Q2

State of the Market Report for PJM

January through June

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

8.14.2014

2014

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 *2014 Quarterly State of the Market Report for PJM: January through June*.

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

Q2 2014 in Review

The state of the PJM markets in the first six months of 2014 reflected the extreme winter weather conditions in January and a return to more typical weather conditions in the second quarter. The stress on the markets during the winter weather was a reminder that markets must work during extreme conditions as well as more normal conditions. PJM markets did work during the extreme conditions but the experience highlighted areas of market design that need improvement. The results of the energy market, the results of the capacity market and the results of the regulation market were competitive in the first half of 2014.

The PJM market design must be robust to stress. Markets that only work under normal conditions are not effective markets. 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. Despite the complex rules, these are markets and not administrative constructs, and have all the potential efficiency benefits of markets. There are 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 overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units offering at, or close to, their marginal costs, although this was not always the case during the high demand hours in January. This is evidence of generally competitive behavior, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. The performance of the PJM markets under scarcity conditions raised a number of concerns related to capacity market incentives, participant offer behavior in the energy market under tight market conditions, natural gas availability and pricing, demand response and interchange transactions. In particular, there are issues related to the ability to increase markups substantially in tight market conditions, to the uncertainties about the pricing and availability of natural gas, and to the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and generate power rather than take an outage.

The energy market reflected the combination of increased, weather related, demand, and higher fuel costs in higher energy market prices. The load-weighted average LMP was 84.2 percent higher in the first six months of 2014 than in the first six months of 2013, $69.92 per MWh versus $37.96 per MWh.

The increase in prices was not solely the result of higher fuel prices although fuel prices played a role. If fuel costs in the first six months of 2014 had been the same as in the first six months of 2013, holding everything else constant, there would have an average increase in load-weighted LMP of 52.0 percent rather than the actual increase of 84.2 percent. The load-weighted LMP would have been $57.71 per MWh instead of the actual $69.92 per MWh in the first six months of 2014.

Although higher energy prices increase net revenues and higher fuel costs decrease net revenues, the net result was substantial increases in net revenues for all technology types in the first six months of 2014 compared to the first six months of 2013, primarily as a result of the extremely high increases in net revenues in the first three months of 2014. Energy net revenues for the first six months of 2014 increased by an average of 730 percent for a new combustion turbine peaking unit, 202 percent for a new combined cycle, 338 percent for a new coal plant, 96 percent for a new nuclear plant, 32 percent for a new wind installation, and 14 percent for a new solar installation.

Particularly in times of stress on markets and when some flaws in markets are revealed, non-market solutions may appear attractive. Top down, integrated resource planning approaches are tempting because it is easy to think that experts know exactly the right mix and location of generation resources and the appropriate definition of resource diversity and therefore which technologies should be favored through exceptions to market rules. The provision of subsidies to favored technologies is tempting for those who would benefit but subsidies are a form of integrated resource planning that is not consistent with markets. Subsidies to existing units are no different in concept than subsidies to planned units and are equally inconsistent with markets. Cost of service regulation is tempting because guaranteed rates of return and fixed prices may look attractive to asset owners in uncertain markets and because cost of service regulation incorporates integrated resource planning.

But the market paradigm and the non-market paradigm are mutually exclusive. Once the decision is made that market outcomes must be fundamentally modified, it will be virtually impossible to return to markets.

Much of the reason that market outcomes are subject to legitimate criticism is that the markets have not been permitted to reveal the underlying supply and demand fundamentals in prices. Before market outcomes are rejected in favor of non-market choices, markets should be permitted to work.

It is more critical than ever to get capacity market prices correct. A number of capacity market design elements have resulted in a substantial suppression of capacity market prices for multiple years. The impact of continued inclusion of limited DR products in the capacity market was $2.2 billion in the 2017/2018 Base Residual Auction, a price reduction of 22.9 percent, holding everything else constant. The impact of the 2.5 percent offset to demand was $2.4 billion, a price reduction of 24.5 percent, holding everything else constant. The impact of continued inclusion of limited DR products combined with the impact of the 2.5 percent offset to demand, was $3.4 billion, a price reduction of 31.3 percent, holding everything else constant.

These market design choices have substantial impacts. This price suppression has had and continues to have an impact on retirement decisions and on decisions to invest in new resources. Premature and uneconomic retirements and the failure to make economic investments in new entry are both the results. No discussion of reliability or of resource diversity or of changes to the capacity market design can ignore the impacts of this price suppression.

The most fundamental required change to the capacity market design is the enforcement of a consistent definition of a capacity resource so that all capacity resources are full substitutes for one another. In the case of imports, substitutability means that the units must have a pseudo tie into PJM. Without that, capacity imports cannot be substitutes for internal capacity. As a result of the fact that all imports are included in the rest of RTO, the inadequate definition of imports has had a larger impact on western zones. In the case of demand resources, substitutability means that resources must have a day-ahead energy market must offer requirement and must be subject to the same offer cap as all other resources and must be an annual product with obligations in the winter as well as the summer. In the case of generation, generation that is classified as available, either in part or in whole, only as maximum emergency generation should not be included as capacity.

An essential part of being full substitutes is the requirement that all capacity resources be physical resources. The requirement to be a physical resource should apply at the time of auctions and should also constitute a binding commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports. Under existing capacity market rules, capacity imports, planned new generation and demand resources all face incentives to buy out of their positions in incremental auctions and do so.

The extreme winter weather revealed the real meaning of being a capacity resource. Capacity resources are, by clearing the capacity market, obligated to make offers in the day-ahead energy market. This obligation exists regardless of whether gas procurement is difficult, regardless of whether gas prices are high and regardless of whether gas procurement is risky. The winter weather also further revealed the problems with treating limited DR as a substitute for annual resources. Although some limited DR did respond, the question should be, how did the performance of limited DR compare to the performance of the coal units or the combined cycle units that were displaced by DR.

The behavior of some generation owners during the extreme weather made issues related to the incentives in the capacity market much more urgent. The incentives in the capacity market are inadequate and the very high outage rates in January are evidence of that. At present only half of capacity market revenues are at risk for failure to perform on high demand days. Gas-fired units with a single fuel are exempt from any capacity market revenue impact that results from lack of fuel outages on high demand days. The incentives in the capacity market should be equivalent to the incentives in an all energy market with scarcity pricing. An increase in capacity market prices must be accompanied by a strengthening of capacity market incentives so that customers can be assured of getting what they pay for.

The price of energy must also reflect supply and demand fundamentals. While the rules on gas procurement and the inclusion of gas costs in energy market offers need clarification, cost-based offer caps should be increased to ensure that offer caps reflect actual marginal costs, even when those marginal costs are well in excess of $1,000 per MWh. But when cost based offers are greater than $1,000 per MWh, price based offers should not exceed cost based offers and cost based offers should not include a ten percent adder. PJM's reserve requirements should reflect dispatchers' actual need for reserves to maintain reliability and those reserve requirements should be reflected in prices and should trigger scarcity pricing when they are not met. Better energy market pricing will help reduce uplift and a broader allocation of uplift to all participants, including UTCs, will help reduce uplift to the level of noise rather than the significant friction on markets that it is today.

The PJM markets and PJM market participants from all sectors face significant challenges, some of which were clearly revealed in January. 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, January through June, 2013 and 2014[1]

	2013 (Jan - Jun)	2014 (Jan - Jun)	Percent Change
Load	382,635 GWh	398,901 GWh	4.3%
Generation	387,313 GWh	407,279 GWh	5.2%
Net Actual Interchange	3,058 GWh	(305) GWh	(110.0%)
Losses	8,622 GWh	9,066 GWh	5.1%
Regulation Requirement*	678 MW	664 MW	(2.1%)
RTO Primary Reserve Requirement	2,063 MW	2,063 MW	0.0%
Total Billing	$15.57 Billion	$31.06 Billion	99.5%
Peak	**Jun 25, 2013 15:00**	**Jun 17, 2014 16:00**	
Peak Load	139,779 MW	141,673 MW	1.4%
Load Factor	0.63	0.65	2.9%
Installed Capacity	**As of 06/30/2013**	**As of 06/30/2014**	
Installed Capacity	185,560 MW	184,007 MW	(0.8%)

* This is an hourly average stated in effective MW.

