Q1

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

5.16.2013

2013

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 *2013 Quarterly State of the Market Report for PJM: January through March*.

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

Introduction

2013 Q1 In Review

The state of the PJM markets in the first three months of 2013 was good. The results of the energy market and the results of the capacity market were competitive.

The goal of a competitive power market is to provide power at the lowest possible price, consistent with cost. PJM markets met that goal in the first three months of 2013. 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 and 2012 continued in the first quarter of 2013.

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.

The market dynamics changed in the first quarter of 2013. A combination of increased, weather related, demand, and higher fuel costs led to a reversal of the downward trend in LMP. PJM LMPs were substantially higher than in the first quarter of 2012. The load-weighted average LMP was $37.41 per MWh, 19.9 percent higher in the first quarter of 2013 than in the first quarter of 2012.

The price of natural gas, especially in the eastern part of PJM, increased in the first three months of 2013, and coal prices were mixed in the first three months of 2013 compared to the first three months of 2012.

As a result of the relative changes in fuel costs, coal-fired units were more competitive with gas-fired units, coal output increased in the first quarter and gas output decreased in the first quarter, also reversing the trend towards reduced coal output.

The results of the energy market dynamics in the first quarter of 2013 were generally positive for new coal units. In a continuation from the fourth quarter of 2012, new coal units ran at a lower fuel-only marginal cost than new combined cycle units. The combination of higher energy prices and gas prices increasing relative to coal prices resulted in significantly higher energy market net revenues for the new entrant coal plant in the first three months of 2013. In the first three months of 2013, energy market net revenues for a coal plant in seven zones exceeded fifty percent of the 2012 annual energy market net revenues.

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. Data on the units receiving operating reserve credits and the reasons for those credits should be made publicly available to permit better understanding of operating reserve levels and to facilitate competition for providing the same services.

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 Summary Statistics

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

Table 1-1 PJM Market Summary Statistics

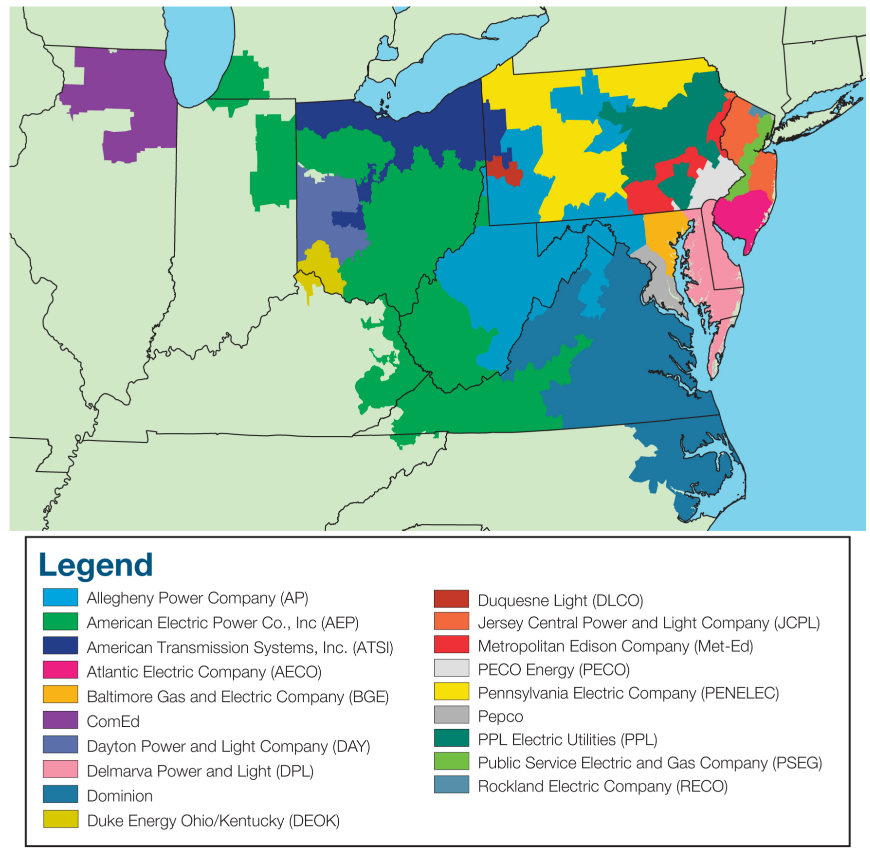
	Period
Energy	**Jan - Mar 2013**
Load	197,288 GWh
Generation	202,674 GWh
Imports (+) / Exports (-)	1,098 GWh
Peak	**Jan 22, 2013 19:00**
Peak Load	126,632 MW
Load Factor	0.721
Installed Capacity	**As of 3/31/2013**
Installed Capacity	181,896 MW
Ancillary Services	**Jan - Mar 2013**
Regulation Requirement *	828 MW
RTO Primary Reserve Requirement	2,063 MW
Total Billing	**Jan - Mar 2013**
Total Billing	$7.762 Billion

* Daily average

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of March 31, 2013, had installed generating capacity of 181,896 megawatts (MW) and about 820 market buyers, sellers and traders of electricity[1] in a region including more than 60 million people[2] in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[3] In the first three months of 2013, PJM had total billings of $7.76 billion, up from $6.94 billion in the first three months of 2012. As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1-1 PJM's footprint and its 19 control zones



1 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
2 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
3 See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2013. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.

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).

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.[4,5]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first three months of 2013, 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 behavior is evaluated as competitive or not competitive. Most important, the outcome of each market, market performance, is evaluated as competitive or not competitive.

