges	8.1%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%	6.0%	7.1%	9.9%
Operating Reserves (Uplift)	2.5%	1.9%	1.8%	1.8%	1.4%	0.8%	0.9%	0.7%	0.9%	1.2%	1.3%	1.6%
Reactive	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%	0.7%	0.9%
PJM Administrative Fees	0.8%	1.2%	1.1%	1.0%	0.5%	0.7%	0.5%	0.3%	0.5%	0.5%	0.6%	0.9%
Transmission Enhancement Cost Recovery									0.2%	0.3%	0.5%	0.7%
Regulation	1.2%	1.1%	1.1%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%	0.5%	0.5%	0.5%
Transmssion Owner (Schedule 1A)	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.2%
Day Ahead Scheduling Reserve (DASR)								0.0%	0.0%	0.0%	0.1%	0.1%
Synchronized Reserves		0.3%	0.4%	0.3%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%
Black Start		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
NERC/RFC							0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RTO Startup and Expansion		0.1%	0.1%	0.2%	0.5%	0.3%	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%	0.1%	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%	0.0%
Non-Synchronized Reserves												0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

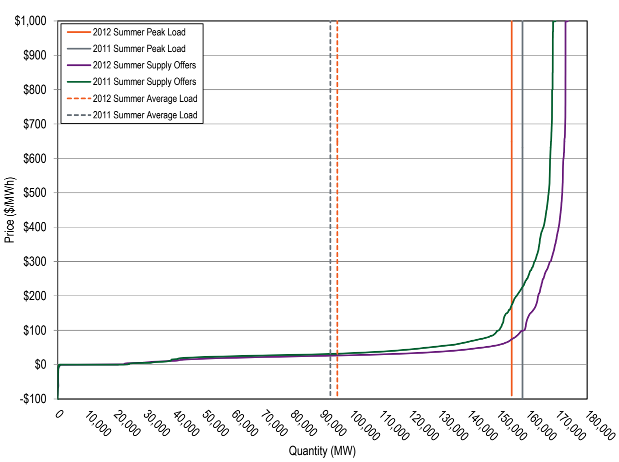
Section Overviews

Overview: Section 2, "Energy Market"

Market Structure

- **Supply.** Average offered supply increased by 4,180, or 2.5 percent, from 169,234 MW in the summer of 2011 to 173,414 MW in the summer of 2012.[54] 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 2012, 2,669 MW of new capacity were added to PJM. This new supply was more than offset by the deactivation of 45 units (6,691.9 MW) since January 1, 2012.

Figure 2 Average PJM aggregate supply curves: Summer 2011 and 2012



- **Demand.** The PJM system peak load for 2012 was 154,344 MW in the HE 1700 on July 17, 2012, which was 3,672 MW, or 2.3 percent, lower than the PJM peak load for 2011, which was 158,016 MW in the HE 1700 on July 21, 2011.[55] The DEOK Transmission Zone accounted for 5,360 MW in the peak hour of 2012. The 2012 peak load excluding the DEOK Transmission Zone was 148,984 MW, also occurring on July 17, 2012, HE 1700, a decrease of 9,032 MW, or 5.7 percent, from the 2011 peak load.
- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segment.
- **Local Market Structure and Offer Capping.** PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2012. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours increased from 0.0 percent in 2011 to 0.6 percent in 2012. In the Real-Time Energy Market offer-capped unit hours increased from 0.9 percent in 2011 to 1.2 percent in 2012.

53 Data are missing for January of 2002.

54 Calculated values shown in Section 2, "Energy Market" are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

55 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2012 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).

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Table 11 Offer-capping statistics: 2008 to 2012

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.9%	0.4%	0.0%	0.0%
2012	1.2%	0.8%	0.6%	0.4%

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 133 units eligible for FMU or AU status in at least one month during 2012, 25 units (18.8 percent) were FMUs or AUs for all months, and 25 (18.8 percent) qualified in only one month of 2012.

  The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and significant changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

- **Local Market Structure.** In 2012, 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 offer cap 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.[56]

Market Performance: Markup, Load, Generation and LMP

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

  All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder 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. Actual participant behavior support this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder.

  In 2012, the unadjusted markup was negative, primarily as a result of competitive behavior by coal units. The unadjusted markup component of LMP was -$1.38 per MWh. The adjusted markup was $.43 per MWh or 1.2 percent of the PJM real-time, load-weighted average LMP of $35.23 per MWh.

  The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Load.** PJM average real-time load in 2012 increased by 5.4 percent from 2011, from 82,546 MW to 87,011 MW. The PJM average real-time load in 2012 would have decreased by 2.0 percent from 2011, from 82,546 MW to 80,909 MW, if the DEOK and ATSI Transmission Zones were not included in this comparison for the months prior to their integration to PJM.[57]

  PJM average day-ahead load in 2012, including DECs and up-to congestion transactions, increased by 15.6 percent from 2011, from 113,866 MW to 131,612 MW. PJM average day-ahead load in 2012, including DECs and up-to congestion transactions, would have been 8.9 percent higher than in 2011, from 113,866 MW to 124,046 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison. The day-ahead load growth was 188.9 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

56 See the *2012 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

57 The ATSI zone was integrated on June 1, 2011. The DEOK zone was integrated on January 1, 2012. The ATSI zone was not included in this comparison for January through May 2011, and January through May 2012. The DEOK zone was not included in this comparison.

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- **Generation.** PJM average real-time generation in 2012 increased by 3.4 percent from 2011, from 85,755 MW to 88,708 MW. PJM average real-time generation in 2012 would have decreased by 2.5 percent from 2011, from 85,755 MW to 83,630 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison.

  PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, increased by 14.8 percent from 2011, from 117,130 MW to 134,479 MW. PJM average day-ahead generation in 2012, including INCs and up-to congestion transactions, would have been 4.7 percent higher than in 2011, from 117,130 MW to 122,599 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison. The day-ahead generation growth was 335.3 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

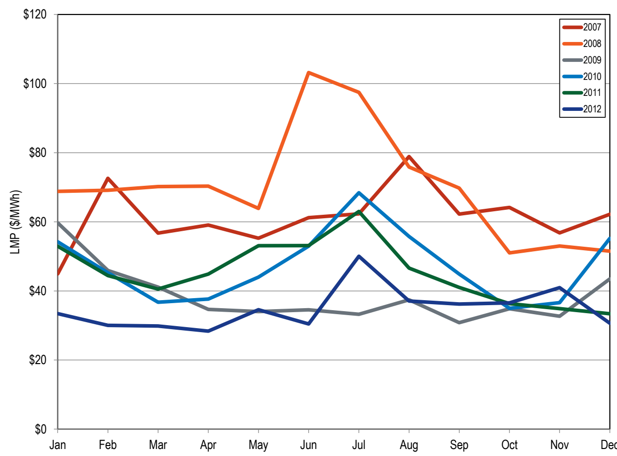
- **Generation Fuel Mix.** During 2012, coal units provided 42.1 percent, nuclear units 34.6 percent and gas units 18.8 percent of total generation. Compared to 2011, generation from coal units decreased 7.4 percent, generation from nuclear units increased 4.0 percent, and generation from gas units increased 39.0 percent.

- **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 the changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion.

  PJM Real-Time Energy Market prices decreased in 2012 compared to 2011. The system average LMP was 22.7 percent lower in 2012 than in 2011, $33.11 per MWh versus $42.84 per MWh. The load-weighted average LMP was 23.3 percent lower in 2012 than in 2011, $35.23 per MWh versus $45.94 per MWh.

  PJM Day-Ahead Energy Market prices decreased in 2012 compared to 2011. The system average LMP was 22.9 percent lower in 2012 than in 2011, $32.79 per MWh versus $42.52 per MWh. The load-weighted average LMP was 23.5 percent lower in 2012 than in 2011, $34.55 per MWh versus $45.19 per MWh.[58]

Figure 3 PJM real-time, monthly, load-weighted, average LMP: 2007 through 2012



- **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. 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 2012, 9.0 percent of real-time load was supplied by bilateral contracts, 23.2 percent by spot market purchase and 67.8 percent by self-supply. Compared with 2011, reliance on bilateral contracts decreased 1.5 percentage points, reliance on spot supply decreased by 3.4 percentage points and reliance on self-supply increased by 4.9 percentage points. In 2012, 6.7 percent of day-ahead load was supplied by bilateral contracts, 22.3 percent by spot market purchases, and 71.0 percent by self-supply. Compared with 2011, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply decreased by 2.1 percentage points, and reliance on self-supply increased by 1.3 percentage points.

58 Tables reporting zonal and jurisdictional load and prices are in Appendix C. See the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

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Scarcity

- **Scarcity Pricing Events in 2012.** PJM did not declare an administrative scarcity event in 2012. PJM's market did not experience any reserve-based shortage events in 2012.
- **Scarcity and High Load Analyses.** There were no reserve shortages in 2012. There were seven high load days and 40 high-load hours in 2012. There were 28 Hot Weather Alerts called in 2012.

Section 2 Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in 2012, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices.

Average real-time supply offered increased by 4,180 MW in the summer of 2012 compared to the summer of 2011, while peak load decreased by 3,672 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. In the Day-Ahead Energy Market, average load in 2012 increased from 2011, from 113,866 MW to 131,612 MW, or 15.6 percent. In the Real-Time Energy Market, average load in 2012 increased from 2011, from 82,546 MW to 87,011 MW, or 5.4 percent. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as 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.

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 price elasticity of demand in affecting price. Energy Market results for 2012 generally reflected supply-demand fundamentals.

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.[59] 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 successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

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 and 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

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

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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 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 new scarcity pricing rules in 2012. There are significant issues with the scarcity pricing true up mechanism in the new PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in 2012.

Overview: Section 3, "Operating Reserve"

Operating Reserve Results

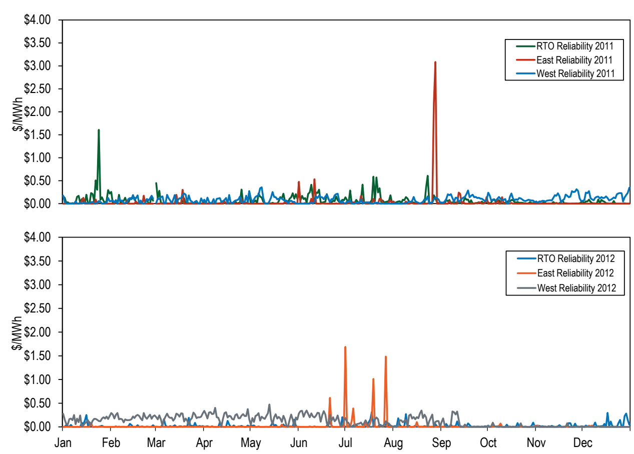
- **Operating Reserve Charges.** Total operating reserve charges in 2012 were $648.7 million. The day-ahead operating reserve charges proportion of total operating reserve charges was 25.6 percent, the balancing operating reserve charges proportion was 66.4 percent, the reactive services charges proportion was 8.0 percent and the synchronous condensing charges proportion was 0.02 percent.