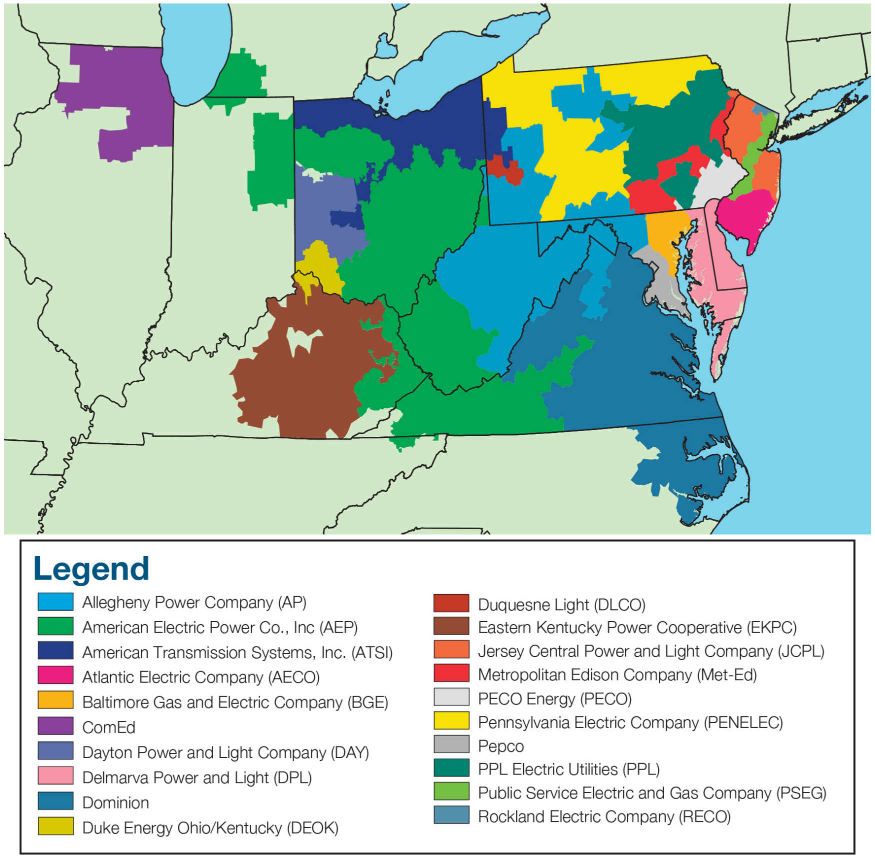
PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of June 30, 2014, had installed generating capacity of 184,007 megawatts (MW) and 894 members including market buyers, sellers and traders of electricity in a region including more than 61 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[2,3,4]

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

1 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."
2 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
3 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
4 See the *2013 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2014.

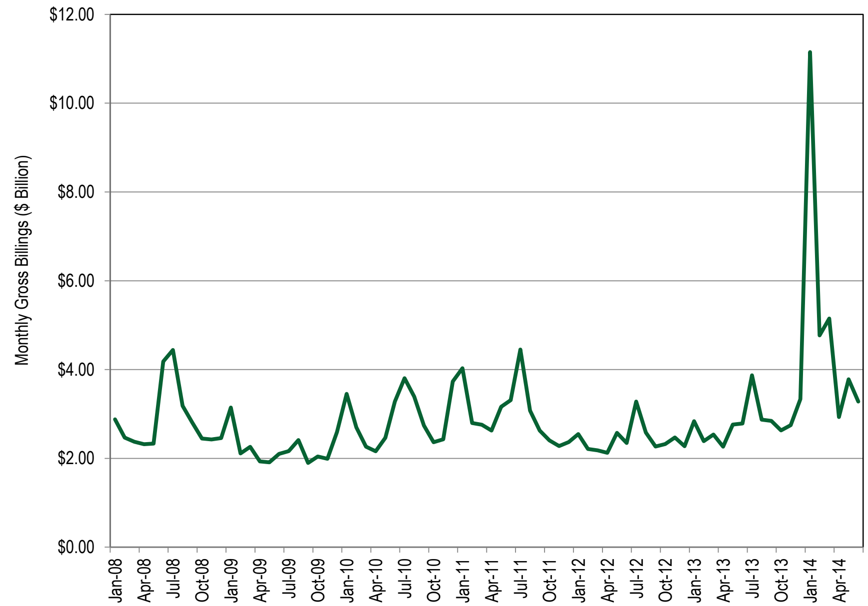
Figure 1-1 PJM's footprint and its 20 control zones



As shown in Figure 1-2, in the first six months of 2014, PJM had total billings of $31.06 billion, up from $15.57 billion in the first six months of 2013.[5] The increase in billings in the first six months of 2014 resulted from high demand and high prices that resulted from extreme cold weather early in the year. In the second quarter of 2014, billings have returned to prior levels.

5 Monthly billing values are provided by PJM.

Figure 1-2 PJM reported monthly billings ($ Billions): January 2008 through June 2014



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.[6,7]

On June 1, 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC).

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first six months of 2014, 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.

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 six months of 2014:

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 six months of 2014 was moderately concentrated. Based on the hourly Energy Market

6 See also the *2013 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

7 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. In June 2013, the Eastern Kentucky Power Cooperative (EKPC) joined PJM. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2013, see *2013 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

measure, average HHI was 1138 with a minimum of 891 and a maximum of 1407 in the first six months of 2014.

- 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, although the behavior of some participants during periods of high demand raises concerns about economic withholding.
- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- 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. The expanding role of UTCs in the Day-Ahead Energy Market continues to cause concerns. Issues related to the definition of gas costs includable in offers and the impact of the uncertainty around gas costs during high demand periods also need to be addressed.

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.[8] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on 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.[9] There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are extremely tight.

Table 1-3 The Capacity Market results were competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[10]
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[11]

8 OATT Attachment M.

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

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

11 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, 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, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the inclusion of imports which are not substitutes for internal capacity resources and inadequate performance incentives.

Table 1-4 The Regulation Market results were competitive

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

- Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 96 percent of the hours in the first six months of 2014.
- Participant behavior in the Regulation Market was evaluated as competitive for the first six months of 2014 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 competitive, after the introduction of the new market design, despite significant issues with the market design.
- Market design was evaluated as flawed. While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement.

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	Mixed

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

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, a significant proportion 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

- Market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as mixed because while there are many positive features of the ARR/FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several problematic features of the ARR/FTR design which need to be addressed. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design and the market design as implemented results in overselling FTRs. FTR funding levels are reduced as a result of these factors.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[12] 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.[13]

Reporting

The MMU performs its reporting function primarily 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. 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

12 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).
13 OATT Attachment M § IV; 18 CFR § 1c.2.

necessary to realize the goals of regulation through competition, and how the markets can be improved.

The MMU also issues reports on specific topics in depth. The MMU regularly issues reports on RPM auctions. In other ad hoc reports, the MMU responds 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.[14] The MMU has direct, confidential access to the FERC.[15] The MMU may also refer matters to the attention of state commissions.[16]

The MMU monitors market behavior for violations of FERC Market Rules.[17] The MMU will investigate and refer "Market Violations," which refers to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[18,19] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[20]

14 OATT Attachment M § IV.
15 OATT Attachment M § IV.K.3.
16 OATT Attachment M § IV.H.
17 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.")
18 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.
19 OATT Attachment M § II(h-1).
20 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.[21] If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[22,23] 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).[24] 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.[25]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests

21 OATT Attachment M § IV.I.1.
22 *Id.*
23 *Id.*
24 See OATT Attachment M–Appendix § II.A.
25 OATT Attachment M–Appendix § II.E.

and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[26,27,28,29]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns.[30] Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals.[31] PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[32] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[33] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[34] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[35] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[36]

26 OATT Attachment M–Appendix § II.B.
27 OATT Attachment M–Appendix § II.C.
28 OATT Attachment M–Appendix § IV.
29 OATT Attachment M–Appendix § VII.
30 OATT Attachment M § IV.
31 OATT § 12A.
32 OATT Attachment M § IV.D.
33 *Id.*
34 *Id.*
35 *Id.*
36 OATT Attachment M § VI.A.