4 See also the *2012 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones." <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.

5 Analysis of 2013 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 2013, see *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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 the first three months of 2013:

Table 1-2 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during the first three months of 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1200 with a minimum of 1047 and a maximum of 1409 in the first three months of 2013.
- 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 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.[6] 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.[7]

Table 1-3 The Capacity Market results were competitive

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

- The aggregate market structure was evaluated as not competitive. 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

6 OATT Attachment M

7 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.

the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.[8]

- 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.[9]
- 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.

Table 1-4 The Regulation Market results were indeterminate for January through March, 2013

	January through March 2013	
Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	To Be Determined	To Be Determined

- The Regulation Market structure was evaluated as not competitive for the first three months of 2013 because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 87 percent of the hours in January through March, 2013.
- Participant behavior in the Regulation Market was evaluated as competitive for January through March, 2013 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 indeterminate, 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 indeterminate, 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.

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

Table 1-5 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 6.3 percent of the hours in January through March, 2013.
- 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 competitive prices.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 1-6 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 1-7 The FTR Auction Markets results were competitive

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

- 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 mixed because while there are many positive features of the FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several features of the FTR design which result in underfunding and features of the FTR design which incorporate subsidies which also contribute to underfunding.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[10] 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.[11]

Reporting

The MMU performs its reporting function by issuing and filing annual and quarterly state of the market reports, and reports on market issues. The state of the market reports provide a comprehensive analysis of the structure, behavior and performance of PJM markets. The reports evaluate whether the market structure of each PJM Market is competitive or not competitive; whether participant behavior is competitive or not competitive; and, most importantly, whether the outcome of each market, the market performance, is competitive or not competitive. The MMU also evaluates the market design for each market. Market design translates participant behavior within the market structure into market performance. The MMU evaluates whether the market design of each PJM market provides the framework and incentives for competitive results. State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

The MMU's quarterly state of the market reports supplement the annual state of the market report for the prior year, and extend the analysis into the current year. Readers of the quarterly state of the market reports should refer to the prior annual report for detailed explanation of reported metrics and market design.

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

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[12] The MMU has direct, confidential access to the FERC.[13] The MMU may also refer matters to the attention of State commissions.[14]

The MMU monitors market behavior for violations of FERC Market Rules.[15] 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,[16] or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[17] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[18]

10 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).

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

12 OATT Attachment M § IV.

13 OATT Attachment M § IV.K.3.

14 OATT Attachment M § IV.H.

15 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.").

16 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.

17 OATT Attachment M § II(h-1).

18 OATT Attachment M § IV.C.

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[19] 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[20] and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[21] 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).[22] The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[23]

The MMU also reviews operational parameter limits included with unit offers,[24] evaluates compliance with the requirement to offer into the energy and capacity markets,[25] evaluates the economic basis for unit retirement requests[26] and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[27]

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.[28] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[29] 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.[30] 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.[31] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[32]

Prioritized Summary of New Recommendations

Table 1-8 includes a brief description and a priority ranking of the MMU's new recommendations for this quarterly report.

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

19 OATT Attachment M § IV.I.1.
20 *Id.*
21 *Id.*
22 See OATT Attachment M–Appendix § II.A.
23 OATT Attachment M–Appendix § II.E.
24 OATT Attachment M–Appendix § II.B.
25 OATT Attachment M–Appendix § II.C.
26 OATT Attachment M–Appendix § IV.
27 OATT Attachment M–Appendix § VII.
28 OATT Attachment M § IV.D.
29 *Id.*
30 *Id.*
31 *Id.*
32 OATT Attachment M § VI.A.

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.

Table 1-8 Prioritized summary of new recommendations

Priority	Section	Description
Low	2 - Energy Market	Load at generation pnodes should be treated as load, rather than negative generation.
Low	2 - Energy Market	Hub definition and change procedures should be published in a PJM manual.
High	3 - Operating Reserve	Operating reserve confidentiality rules should be revised for more transparency.
High	9 - Ancillary Services	Black start confidentiality rules should be revised for more transparency.

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,"[33] 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 *2013 Quarterly State of the Market report for PJM: January through March*, the MMU makes the following new recommendations.

From Section 2, "Energy Market":

- The MMU recommends that PJM real-time and day-ahead generation be calculated using gross generation instead of net generation. What PJM treats as negative generation is actually load and should be included in the calculations of PJM real-time and day-ahead load.
- The MMU recommends that PJM include in a manual the process of initially defining hubs and then approving additions, deletions and changes to hub definitions. (New Recommendation)

From Section 3, "Operating Reserve":

- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow a more transparent disclosure of information regarding the reasons for operating reserves in specific locations of the PJM region. This would include the publication of operating reserve information by unit.

From Section 4, "Capacity":

- There are no new recommendations in Section 4.

From Section 5, "Demand Response":

- There are no new recommendations in Section 5.

From Section 6, "Net Revenue":

- There are no new recommendations in Section 6.

From Section 7, "Environmental and Renewables":

- There are no new recommendations in Section 7.

From Section 8, "Interchange Transactions":

- There are no new recommendations in Section 8.

From Section 9, "Ancillary Services":

- The MMU recommends that PJM revise the current confidentiality rules in order to allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.

33 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

From Section 10, "Congestion and Marginal Losses":

- There are no new recommendations in Section 10.

From Section 11, "Planning":

- There are no new recommendations in Section 11.