Table 12 Total operating reserve charges: 1999 through 2012[60]

	Total Operating Reserve Charges	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing
1999	$133,897,428	NA	7.5%
2000	$216,985,147	62.1%	9.6%
2001	$284,046,709	30.9%	8.5%
2002	$273,718,553	(3.6%)	5.8%
2003	$376,491,514	37.5%	5.4%
2004	$537,587,821	42.8%	6.2%
2005	$712,601,789	32.6%	3.1%
2006	$365,572,034	(48.7%)	1.7%
2007	$503,279,869	37.7%	1.6%
2008	$474,268,500	(5.8%)	1.4%
2009	$322,729,996	(32.0%)	1.2%
2010	$622,843,365	93.0%	1.8%
2011	$603,164,922	(3.2%)	1.7%
2012	$648,728,097	7.6%	2.2%

- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.2001 per MWh, the balancing operating reserve reliability rates averaged $0.0245, $0.0219 and $0.1154 per MWh for the RTO, Eastern and Western Regions, the balancing operating reserve deviation rates averaged $0.8147, $0.3332 and $0.1265 per MWh for the RTO, Eastern and Western Regions. Lost opportunity cost rate averaged $1.3223 per MWh and canceled resources rate averaged $0.0235 per MWh.

Figure 4 Daily balancing operating reserve reliability rates ($/MWh): 2011 and 2012



60 The total operating reserve charges in Table 3-6 are different than the total charges published in the *2011 State of the Market Report for PJM* and previous versions because previous versions did not include operating reserve charges for load response nor reactive services charges. PJM may recalculate new settlements after the State of the Market Report is published.

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- **Operating Reserve Credits.** Four operating reserve categories accounted for 97.8 percent of all operating reserve credits. Balancing generator operating reserves were 35.1 percent, lost opportunity cost were 29.5 percent, day-ahead generator operating reserves were 25.6 percent and reactive services were 7.6 percent of all credits.

Characteristics of Credits

- **Types of units.** Coal units received 74.3 percent of all day-ahead generator credits and 48.5 percent of all balancing generator credits. Wind units received 94.6 percent of all canceled resources credits. Combustion turbines and diesels received 87.3 percent of the lost opportunity cost credits. Combined cycles and coal units received 80.1 percent of all reactive services credits.

- **Economic – Noneconomic Generation.** In 2012, 84.2 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.9 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In 2012, 83.3 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 5.8 percent by transactions at hubs and 10.9 percent by transactions at interfaces.

- Generators in the Eastern Region paid 11.5 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 49.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 12.3 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 50.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

- Generators paid 13.3 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.9 percent of all credits.

Load Response Resource Operating Reserves

- In 2012, 96.4 percent of the total energy revenues for end use customers for providing demand reductions as part of the Economic Load Response Program was paid as economic load response credits. The remaining 3.6 percent was operating reserve credits.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 22.7 percent of all credits. The top 10 organizations received 81.7 percent of all credits. Concentration indexes for the three largest operating reserve categories classifies them as highly concentrated. Day-ahead operating reserves HHI was 3720, balancing operating reserves was 3105 and lost opportunity cost HHI was 4169.

- **Day-Ahead Unit Commitment for Reliability:** On September 13, 2012, PJM increased the number and MWh of units scheduled as must run in the Day-Ahead Energy Market because the units were regularly needed for reliability in real time. PJM identified the need to schedule these units in the Day-Ahead Energy Market after determining that these units were affecting the commitment process for combustion turbines in real time. The increase in day ahead scheduling was intended to reduce the divergence between the scheduled resources in the Day-Ahead Market and the actual resources operating in the Real-Time Energy Market. The addition of units scheduled as must run in the Day-Ahead Energy Market shifted substantial operating reserve credits from the Balancing Energy Market to the Day-Ahead Energy Market. This is significant because day-ahead operating reserve charges and balancing operating reserve charges are allocated differently. FERC accepted proposed revisions to PJM's tariff and operating agreement to change the allocation methodology for operating reserve make whole payments in the Day-Ahead Energy Market for reliability purposes.

- **Lost Opportunity Cost Credits:** In 2012, lost opportunity cost credits increased by $18.8 million compared to 2011. In 2012, the top three control zones receiving lost opportunity cost credits, AP, ComEd and Dominion combined for 64.4 percent

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of all lost opportunity cost credits, 60.3 percent of all the day-ahead generation from pool-scheduled combustion turbines and diesels, 65.8 percent of all day-ahead generation not called in real time by PJM from those unit types and 68.5 percent of all day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.

- **Lost Opportunity Cost Calculation:** In 2012, lost opportunity cost credits would have been reduced by $60.8 million, or 31.8 percent, if all changes proposed by the MMU had been implemented.
- **Wind Units Lost Opportunity Cost:** In 2012, lost opportunity cost credits paid to wind units would have been reduced by $3.1 million, or 65.6 percent, if all changes proposed by the MMU had been implemented.
- **Black Start and Voltage Support Units:** Certain units located in the AEP zone are relied on for their ALR blackstart capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant blackstart units provide blackstart service under the ALR option, which means that the units must be running even if not economic. The MMU raised the issue that such costs should be categorized as black start costs rather than operating reserve charges. This issue was resolved in PJM's tariff and operating agreement filing with FERC.
- **Con Edison – PSEG Wheeling Contracts Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG. These units are often run out of merit and received substantial balancing operating reserves credits.
- **Up-to Congestion Transactions:** Up-to congestion transactions do not pay operating reserve charges despite that they affect dispatch and commitment in the Day-Ahead Energy Market. The impact of assigning operating reserve charges to up-to congestion transactions on the payments by other participants would be significant. For example, in 2012, the RTO deviation rate would have been reduced by 59.3 percent if up-to congestion transactions had been included in the calculation of operating reserve charges.

Section 3 Conclusion

Day-ahead and real-time operating reserve credits are 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. Sometimes referred to as uplift or make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at 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.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

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 operating reserve payments. When units receive substantial revenues through operating reserve payments, these payments are not transparent to the market and other market participants do not have the opportunity to compete for them. As a result, substantial operating reserve payments to a concentrated group of units and organizations persists.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters and the decisions of PJM operators. Operating reserve credits 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.

PJM has improved its oversight of operating reserves and continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.

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However, given the impact of operating reserve charges on market participants, particularly virtual market participants, the MMU recommends that PJM take another step towards more precise definition and clearly identify and classify all reasons for incurring operating reserve charges in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

The MMU recommends that the allocation of operating reserve charges to participants be carefully reexamined to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. For example, there has not been an analysis of the impact of up-to congestion transactions and their impact on the payment of operating reserve credits. Up-to congestion transactions continue to pay no operating reserve charges, which means that all others who pay operating reserve charges are paying too much. In addition, the issue of netting using internal bilateral transactions should be addressed.

Overall, the MMU recommends that the goal be to minimize the total level of operating reserve credits paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. The goal should be to minimize the total incurred operating reserve charges and to increase the transactions over which those charges are spread in order to reduce the impact of operating reserve charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with operating reserve charges and to reduce the impact of operating reserve charges on decisions about how and when to participate in PJM markets.

Overview: Section 4, "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.[61]

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.[62] 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.[63] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13 and four months, prior to the delivery year. 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.[64]

RPM prices are locational and may vary depending on transmission constraints.[65] 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

61 The terms *PJM Region, RTO Region and RTO* are synonymous in the *2011 State of the Market Report for PJM*, Section 4, "Capacity Market" and include all capacity within the PJM footprint.
62 See 126 FERC ¶ 61,275 (2009) at P 86.
63 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
64 See 126 FERC ¶ 61,275 (2009) at P 88.
65 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.

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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. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand-side 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 2012, PJM installed capacity resources increased from 178,854.1 MW on January 1 to 181,990.1 on December 31, primarily due to the integration of the Duke Energy Ohio and Kentucky (DEOK) Control Zone into PJM.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of 2012, 41.8 percent was coal; 28.6 percent was gas; 18.1 percent was nuclear; 6.3 percent was oil; 4.3 percent was hydroelectric; 0.4 percent was solid waste; 0.4 percent was wind, and 0.0 percent was solar.

Table 13 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2012

	1-Jan-12		31-May-12		1-Jun-12		31-Dec-12	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,190.4	42.0%	79,311.0	42.8%	79,664.6	42.9%	75,989.2	41.8%
Gas	49,769.3	27.8%	51,180.1	27.6%	51,949.1	28.0%	52,003.2	28.6%
Hydroelectric	8,047.0	4.5%	8,047.0	4.3%	7,879.8	4.2%	7,879.8	4.3%
Nuclear	32,492.6	18.2%	33,085.0	17.9%	33,149.5	17.8%	33,024.0	18.1%
Oil	11,977.3	6.7%	12,260.4	6.6%	11,532.9	6.2%	11,531.2	6.3%
Solar	15.3	0.0%	16.3	0.0%	47.0	0.0%	47.0	0.0%
Solid waste	705.1	0.4%	689.1	0.4%	736.1	0.4%	736.1	0.4%
Wind	657.1	0.4%	660.1	0.4%	779.6	0.4%	779.6	0.4%
Total	178,854.1	100.0%	185,249.0	100.0%	185,738.6	100.0%	181,990.1	100.0%

- **Supply.** Total internal capacity increased 10,070.6 MW from 159,882.7 MW on June 1, 2011, to 169,953.3 MW on June 1, 2012. This increase was the result of the reclassification of the Duquesne resources as internal at the time of the 2012/2013 RPM Base Residual Auction (3,187.2 MW), new generation (785.5 MW), reactivated generation (0.0 MW), net generation capacity modifications (cap mods) (-1,637.3 MW), Demand Resource (DR) modifications (8,028.7 MW), Energy Efficiency (EE) modifications (652.5 MW), the EFORd effect due to lower sell offer EFORds (-944.1 MW), and lower Load Management UCAP conversion factor (-1.9 MW).
- **Demand.** There was a 3,237.4 MW increase in the RPM reliability requirement from 154,251.1 MW on June 1, 2011, to 157,488.5 MW on June 1, 2012. This increase was primarily due to the inclusion of the Duquesne Zone in the preliminary forecast peak load for the 2012/2013 RPM Base Residual Auction. On June 1, 2012, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 71.9 percent, up slightly from 71.4 percent on June 1, 2011.
- **Market Concentration.** For the 2012/2013, 2013/2014, 2014/2015, and 2015/2016 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2012/2013 RPM First Incremental Auction, 2012/2013 ATSI Integration Auction, 2012/2013 RPM Second Incremental Auction, 2012/2013 RPM Third Incremental Auction, 2013/2014 BRA, 2013/2014 RPM First Incremental Auction, 2013/2014 RPM Second Incremental Auction, and the 2015/2016 BRA failed the three pivotal supplier (TPS) market structure test.[66] In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test, and six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 BRA, all participants in the RTO and PSEG North RPM markets failed the TPS test, and seven participants in the incremental supply in MAAC passed the TPS test. 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

66 There are 26 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).

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submitted sell offer, absent mitigation, would have increased the market clearing price.[67,68,69]

- **Imports and Exports.** Net exchange decreased 2,067.1 MW from June 1, 2011 to June 1, 2012. Net exchange, which is imports less exports, decreased due to a decrease in imports of 2,588.4 MW primarily due to the reclassification of the Duquesne resources to internal, offset by a decrease in exports of 521.3 MW.

- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market decreased by 2,764.9 MW from 9,883.4 MW on June 1, 2011 to 7,118.5 MW on June 1, 2012. Demand-side resources include Demand Resources (DR) and Energy Efficiency (EE) resources cleared in RPM Auctions and certified/forecast interruptible load for reliability (ILR). Effective with 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 Resource type is eligible to be offered in RPM Auctions.[70]

Market Conduct

- **2012/2013 RPM Base Residual Auction.**[71] Of the 1,133 generation resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). The MMU calculated offer caps for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR values.