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[37] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets. In this *2014 Quarterly State of the Market Report for PJM: January through June*, the MMU is making no new recommendations for the second quarter of 2014.

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-8 provides the average price and total revenues paid, by component, for the first six months of 2013 and the first six months of 2014.

Table 1-8 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 94.6 percent of the total price per MWh in the first six months of 2014.

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.

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

- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and non firm point to point transmission service.[38]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead, balancing and synchronous condensing charges.[39]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[40]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[41]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC²) and OATT Schedule 9 funding of FERC, OPSI and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[42]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[43]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[44]
- 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.[45]
- 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.[46]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[47]
- The Black Start component is the average cost per MWh of black start service.[48]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[49]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[50]
- The Economic Load Response component is the average cost per MWh of day ahead and real time economic load response program charges to LSEs.[51]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[52]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[53]
- The Emergency Energy component is the average cost per MWh of emergency energy.[54]

38 OATT §§ 13.7, 14.5, 27A & 34.
39 OA Schedules 1 §§ 3.2.3 & 3.3.3.
40 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-9 includes all reactive services charges.
41 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
42 OATT Schedule 12.
43 Reliability Assurance Agreement Schedule 8.1.
44 OATT PJM Emergency Load Response Program.
45 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
46 OATT Schedule 1A.
47 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
48 OATT Schedule 6A. The line item in Table 1-9 includes all Energy Uplift (Operating Reserves) charges for Black Start.
49 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
50 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
51 OA Schedule 1 § 3.6.
52 OA Schedule 1 § 5.3b.
53 OA Schedule 1 § 3.2.3A.001.
54 OA Schedule 1 §3.2.6.

Table 1-8 Total price per MWh by category: January through June, 2013[55] and 2014

Category	Jan-Jun 2013 $/MWh	Jan-Jun 2014 $/MWh	Percent Change Totals	Jan-Jun 2013 Percent of Total	Jan-Jun 2014 Percent of Total
Load Weighted Energy	$37.96	$69.92	84.2%	73.6%	78.6%
Capacity	$5.69	$8.56	50.4%	11.0%	9.6%
Transmission Service Charges	$4.97	$5.67	14.1%	9.6%	6.4%
Energy Uplift (Operating Reserves)	$0.73	$2.07	184.4%	1.4%	2.3%
Regulation	$0.26	$0.46	75.4%	0.5%	0.5%
PJM Administrative Fees	$0.44	$0.45	2.1%	0.9%	0.5%
Reactive	$0.65	$0.42	(36.2%)	1.3%	0.5%
Transmission Enhancement Cost Recovery	$0.41	$0.39	(5.0%)	0.8%	0.4%
Synchronized Reserves	$0.03	$0.36	980.9%	0.1%	0.4%
Emergency Load Response	$0.00	$0.11	NA	0.0%	0.1%
Capacity (FRR)	$0.15	$0.10	(30.7%)	0.3%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.09	1,988.7%	0.0%	0.1%
Transmission Owner (Schedule 1A)	$0.08	$0.09	8.6%	0.2%	0.1%
Emergency Energy	$0.00	$0.07	NA	0.0%	0.1%
Black Start	$0.15	$0.06	(59.3%)	0.3%	0.1%
Non-Synchronized Reserves	$0.00	$0.03	1,409.0%	0.0%	0.0%
Load Response	$0.01	$0.03	315.1%	0.0%	0.0%
NERC/RFC	$0.02	$0.02	4.6%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(9.7%)	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	4.9%	0.0%	0.0%
Total	$51.58	$88.90	72.4%	100.0%	100.0%

Section Overviews

Overview: Section 3, “Energy Market”

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation decreased by 1,011 MW, or 0.6 percent, from 171,274 MW in the first six months of 2013 to 170,262 MW in the first six months of 2014.[56] In 2014, 1,030 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 11 units (1,179 MW) since January 1, 2014. The decrease in offered generation in the first six months of 2014 was in part a result of a 2,189 MW reduction in net capacity between July 2013 and June 2014.[57]

  PJM average real-time generation in the first six months of 2014 increased by 5.1 percent from the first six months of 2013, from 87,974 MW to 92,458 MW. The PJM average real-time generation in the first six months of 2014 would have increased by 4.3 percent from the first six months of 2013, from 87,974 MW to 91,722 MW, if the EKPC Transmission Zone had not been included.[58]

  PJM average day-ahead supply in the first six months of 2014, including INCs and up-to congestion transactions, increased by 11.6 percent from the first six months of 2013, from 148,381 MW to 165,620 MW. The PJM average day-ahead supply, including INCs and up-to congestion transactions, would have increased by 11.1 percent from the first six months of 2013, from 148,381 MW to 164,822 MW, if the EKPC Transmission Zone had not been included. The day-ahead supply growth was 127.5 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segment.

- **Generation Fuel Mix.** During the first six months of 2014, coal units provided 45.9 percent, nuclear units 33.1 percent and gas units 15.7 percent of total generation. Compared to the first six months of 2013, generation from coal units increased 9.1 percent, generation from nuclear units decreased 0.7 percent, and generation from gas units increased 5.4 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, during the first six months of 2014, coal units were 47.6 percent

55 The 2013 total price per MWh is higher than previously reported due to the addition of the Capacity (FRR) component.

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

57 The net capacity additions are calculated by taking the difference between the new generation (1,622 MW) and the retired generation (3,808 MW) after July 1, 2013.

58 The EKPC Zone was integrated on June 1, 2013.

of marginal resources and natural gas units were 40.9 percent of marginal resources. In the first six months of 2013, coal units were 57.6 percent and natural gas units were 33.3 percent of the marginal resources.

In the PJM Day-Ahead Energy Market, during the first six months of 2014, up-to congestion transactions were 94.2 percent of marginal resources, INCs were 1.4 percent of marginal resources, DECs were 2.1 percent of marginal resources, and generation resources were 2.2 percent of marginal resources in the first six months of 2014.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first six months of 2014 was 141,673 MW in the HE 1700 on June 17, 2014, which was 1,895 MW, or 1.4 percent, higher than the PJM peak load for the first six months of 2013, which was 139,779 MW in the HE 1600 on June 25, 2013.

  PJM average real-time load in the first six months of 2014 increased by 4.2 percent from the first six months of 2013, from 86,897 MW to 90,529 MW. The PJM average real-time load in the first six months of 2014 would have increased by 3.4 percent from the first six months of 2013, from 86,897 MW to 89,881 MW, if the EKPC Transmission Zone had not been included.

  PJM average day-ahead demand in the first six months of 2014, including DECs and up-to congestion transactions, increased by 10.7 percent from the first six months of 2013, from 145,280 MW to 160,805 MW. The PJM average day-ahead demand, including DECs and up-to congestion transactions, would have increased by 10.1 percent from the first six months of 2013, from 145,280 MW to 159,959 MW, if the EKPC Transmission Zone had not been included. The day-ahead demand growth was 154.8 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first six months of 2014, 9.6 percent of real-time load was supplied by bilateral contracts, 28.3 percent by spot market purchases and 62.1 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 1.0 percentage points, reliance on spot market purchases increased by 3.3 percentage points and reliance on self-supply decreased by 2.3 percentage points.

- **Supply and Demand: Scarcity.** In the first six months of 2014, shortage pricing was triggered on two days in PJM. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.1 percent in the first six months 2013 to 0.2 percent in the first six months of 2014. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.3 percent in the first six months of 2013 to 0.7 percent in the first six months of 2014.