From Section 12, "FTRs and ARRs":

- There are no new recommendations in Section 12.

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-9 provides the average price and total revenues paid, by component, for the first three months of 2012 and 2013.

Table 1-9 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 95.7 percent of the total price per MWh in the first three months of 2013.

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.[34]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[35]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[36]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[37]
- 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.[38]
- 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.[39]
- 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.[40]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[41]

34 OATT §§ 13.7, 14.5, 27A & 34.
35 OA Schedules 1 §§ 3.2.3 & 3.3.3.
36 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.
37 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
38 OATT Schedule 12.
39 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
40 OATT Schedule 1A.
41 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.

- The Black Start component is the average cost per MWh of black start service.[42]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[43]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[44]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[45]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[46]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[47]

42 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.
43 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
44 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
45 OA Schedule 1 § 3.6.
46 OA Schedule 1 § 5.3b.
47 OA Schedule 1 § 3.2.3A.001.

Table 1-9 Total price per MWh by category and total revenues by category: January through March, 2012 and 2013

Category	Jan-Mar 2012 $/MWh	Jan-Mar 2013 $/MWh	Percent Change Totals	Jan-Mar 2012 Percent of Total	Jan-Mar 2013 Percent of Total
Load Weighted Energy	$31.21	$37.41	19.9%	68.6%	74.9%
Capacity	$7.51	$4.83	(35.7%)	16.5%	9.7%
Transmission Service Charges	$4.80	$4.69	(2.4%)	10.6%	9.4%
Operating Reserves (Uplift)	$0.49	$0.94	90.2%	1.1%	1.9%
Reactive	$0.48	$0.63	30.7%	1.1%	1.3%
PJM Administrative Fees	$0.36	$0.44	20.6%	0.8%	0.9%
Transmission Enhancement Cost Recovery	$0.28	$0.40	46.2%	0.6%	0.8%
Regulation	$0.17	$0.28	60.9%	0.4%	0.6%
Black Start	$0.02	$0.14	524.6%	0.0%	0.3%
Transmission Owner (Schedule 1A)	$0.08	$0.08	(3.4%)	0.2%	0.2%
Synchronized Reserves	$0.03	$0.04	45.1%	0.1%	0.1%
NERC/RFC	$0.02	$0.02	3.6%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(0.5%)	0.0%	0.0%
Load Response	$0.01	$0.01	(17.8%)	0.0%	0.0%
Non-Synchronized Reserves		$0.00			0.0%
Transmission Facility Charges	$0.00	$0.00	(6.4%)	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	2,106.1%	0.0%	0.0%
Total	$45.48	$49.92	9.8%	100.0%	100.0%

Section Overviews

Overview: Section 2, "Energy Market"

Market Structure

- **Supply.** Average offered supply increased by 4,230, or 2.4 percent, from 173,590 MW in the first three months of 2012 to 177,820 MW in the first three months of 2013.[48] The increase in offered supply was in part the result of 362 MW of new capacity added to PJM in 2013. This new supply was partially offset by the deactivation of 2 units (169 MW) since January 1, 2013.
- **Demand.** The PJM system peak load for the first three months of 2013 was 126,632 MW in the HE 1900 on January 22, 2013, which was 4,093 MW, or 3.3 percent, higher than the PJM peak load for the first three

48 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.

months of 2012, which was 122,539 MW in the HE 1900 on January 3, 2013.[49]

- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segmen t, but high concentration in the intermediate and peaking segments.
- **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 the first three months of 2013. PJM offer caps units 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 first three months of 2013, offer capping levels increased as a result of the inclusion of units that are committed for reliability reasons to provide black start and reactive service. In the Day-Ahead Energy Market offer-capped unit hours increased from 0.1 percent in the first three months of 2012 to 4.1 percent in the first three months of 2013. In the Real-Time Energy Market offer-capped unit hours increased from 1.9 percent in the first three months of 2012 to 3.6 percent in the first three months of 2013.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 48 units eligible for FMU or AU status in at least one month during the first three months of 2013, 35 units (72.9 percent) were FMUs or AUs for all three months, and 7 units (14.6 percent) qualified in only one month of 2013.

  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 the first three months of 2013, 11 Control Zones experienced congestion resulting from one or more constraints binding for 25 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.

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. A review of actual participant behavior supports 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 from the cost offer. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer.

  In the first three months of 2013, the unadjusted markup was negative, primarily as a result of competitive behavior by coal units. The unadjusted markup component of LMP was -\$2.69 per MWh. The adjusted markup was less negative, -\$0.95 per MWh or -2.5 percent of the PJM real-time, load-weighted average LMP of \$37.41 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.

49 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).

This is strong evidence of competitive behavior and competitive market performance.

- **Load.** PJM average real-time load in the first three months of 2013 increased by 5.8 percent from the first three months of 2012, from 86,329 MW to 91,337 MW.

  PJM average day-ahead load in the first three months of 2013, including DECs and up-to congestion transactions, increased by 11.1 percent from the first three months of 2012, from 129,258 MW to 143,585 MW. The day-ahead load growth was 91.4 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Generation.** PJM average real-time generation in the first three months of 2013 increased by 5.3 percent from the first three months of 2012, from 88,068 MW to 92,776 MW.

  PJM average day-ahead generation in the first three months of 2013, including INCs and up-to congestion transactions, increased by 11.4 percent from the first three months of 2012, from 132,178 MW to 147,246 MW. The day-ahead generation growth was 109.4 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

  The MMU recommends that PJM real-time and day-ahead generation be calculated using gross generation instead of net generation. What PJM treats as negative generation is actually load and should be included in the calculations of PJM real-time and day-ahead load.