- **2012/2013 ATSI Integration Auction.**[72] Of the 173 generation resources which submitted offers, 26 resources elected the offer cap option of 1.1 times the BRA clearing price (15.0 percent). Unit-specific offer caps were calculated for 12 resources (6.9 percent). The MMU calculated offer caps 131 resources (75.7 percent), of which 117 were based on the technology specific default (proxy) ACR values.

- **2012/2013 RPM First Incremental Auction.** Of the 162 generation resources which submitted offers, unit-specific offer caps were calculated for 14 resources (8.6 percent). The MMU calculated offer caps for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR values.

- **2012/2013 RPM Second Incremental Auction.** Of the 188 generation resources which submitted offers, unit-specific offer caps were calculated for 8 resources (4.3 percent). The MMU calculated offer caps for 88 resources (46.8 percent), of which 80 were based on the technology specific default (proxy) ACR values.

- **2012/2013 RPM Third Incremental Auction.** Of the 298 generation resources which submitted offers, unit-specific offer caps were calculated for two generation resources (0.7 percent). The MMU calculated offer caps for 37 generation resources (12.4 percent), of which 35 were based on the technology specific default (proxy) ACR values.

- **2013/2014 RPM Base Residual Auction.**[73] Of the 1,170 generation resources which submitted offers, unit-specific offer caps were calculated for 107 resources (9.1 percent). The MMU calculated offer caps for 700 resources (59.9 percent), of which 587 were based on the technology specific default (proxy) ACR values.

- **2013/2014 RPM First Incremental Auction.** Of the 192 generation resources which submitted offers, unit-specific offer caps were calculated for 27 resources (14.1 percent). The MMU calculated offer caps for 101 resources (52.6 percent), of which 74 were based on the technology specific default (proxy) ACR values.

- **2013/2014 RPM Second Incremental Auction.** Of the 163 generation resources which submitted offers, unit-specific offer caps were calculated for eight generation resources (4.9 percent). The MMU calculated offer caps for 77 generation resources

67 OATT Attachment DD (Reliability Pricing Model) § 6.5.

68 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.

69 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).

70 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

71 For a more detailed analysis of the 2012/2013 RPM Base Residual Auction, see "Analysis of the 2012/2013 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf> (August 6, 2009).

72 For a more detailed analysis of the 2012/2013 ATSI Integration Auction, see "Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions," <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf> (January 14, 2011).

73 For a more detailed analysis of the 2013/2014 RPM Base Residual Auction, see "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

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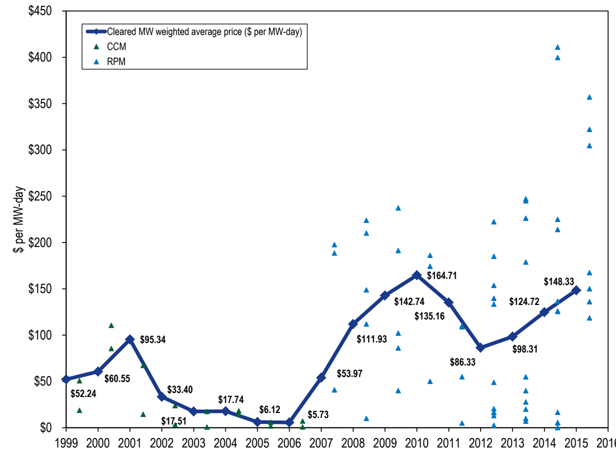
(47.2 percent), of which 65 were based on the technology specific default (proxy) ACR values.

- **2014/2015 RPM Base Residual Auction.**[74] Of the 1,152 generation resources which submitted offers, unit-specific offer caps were calculated for 141 resources (12.2 percent). The MMU calculated offer caps for 698 resources (60.6 percent), of which 550 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM First Incremental Auction.** Of the 190 generation resources which submitted offers, unit-specific offer caps were calculated for 21 generation resources (11.1 percent). The MMU calculated offer caps for 96 generation resources (50.5 percent), of which 71 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM Base Residual Auction.** Of the 1,168 generation resources which submitted offers, unit-specific offer caps were calculated for 188 generation resources (16.1 percent). The MMU calculated offer caps for 670 generation resources (57.4 percent), of which 478 were based on the technology specific default (proxy) ACR values.

Market Performance

- Annual weighted average capacity prices increased from a 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.
- RPM net excess decreased 4,661.9 MW from 10,638.4 MW on June 1, 2011, to 5,976.5 MW on June 1, 2012.
- For the 2012/2013 Delivery Year, RPM annual charges to load totaled approximately $3.9 billion.

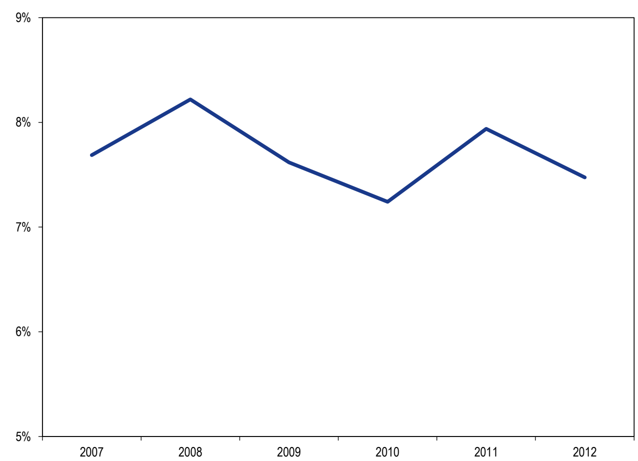
Figure 5 History of capacity prices: Calendar year 1999 through 2015[75]



Generator Performance

- **Forced Outage Rates.** Average PJM EFORd decreased from 7.9 percent in 2011 to 7.5 percent in 2012.[76]

Figure 6 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2012



- **Generator Performance Factors.** The PJM aggregate equivalent availability factor increased from 83.7 percent in 2011 to 84.1 percent in 2012.

74 For a more detailed analysis of the 2014/2015 RPM Base Residual Auction, see "Analysis of the 2014/2015 RPM Base Residual Auction Report," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

75 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2015 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.

76 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 resources in the RPM. Data is for the twelve months ending December 31, as downloaded from the PJM GADS database on January 25, 2013. 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.

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- **Outages Deemed Outside Management Control (OMC).** According to North American Electric Reliability Corporation (NERC) criteria, an outage may be classified as an OMC outage if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. In 2012, 12.4 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Section 4 Conclusion

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to, or slightly above, the demand for capacity. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets or does not have adequate optionality value, will retire. Demand is almost entirely inelastic, because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. This is not surprising in that the PJM Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The PJM Capacity Market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

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, by market shares and by the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in 2012. 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 2012.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. In 2011 and 2012, the MMU prepared a number of RPM-related reports and testimony, shown in Table 4-2.

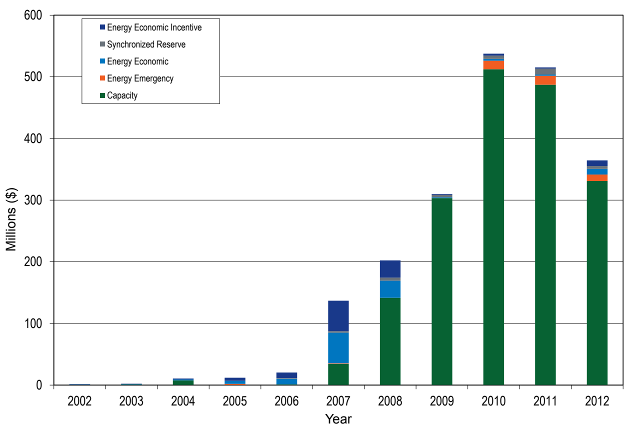
Overview: Section 5, "Demand Response"

- **Demand-Side Response Activity.** In 2012, the total MWh of load reduction under the Economic Load Response Program increased by 124,170 MWh compared to the same period in 2011, from 17,398 MWh in 2011 to 141,568 MWh in 2012, a 714 percent increase. Total payments under the Economic Program increased by $7,106,385, from $2,052,996 in 2011 to $9,159,381 in 2012, a 346 percent increase.

  Settled MWh and credits were greater in 2012 compared to 2011, and there were more settlements submitted compared to the same period in 2010. Participation levels increased following the implementation of Order 745, on April 1, 2012, allowing payment of full LMP for demand resources. On the peak load day for 2012 (July 17, 2012), there were 2,302.4 MW registered in the Economic Load Response Program, compared to 2,041.5 MW for 2011 (July 21,2011).

Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to participants in PJM demand side programs. In 2012, Load Management (LM) Program revenue decreased $156.0 million, or 32.0 percent, from $487 million to $331 million. Through 2012 Synchronized Reserve credits for demand side resources decreased by $4.9 million compared to the same period in 2011, from $9.4 million to $4.5 million in 2012.

Figure 7 Demand Response revenue by market: 2002 through 2012



- **Locational Dispatch of Demand-Side Resources.** PJM dispatches demand-side resources on a subzonal basis when appropriate, but only on a voluntary basis. Beginning with the 14/15 Delivery Year, demand resources will be dispatchable on a subzonal basis. More locational deployment of demand-side resources improves efficiency in a nodal market.
- **Load Management Product.** The load management product is currently defined as an emergency product. The Load Management product is an economic product and should be treated as an economic product in the PJM market design and in PJM dispatch. Demand resources should be called when the resources are required and prior to the declaration of an emergency. The MMU recommends that the DR program be classified as an economic program and not an emergency program.
- **Emergency Event Day Analysis.** Load management event rules allow overcompliance to be reported when there is no actual overcompliance. Settlement MWh are not netted across hours or across registrations within hours for compliance purposes, but are treated as zero even if load actually increases. Considering all and only reported values, the observed load reduction of the two events in 2012 should have been 3,713.4, rather than the 3,922.5 reported. Overall, compliance decreases from the reported 103.0 percent to 97.6 percent. This does not include locations that did not report their load during the emergency event days.

Section 5 Conclusions

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. 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.

Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market locational marginal price (LMP). End use customers pay load serving entities (LSEs) an annual amount designed to recover, among other things, the total cost of wholesale power for the year.[77] End use customers paying fixed retail rates do not face even the hourly zonal average LMP. Thus, it would be a substantial step forward for customers to face the hourly zonal average price. But the actual market price of energy and the appropriate price signal for end use customers is the nodal locational marginal price. Within a zone, the actual costs of serving load, as reflected in the nodal hourly LMP, can vary substantially as a result of

77 In PJM, load pays the average zonal LMP, which is the weighted average of the actual nodal locational marginal price. While individual customers have the option to pay nodal LMP, very few customers do so.

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transmission constraints. A customer on the high price side of a constraint would have a strong incentive to add demand side resources if they faced the nodal price while that customer currently has an incentive to use more energy than is efficient, under either a flat retail rate or a rate linked to average zonal LMP. The nodal price provides a price signal with the actual locational marginal value of energy. In order to achieve the full benefits of nodal pricing on the supply and the demand side, load should ultimately pay nodal prices. However, a transition to nodal pricing could have substantial impacts and therefore must be managed carefully.

Today, most end use customers do not face the market price of energy, that is the locational marginal price of energy, or the market price of capacity, the locational price of capacity. Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP, either on an average zonal or on a nodal basis. This results in a market failure because when customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. This market failure does not imply that PJM markets have failed. This market failure means that customers do not pay the actual hourly locational cost of energy as a result of the disconnect between wholesale markets and retail pricing. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the actual hourly locational price of power used by customers is determined by the wholesale power market, regardless of the average price actually paid by customers. The transition to a more functional demand side in the wholesale power market requires that the default energy price for all customers be the day-ahead or real-time hourly locational marginal price (LMP) and the locational clearing price of capacity. While the initial default energy price could be the zonal average LMP, the transition to nodal LMP pricing should begin.