  In the first six months of 2014, 14 control zones experienced congestion resulting from one or more constraints binding for 50 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.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 2.9 percent in the first six months of 2013 to 0.5 percent in the first six months of

2014. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 2.3 percent in the first six months of 2013 to 0.4 percent in the first six months of 2014.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the PJM Real-Time Energy Market in the first six months of 2014, 70.0 percent of marginal units had an average markup index less than or equal to 0.0. Nonetheless, some marginal units do have substantial markups. In the first six months of 2014, 11.4 percent of units had average dollar markups greater than or equal to $150. Only 4.0 percent of units had average dollar markups greater than or equal to $150 in the first six months of 2013. Markups increased during the high demand days in January.

  In the PJM Day-Ahead Energy Market in the first six months of 2014, 92.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.02. Nonetheless, some marginal units do have substantial markups.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 93 units eligible for FMU or AU status in at least one month during the first six months of 2014, 62 units (66.7 percent) were FMUs or AUs for all six months, and 5 units (5.3 percent) qualified in only one month.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up-to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In the first six months of 2014, up-to congestion transactions continued to displace increment offers and decrement bids.

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in the first six months of 2014, 55.1 percent were offered as available for economic dispatch, 23.1 percent were offered as self scheduled, and 21.8 percent were offered as self scheduled and dispatchable.

Market Performance

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect 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 Market prices in the first six months of 2014 were between $800 and $900 for 4 hours, between $900 and $1,000 for one hour, greater than $1,000 for six hours, and greater than $1,800 for one hour.

  PJM Real-Time Energy Market prices increased in the first six months of 2014 compared to the first six months of 2013. The load-weighted average LMP was 84.2 percent higher in the first six months of 2014 than in the first six months of 2013, $69.92 per MWh versus $37.96 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first six months of 2014 compared to the first six months of 2013. The load-weighted average LMP was 84.8 percent higher in the first six months of 2014 than in the first six months of 2013, $70.67 per MWh versus $38.23 per MWh.[59]

- **Components of LMP.** LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch in which marginal units determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder and it is possible to decompose PJM system's load-weighted LMP by the components of unit offers.

  In the PJM Real-Time Energy Market, for the first six months of 2014, 23.4 percent of the load-weighted LMP was the result of coal costs, 39.1

59 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

percent was the result of gas costs and 0.47 percent was the result of the cost of emission allowances.

In the PJM Day-Ahead Energy Market, for the first six months of 2014, 24.7 percent of the load-weighted LMP was the result of the cost of gas, 16.0 percent was the result of the cost of up-to congestion transactions and 15.2 percent was the result of the cost of DEC.

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

  In the PJM Real-Time Energy Market in for the first six months of 2014, the adjusted markup component of LMP was positive, $2.88 per MWh or 4.1 percent of the PJM real-time, load-weighted average LMP. The real-time load-weighted average LMP for the month of January had the highest markup component, $9.10 per MWh using adjusted cost offers, or 7.18 percent of the real-time load-weighted average LMP in January, a substantial increase over 2013. For the first six months of 2013, the adjusted markup was $0.30 per MWh or 0.8 percent of the PJM real-time load-weighted average LMP.

  In the PJM Day-Ahead Energy Market, marginal INC, DEC and transactions have zero markups. In the first six months of 2014, the adjusted markup component of LMP resulting from generation resources was -$0.59 per MWh.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.55 per MWh in the first six months of 2013 and -$1.38 per MWh in the first six months of 2014. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- In the first six months of 2014, shortage pricing was triggered on two days in January. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by a shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.
- The performance of the PJM markets under scarcity conditions raised a number of concerns including concerns related to capacity market incentives, participant offer behavior under tight market conditions, natural gas availability and pricing, demand response and interchange transactions.

Section 3 Recommendations

- The MMU recommends the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and 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.

  The MMU and PJM have proposed a compromise that would maintain the ability of certain generating units to qualify for FMU adders but limit FMU adders to units with net revenues less than unit going forward costs or ACR.

- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules.

- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[60]
- The MMU recommends that PJM not use the ATSI closed loop interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product.
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent.
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power.
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[61] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[62]
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.
- The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal.
- The MMU recommends that PJM create and implement clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources.

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first six months of 2014, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average real-time offered generation decreased by 1,011 MW in the first six months of 2014 compared to the first six months of 2013, while peak load increased by 1,895 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. 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

60 PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.
61 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).
62 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.

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 the impact of the price elasticity of demand on prices. Energy market results for the first six months of 2014 generally reflected supply-demand fundamentals, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. These issues relate to the ability to increase markups substantially in tight market conditions, to the uncertainties about the pricing and availability of natural gas, and to the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[63] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets. Before 2011, these units were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic in the Real-Time Energy Market has steadily increased. In the Day-Ahead Energy Market, PJM started to commit these units as offer capped in September 2012, as part of a broader effort to maintain consistency between Real-Time and Day-Ahead Energy Markets.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers 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 scarcity pricing rules in 2012. There are significant issues

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

with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case during the high demand hours in January. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. Given the structure of the Energy Market, the tighter markets and the change in some participants' behavior are sources of concern in the Energy Market. The MMU concludes that the PJM energy market results were competitive in the first six months of 2014.

Overview: Section 4, "Energy Uplift"

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by 90.8 percent or $394.8 million in the first six months of 2014 compared to the first six months of 2013, from $434.6 million to $829.5 million. This change was the result of an increase of $498.4 million in balancing operating reserve charges, an increase of $16.4 million in day-ahead operating reserve charges and an increase of $0.1 million in synchronous condensing charges. These increases were partially offset by a decrease of $86.3 million in reactive services charges and a decrease of $33.8 million in black start services charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.161 per MWh. The balancing operating reserve reliability rates averaged $1.047, $0.031 and $0.015 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $2.094, $0.596 and $0.182 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $1.928 per MWh and the canceled resources rate averaged $0.0003 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and PENELEC control zones had the three highest reactive local voltage support rates: $0.726, $0.279 and $0.276 per MWh. The reactive transfer interface support rate averaged $0.002 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 49.9 percent of all day-ahead generator credits and 57.9 percent of all balancing generator credits. Combustion turbines and diesels received 64.5 percent of the lost opportunity cost credits. Coal units received 81.5 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits:** The top 10 units receiving energy uplift credits received 38.6 percent of all credits. The top 10 organizations received 82.5 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 4644, balancing operating reserves HHI was 2850, lost opportunity cost HHI was 4112 and reactive services HHI was 6288.
- **Economic and Noneconomic Generation.** In the first six months of 2014, 89.1 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.7 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability:** In the first six months of 2014, 4.3 percent of the total day-ahead generation was scheduled as must run by PJM, of which 27.9 percent received energy uplift payments.

Geography of Charges and Credits

- In the first six months of 2014, 90.9 percent of all charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions (at control zones or buses within a control zone), demand and generators, 2.0 percent by transactions at hubs and aggregates and 7.1 percent by transactions at interfaces.

Energy Uplift Issues

- **Lost Opportunity Cost Credits:** In the first six months of 2014, lost opportunity cost credits increased by $81.2 million compared to the first six months of 2013. In the first six months of 2014, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and PENELEC accounted for 57.8 percent of all lost opportunity cost credits, 45.6 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 51.0 percent of all day-ahead generation not committed in real time by PJM from those unit types and 60.6 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Black Start Service Units:** Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis during periods when the units are not economic. These black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In the first six months of 2014, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $14.2 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.

Energy Uplift Recommendations

- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to energy uplift proposed by the MMU on the rates paid by participants would be significant. For example, in the first six months of 2014, the average rate paid by a DEC in the Eastern Region would have been $0.421 per MWh, which is $3.532 per MWh less than the actual average rate paid.

Section 4 Recommendations

- The MMU recommends that PJM clearly identify the reasons for paying operating reserve credits in the Day-Ahead and the Real-Time Energy Markets to help ensure that all market participants understand the reasons for uplift costs and to provide a basis for the appropriate allocation of operating reserve charges.
- The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces.
- The MMU recommends that PJM estimate the impact closed loop interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets, and the capacity market to avoid unintended consequences.
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level and reasons for the level of operating reserve payments by unit in the PJM region.
- The MMU recommends the elimination of the day-ahead operating reserve category to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output.
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits.
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.
- The MMU recommends four modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market.