- **Generation Fuel Mix.** During the first three months of 2013, coal units provided 44.5 percent, nuclear units 35.5 percent and gas units 15.1 percent of total generation. Compared to the first three months of 2012, generation from coal units increased 16.2 percent, generation from nuclear units increased 2.0 percent, and generation from gas units decreased 17.2 percent. This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first three months of 2013, particularly in eastern zones, and lower or constant coal prices.

- **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 increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 19.6 percent higher in the first three months of 2013 than in the first three months of 2012, $36.33 per MWh versus $30.38 per MWh. The load-weighted average LMP was 19.9 percent higher in the first three months of 2013 than in the first three months of 2012, $37.41 per MWh versus $31.21 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $36.46 per MWh versus $30.82 per MWh. The load-weighted average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $37.26 per MWh versus $31.51 per MWh.[50]

  There is currently no documentation addressing how hubs are defined and changed in the tariff or manuals. The MMU recommends that PJM include in the appropriate manual the process of initially defining hubs and the the process for approving additions, deletions and changes to hub definitions. According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

- **Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot

50 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."

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. For the first three months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 22.8 percent by spot market purchase and 66.8 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot supply decreased by 0.4 percentage points and reliance on self-supply decreased by 1.0 percentage points. For the first three months of 2013, 6.9 percent of day-ahead load was supplied by bilateral contracts, 22.6 percent by spot market purchases, and 70.5 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.2 percentage points, reliance on spot supply increased by 0.3 percentage points, and reliance on self-supply decreased by 0.5 percentage points.

Scarcity

- **Scarcity Pricing Events in 2013.** PJM's market did not experience any reserve-based shortage events in the first three months of 2013.

Section 2 Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first three months of 2013, 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 4,230 MW in the first three months of 2013 compared to the first three months of 2012, while peak load increased by 4,093 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. In the Day-Ahead Energy Market, average load in the first three months of 2013 increased from the first three months of 2012, from 129,258 MW to 143,585 MW, or 11.1 percent. In the Real-Time Energy Market, average load in the first three months of 2013 increased from the first three months of 2012, from 86,329 MW to 91,337 MW, or 5.8 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 the first three months of 2013 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.[51] 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

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

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 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 the first three months of 2013.

Overview: Section 3, “Operating Reserve”

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges increased by 111.8 percent in the first three months of 2013 compared to the first three months of 2012, to a total of $260.2 million.Total operating reserve charges in the first three months of 2013 were $260.2 million. The day-ahead operating reserve charges proportion of total operating reserve charges was 9.0 percent, the balancing operating reserve charges proportion was 61.1 percent, the reactive services charges proportion was 21.4 percent, the synchronous condensing charges proportion was 0.001 percent and the black start services charges proportion was 8.5 percent.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.082 per MWh, the day-ahead operating reserve rate including unallocated congestion charges averaged $0.114 per MWh, the balancing operating reserve reliability rates averaged $0.058, $0.065 and $0.003 per MWh for the RTO, Eastern and Western Regions, the balancing operating reserve deviation rates averaged $1.001, $5.967 and $0.055 per MWh for the RTO, Eastern and Western Regions. Lost opportunity cost rate averaged $0.655 per MWh and canceled resources rate averaged $0.0002 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 52.6 percent of all day-ahead generator credits and 69.2 percent of all balancing generator credits. Combustion turbines and diesels received 77.7 percent of the lost opportunity cost credits. Combined cycles and coal units received 88.7 percent of all reactive services credits.
- **Economic – Noneconomic Generation.** In the first three months of 2013, 82.3 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.3 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In the first three months of 2013, 79.7 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 6.3 percent by transactions at hubs and 14.0 percent by transactions at interfaces.
- Generators in the Eastern Region paid 17.4 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 87.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 14.7 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 12.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators paid 13.7 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.99 percent of all credits.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 48.6 percent of all credits. The top 10 organizations received 90.8 percent of all credits. Concentration indexes for the three largest operating reserve categories classifies them as highly concentrated. Day-ahead operating reserves HHI was 5372, balancing operating reserves was 5291 and lost opportunity cost HHI was 5418.
- **Day-Ahead Unit Commitment for Reliability:** In the first three months of 2013, 4.1 percent of the total day-ahead generation was scheduled as must run by PJM, of which, 67.4 percent was made whole.
- **Lost Opportunity Cost Credits:** In the first three months of 2013, lost opportunity cost credits decreased by $1.2 million compared to the first three months of 2012. In the first three months of 2013, the top three control zones receiving lost opportunity cost credits, ATSI, AP and ComEd combined for 70.3 percent of all lost opportunity cost credits, 54.0 percent of all the day-ahead generation from pool-scheduled combustion turbines and diesels, 73.4 percent of all day-ahead generation not called in real time by PJM from those unit types and 82.0 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 the first three months of 2013, lost opportunity cost credits would have been reduced by $6.7 million, or 34.0 percent, if all changes proposed by the MMU had been implemented.
- **Black Start Service Units:** Certain units located in the AEP zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the ALR option, which means that the units must be running even if not economic. In the first three months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $22.2 million.
- **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 the first three months of 2013, the RTO deviation rate would have been reduced by 74.7 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, the details of the rules which define payments 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. But these costs are collected as operating reserves rather than reflected in price as a result of the rules governing the determination of LMP in situations where something other than a simple thermal transmission constraint affects unit dispatch.