PJM's Economic Load Response Program (ELRP) is designed to address this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale zonal price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market.[78] In PJM's Economic Load Response Program, participants have the option to receive credits for load reductions based on a more locationally defined pricing point than the zonal LMP. PJM's PRD program does incorporate some aspects of nodal pricing, although the link between the nodal wholesale price and the retail price is extremely attenuated.

FERC Order 745 was implemented effective April 1, 2012. Order 745 requires RTOs and ISOs to pay full LMP to demand resources rather than LMP less the cost of generation and transmission paid by retail customers, if the demand resources are cost effective as determined by a "Net Benefits Test" (NBT).[79] This approach is based on the view that dispatching demand resources may result in a net increase in cost to non-demand response loads, and requires the NBT as mitigation. The payment of full LMP to demand resources, effective April 1, 2012, increased participation in the Economic Load Response Program. This change explicitly permitted subsidies to be paid to retail customers on fixed rates that incorporate a fixed price of wholesale power, and to customers paying LMP for wholesale power. While the subsidy has a rationale as an incentive for fixed rate retail customers, there is no reason to provide this subsidy to LMP customers who are already receiving the price signal from the wholesale power market.

PJM's Load Management (LM) Program in the RPM market attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity. The PJM market design also creates the opportunity for demand resources to participate in ancillary services markets.[80] Within the LM Program, there are new shortage pricing rules that increase maximum bid offers for the 2012/2013 DY to $1,500/MWh.

PJM's demand side programs, by design, provide a work around for end use customers that are not directly exposed to the incremental, locational costs of energy

78 While the primary purpose of the ELRP is to replicate the hourly zonal price signal to customers on fixed retail rate contracts, customers with zonal or nodal hourly LMP contracts are currently eligible to participate in the DA scheduling and the PJM dispatch options of the Program.

79 The NBT uses a single monthly price for PJM and does not reflect hourly, locational price differences in the Real-Time and Day-Ahead markets.

80 See *2012 State of the Market Report for PJM*, Volume 2, "Section 9: Ancillary Service Markets."

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and capacity. The demand side programs should be understood as one relatively small part of a transition to a fully functional demand side for PJM markets. The complete transition to a fully functional demand side will require explicit agreement and coordination among the Commission, state public utility commissions and RTOs/ISOs.

If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM Economic Load Response Program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption. The MMU recommends that actual meter load data should be provided in order to measure and verify actual demand resource behavior.

The MMU recommends that demand side measurement and verification should be further modified to more accurately reflect compliance. Increases in load during event hours should not be considered zero response, but should be included for reporting and determining compliance. Load management testing does not adequately reflect actual resource performance during event days. Testing should be initiated by PJM with limited warning to CSPs in order to more accurately reflect the conditions of an emergency event.

Overview: Section 6, "Net Revenue"

Net Revenue

- Net revenues are significantly affected by energy prices, fuel prices and capacity prices. Revenue from the capacity market was lower in 2012 in all zones except DPL and PSEG. The combination of these factors resulted in lower total net revenues for the new entrant CT in all zones, for the new entrant CC in all zones and for the new entrant CP in all zones. The total net revenues for an IGCC plant, a nuclear plant, a solar installation and a wind installation were also affected by lower energy revenues and lower capacity revenues in 2012.
- The total net revenues did not cover the annual levelized fixed costs of a new entrant CT in any zone. The total net revenues covered the annual levelized fixed costs of a new entrant CC in three zones and covered more than 90 percent of annual levelized fixed costs in nine of 16 relevant zones. The total net revenues did not cover the annual levelized fixed costs of a new entrant CP in any zone and did not exceed 20 percent of the annual levelized fixed costs of a new entrant CP in any zone.
- The total net revenues covered only five percent of the annual levelized fixed costs of a new entrant IGCC. The total net revenues covered only 28 percent of the annual levelized fixed costs of a new entrant nuclear plant. The total net revenues covered more than 65 percent of the annual levelized fixed costs of a new entrant wind installation. The total net revenues covered 97 percent of the annual levelized fixed costs of a new entrant solar installation. Production tax credits and renewable energy credits accounted for more than 40 percent of the net revenue of a wind installation and more than 80 percent of the net revenue of a solar installation.
- Of existing sub-critical coal units, 39 percent did not recover even avoidable costs from total net revenues and of existing supercritical coal units, 15 percent did not recover even avoidable costs from total net revenues. Coal units that have not declared their intent to retire and did not cover avoidable costs from total market revenues comprise 3,725 MW of capacity. These units can be considered to be at risk of retirement.

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Figure 8 New entrant CC net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2012

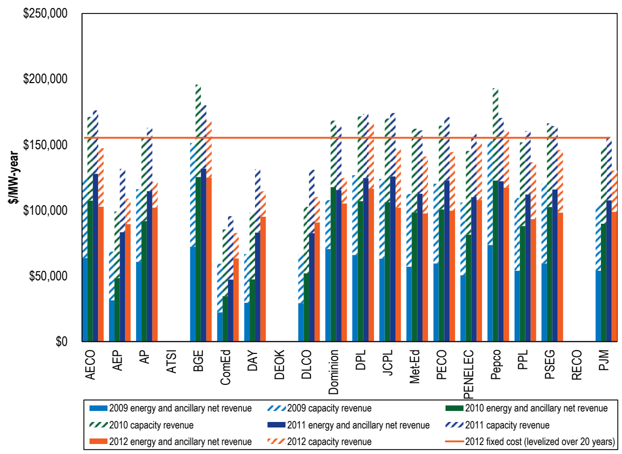
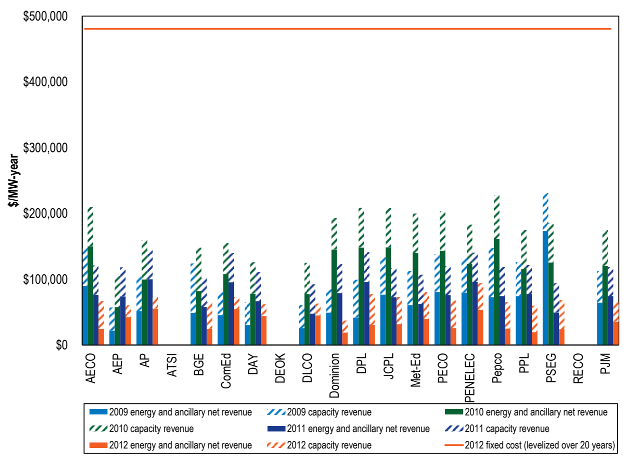


Figure 9 New entrant CP net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2012



Section 6 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.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to nonmarket and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

PJM's RPM is an explicit effort to address these issues. RPM is a capacity market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs and other inframarginal units.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the capacity market provides a significant stream of revenue that contributes to the recovery of total costs for new and existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The capacity market is also a significant source of net revenue to cover the fixed costs of investing in new intermediate and base load units, although capacity revenues are a larger part of net revenue for peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when the energy net revenues used as the offset in determining capacity market prices are higher than actual energy net revenues, there is a corresponding lag in capacity market prices which will tend to lead to an under recovery of the fixed costs of CTs. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

Overview: Section 7, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.**[81] On December 16, 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. The rule establishes a compliance deadline of April 16, 2015. A source may obtain an extension for up to one additional year where necessary for the installation of controls. The CAA defines MACT as the average emission rate of the best performing 12 percent of existing resources (or the best performing five sources for source categories with less than 30 sources).

  The MATS rule affected offers in the 2015/2016 RPM Base Residual Auction, held in May 2012.

  In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires 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.

- **Cross-State Air Pollution Rule.** On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR, which previously had been subject to a stay.[82] EPA has filed a petition for rehearing. While a decision on rehearing is pending, the Clean Air Interstate Rule (CAIR) remains in effect. The EPA continues to process a number of pending requests under CAIR, including State Implementation Plans (SIPs), originally submitted under CSAPR.

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[83] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter. The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs), and particulate matter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.

81 MATS replaces the Clean Air Mercury Rule (CAMR). It has been widely known previously as the "HAP" or "Utility MACT" rule.

82 *See* EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

83 *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 (January 14, 2013).

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- **Greenhouse Gas Emissions Rule.** 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 CO2 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.[84]

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days. New Jersey's HEDD rule,[85] 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.[86] New Jersey's HEDD rule is implemented in two phases. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports and are subject to various behavioral requirements. After May 1, 2015, new, reconstructed or modified turbines must comply with certain technology standards. Owners/operators of existing HEDD units were each required to submit by May 1, 2010 and update annually a 2015 HEDD Emission Limit Achievement Plan, describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_X emission rates.

  The HEDD rule affected offers in the 2015/2016 RPM Base Residual Auction, held in May 2012.

- **Regional Greenhouse Gas Initiative (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 CO2 emissions from power generation facilities. Auction prices in 2012 for the 2012-2014 compliance period were $1.93 per ton throughout the year, the price floor for 2012.

Emissions Controls in PJM Markets

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. At the end of 2012, 68.2 percent of coal steam MW's had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 97.6 percent of coal steam MW had some type of particulate control. NO_x emission controlling technology is used by nearly all fossil fuel unit types, and 90.9 percent of fossil fuel fired capacity in PJM has NO_x emission control technology in place.

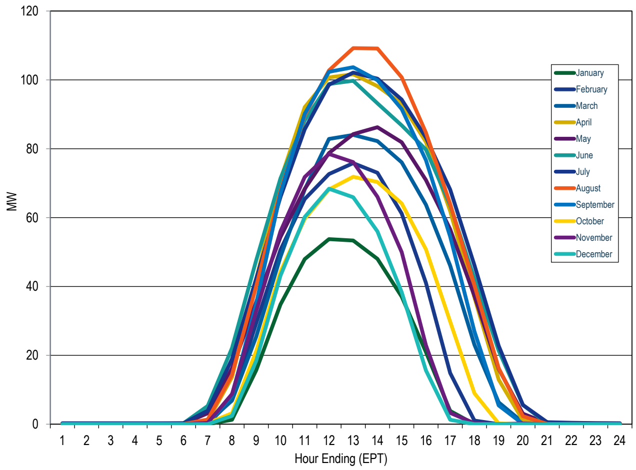
State Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of 2012, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from a requirement that renewables serve 1.5 percent of all load served in Ohio, to 9.21 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards.

Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they offer a payment to renewable resources in addition to the wholesale price of energy which is greater than the marginal cost of producing energy. The out of market payments in the form of RECs and federal production tax credits mean these units have an incentive to generate MWh until the negative LMP is equal to the marginal cost of producing minus the credit received for each MWh. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

84 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
85 N.J.A.C. § 7:27–19.
86 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

Figure 10 Average hourly real-time generation of solar units in PJM: 2012



Section 7 Conclusion

Environmental requirements and renewable energy mandates at both the Federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit 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.