  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.
  - The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time.
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the operating reserve credits calculation.
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above which is currently allocated to real-time RTO load.
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves and the timing of commitment decisions.

Section 4 Conclusion

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

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

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

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

PJM has recognized the importance of addressing the issues that result in large amounts of energy uplift charges. In 2013, PJM stakeholders created the Energy Market Uplift Senior Task Force (EMUSTF).[64] The main goals of the EMUSTF are to evaluate the causes of energy uplift payments, develop ways to minimize energy uplift payments while maintaining prices that are consistent with operational reliability needs, and explore the allocation of such payments. In December 2013, PJM stakeholders created the Market Implementation Committee – Energy/Reserve Pricing and Interchange Volatility group to address issues such as improving the incorporation of operators' actions in LMP.[65]

The MMU recommended and supports PJM in the reexamination of the allocation of uplift charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. For example, up-to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated.

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

64 See "Problem Statement – Energy Market Uplift Costs," Energy Market Uplift Senior Task Force (July 30, 2013) <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20130730/20130730-problem-statement-energy-market-uplift-costs.ashx>.
65 See "Problem Statement – Energy/Reserve Pricing and Interchange Volatility," Market Implementation Committee (December 11, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20131212/20131212-item-01b-energy-reserve-problem-statement-updated.ashx>.

Overview: Section 5, "Capacity Market"

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[66]

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

RPM prices are locational and may vary depending on transmission constraints.[70] 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

66 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2014 Quarterly State of the Market Report for PJM: January through June*, Section 5, "Capacity Market," and include all capacity within the PJM footprint.
67 See 126 FERC ¶ 61,275 (2009) at P 86.
68 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
69 See 126 FERC ¶ 61,275 (2009) at P 88.
70 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.

generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, although the performance incentives are inadequate. 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 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 first six months of 2014, PJM installed capacity increased 911.7 MW or 0.5 percent from 183,095.2 MW on January 1 to 184,006.9 MW on June 30. 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 June 30, 2014, 40.6 percent was coal; 29.9 percent was gas; 17.9 percent was nuclear; 6.1 percent was oil; 4.6 percent was hydroelectric; 0.4 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Market Concentration.** In the 2017/2018 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[71] 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.[72,73,74]
- **Imports and Exports.** Of the 4,944.7 MW of imports in the 2017/2018 RPM Base Residual Auction, 4,525.5 MW cleared. Of the cleared imports, 2,624.3 MW (58.0 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 9,493.6 MW for June 1, 2014 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2014/2015 Delivery Year (16,020.7 MW) less replacement capacity (6,527.1 MW).

Market Conduct

- **2017/2018 RPM Base Residual Auction.** Of the 1,202 generation resources which submitted offers, unit-specific offer caps were calculated for 131 generation resources (10.9 percent). The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2017/2018 RPM Base Residual Auction was conducted in the first six months of 2014. In the 2017/2018 RPM Base Residual Auction, the RTO clearing price for Annual Resources was $120.00 per MW-day.
- The weighted average capacity price for the 2014/2015 Delivery Year is $126.40 per MW-day, including all RPM Auctions for the 2014/2015 Delivery Year held through the first six months of 2014.
- The Delivery Year weighted average capacity price was $116.55 per MW-day in 2013/2014.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first six months of 2014 was 11.2 percent, an increase from 8.6 percent for the first six months of 2013.[75]

71 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given Delivery Year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).

72 See OATT Attachment DD § 6.5.

73 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.

74 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).

75 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data is for the three months ending June 30, 2014, as downloaded from the PJM GADS database on July 27, 2014. 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.

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first six months of 2014 was 80.3 percent, a decrease from 81.8 percent for the first six months of 2013.
- **Outages Deemed Outside Management Control (OMC).** In the first six months of 2014, 12.9 percent of forced outages were classified as OMC outages, and 22.5 percent of OMC outages were due to lack of fuel. 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.

Section 5 Recommendations[76,77,78,79]

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[80,81]
- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources.
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve.
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model.
- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.
- The MMU recommends that clear, explicit operational protocols be defined for recalling the energy output of Capacity Resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details.
- The MMU recommends improvements to the performance incentive requirements of RPM:
  - The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent.
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage.
  - The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market.
  - The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[82]

Section 5 Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market

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

77 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).

78 See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

79 See "Analysis of the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf> (September 24, 2013).

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

81 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

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

structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in the first six months of 2014. 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 six months of 2014.[83]

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[84,85,86,87] In 2013 and 2014, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

As an example of such reports, the MMU prepared a report that addresses and quantifies the impact on market outcomes in the Base Residual Auction (BRA) for the 2017/2018 Delivery Year of the Short-Term Resource Procurement Target (2.5 percent offset) and demand side resources both separately and together. (Demand side resources include Demand Resources, DR, and Energy Efficiency resources, EE.) The report demonstrates that the limited DR product and the 2.5 percent offset significantly suppress prices.[88]

The MMU continues to recommend that the use of the 2.5 percent demand adjustment be terminated immediately.[89] The 2.5 percent demand reduction is a barrier to entry in the capacity market. The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in Incremental Auctions, is not supportable and has no basis in economics. There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. Removing a portion of demand affects prices at the margin, which is where the critical signal to the market is determined.

The results of the report show that even when all DR is removed and the 2.5 percent offset is eliminated and holding everything else constant, prices would have risen to greater than net CONE but less than the maximum price and PJM's reliability target would have been maintained. This a measure of the impact of the removal of DR and the 2.5 percent offset and is also a measure of the price suppression effect of DR and the 2.5 percent offset.

The fact that this set of sensitivity analyses holds everything else constant is important for considering the actual impacts of the simultaneous elimination of DR and the 2.5 percent offset. The results of these sensitivity analyses are worst case, in the sense that the increases in prices and reductions in quantities cleared are the maximum levels, because they do not include any market response which would mitigate the impact on prices and cleared quantities of eliminating DR. If both these adjustments had been made prior to the 2017/2018 BRA, it is likely that additional generation resources would have entered the market, that prices would likely have been lower than the prices in these sensitivity analyses and that reliability would have been greater than in these sensitivity analyses.

Overview: Section 6, "Demand Response"

- **Demand Response Jurisdiction.** In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated in its entirety Order No. 745, which provided for payment of demand-side resources at full LMP.[90] The decision calls into question the jurisdictional foundation for all demand response programs currently subject to FERC oversight, and, in particular, for those programs that involve FERC

83 For more complete conclusions, see *2013 State of the Market Report for PJM*, Section 4, "Capacity Market."

84 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).

85 See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

86 See "Analysis of the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf> (September 24, 2013).

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

88 The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_20140710.pdf> (July 10, 2014.)

89 See also the *Protest of the Independent Market Monitor for PJM*, Docket No. ER12-513 (December 22, 2011).

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

regulated payments to demand resources. An appeal to the court for en banc review is pending.

- **Demand Response Activity.** Economic program credits increased by $11.2 million, from $2.6 million in the first six months of 2013 to $13.8 million in the first six months of 2014, a 439 percent increase.[91] Emergency energy revenue increased by $43.0 million, from $0.0 million in the first six months of 2013 to $43.0 million compared to the first six months of 2013. The capacity market is the primary source of revenue to participants in PJM demand response programs. In the first six months of 2014, capacity market revenue increased by $130.8 million, or 83.6 percent, from $156.6 million in the first six months of 2013 to $287.4 million in the first six months of 2014.[92]

  All demand response energy payments are uplift. LMP does not cover demand response energy payments. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[93] Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market.

- **Locational Dispatch of Demand Resources.** PJM dispatches demand resources on a zonal or subzonal basis when appropriate, but subzonal dispatches are only on a voluntary basis. Beginning with the 2014/2015 Delivery Year, demand resources will be dispatchable for mandatory reduction on a subzonal basis, defined by zip codes. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources.