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. 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 MMU recommends that the goal should be to have dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of operating reserve charges.

The MMU recommended and supports PJM in the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.[52] 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.

52 PJM presented a problem statement at the Markets and Reliability Committee (MRC) to perform a holistic review of operating reserves. See "Item 10 – Operating Reserves Problem Statement" for PJM's MRC April 25, 2013 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mrc/20130425/20130425-item-10-operating-reserves-problem-statement.ashx> (Accessed April 26, 2013).

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.[53]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future.[54] Effective with the 2012/2013 Delivery Year, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[55] 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.[56]

RPM prices are locational and may vary depending on transmission constraints.[57] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. 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 the period January 1, through March 31, 2013, PJM installed capacity decreased 115.1 MW or 0.1 percent from 182,011.1 MW on January 1 to 181,896.0 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on March 31, 2013, 41.8 percent was coal; 28.6 percent was gas; 18.2 percent was nuclear; 6.2 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.
- **Market Concentration.** In the 2013/2014 RPM Third Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test. The result was that offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[58,59,60]
- **Imports and Exports.** Of the 44.7 MW of imports in the 2013/2014 RPM Third Incremental Auction, all 44.7 MW cleared. Of the cleared imports, 14.5 MW (32.4 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,583.4 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (1,100.4 MW).

53 The terms *PJM Region, RTO Region* and *RTO* are synonymous in the *2012 State of the Market Report for PJM*, Section 4, "Capacity Market" and include all capacity within the PJM footprint.
54 See 126 FERC ¶ 61,275 (2009) at P 86.
55 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
56 See 126 FERC ¶ 61,275 (2009) at P 88.
57 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.
58 See OATT Attachment DD § 6.5.
59 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.
60 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

Market Conduct

- **2013/2014 RPM Third Incremental Auction.** Of the 410 generation resources which submitted offers, unit-specific offer caps were calculated for zero generation resources (0.0 percent). The MMU calculated offer caps for 44 generation resources (10.7 percent), all of which were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2013/2014 RPM Third Incremental Auction was conducted in the first quarter of 2013. In the 2013/2014 RPM Third Incremental Auction, the RTO clearing price was $4.05 per MW-day.
- Annual weighted average capacity prices increased from a Capacity Credit Market (CCM) weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010. The annual weighted average capacity price then declined to $86.33 per MW-day in 2012 before increasing again to $148.33 per MW-day in 2015.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd for January through March is 8.3 percent, an increase from the 7.5 percent average PJM EFORd for 2012.[61]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for January through March is 85.6 percent, an increase from the 84.1 percent PJM aggregate equivalent availability factor for 2012.
- **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 the first three months of 2013, 25.4 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

61 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 or the three months ending March 31, as downloaded from the PJM GADS database on May 2, 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.

Section 4 Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in the first three months of 2013. 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 the first three months of 2013.[62]

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[63,64,65,66]

Overview: Section 5, "Demand Response"

- **Demand-Side Response Activity.** In the first three months of 2013, total load reduction under the Economic Load Response Program increased by 12,936 MWh compared to the same period in 2012, from 1,030 MWh in

62 For more complete conclusions, see *2012 State of the Market Report for PJM*, Section 4, "Capacity Market."
63 See "Analysis of the 2011/2012 RPM Auction Revised" <http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf> (October 1, 2008).
64 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)
65 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).
66 See "IMM Response to Maryland PSC re: Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results" <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Response_to_MDPSC_RPM_and_2013-2014_BRA_Results.pdf> (October 4, 2010).

the first three months of 2012 to 13,966 MWh in the first three months of 2013, a 1,256 percent increase. Total payments under the Economic Program increased by $659,823, from $30,406 in the first three months of 2012 to $690,229 in the same period of 2013, a 2,170 percent increase.

Settled reductions and credits were greater in the first three months of 2013 compared to 2012. Participation levels increased following the implementation of Order No. 745, on April 1, 2012, allowing payment of full LMP for demand resources.

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 the first three months of 2013, Load Management (LM) Program revenues revenue decreased $38.4 million, or 36.8 percent, from $104 million to $66 million. Through the first three months of 2013, Synchronized Reserve credits for demand side resources decreased by $0.6 million compared to the same period in 2012, from $1.3 million to $0.7 million in 2013.

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.

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.[67]

Overview: Section 6, “Net Revenue”

Net Revenue

- In the first three months of 2013, energy market net revenues for a coal plant in seven zones exceeded fifty percent of the 2012 annual energy market net revenues. This increase in net revenues was a result of the change in the relative prices of coal and gas and higher energy market prices.

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

67 For additional conclusions see the *2012 State of the Market Report for PJM*, Section 5, "Demand Response."

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.**[68] 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

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

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).

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.[69] 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).[70] 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.
- **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 CO_2 per MWh. In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the GHG rule, rejecting challenges brought by industry groups and a number of states.[71]

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,[72] 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.[73]
- **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 CO_2 emissions from power generation facilities. Auction prices in 2013 for the 2012-2014 compliance period were $2.80 per ton, above the price floor for 2013.

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. On March 31, 2013, 68.4 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

69 *See* EME Homer City Generations, L.P. v. EPA, NO. 11-1302.
70 *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).
71 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
72 N.J.A.C. § 7:27–19.
73 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).

by nearly all fossil fuel unit types, and 91.0 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 March 31, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 2.0 percent of all load served in Ohio, to 10.7 percent of all load served in Maryland. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

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.