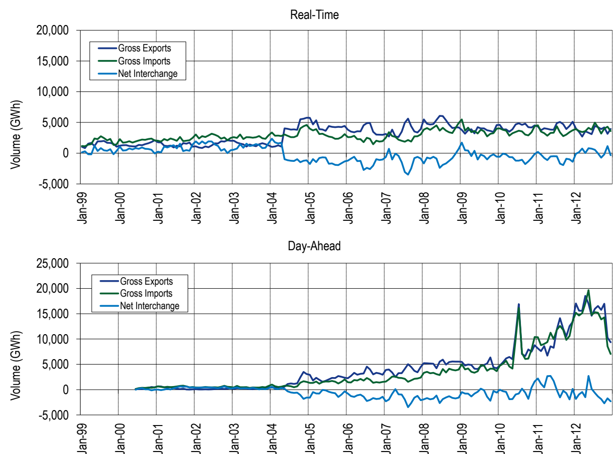
PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. PJM markets also provide a flexible mechanism that incorporates renewable resources and renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Overview: Section 8, "Interchange Transactions"

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** PJM was a monthly net exporter of energy in the Real-Time Energy Market in January, August, September, October and December, and a net importer of energy in the remaining months of 2012.[87] The total 2012 real-time net interchange of 2,770.9 GWh (import) was greater than net interchange of -9,761.8 GWh (export) in 2011.

Figure 11 PJM real-time and day-ahead scheduled import and export transaction volume history: 2012



- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** PJM was a monthly net importer of energy in the Day-Ahead Energy Market in May and June, and a net exporter of energy in the remaining months of 2012. The total 2012 day-ahead net interchange of -12,548.4 GWh (export) was less than net interchange of 6,576.2 GWh (import) in 2011.

  Figure 8-1 shows the correlation between net up-to congestion transactions and the net Day-Ahead Market interchange. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 24,808 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012, compared to an average of 13,396 bids per day, with an average cleared volume of 530,476 MWh per day, for 2011.

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2012, gross imports in the Day-Ahead Energy Market were 364 percent of the Real-Time Energy Market's gross imports (313 percent for 2011), gross exports in the Day-Ahead Energy Market were 416 percent of the Real-Time Energy Market's gross exports (240

87 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

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percent for 2011). In 2012, net interchange was -12,548.4 GWh in the Day-Ahead Energy Market and 2,770.9 GWh in the Real-Time Energy Market compared to 6,576.2 GWh in the Day-Ahead Energy Market and -9,761.8 GWh in the Real-Time Energy Market for 2011.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for 2012, there were net scheduled exports at ten of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 69.6 percent of the total net exports: PJM/Eastern Alliant Energy Corporation (ALTE) with 26.5 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 21.8 percent, and PJM/MidAmerican Energy Company (MEC) with 21.3 percent of the net export volume.[88]

- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for 2012, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.[89] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 78.4 percent of the total net exports: PJM/MISO with 61.9 percent, and PJM/NYIS with 16.5 percent of the net export volume.

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for 2012, there were net scheduled exports at ten of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 77.8 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 31.5 percent, PJM/MidAmerican Energy Company (MEC) with 28.0 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 18.4 percent of the net export volume.[90]

- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for 2012, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for real-time transactions.[91] The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 71.3 percent of the total net exports: PJM/SouthEXP with 43.2 percent, PJM/Northwest with 16.6 percent and PJM/ PJM/Ontario Independent Electricity System Operator (IMO) with 11.6 percent of the net export volume.

- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for 2012, up-to congestion transactions had net exports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points for up-to congestion transactions accounted for 65.6 percent of the total net up-to congestion exports: PJM/SouthEXP with 49.1 percent and PJM/Ontario Independent Electricity System Operator (IMO) with 16.5 percent of the net export up-to congestion volume.[92]

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2012, the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average hourly flow. However, the direction of flows was consistent with price differentials in only 47 percent of hours in 2012.

- **PJM and New York ISO Interface Prices.** In 2012, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. However, the direction of flows was consistent with price differentials in only 52.8 percent of the hours in 2012.

- **Neptune Underwater Transmission Line to Long Island, New York.** In 2012, the PJM average hourly LMP at the Neptune Interface was $34.14 while the NYISO LMP at the Neptune Bus was $43.92, a difference of $9.78.[93] The average hourly flow during

88 In the Real-Time Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

89 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

90 In the Day-Ahead Market, two PJM interface had a net interchange of zero (PJM/Carolina Power and Light – Western (CPLW) and PJM/City Water Light & Power (CWLP)).

91 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

92 In the Day-Ahead Market, five PJM interface pricing points (PJM/CPLE, PJM/DUKIMP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

93 In 2012, there were 3,056 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $32.96 while the NYISO LMP at the Neptune Bus during non-zero flows was $39.70, a difference of $6.74.

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2012 was -257 MW.[94] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64.5 percent of the hours in 2012.

- **Linden Variable Frequency Transformer (VFT) Facility.** In 2012, the average hourly difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average hourly flow. The average hourly flow during 2012 was -72 MW.[95] (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 59.5 percent of the hours in 2012.
- **Hudson DC Line.** The Hudson direct current (DC) line will be a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM and NYISO. While the Hudson DC line will be a bidirectional line, power flows will only be from PJM to New York. The Hudson DC line is expected to be in service by the end of the second quarter of 2013.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the 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 one or more specific interfaces.

  In 2012, net scheduled interchange was 898 GWh and net actual interchange was 672 GWh, a difference of 226 GWh, compared to net scheduled interchange of -7,072 GWh and net actual interchange of -7,576 GWh, a difference of 504 GWh in 2011.[96] This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM called fewer TLRs in 2012 than in 2011. The fact that PJM has issued only 37 TLRs in 2012, compared to 62 in 2011, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO.
- **Up-To Congestion.** Following elimination of the requirement to procure transmission for up-to congestion transactions in 2010, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 67,295 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012, compared to an average of 29,665 bids per day, with an average cleared volume of 530,476 MWh per day, in 2011 (Figure 8-10).
- **Elimination of Sources and Sinks.** The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[97] These modifications are currently being evaluated by PJM.
- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports. The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  PJM and MISO have agreed to allow for unlimited spot market ATC on the NYISO Interface. These modifications are currently being evaluated by PJM. The MMU continues to recommend that PJM permit unlimited spot market imports and exports at all PJM Interfaces.

94 The average hourly flow during 2012, ignoring hours with no flow, on the Neptune DC Tie line was -393 MW.

95 The average hourly flow during 2012, ignoring hours with no flow, on the Linden VFT line was -89 MW.

96 The "Net Scheduled" values shown in Table 8-18 include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. As a result, the net interchange in this table does not match the interchange values shown in Table 8-1 through Table 8-6.

97 See "Meeting Minutes, "Minutes from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> . (May 16, 2011)

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Section 8 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 non-market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non-market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion hedging tools (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non-market areas do not include these features. The market areas are extremely transparent and the non-market areas are not transparent.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during 2012, including evolving transaction patterns, economics and issues. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint, and has continued to be a net exporter in most months since that time. The net direction of power flows is generally a result of price differences net of transactions costs. Up-to congestion transactions have played a significant role in power flows between balancing authorities in the Day-Ahead Market since their modification in late 2010.

In 2012, the direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences for 53.3 percent of the hours for transactions between PJM and MISO and for 47.2 percent of the hours for transactions between PJM and NYISO. The MMU recommends that PJM continue to work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by relying on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

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 such markets. The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely to the expected actual power flows as possible would result in a more economic dispatch of the entire Eastern Interconnection.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012. The average of the daily operating reserve rates paid by virtual transactions was $0.56 per MWh for the lowest five percent of all days in 2012.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[98] The MMU has confirmed that the rules governing the assignment of interface

98 See Docket Nos. ER12-1338-000 and ER12-1343-000.

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pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. However, the MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

Overview: Section 9, "Ancillary Services"

Regulation Market

In 2012, the PJM Regulation Market continued to be operated as a single market. Significant technical and structural changes were made to the Regulation Market in 2012. On May 7, 2012, PJM switched to an improved optimizer, the Ancillary Services Optimizer (ASO). On October 1, 2012, PJM implemented Performance Based Regulation, to comply with FERC Order No. 755.[99] On November 16, 2012, FERC modified the PJM market design that was introduced on October 1, 2012.[100]

Market Structure

- **Supply.** In 2012, the supply of offered and eligible regulation in PJM was both stable and adequate. The ratio of offered and eligible regulation to regulation required averaged 3.61 for 2012. This is a 20.3 percent increase over 2011 when the ratio was 3.00.
- **Demand.** The on-peak regulation requirement, as of December 31, 2012, is equal to 0.70 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 0.70 percent of the forecast valley load for the PJM RTO for the day. In 2011, the on-peak regulation requirement was equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement was equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in 2012 was 921 MW (840 MW off peak, and 1,015 MW on peak). This is a 4 MW decrease in the average hourly regulation demand of 925 MW in 2011 (842 MW off peak, and 1,071 MW on peak).

  Of the LSEs' obligation to provide regulation during 2012, 78.6 percent was purchased in the spot market (81.8 percent in 2011), 19.0 percent was self scheduled (15.6 percent in 2011), and 2.5 percent was purchased bilaterally (2.6 percent in 2011).[101]
- **Market Concentration.** In 2012, the PJM Regulation Market had a weighted, average Herfindahl-Hirschman Index (HHI) of 1,735 which is classified as "moderately concentrated."[102] The minimum hourly HHI was 788 and the maximum hourly HHI was 4962.[103] In 2012, 43 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (82.1 percent of hours failed the three pivotal supplier test in 2011). The MMU concludes from these results that the PJM Regulation Market in 2012 was characterized by structural market power in 43 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with costs parameters to verify the offer, and may optionally submit a price offer. Under the new market design, offers include both a capability offer and a performance offer. The performance offer is converted to \$/MW by multiplying the MW offer by the ΔMW/MW value of the signal type of the unit. Owners must also specify which signal type the unit will be following, RegA or RegD.[104] As of December 31, 2012, there were seven distinct resources (three generation and four demand response) offering performance regulation and following the RegD signal.
- **Price.** The weighted Regulation Market clearing price for the PJM Regulation Market for January through September, 2012 was \$14.92 per MWh. This

99 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

100 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,130 (2012)

101 Due to rounding, percentages might not sum to 100 percent.

102 See the *2012 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

103 HHI and market share are commonly used but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. This assumption and related conclusion are not generally correct in electricity markets, like the Regulation Market, where location and unit specific parameters are significant determinants of the costs to provide service, not the relative market share of the participant. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

104 See Appendix F "Ancillary Services Markets."

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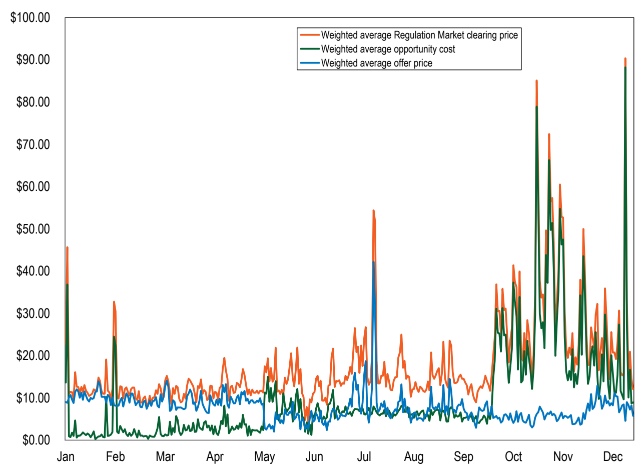
was a decrease of $2.11, or 12.4 percent, from the weighted average price for regulation in January through September, 2011. The cost of regulation from January through September, 2012 was $20.59 per MWh. This is an $11.64 (36.1 percent) decrease from the same time period in 2011.

The Regulation Market changed significantly on October 1, 2012, with the introduction of Performance Regulation. For October through December 2012, the weighted average market clearing price was $36.52 per MWh. This is a 148.2 percent increase from the weighted average market clearing price of $14.71 for the same period in 2011. The total cost of regulation from October through December 2012, was $43.86 per MWh. This is a $23.40 per MWh increase (114.3 percent) over the cost of regulation during the same time period of 2011.