- **Emergency Event Day Analysis.** PJM's calculations overstate participants' compliance during emergency load management events. In PJM's calculations, load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance purposes, but are treated as zero. This skews the compliance results towards higher compliance since poorly performing demand resources are not used in the compliance calculation. Considering all positive and negative reported values, the observed average load reduction of the eight events in the first six months of 2014 should have been 1,658.9 MW, rather than the 2,163.7 MW calculated using PJM's method. The observed compliance is 28.0 percent rather than PJM's calculated 36.5 percent. This does not include locations that did not report their load during the emergency event days. All locations should be required to report their load.

Section 6 Recommendations

- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year.
- The MMU recommends that the emergency load response program be classified as an economic program, responding to economic price signals and not an emergency program responding only after an emergency is called.
- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[94]
- The MMU recommends that demand response programs adopt an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[95]
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. This recommendation has been adopted.
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid.

91 Economic credits are synonymous with revenue received for reductions under the economic load response program.
92 The total credits and MWh numbers for demand resources were calculated as of August 5, 2014 and may change as a result of continued PJM billing updates.
93 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.
94 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.
95 *Id* at 1.

- The MMU recommends that measurement and verification methods for demand resources be further modified to more accurately reflect compliance.
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations.
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[96]
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop.
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately resemble the conditions of an emergency event.

Section 6 Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real time energy price signals in real time, will have the ability to react to real time prices in real time and will have the ability to receive the direct benefits or costs of changes in real time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. 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.

With exception of large wholesale customers in some areas, most customers in PJM are not on retail rates that directly expose them to the wholesale price of energy or capacity. As a result, most customers in PJM do not have the direct ability to see, respond to or benefit from a response to price signals in PJM's markets. PJM's demand side programs are generally designed to allow customers (or their intermediaries in the form of load serving entities (LSEs) or curtailment service providers (CSPs)) to either directly, or through intermediaries, be paid as if they were directly paying the wholesale price of energy and capacity and avoiding those prices when reducing load. PJM's demand side programs are designed to provide direct incentives for load resources to respond, via load reductions, to wholesale market price signals and/or system emergency events.

If retail markets reflected hourly wholesale prices and customers or their intermediaries 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, as long as there are demand side programs, 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.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. That is a prerequisite to a functional market design.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day ahead market and should

96 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed November 11, 2013) ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year and not be limited to a small number of hours.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market.

In order to be a substitute for generation, compliance by demand resources to PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

Overview: Section 7, "Net Revenue"

Net Revenue

- The net revenues reported are theoretical energy and ancillary net revenues and do not include capacity market revenues.
- Energy net revenues are affected by fuel prices and energy prices. Natural gas prices and energy prices were significantly higher in the first three months of 2014 than in the first three months of 2013, resulting in large increases in net revenues in the first three months of 2014.
- Although higher energy prices increase net revenues and higher fuel costs decrease net revenues, the net result was substantial increases in net revenues for all technology types in the first six months of 2014 compared to the first six months of 2013, primarily as a result of the extremely high increases in net revenues in the first three months of 2014. Energy net revenues increased by an average of 730 percent for a new CT, 202 percent for a new CC, 338 percent for a new CP, 7,227 percent for a new DS, 96 percent for a new nuclear plant, 32 percent for a new wind installation, and 14 percent for a new solar installation.

Section 7 Conclusion

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

The net revenue results illustrate some fundamentals of the PJM wholesale power market. High loads that result in high prices tend to increase energy market net revenues for all unit types. Even a relatively small number of shortage pricing hours can significantly increase net revenues. This illustrates the potential role of scarcity pricing as a source of net revenues and also makes it more important to address the appropriate net revenue offset mechanism in the capacity market.

Overview: Section 8, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** 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.[97] The rule establishes a compliance deadline of April 16, 2015.

  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 (PM). On March 28, 2013, the EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[98]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[99]

  On April 29, 2014, the U.S. Supreme Court upheld EPA's Cross-State Air Pollution Rule (CSAPR), clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect.[100]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, the EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[101] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE includes facilities located behind the meter. 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.

  Pending initiatives in Pennsylvania and the District of Columbia would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics.[102]

  In PJM's recent filing to improve its ability to dispatch DR prior to emergency system conditions, PJM proposed to retain the PJM Emergency Load Response Program which would allow RICE to continue to use the EPA's exception.[103] The MMU protested retention of the emergency program, particularly for the purpose of according discriminatory preference to resources that are not good for reliability, the markets or the environment.[104] An order from the Commission in this matter is now pending.

- **Greenhouse Gas Emissions Rule.** On September 20, 2013, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[105] Once GHG NSPS standards for CO_2 are in place, the CAA permits the EPA to take the much more significant step of regulating CO_2 emissions from existing sources.[106] In

97 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

98 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).

99 CAA § 110(a)(2)(D)(i)(I).

100 See EPA et al. v. EME Homer City Generation, L.P. et al., No. 12-1182.

101 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

102 *See* Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia Bill 20-569.

103 PJM Tariff filing, FERC Docket No. ER14-822 (December 24, 2013).

104 Comments, Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, FERC Docket No. ER14-822 (January 14, 2014) at 3-6.

105 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Propose Rule*, EPA-HQ-OAR-2013-0495 ("GHG NSPS").

106 *See* CAA § 111(b)&(d).

anticipation of timely issuance of a final GHG NSPS, the EPA issued a proposed rule for regulating CO_2 from certain existing power generation facilities on June 2, 2014, the Existing Stationary Sources Notice of Proposed Rulemaking ("ESS NOPR").[107] The ESS NOPR established interim and final emissions goals for each state that must be met, respectively, by 2020 and 2030. States have flexibility to meet these goals, including through participation in multistate CO_2 credit trading programs.

- **Cooling Water Intakes.** Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best available technology for minimizing adverse environmental impacts. A final rule implementing this requirement was issued May 19, 2014.[108]

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.[109] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[110]
- **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 2014 for the 2012-2014 compliance period were $5.02 per ton, above the price floor for 2014. The clearing price is equivalent to a price of $5.53 per metric tonne, the unit used in other carbon markets.

107 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, 79 Fed. Reg. 34830 (June 18, 2014).
108 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667.
109 N.J.A.C. § 7:27-19.
110 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective non-catalytic reduction (SNCR).

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On June 30, 2014, 71.1 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 98.7 percent of coal steam MW had some type of particulate control, and 92.2 percent of fossil fuel fired capacity in PJM had NO_x emission control technology.

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 June 30, 2014, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have not enacted renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Renewable energy credits (RECs) and federal production tax credits provide out of market payments to qualifying resources, primarily wind and solar, which create an incentive to generate MWh until the LMP is equal to the marginal cost of producing power minus the credit received for each MWh. The credits provide an incentive to make negative energy offers when the net of marginal cost and credits is negative. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation. RECs markets are not transparent. Data on RECs prices and markets are not publicly available. 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 ensure that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Overview: Section 9, “Interchange Transactions”

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first six months of 2014, PJM was a net importer of energy in the Real-Time Energy Market in January, May and June, and a net exporter of energy in the remaining three months.[111] During the first six months of 2014, the real-time net interchange of -863.1 GWh was lower than net interchange of 4,023.3 GWh in the first six months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first six months of 2014, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. During the first six months of 2014, the total day-ahead net interchange of -9,182.5 GWh was greater than net interchange of -9,161.6 GWh during the first six months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first six months of 2014, gross imports in the Day-Ahead Energy Market were 109.8 percent of gross imports in the Real-Time Energy Market (158.0 percent during the first six months of 2013), gross exports in the Day-Ahead Energy Market were 138.3 percent of the gross exports in the Real-Time Energy Market (242.0 percent during the first six months of 2013).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first six months of 2014, there were net scheduled exports at 12 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 six months of 2014, there were net scheduled exports at 11 of PJM’s 18 interface pricing points eligible for real-time transactions.[112]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first six months of 2014, there were net scheduled exports at 12 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 six months of 2014, there were net scheduled exports at 11 of PJM’s 19 interface pricing points eligible for day-ahead transactions.
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first six months of 2014, up-to congestion transactions were net exports at six of PJM’s 19 interface pricing points eligible for day-ahead transactions.
- **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.