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.** During the first three months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market.[74] During the first three months of 2013, the real-time net interchange of 1,640.5 GWh was greater than net interchange of 800.7 GWh in the first three months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first three months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market. During the first three months of 2013, the total day-ahead net interchange of -6,592.7 GWh was greater than net interchange of -3,224.6 GWh during the first three months of 2012.

  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 34,149 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 20,000 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2013, gross imports in the Day-Ahead Energy Market were 149.2 percent of gross import in the Real-Time Energy Market (408.9 percent during the first three months of

74 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.

2012), gross exports in the Day-Ahead Energy Market were 243.3 percent of the gross exports in the Real-Time Energy Market (472.7 percent during the first three months of 2012). In the first three months of 2013, net interchange was -6,592.7 GWh in the Day-Ahead Energy Market and 1,640.5 GWh in the Real-Time Energy Market compared to -3,224.6 GWh in the Day-Ahead Energy Market and 800.7 GWh in the Real-Time Energy Market for the first three months of 2012.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2013, there were net scheduled exports at ten of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2013, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eleven of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eight of PJM's 18 interface pricing points eligible for day-ahead.[75]
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first three months of 2013, up-to congestion transactions had net exports at six of PJM's 18 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2013, the direction of the average hourly flow was inconsistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in only 42.6 percent of hours in the first three months of 2013.
- **PJM and New York ISO Interface Prices.** In the first three months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 56.2 percent of the hours in the first three months of 2013.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[76] The average hourly flow during the first three months of 2013 was -350 MW.[77] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 84.4 percent of the hours in the first three months of 2013.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus.[78] The average hourly flow during the first three months of 2013 was -188 MW.[79] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 77.6 percent of the hours in the first three months of 2013.
- **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.

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

76 In the first three months of 2013, there were 92 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 $44.34 while the NYISO LMP at the Neptune Bus during non-zero flows was $88.60, a difference of $44.26.

77 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -366 MW.

78 In the first three months of 2013, there were 144 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $63.15 while the NYISO LMP at the Neptune Bus during non-zero flows was $154.78, a difference of $91.63.

79 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Linden VFT line was -202 MW.

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.

  For the first three months of 2013, net scheduled interchange was 1,076 GWh and net actual interchange was 1,098 GWh, a difference of 22 GWh. For the first three months of 2012, net scheduled interchange was 310 GWh and net actual interchange was 110 GWh, a difference of 200 GWh.[80] This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued eight TLRs in the first three months of 2013, compared to six TLRs issued in the first three months of 2012. The fact that PJM has issued only eight TLRs in the first three months of 2013, 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 service 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 94,511 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 50,305 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012 (Figure 8-12).

- **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.[81] 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 although MISO has not implemented a corresponding restriction. 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.

  The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces.

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 the first three months of 2013, including evolving transaction patterns, economics and issues. PJM became a consistent

80 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.

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

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 the first three months of 2013, 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 57.4 percent of the hours for transactions between PJM and MISO and for 43.8 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.

On January 15, 2013, PJM and NYISO implemented the market to market provisions of the PJM/NYISO Joint Operating Agreement (JOA). Coordination between NYISO and PJM includes joint redispatch and coordinated operation of the Ramapo PARs located at the NYISO – PJM interface. The goal of this real-time coordination is a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints.[82]

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 as possible to the expected actual power flows 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 operation of the PJM Day-Ahead Market and 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.

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.[83] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. 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.

82 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (January 17, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>. (Accessed May 6, 2013)

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

Overview: Section 9, "Ancillary Services"

Regulation Market

The PJM Regulation Market continues to be operated as a single market.

Market Structure

- **Supply.** In January through March 2013, 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 4.39. This is 33.4 percent increase over January through March 2012 when the ratio was 3.29, was the result of the decrease in demand.
- **Demand.** The on-peak regulation requirement 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. The average hourly regulation demand in January through March, 2013, was 829 MW. This is a 124 MW decrease in the average hourly regulation demand of 953 MW in the same period of 2012.
- **Market Concentration.** In January through March 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1995 (1611 in January through March 2012), which is classified as "highly concentrated."[84] In January through March 2013, 88 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (67 percent of hours failed the three pivotal supplier test in January through March 2012).

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.[85] As of March 31, 2013, there were 14 distinct resources (five generation and nine demand response) offering performance regulation and following the RegD signal.
- **Price and Cost.** The weighted Regulation Market Clearing Price for the PJM Regulation Market for January through March 2013 was $33.87. This is an increase of $21.26, or 168.6 percent, from the weighted average price for regulation in January through March 2012. The cost of regulation from January through March 2013 was $38.95. This is a $22.19 (132.4 percent) increase from the same time period in 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."[86]

Market Structure

- **Supply.** In January through March, 2013, 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, 2012, 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, 2012, the requirement remained at 1,300 MW.

84 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.

85 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

86 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 59 (April 1, 2013), p. 75.

- **Market Concentration.** For January through March, 2013, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 4161 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in January through March, 2012, was 2638, which is classified as "highly concentrated."[87] In January through March, 2013, 35 percent of hours had a maximum market share greater than 40 percent, compared to 43 percent of hours in January through March, 2012.

  In the Mid-Atlantic Subzone, in January through March, 2013, 6.3 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In January through March, 2012, 49 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 January through March 2013 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 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 $7.35 per MW in January through March, 2013, an increase of $1.29 per MW over January through March, 2012. The total cost of synchronized reserves per MW in January through March 2013 was $12.58, a $4.82 increase from the $7.76 cost of synchronized reserve in January through March 2012. The market clearing price was 58 percent of the total synchronized reserve cost per MW in January through March, 2013, down from 78 percent in January through March, 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 the first quarter of 2013.