Figure 12 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): 2012



Synchronized Reserve Market

Although PJM has retained the two synchronized reserve markets it implemented on February 1, 2007 their definition has changed. The RFC Synchronized Reserve Zone has now merged with the former Southern Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated Dominion to become the Mid-Atlantic Dominion Reserve Zone. PJM further retains the right to define new zones or subzones "as needed for system reliability."[105]

Market Structure

- **Supply.** In 2012, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side resources are relatively low cost, and their participation in this market lowers overall Synchronized Reserve prices.
- **Demand.** PJM made a minor change to the default hourly required synchronized reserve requirements on October 1, 2012. When the RFC Zone became the RTO Zone on October 1, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. Although the Mid-Atlantic Sub-zone became the Mid-Atlantic Dominion Sub-zone on October 1, the requirement remained at 1,300 MW.
- **Market Concentration.** For all of 2012, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 3570 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in 2011 was 2637, which is classified as "highly concentrated."[106] In 2012, 56 percent of hours had a maximum market share greater than 40 percent, compared to 46 percent of hours in 2011.

  In the Mid-Atlantic Subzone, in 2012, 22 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In 2011, 63 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Dominion Subzone Synchronized Reserve Market in 2012 was characterized by structural market power.

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, which together comprise the total offer for each unit to the Synchronized Reserve

105 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 57 (December 1, 2012), p. 74.

106 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

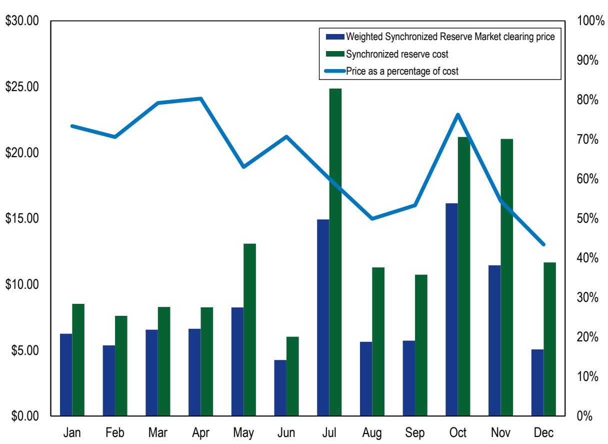
Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $8.02 per MW in 2012, a $3.79 per MW decrease from 2011. The total cost of synchronized reserves per MWh in 2012 was $12.71, a $2.77 decrease (17.9 percent) from the $15.48 cost of synchronized reserve in 2011. The market clearing price was 65 percent of the total synchronized reserve cost per MW in 2012, down from 76 percent in 2011.

  One goal of shortage pricing is to have the synchronized reserve price reflect the total cost of synchronized reserve. Although both price and cost are lower in 2012, the price/cost ratio was high from October through December, 2012.

Figure 13 Comparison of Mid-Atlantic Dominion Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through December 2012



- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit in 2012.

DASR

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[107] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[108] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** The MMU calculates that in 2012, zero hours in the DASR market would have failed the three pivotal supplier test. The current structure of PJM's DASR Market does not include the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.
- **Demand.** In 2012, the required DASR was 7.03 percent of peak load forecast, down from 7.11 percent in 2011.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero; however, there is an opportunity cost associated with this direct marginal cost. As of December 31, 2012, twelve percent of offers reflected economic withholding. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[109] Units that do not offer have their offers set to zero.
- **DSR.** Demand side resources do participate in the DASR Market, but no demand resource cleared the DASR Market in 2012.

Market Performance

- **Price.** The weighted DASR market clearing price in 2012 was $0.57 per MW. In 2011, the weighted price of DASR was $0.55 per MW.

107 See 117 FERC ¶ 61,331 (2006).
108 See PJM. "Manual 13: Emergency Operations," Revision 52, (February 1, 2013); pp 11-12.
109 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 57 (December 1, 2012), p. 141.

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Black Start Service

Black start service is necessary to help 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 is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid.[110]

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 all costs associated with providing this service, as defined in the tariff. In 2012, black start charges were $50.2 million. This is 151 percent higher than 2011, when total black start service charges were $20.0 million. There was substantial zonal variation. Black start zonal charges in 2012 ranged from $0.02 per MW in the ATSI zone (total charges: $119,167) to $3.62 per MW in the AEP zone (total charges: $32,468,706).

Section 9 Conclusion

The MMU continues to conclude that the results of the Regulation Market were not competitive in the first three quarters of 2012.[111] The Regulation Market results were not competitive because the 2008 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 and the definition of opportunity cost elsewhere in the PJM tariff. This conclusion is not based on the behavior of market participants, which remains competitive.

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 recommends that the definition of opportunity cost be consistent across all markets.

More importantly for the Regulation Market is that the design of the market was changed very significantly effective October 1, 2012. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. It is too early to reach a definitive conclusion about performance under the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information on performance. It is essential that the Regulation Market incorporate the consistent implementation of the marginal benefit factor in optimization, pricing and settlement. But the experience of the last quarter of 2012 is cause for optimism with respect the performance of the Regulation Market under the new market design.

The structure of each 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. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service 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 spinning events has been an issue. As a result, the MMU recommends that the rules for compliance be reevaluated.

The MMU concludes that the DASR Market results were competitive in 2012, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

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.

110 OATT Schedule 1 § 1.3BB.

111 The *2009 State of the Market Report for PJM* provided the basis for this conclusion. The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market. See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

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Overall, the MMU concludes that the Regulation Market results were not competitive in the first three quarters of 2012 as a result of the identified market design issues but that although it is not yet possible to reach a definitive conclusion about the new design, there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results were competitive in 2012. The MMU concludes that the DASR Market results were competitive in 2012.

Overview: Section 10, "Congestion and Marginal Losses"

Marginal Loss Cost

Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. Losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal losses when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[112] The primary benefit of a marginal loss calculation is that it more accurately models the physical reality of power system losses, which permits increased efficiency and more optimal asset utilization. Marginal loss modeling creates a separate marginal loss price for every location on the power grid. This marginal loss price (MLMP) is a component of LMP that is charged to load and credited to generation.

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 costs 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.[113] Unlike the other categories of marginal loss accounting, inadvertent loss costs are common costs not directly attributable to specific participants. Inadvertent loss costs are distributed to load on a load ratio basis. Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

Marginal loss costs can be positive or negative with respect to the reference bus. If an increase in load at a bus would decrease losses, the marginal loss component of LMP of that bus will be negative. If an increase in generation at a bus would result in an increase in losses, the marginal loss component of that bus will be negative. If an increase of load at a bus would increase losses, the marginal loss component of LMP at that bus will be positive. If an increase in generation at a bus results in a decrease of system losses, then the marginal loss component of LMP at that bus will be 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.

Marginal loss credits or 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 paid back in full to load and exports on a load ratio basis.

- **Total Marginal Loss Costs.** Total marginal loss costs in 2012 decreased by $397.9 million or 28.8 percent from 2011, from $1,379.6 million to $981.7

112 For additional information, see OATT Section 3.4.
113 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

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million. Day-ahead net marginal loss costs in 2012 decreased by $426.8 million or 29.8 percent from 2011, from $1,430.5 million to $1,003.8 million. Balancing net marginal loss costs increased in 2012 by $28.9 million or 56.7 percent from 2011, from -$51.0 million to -$22.1 million.[114]

- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and energy import levels, and changes in the dispatch of generation. Monthly total marginal loss costs in 2012 ranged from $51.0 million in April to $143.4 million in July.
- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments that is paid back in full to load and exports on a load ratio basis.[115] The marginal loss credits decreased in 2012 by $200.0 million or 34.1 percent from 2011, from $586.8 million to $386.7 million.
- **Zonal Total Marginal Loss Costs.** In 2012, zonal total marginal loss costs ranged from $2.1 million in RECO to $205.9 million in AEP. Compared to 2011, 2012 had a decrease in total marginal loss costs across the PJM control zones, except the ATSI control zone, which had an increase.[116,117]

Congestion Cost

Total congestion costs equal net congestion costs plus explicit congestion costs plus net inadvertent congestion costs. Net congestion costs equal load congestion payments minus generation congestion credits. Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. Net inadvertent congestion costs are the congestion costs associated with hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour. Unlike the other categories of congestion cost accounting, inadvertent congestion costs are common costs not directly attributable to specific participants. Inadvertent congestion costs are distributed to load on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs.

Congestion charges can be both positive and negative. When a constraint binds, the price effects of that constraint vary. The system marginal price (SMP) is uniform for all areas, while the congestion components of Locational Marginal Price (LMP) will either be positive or negative in a specific area, meaning that actual LMPs are above or below the SMP.[118]

Day-ahead congestion charges and credits are based on MWh and LMP in the Day-Ahead Energy Market. Balancing congestion charges and credits are based on load or generation deviations between the Day-Ahead and Real-Time Energy Markets and 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 real-time LMP has a positive congestion component, positive balancing congestion costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative congestion component, negative balancing congestion 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 congestion component, negative balancing congestion costs will result. Similarly, if there is a negative load deviation

114 Total marginal loss costs in PJM in 2012 also changed due to the addition of the DEOK Control Zone, which accounted for $3.2 million or 0.3 percent of the total marginal loss costs. The ATSI Control Zone had an increase in total marginal loss cost in 2012 because it became part of PJM on June 1, 2011, which left the first five months of 2011 out of the 2011 total marginal loss cost for ATSI.

115 See PJM. "Manual 28: Operating Agreement Accounting," Revision 56 (October 1, 2012). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

116 Net residual market adjustments are common costs, not directly attributable to specific participants, that are deducted from total marginal loss credits before marginal loss credits are distributed on a load weighted ratio basis. Net residual market adjustments consist of the Known Day-Ahead Error Value (KDAEV), day-ahead loss MW congestion value and balancing loss MW congestion value. KDAEV are costs associated with MW imbalances created by discontinuities in, and adjustments to, the day-ahead market solution. The day-ahead and balancing loss congestion values are congestion costs associated with loss related MW.

117 See the *2012 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses," at "Zonal Marginal Loss Costs."

118 The SMP is the price at the distributed load reference bus.

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at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result.

- **Total Congestion.** Total congestion costs decreased by $470.0 million or 47.0 percent, from $999.0 million in 2011 to $529.0 million in 2012. Day-ahead congestion costs decreased by $465.1 million or 37.4 percent, from $1,245.0 million in 2011 to $779.9 million in 2012. Balancing congestion costs decreased by $4.9 million or 2.0 percent from -$246.0 million in 2011 to -$250.9 million in 2012.

and the Bedington – Black Oak interface. (Table 10-27)

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in 2012.[119] Day-ahead congestion frequency increased by 60.3 percent from 155,670 congestion event hours in 2011 to 249,572 congestion event hours in 2012. Day-ahead, congestion-event hours decreased on internal PJM interfaces and transformers but increased on transmission lines and reciprocally coordinated flowgates between PJM and the MISO.