111 Calculated values shown in Section 9, “Interchange Transactions,” are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

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

For the first six months of 2014, net scheduled interchange was -701 GWh and net actual interchange was -305 GWh, a difference of 396 GWh. For the first six months of 2013, net scheduled interchange was 2,989 GWh and net actual interchange was 3,058 GWh, a difference of 69 GWh. This difference is inadvertent interchange.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first six months of 2014, the direction of the average hourly flow was consistent 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 51.8 percent of the hours in the first six months of 2014.
- **PJM and New York ISO Interface Prices.** In the first six months of 2014, 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 57.4 percent of the hours in the first six months of 2014.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first six months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[113] The direction of flow was consistent with price differentials in 62.1 percent of the hours in the first six month of 2014.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first six months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO Linden Bus.[114] The direction of flow was consistent with price differentials in 59.0 percent of the hours in the first six months of 2014.
- **Hudson DC Line.** In the first six months of 2014, the average hourly flow (PJM to NYISO) was inconsistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO Hudson Bus.[115] The direction of flow was consistent with price differentials in 61.7 percent of the hours in the first six months of 2014.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued three TLRs of level 3a or higher during the first six months of 2014, compared to 23 such TLRs issued during the first six months of 2013.
- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased to 209,819 bids per day with an average cleared volume of 1,609,507 MWh per day in the first six months of 2014, compared to an average of 107,215 bids per day, with an average cleared volume of 1,272,955 MWh per day, in the first six months of 2013. (Figure 9-13).
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule to become compliant with Order No. 764.[116,117] PJM and the MMU remain concerned about the potential impacts of this rule change on market participants' scheduling behavior, and will continue to monitor and address as necessary any scheduling behavior that raises operational or market manipulation concerns resulting from the removal of the 45 minute scheduling duration rule.[118]

Section 9 Recommendations

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point.

113 In the first six months of 2014, there were 400 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 $70.28 while the NYISO LMP at the Neptune Bus during non-zero flows was $81.73, a difference of $11.45.

114 In the first six months of 2014, there were 787 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 $75.60 while the NYISO LMP at the Neptune Bus during non-zero flows was $79.56, a difference of $3.96.

115 In the first six months of 2014, there were 2,941 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $126.68 while the NYISO LMP at the Hudson Bus during non-zero flows was $131.99, a difference of $5.31.

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

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

118 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.pjm.com/~/media/documents/reports/20140729-pjm-imm-joint-statement-on-interchange-scheduling.ashx>.

- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction.
- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.
- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling.
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point.
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.
- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights.

Section 9 Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed 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 offsets (FTRs and 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's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and generator offers results in an efficient dispatch and efficient prices.

Overview: Section 10, "Ancillary Services"

Primary Reserve

Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement. PJM's primary reserves are made up of resources, both synchronized and non-synchronized, that can provide energy within ten minutes.

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (energy or demand response currently synchronized to the grid and available within ten minutes), and non-synchronized reserve (energy currently off-line but can be started and provide energy within ten minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. The primary reserve requirement in the RTO Reserve Zone is currently 2,063 MW of which at least 1,700 MW must be available within the Mid-Atlantic Dominion (MAD) subzone. Adjustments to the primary reserve requirement can occur when grid maintenance or outages change the largest contingency. The actual demand for primary reserve in the RTO for the first six months of 2014 was 2,087 MW. The actual

demand for primary reserve in the MAD subzone in the first six months of 2014 was 1,700 MW.

Tier 1 Synchronized Reserve

Tier 1 synchronized reserve is part of primary reserve comprised of all on-line resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event.

- **Supply.** In the first six months of 2014, an average supply of 1,083 MW of tier 1 was identified hourly for the entire RTO synchronized reserve, and an average supply of 846 MW of tier 1 was identified hourly for the Mid-Atlantic Dominion subzone.
- **Demand.** There is no fixed required amount of tier 1 synchronized reserve. Tier 1 synchronized reserve is estimated and not assigned.
- **Price and Cost.** The price for synchronized reserves is typically zero, as there is no incremental cost associated with providing the ability to ramp up from the current economic dispatch point. However, a tariff change included in the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the non-synchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear but it has had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $75,248,584.

  The additional payments to tier 1 synchronized reserves can be considered a windfall because the additional payment does not create an incentive to provide more tier 1 synchronized reserves and the additional payment is not a payment for performance as all estimated tier 1 synchronized reserves receive the payment regardless of whether they provided a ny response.
- **Tier 1 Synchronized Reserve Spinning Event Response.** Tier 1 synchronized reserve is awarded credits when a spinning event occurs and it responds. These spinning event response credits for tier 1 response are independent of the tier 1 estimated, independent of the synchronized reserve market clearing price, and independent of the non-synchronized reserve market clearing price.

  The MMU analysis shows that only 27.0 percent of tier 1 synchronized reserve identified hour ahead as available for both synchronized reserve and primary reserve actually responded to spinning events.

Tier 2 Synchronized Reserve Market

Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2. Tier 2 synchronized reserve is primary reserve (ten minute availability) that must be dispatched in order to satisfy the synchronized reserve requirement. When the synchronized reserve requirement cannot be filled with tier 1 synchronized reserve, PJM conducts a market to satisfy the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve subzone (MAD).

Market Structure

- **Supply.** In the first six months of 2014, the supply of offered and eligible synchronized reserve was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone, except for two hours on January 6, 2014, and eight hours on January 7, 2014.
- **Demand.** The default hourly required synchronized reserve requirement is 1,375 MW in the RTO Reserve Zone and 1,300 MW for the Mid-Atlantic Dominion Reserve subzone.
- **Market Concentration.** In the first six months of 2014, the weighted average HHI for cleared inflexible tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone was 4406 which is classified as highly concentrated. The HHI for flexible synchronized reserve cleared during real-time market solutions (which was only 12.6 percent of all tier 2

synchronized reserve) was 8650. The MMU calculates that during the first six months of 2014, 43.2 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion subzone and 38.3 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone.

The MMU concludes from these results that both the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market, in the first six months of 2014, were characterized by structural market power.

Market Conduct

- **Offers.** Synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost, which is calculated by PJM. Compliance with the must-offer rule for Tier 2 synchronized reserve is greatly improved.

Market Performance

- **Price.** The cleared synchronized reserve weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Dominion (MAD) subzone was $15.18 per MW in the first six months of 2014, a $7.73 increase from the first six months of 2013.

  The cleared synchronized reserve weighted average price for tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was $18.15 per MW in the first six months of 2014.

Non-Synchronized Reserve Market

Non-synchronized reserve is a component of primary reserve and shares its market definitions including the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone (MAD). After the hour ahead market solution satisfies the requirement for synchronized reserve the remainder of the primary reserve requirement is satisfied with non-synchronized reserve. Non-synchronized reserve is non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes at the direction of PJM dispatch.

Market Structure

- **Supply.** In the first six months of 2014, the supply of eligible non-synchronized reserve was sufficient to cover the primary reserve requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone, except for two hours on January 6, 2014, and eight hours on January 7, 2014.
- **Demand.** In the RTO Zone, the market cleared an hourly average of 396.9 MW of non-synchronized reserve during the first six months of 2014. In 93.9 percent of hours the market clearing price was $0. In the MAD subzone, the market cleared an hourly average of 593.0 MW of non-synchronized reserve. In 90.7 percent of hours the market clearing price was $0.

Market Conduct

- **Offers.** No offers are made for non-synchronized reserve. Non-emergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for non-synchronized reserves by the market solution software.

Market Performance

- **Price.** Prices are a function of the opportunity costs of any resources taken for non-synchronized reserves. The cleared non-synchronized reserve weighted average price in the RTO Reserve Zone was $0.93 per MW for the first six months of 2014. The cleared non-synchronized reserve weighted average price in the Mid-Atlantic Dominion (MAD) subzone was $2.68 per MW.