DASR

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[88] 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.[89] 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 January through March, 2013, 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 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero, but there is an opportunity cost associated with this direct marginal cost. As of March 31, 2013, thirteen percent of offers reflected economic withholding. PJM rules require all units with reserve capability that can be converted into

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

88 See 117 FERC ¶ 61,331 (2006).

89 See PJM. "Manual 13: Emergency Operations," Revision 52, (February 1, 2013); pp 11-12.

energy within 30 minutes to offer into the DASR Market.[90] Units that do not offer have their offers set to zero.

- **DSR.** Demand side resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in January through March, 2013.

Market Performance

- **Price.** The weighted DASR market clearing price in January through March, 2013 was $0.01 per MW. In January through March, 2012, the weighted price of DASR was $0.01 per MW.

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.[91]

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 January through March, 2013, black start credits were $27.6 million. Black start zonal credits in January through March 2013 ranged from $0.03 per MW in the ATSI zone (total credits of $38,980) to $10.66 per MW in the AEP zone (total credits of $22,352,763).

Section 9 Conclusion

The design of the Regulation Market 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 and the first quarter of 2013 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 structure of the DASR Market was competitive in the first three months of 2013, 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.

Overall, the MMU concludes that it is not yet possible to reach a definitive conclusion about the new Regulation Market design, but there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results

90 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 59 (April 1, 2013), p. 145.
91 OATT Schedule 1 § 1.3BB.

were competitive in the first three months of 2013. The MMU concludes that the DASR Market results were competitive in the first three months of 2013.

Overview: Section 10, "Congestion and Marginal Losses"

Energy Cost

- **Total Energy Costs.** Total energy costs in the first three months of 2013 decreased by $41.5 million or 30.4 percent from the first three months of 2012, from -$136.4 million to -$177.9 million. Day-ahead net energy costs in the first three months of 2013 decreased by $79.1 million or 69.0 percent from the first three months of 2012, from -$114.6 million to -$193.8 million. Balancing net energy costs in the first three months of 2013 increased by $44.5 million or 155.5 percent from the first three months of 2012, from -$28.6 million to $15.9 million.
- **Monthly Total Energy Costs.** Significant monthly fluctuations in total energy costs were the result of load and energy import levels, and changes in dispatch of generation. Monthly total energy costs in the first three months of 2013 ranged from -$63.0 million in January to -$54.8 million in February.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in the first three months of 2013 increased by $43.2 million or 18.5 percent from the first three months of 2012, from $234.3 million to $277.6 million. Day-ahead net marginal loss costs in the first three months of 2013 increased by $48.1 million or 19.4 percent from the first three months of 2012, from $248.1 million to $296.2 million. Balancing net marginal loss costs decreased in the first three months of 2013 by $4.8 million or 35.2 percent from the first three months of 2012, from -$13.8 million to -$18.6 million.
- **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 the first three months of 2013 ranged from $86.7 million in February to $101.1 million in January.
- **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.[92] The marginal loss credits increased in the first three months of 2013 by $1.8 million or 1.8 percent from the first three months of 2012, from $97.7 million to $99.4 million.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $63.5 million or 51.9 percent, from $122.4 million in the first three months of 2012 to $185.9 million in the first three months of 2013.[93]
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $151.0 million or 83.5 percent, from $180.9 million in the first three months of 2012 to $331.9 million in the first three months of 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $87.5 million or 149.8 percent from -$58.4 million in the first three months of 2012 to -$145.9 million in the first three months of 2013.
- **Monthly Congestion.** Monthly congestion costs in the first three months of 2013 ranged from $48.5 million in March to $77.4 million in February.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the Readington - Roseland line,

92 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.

93 The total zonal congestion numbers were calculated as of April 16, 2013 and are, based on continued PJM billing updates, subject to change.

the Clover and the Cloverdale transformers, and the West Interface. (Table 10-28)

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in the first three months of 2013. Day-ahead congestion frequency increased by 49.1 percent from 54,596 congestion event hours in the first three months of 2012 to 81,378 congestion event hours in the first three months of 2013. Day-ahead, congestion-event hours decreased on the, flowgates while congestion frequency on internal PJM interfaces, transmission lines and transformers increased.

- Real-time congestion frequency increased by 45.1 percent from 4,129 congestion event hours in the first three months of 2012 to 5,914 congestion event hours in the first three months of 2013. Real-time, congestion-event hours increased on the flowgates, the interfaces, the transformers, and the transmission lines.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In the first three months of 2013, for only 3.1 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In the first three months of 2013, for 45.1 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 the first three months of 2013. With $81.8 million in total congestion costs, it accounted for 44.0 percent of the total PJM congestion costs in the first three months of 2013. The top five constraints in terms of congestion costs together contributed $72.8 million, or 39.2 percent, of the total PJM congestion costs in 2012. The top five constraints were the AP South and West interfaces, the Readington – Roseland transmission line, and Clover and Cloverdale transformers.

- **Zonal Congestion.** AP was the most congested zone in the first three months of 2013. AP had -$8.3 million in total load costs, -$44.8 million in total generation credits and -$1.6 million in explicit congestion, resulting in $34.9 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 AP South interface, the Bedington transformer, the Readington – Roseland and the Dickerson - Pleasant View line, and the 5004/5005 Interface contributed $29.0 million, or 83.0 percent of the total AP Control Zone congestion costs.