Table 14 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2011 and 2012

	2011				2012			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.45	$49.53	$4.67	$3.25	$37.36	$35.08	$0.66	$1.62
AEP	$42.90	$48.10	($3.25)	($1.96)	$32.71	$34.19	($0.51)	($0.97)
AP	$47.66	$47.96	($0.16)	($0.15)	$34.29	$34.26	$0.09	($0.06)
ATSI	$46.14	$50.87	($3.07)	($1.66)	$33.55	$34.32	($0.69)	($0.08)
BGE	$57.10	$49.19	$5.16	$2.75	$39.55	$34.85	$2.76	$1.93
ComEd	$38.12	$48.12	($6.46)	($3.55)	$30.72	$34.60	($1.98)	($1.90)
DAY	$43.25	$48.64	($4.21)	($1.18)	$33.76	$34.58	($0.65)	($0.16)
DEOK	NA	NA	NA	NA	$32.18	$34.45	($0.49)	($1.79)
DLCO	$42.60	$48.39	($4.13)	($1.67)	$33.05	$34.42	($0.30)	($1.07)
Dominion	$53.16	$49.11	$3.35	$0.70	$36.56	$34.76	$1.31	$0.48
DPL	$56.97	$49.29	$4.20	$3.48	$38.91	$34.94	$1.86	$2.11
JCPL	$56.24	$49.45	$3.73	$3.06	$37.03	$35.10	$0.47	$1.47
Met-Ed	$52.37	$48.08	$3.28	$1.01	$35.44	$34.29	$0.50	$0.65
PECO	$55.35	$48.61	$4.33	$2.41	$36.40	$34.62	$0.72	$1.06
PENELEC	$47.41	$47.72	($0.56)	$0.24	$34.69	$33.95	$0.12	$0.62
Pepco	$54.99	$48.72	$4.49	$1.79	$38.26	$34.58	$2.39	$1.29
PPL	$52.82	$48.27	$3.63	$0.93	$34.82	$34.22	$0.12	$0.48
PSEG	$56.24	$48.89	$4.27	$3.09	$37.25	$34.81	$0.79	$1.65
RECO	$53.55	$49.45	$1.75	$2.35	$36.91	$35.20	$0.34	$1.36
PJM	$45.19	$45.40	($0.06)	($0.15)	$34.55	$34.46	$0.11	($0.01)

- **Monthly Congestion.** Significant monthly fluctuations in congestion costs were the result of changes in load and energy import levels, changes in the dispatch of generation and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in 2012 ranged from $24.9 million in October to $73.1 million in July.

- **Geographic Differences in CLMP.** Differences in CPLM among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the Graceton – Raphael Road line, the Woodstock flowgate (reciprocally coordinated between PJM and MISO, West Interface,

Real-time congestion frequency decreased by 7.1 percent from 22,513 congestion event hours in 2011 to 20,917 congestion event hours in 2012. Real-time, congestion-event hours decreased on the internal PJM interfaces and transformers, but increased on transmission lines and reciprocally coordinated flowgates between PJM and MISO.

Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In 2012, for only 3.2 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In 2012,

119 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.

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for 38.3 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

The AP South Interface was the largest contributor to congestion costs in 2012. With $68.5 million in total congestion costs, it accounted for 16.1 percent of the total PJM congestion costs in 2012. The top five constraints in terms of congestion costs together contributed $177.0 million, or 41.6 percent, of the total PJM congestion costs in 2012. The top five constraints were the AP South interface, the West interface, the Bedington - Black Oak interface, the Woodstock flowgate (a reciprocally coordinated flowgate between PJM and MISO) and the Graceton - Raphael Road line.

- **Zonal Congestion.**[120] ComEd was the most congested zone in 2012.[121] ComEd had -$334.2 million in total load costs, -$521.6 million in total generation credits and -$16.4 million in explicit congestion, resulting in $171.0 million in net congestion costs, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The Nelson - Cordova transmission line, Woodstock flowgate, Rantoul - Rantoul Jct flowgate, Oak Grove – Galesburg flowgate and the Prairie State - W Mt. Vernon flowgate contributed $81.0 million, or 47.4 percent of the total ComEd Control Zone congestion costs.

  The AEP Control Zone was the second most congested zone in PJM in 2012, with $104.2 million. The Monticello - East Winamac flowgate contributed $12.4 million or 11.9 percent of the total AEP Control Zone congestion cost in 2012. The Dominion Control Zone was the third most congested zone in PJM in 2012, with a cost of $63.3 million.

- **Ownership.** In 2012, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2012, financial companies received $83.1 million in net congestion credits, a decrease of $91.6 million or 52.4 percent compared to 2011. In 2012, physical companies paid $612.1 million in net congestion charges, a decrease of $561.5 million or 47.8 percent compared to 2011.

Section 10 Conclusion

Marginal losses are the costs of incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. When calculating marginal losses, load is charged and generation is credited for the power losses to the system. Marginal loss costs have been decreasing since 2010, due to decreases in LMP and decreases in fuel costs. Total marginal loss costs decreased in 2012 by $397.9 million or 28.8 percent from 2011, from $1,379.6 million to $981.7 million.

Marginal loss credits are distributed to load and exports. Marginal loss credits decreased in 2012 by $200.0 million or 34.1 percent from 2011, from $586.8 million to $386.7 million.

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 and the geographic distribution of load. Total congestion costs decreased by $470.0 million or 47.0 percent, from $999.0 million in 2011 to $529.0 million in 2012. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 88.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2011 to 2012 planning period. In the first seven months of the 2012 to 2013 planning period, total ARR and FTR revenues offset 82.1 percent of the congestion costs. FTRs were paid at 80.6 percent of the target allocation level for the 2011 to 2012 planning period, and at 74.9 percent of the target allocation level for the first seven months of the 2012 to 2013 planning

120 Tables reporting zonal congestion have been moved from this section of the report to Appendix G. See the *2012 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses."

121 The total zonal congestion numbers were calculated as of March 2, 2013 and are, based on continued PJM billing updates, subject to change. As of March 2, 2013, the total zonal congestion related numbers presented here differed from the March 2, 2013 PJM totals by $0.10 Million, a discrepancy of 0.02 percent (.00019).

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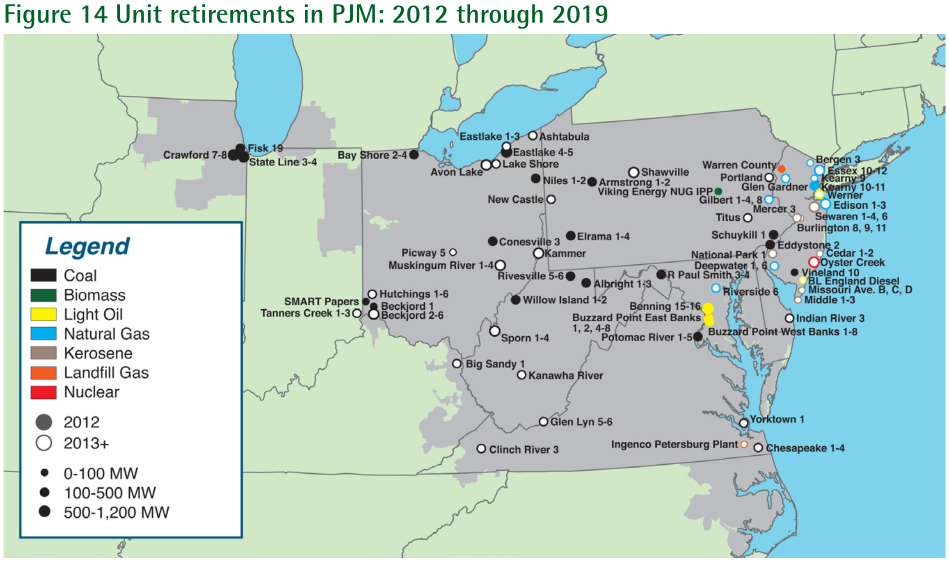
period.[122] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

Overview: Section 11, "Planning"

Planned Generation and Retirements

- **Planned Generation.** At December 31, 2012, 76,387 MW of capacity were in generation request queues for construction 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 approximately 21,359 MW of nameplate capacity, 28.0 percent of the MW in the queues, and combined-cycle projects account for 42,724 MW, 55.8 percent of the MW in the queues.
- **Generation Retirements.** A total of 7,130.9 MW of generation capacity retired from January 1, 2012 through January 1, 2013, and it is expected that a total of 21,524.9 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Retirements from January 1, 2011 through January 1, 2013, account for 8,453.2 MW. Units planning to retire in 2013 account for 237.4 MW, or 1.1 percent of planned retirements during this period. Overall, 3,951.1 MW, or 18.4 percent of all retirements from 2011 through 2019, are expected in the AEP zone.

Figure 14 Unit retirements in PJM: 2012 through 2019



- **Generation Mix.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, despite retirements of coal units.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a 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.[123] The process is complex and time consuming as a result of the nature 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, including 7,584.2 MW that should already be in service based on the original queue date, but that is not yet even under construction. These projects may also create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

122 See the *2012 State of the Market Report for PJM* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-23, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013"

123 OATT Parts IV & VI.

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Key Backbone Facilities

- **PJM baseline transmission projects are implemented to resolve reliability criteria violations.** PJM backbone transmission projects are a subset of significant baseline projects. The backbone projects are intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are: Mount Storm – Doubs; Jacks Mountain; and Susquehanna – Roseland. The total planned costs for all of these projects are approximately 1.7 billion dollars.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[124] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.
- **Competitive Grid Development.** In Order No. 1000, the FERC requires that each public utility transmission provider (including PJM) remove from its FERC approved tariff and agreements, as necessary and subject to certain limitations, a federal right of first refusal (ROFR) for certain new transmission projects.[125,126] A key limitation is the ability to retain ROFR for upgrades to the existing transmission infrastructure.

Section 11 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 energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in that area. In addition, despite Order 1000, there is not yet a robust mechanism to permit competition between transmission developers to build transmission projects. 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 effectively forestalls the ability of generation to compete. There is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no evaluation of whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be a goal of PJM market design.

Overview: Section 12, "FTR and ARRs"

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2013 to 2016 Long Term FTR Auction include the Gainesville Transformer, approximately 40 miles west of Washington, D.C., and the Monticello – East Winamac Flowgate, approximately 120 miles north of Indianapolis, IN. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2012 to 2013 planning period include the Cumberland Ave – Bush Flowgate, approximately 100 miles northwest of Indianapolis, IN and the Stephenson – Stonewall Flowgate, approximately 100 miles northwest of Washington, D.C. The geographic location of these constraints is shown in Figure 12-1.

  Market participants can also sell FTRs. In the 2013 to 2016 Long Term FTR Auction, total participant FTR sell offers were 211,316 MW, down from 251,290 MW during the 2012 to 2015 Long Term FTR Auction. In the Annual FTR Auction for the 2012 to 2013 planning period, total participant FTR sell offers were 356,299 MW, up from 337,510 MW

124 See 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

125 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶31,323 (2011).

126 *Id.* at PP 313–322.

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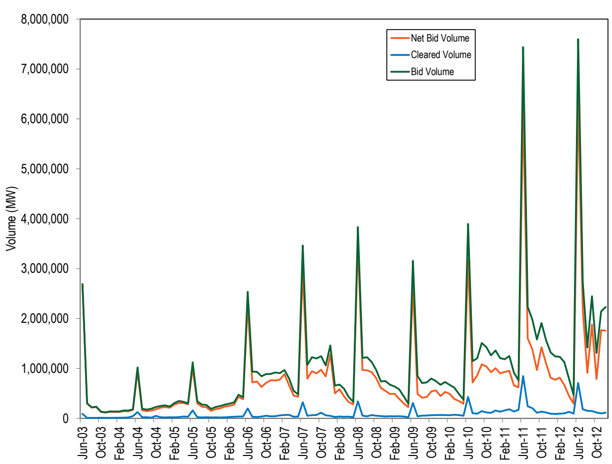
during the 2011 to 2012 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2012) of the 2012 to 2013 planning period, total participant FTR sell offers were 3,589,825 MW, down from 3,984,782 MW for the same period during the 2011 to 2012 planning period.