  The ComED Control Zone was the second most congested zone in PJM in the first three months of 2013, with $34.3 million. The Crete - St Johns Tap flowgate contributed $4.8 million or 13.9 percent of the total ComEd Control Zone congestion cost in first three months of 2013. The AEP Control Zone was the third most congested zone in PJM in the first three months of 2013, with a cost of $25.5 million.

- **Ownership.** In the first three months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In the first three months of 2013, financial companies received $28.3 million in net congestion credits, an increase of $8.1 million or 40.0 percent compared to the first three months of 2012. In the first three months of 2013, physical companies paid $214.2 million in net congestion charges, an increase of $71.6 million or 50.2 percent compared to the first three months of 2012.

Section 10 Conclusion

Energy costs are the incremental costs to the system, which are the same at every bus for each hour, without taking losses and congestion into account.

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 had been decreasing since 2010, due to decreases in LMP and fuel costs. However, increases in the LMP and fuel costs have led to higher marginal loss costs in the first three months of 2013 compared to the first three months of 2012. Total marginal loss costs increased in the first three months of 2013 by $43.2 million or 18.5 percent from the first three months of 2012, from $234.3 million to $277.6 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.

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 ten months of the 2012 to 2013 planning period, total ARR and FTR revenues offset 89.9 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 69.5 percent of the target allocation level for the first ten months of the 2012 to 2013 planning period.[94] 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 March 31, 2013, 73,156 MW of capacity were in generation request queues for construction through 2020, compared to an average installed capacity of 197,000 MW in the first three months of 2013. Wind projects account for approximately 19,079 MW of nameplate capacity, 26.1 percent of the MW in the queues, and combined-cycle projects account for 42,217 MW, 57.7 percent of the MW in the queues.
- **Generation Retirements.** As shown in Table 11-11, 11,844.2 MW are planning to deactivate by the end of calendar year 2019. A total of 7,130.9 MW of generation capacity retired from January 1, 2012 through March 31, 2013, and it is expected that a total of 20,297.4 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 March 31, 2013, account for 8,453.2 MW, or 39.6 percent of retirements during this period. Units planning to retire in 2013 account for 237.4 MW, or 1.2 percent of retirements during this period. Overall, 3,508.1 MW, or 29.6 percent of all MW planned for deactivation from 2013 through 2019, are expected in the AEP zone.
- **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.[95] 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.

94 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"

95 OATT Parts IV & VI.

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.

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.[96] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

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.** Market participants can also sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the first ten months (June 2012 through March 2013) of the 2012 to 2013 planning period, total participant FTR sell offers were 4,627,336 MW, down from 5,330,537 MW for the same period during the 2011 to 2012 planning period.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2012 to 2013 (June 2012 through March 2013) planning period increased 11.8 percent from 16,367,977 MW for the same time period of the prior planning period, to 18,299,865 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 83.0 percent of prevailing flow and 87.9 percent of counter flow FTRs for 2013. Financial entities owned 65.0 percent of all prevailing and counter flow FTRs, including 56.3 percent of all prevailing flow FTRs and 81.5 percent of all counter flow FTRs during the same time period.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first ten months of the 2012 to 2013 planning period were $492,556 (0.06 percent of total FTR target allocations).

96 *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).

- **Credit Issues.** Four participants defaulted during 2013 from eight default events. The average of these defaults was $68,812 with four based on inadequate collateral and four based on nonpayment. The average collateral default was $13,275 and the average nonpayment default was $124,349. The majority of these defaults were promptly cured. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** For the first ten months of the 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,976,401 MW (10.8 percent) of FTR buy bids and 651,226 MW (14.1 percent) of FTR sell offers.
- **Price.** The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2012 to 2013 planning period was $0.12, up from $0.10 per MW in the first ten months of the 2011 to 2012 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $21.7 million in net revenue for all FTRs for the first ten months of the 2012 to 2013 planning period, down from $24.8 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.[97] FTRs were paid at 69.5 percent of the target allocation level for the first ten months of the 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $533.2 million of FTR revenues during the first ten months of the 2012 to 2013 planning period and $799.4 million during the 2011 to 2012 planning period. For the first ten months of the 2012 to 2013 planning period, the top sink and top source with the highest positive FTR target allocations were PSEG and Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were both Western Hub.
- **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 $67.4 million in profits for physical entities, of which $63.6 million was from self-scheduled FTRs, and $45.1 million for financial entities. As shown in Table 12-9, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in March 2013.

Auction Revenue Rights

Market Structure

- **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 14,211.2 MW of residual ARRs with a total target allocation of $4,475,521.
- **ARR Reassignment for Retail Load Switching.** There were 48,077 MW of ARRs associated with approximately $464,100 of revenue that were reassigned in the first ten 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

- **Revenue Adequacy.** For the first ten months of the 2012 to 2013 planning period, the ARR target allocations were $565.4 million while PJM collected $624.6 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions through March 31,

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

2013, 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 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **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 89.8 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 has received a lot of attention in the PJM FTR market. 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 the 2012 to 2013 planning period, the reported payout ratio is 69.5 percent while the correctly calculated payout ratio is 72.2 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 the first ten months of the 2012 to 2013 planning period would have been 85.2 percent instead of the reported 69.5 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

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

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the 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 the first ten months of the 2012 to 2013 planning period from the reported 69.5 percent to 89.1 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.