- **Demand.** The PJM tariff specifies that PJM has the authority to limit the maximum number of FTR bids to 5,000 per participant for a monthly auction, or a single round of an annual auction, if necessary to avoid related system performance issues.[127] On this basis, PJM currently limits the maximum number of bids that could be submitted by a participant for any individual period in an auction to 10,000 bids.

  In the 2013 to 2016 Long Term FTR Auction, total FTR buy bids increased 15.5 percent from 2,400,881 MW to 2,772,621 MW. In the Annual FTR Auction total FTR buy bids and self-scheduled bids decreased 21.4 percent from 3,260,695 MW to 2,561,835 MW. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2012 to 2013 (June through December 2012) planning period increased 16.8 percent from 12,767,075 MW for the same time period of the prior planning period, to 14,906,684 MW.

Figure 15 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2012



- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2012 to 2013 Annual FTR Auction was low for peak and off peak FTR obligations and moderately concentrated for 24-hour FTR obligations. The ownership concentration was also moderately concentrated for peak and off peak FTR buy bid options and highly concentrated for 24-hour FTR buy bid options for the same time period. The level of concentration is descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction.

  For the 2013 through 2016 Long Term FTR Auction, financial entities purchased 80.4 percent of prevailing flow FTRs and 91.9 percent of counter flow FTRs. In the Annual FTR Auction, planning period 2012 through 2013, financial entities purchased 55.8 percent of prevailing flow FTRs and 77.8 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 81.1 percent of prevailing flow and 84.6 percent of counter flow FTRs for 2012. Financial entities owned 62.8 percent of all prevailing and counter flow FTRs, including 54.4 percent of all prevailing flow FTRs and 80.1 percent of all counter flow FTRs during the same time period.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first seven months of the 2012 to 2013 planning period were $398,630.

- **Credit Issues.** Twenty participants defaulted during 2012 from twenty one default events. The average of these defaults was $381,772 with nine based on inadequate collateral and eleven based on nonpayment. The average collateral default was $790,300 and the average nonpayment default was $47,522. The majority of these defaults were promptly cured. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** The 2013 to 2016 Long Term FTR Auction cleared 290,700 MW (10.5 percent of demand) of FTR buy bids, compared to 259,885 MW (10.8 percent) in the 2012 to 2015 Long Term FTR Auction. The 2013 to 2016 Long Term FTR Auction also cleared 56,692 MW (26.8 percent) of FTR sell offers, up

127 OA Schedule 1 § 7.3.5(d).

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from 31,288 MW (12.5 percent) in the 2012 to 2015 Long Term FTR Auction.

For the 2012 to 2013 planning period, the Annual FTR Auction cleared 371,295 MW (14.5 percent) of FTR buy bids, compared to 387,743 MW (11.9 percent) for the 2011 to 2012 planning period. The 2012 to 2013 Annual FTR Auction also cleared 35,275 MW (9.9 percent) of FTR sell offers for the 2012 to 2013 planning period, up from 24,960 MW (7.4 percent) for the 2011 to 2012 planning period.

For the first seven months of the 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,437,437 MW (9.6 percent) of FTR buy bids and 484,697 MW (13.5 percent) of FTR sell offers.

- **Price.** In the 2013 to 2016 Long Term FTR Auction, 95.9 percent of FTRs were purchased for less than $1 per MW, down from 96.5 percent in the previous Long Term FTR Auction. The weighted-average price for 24-hour buy bids in the Long Term FTR Auction remained constant at $0.36 per MW. Counter flow buy bid prices were negative, but approximately equal in magnitude, than prevailing flow FTR bid prices.

  For the 2012 to 2013 Annual Auction, 90.4 percent of FTRs were purchased for less than $1 per MW, up from 87.1 percent in the previous Annual FTR Auction. The weighted-average price for 24-hour buy bid obligations in the 2012 to 2013 planning period was $0.40 per MW, down from $0.68 in the 2011 to 2012 planning period.

  The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2012 to 2013 planning period was $0.12, down from $0.13 per MW in the first seven months of the 2011 to 2012 planning period.

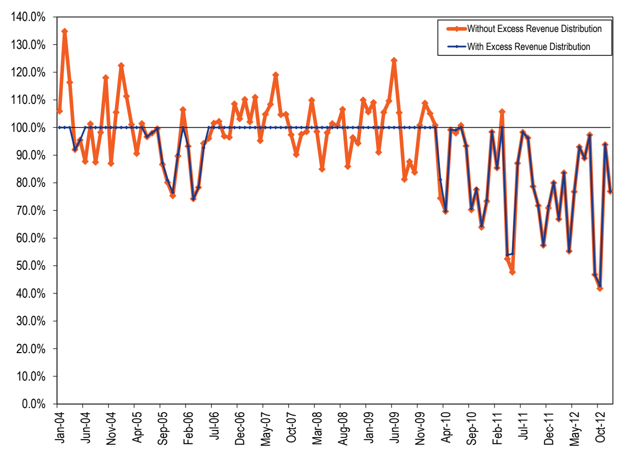
- **Revenue.** The 2013 to 2016 Long Term FTR Auction generated $28.6 million of net revenue for all FTRs, up from $20.5 million in the 2012 to 2015 Long Term FTR Auction.

  The 2012 to 2013 planning period Annual FTR Auction generated $602.9 million of net revenue for all FTRs, down from $1,029.7 million for the 2012 to 2013 planning period.

  The Monthly Balance of Planning Period FTR Auctions generated $17.3 million in net revenue for all FTRs for the first seven months of the 2012 to 2013 planning period, down from $21.9 million for the same time period in the 2011 to 2012 planning period.

- **Revenue Adequacy.** FTRs were paid at 80.6 percent of the target allocation for the 2011 to 2012 planning period.[128] FTRs were paid at 74.8 percent of the target allocation level for the first seven months of the 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $335.1 million of FTR revenues during the first seven months of the 2012 to 2013 planning period and $799.4 million during the 2011 to 2012 planning period. For the first seven months of the 2012 to 2013 planning period, the top sink and top source with the highest positive FTR target allocations were Northern Illinois Hub and Quad Cities 1. Similarly, the top sink and top source with the largest negative FTR target allocations were Quad Cities 2 and Eastern Hub.

Figure 16 FTR payout ratio with adjustments by month, excluding and including excess revenue distribution: January 2004 through December 2012



- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self-scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall, with -$7.6 million in profits for physical entities, of which $151.3 million was from self-scheduled FTRs, and $78.8 million for

128 Unless specifically noted, payout ratios reported in this section are calculated using PJM's method and are consistent with PJM's reported payout ratios.

financial entities. FTR profits generally increased in the summer and winter months when congestion was higher and decreased in the shoulder months when congestion was lower. As shown in Table 12-19, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in 2012. Prevailing flow FTRs, purchased by financial entities, were not profitable in 2012.

Auction Revenue Rights

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2012 to 2013 planning period were the Pleasant Prairie – Zion Flowgate, approximately 60 miles south of Milwaukee, WI, and the Breed – Wheatland Flowgate, approximately 120 miles west of Indianapolis, IN. The geographic location of these constraints is shown in Figure 12-1. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation.

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the Annual ARR Allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. In the 2012 to 2013 planning period PJM allocated a total of 9,647.6 MW with a total target allocation of $3,471,223.

- **Demand.** Total requested volume in the annual ARR allocation was 164,770 MW for the 2012 to 2013 planning period with 64,160 MW requested in Stage 1A, 27,325 MW requested in Stage 1B and 57,053 MW requested in Stage 2. This is up from 148,538 MW for the 2011 to 2011 planning period with 64,160 MW requested in Stage 1A, 22,208 MW requested in Stage 1B and 57,053 MW requested in Stage 2. The ATSI integration accounted for 5,434 MW of increased demand. The total ARR volume allocated is limited by the amount of network service and firm point-to-point transmission service. Several constraints were over allocated in the 2012 to 2013 Stage 1A ARR Allocation, consistent with the tariff, with a total over allocation of 892 MW.

- **Stage 1A Infeasibility.** In the 2012 to 2013 planning period PJM was required, per the PJM OATT Section 7.4.2 (i) to artificially increase the modeled line ratingsof several facilities over their physical capability, to accommodate Stage 1A ARR requests in the ARR Allocation model. The ultimate result of these increased line ratings is an over allocation of ARRs, which contributes to FTR underfunding. PJM was required to increase capability on nine separate facilities for a total of 892 MW.

- **ARR Reassignment for Retail Load Switching.** There were 22,543 MW of ARRs associated with approximately $226,900 of revenue that were reassigned in the first seven months of the 2012 to 2013 planning period. There were 41,770 MW of ARRs associated with approximately $758,900 of revenue that were reassigned for the full twelve months of the 2011 to 2012 planning period.

Market Performance

- **Volume.** Of 164,770 MW in ARR requests for the 2012 to 2013 planning period, 97,986 MW (59.5 percent) were allocated. Market participants self scheduled 40,195 MW (45.1 percent) of these allocated ARRs as Annual FTRs. Of 148,538 MW in ARR requests for the 2011 to 2012 planning period, 102,476 MW (69.0 percent) were allocated. Market participants self scheduled 46,017 MW (44.9 percent) of these allocated ARRs as Annual FTRs.

- **Revenue.** There are no ARR revenues. ARRs are allocated to qualifying customers because they pay for the transmission system.

- **Revenue Adequacy.** For the first seven months in the 2012 to 2013 planning period, the ARR target allocations were $565.4 million while PJM collected $620.2 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions through December 31, 2012, making ARRs revenue adequate. For the 2011 to 2012 planning period, the ARR target allocations were $982.9 million while PJM collected $1,091.8

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million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARR Proration.** Stage 1A ARR requests may not be prorated. As a result, several facilities were overallocated for a total of 892 MW. Of the requested ARRs for Stage 1B, 11,581 MW were prorated and of the requested ARRs for Stage 2, 55,201 MW were prorated for the 2012 to 2013 planning period. For the 2011 to 2012 planning period Stage 1A was not prorated nor overallocated. Some of the requested ARRs for the 2011 to 2012 planning period were prorated in Stage 1B and Stage 2 as a result of binding transmission constraints.
- **ARRs and FTRs as an Offset to Congestion.** The effectiveness of ARRs as an offset to congestion can be measured by comparing the revenue received by ARR holders to the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2012 to 2013 planning period, the total revenues received by ARR holders, including self-scheduled FTRs, offset 82.1 percent of the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 88.8 percent of the total congestion costs within PJM and for the 2010 to 2011 planning period 97.3 percent.

Section 12 Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with 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.

Revenue adequacy received a lot of attention in the PJM FTR market in 2012. There are several factors that can affect the reported, 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. FTR holders appropriately receive revenues based on actual congestion in both day ahead and real time markets. When day ahead congestion differs significantly from real time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with the differences between modeling in the day ahead and real time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The payout ratio reported by PJM is understated. The reported payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs. For 2012 the reported payout ratio is 73.5 percent while the correctly calculated payout ratio is 76.9 percent. The MMU recommends that the calculation of the FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

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.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in 2012 would have been 88.1 percent instead of the reported 73.5 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

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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 burden of underfunding 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 result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio in 2012 from the reported 73.5 percent to 91.2 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

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 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; differences in day ahead and real time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load; the overallocation of ARRs; the appropriateness of seasonal ARR allocations; and the role of up-to congestion transactions. The MMU recommends that these issues be reviewed and modifications implemented where possible. Funding issues that persist as a result of modeling differences should be borne by FTR holders operating in the voluntary FTR market.

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