Secondary Reserve

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve.[119] It is designed to provide price signals that encourage resources to provide 30-minute reserve. The DASR market has no performance obligations.

119 See PJM. "Manual 35, Definitions and Acronyms," Revision 35, (April 11, 2014), p. 89.

Market Structure

- **Concentration.** The MMU calculates that in the first six months of 2014, zero hours in the DASR Market failed the three pivotal supplier test.
- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0 per MW. DASR is calculated by the day-ahead market solution as the lesser of the thirty minute energy ramp rate or the emergency maximum MW minus the day-ahead dispatch point for all on-line units. For the first six months of 2014, the average available hourly DASR was 40,768 MW.
- **Demand.** The DASR requirement in 2014 is 6.27 percent of peak load forecast, down from 6.91 percent in 2013. The DASR MW purchased averaged 5,951 MW per hour for the first six months of 2014.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. On June 30, 2014, 11.2 percent of resources offered DASR at levels above $5 per MW.
- **DR.** Demand resources are eligible to participate in the DASR Market. As of June 30, 2014, six demand resources have entered offers for DASR.

Market Performance

- **Price.** The weighted average DASR market clearing price in the first six months of 2014 was $1.63 per MW. This is a $1.57 per MW increase from the first six months of 2013, which had a weighted price of $0.06 per MW.

Regulation Market

The PJM Regulation Market is a single market for the RTO. Regulation is provided by demand response and generation resources that must qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three of these services at least cost. The PJM Regulation Market design includes three clearing price components (capability, performance, and lost opportunity cost), the rate of substitution between RegA and RegD resources (marginal benefit factor) and a measure of the quality of response (performance score) by a regulation resource to a regulation signal. The marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

Market Structure

- **Supply.** In the first six months of 2014, the average hourly eligible supply of regulation was 1,336 actual MW (980 effective MW). This is a decrease of 30 actual MW (137 effective MW) from the first six months of 2013, when the average hourly eligible supply of regulation was 1,366 actual MW (1,118 effective MW).
- **Demand.** The average hourly regulation demand was 674 actual MW (664 effective MW) in the first six months of 2014. This is a 104 actual MW (14 effective MW) decrease in the average hourly regulation demand of 777 actual MW (678 effective MW) in the same period of the first six months of 2013..
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 1.98. This is a 13.1 percent increase over the first six months of 2013 when the ratio was 1.75.
- **Market Concentration.** In the first six months of 2014, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1901 which is classified as highly concentrated. In the first six months of 2014, the three pivotal supplier test was failed in 96 percent of hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with cost parameters to verify the offer, and may optionally submit a price offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[120] As of June 30, 2014, there were 277 resources following the RegA signal and 41 resources following the RegD signal.

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

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $62.09 per MW of regulation in the first six months of 2014, an increase of $30.29 per MW of regulation, or 106.2 percent, from the first six months of 2013. The cost of regulation in the first six months of 2014 was $75.20 per MW of regulation, a $38.73 per MW of regulation, or 106.2 percent, increase from the first six months of 2013.
- **RMCP Credits.** RegD resources continue to be underpaid relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment, pricing, and settlement processes. In the first six months of 2014, RegA resources received RMCP credits per effective MW on average 1.9 times higher than RegD resources. If the Regulation Market were functioning correctly, RegD and RegA resources would be paid equally per effective MW.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid.[121]

In the first six months of 2014, total black start charges were $25.2 million with $10.9 million in revenue requirement charges and $14.3 million in operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Black start operating reserve charges are paid for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Black start zonal charges in the first six months of 2014 ranged from $0.02 per MW-day in the ATSI Zone (total charges were $58,250) to $3.32 per MW-day in the AEP Zone (total charges were $13,714,398).

121 OATT Schedule 1 § 1.3BB.

Reactive

Reactive service, reactive supply and voltage control from generation or other sources service, is provided by generation and other sources of reactive power (measured in VAR). Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

In the first six months of 2014, total reactive service charges were $163.0 million with $140.8 million in revenue requirement charges and $22.2 million in operating reserve charges. Reactive service revenue requirements are based on FERC-approved filings. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service. Total charges in the first six months of 2014 ranged from $1.7 thousand in the RECO Zone to $20.3 million in the AEP Zone.

Section 10 Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process.
- The MMU recommends that the rule requiring the payment of the tier 2 price to tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced. As of the end of June, 2014 compliance with the tier 2 must-offer provision reached 96.7 percent.
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.

- The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, January 6, 2014, and January 7, 2014, and that PJM replace the DASR Market with a real time secondary reserve product that is available and dispatchable in real time.
- The MMU recommends that PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market.

Section 10 Conclusion

While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. Instead, the market design makes use of the marginal benefit factor in the optimization and pricing, but a mileage ratio multiplier in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design is causing effective MW provided by RegD resources to be underpaid per effective MW. These issues have led to the MMU's conclusion that the Regulation Market design, as currently implemented, is flawed.

The structure of each Tier 2 Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the 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. Compliance with calls to respond to actual spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

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

The MMU concludes that the new Regulation Market results were competitive. The MMU concludes that the Synchronized Reserve Market results were competitive. The MMU concludes that the DASR Market results were competitive.

Overview: Section 11, "Congestion and Marginal Losses"

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $1,136.1 million or 372.1 percent, from $306.0 million in the first six months of 2013 to $1,442.2 million in the first six months of 2014. Total congestion costs increased because of the cold weather in January 2014, but congestion was also much higher in March 2014 than in March 2013 and congestion was higher in each of the first six months of 2014 than in the first six months of 2013.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,164.7 million or 221.0 percent, from $527.1 million in the first six months of 2013 to $1,691.8 million in the first six months of 2014.
- **Balancing Congestion.** Balancing congestion costs decreased by $28.6 million or 12.9 percent, from -$221.1 million in the first six months of 2013 to -$249.7 million in the first six months of 2014.

- **Monthly Congestion.** Monthly total congestion costs in the first six months of 2014 ranged from $63.1 million in May to $825.2 million in January.
- **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 West Interface, the Breed – Wheatland flowgate, the Cloverdale transformer, and the Bedington - Black Oak Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first six months of 2014. The number of congestion event hours in the Day-Ahead Energy Market was about 14 times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency increased by 31.0 percent from 174,119 congestion event hours in the first six months of 2013 to 228,167 congestion event hours in the first six months of 2014.

  Real-time congestion frequency increased by 66.5 percent from 10,032 congestion event hours in the first six months of 2013 to 16,699 congestion event hours in the first six months of 2014.
- **Congested Facilities.** Day-ahead, congestion-event hours increased on all types of congestion facilities. Real-time, congestion-event hours increased on all types of congestion facilities.

  The AP South Interface was the largest contributor to congestion costs in the first six months of 2014. With $455.4 million in total congestion costs, it accounted for 31.6 percent of the total PJM congestion costs in the first six months of 2014.
- **Zonal Congestion.** AEP had the largest total congestion costs among all control zones in the first six months of 2014. AEP had $367.6 million in total congestion costs, comprised of -$717.0 million in total load congestion payments, -$1,138.9 million in total generation congestion credits and -$54.3 million in explicit congestion costs. The AP South Interface, the West Interface, the Breed – Wheatland, Monticello - East Winamac and the Cook - Palisades flowgates contributed $268.7 million, or 73.1 percent of the total AEP Control Zone congestion costs.
- **Ownership.** In the first six months of 2014, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. UTCs are in the explicit cost category and comprise most of that category. Explicit costs are the primary source of congestion credits to financial entities. In the first six months of 2014, financial companies received $202.1 million in congestion credits, an increase of $146.8 million or 265.6 percent compared to the first six months of 2013. In the first six months of 2014, physical companies paid $1,644.2 million in congestion charges, an increase of $1,282.9 million or 355.1 percent compared to the first six months of 2013.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $511.7 million or 103.5 percent, from $494.5 million in the first six months of 2013 to $1,006.2 million in the first six months of 2014. Total marginal loss costs increased because of the cold weather in January, but marginal loss costs were also significantly higher in February and March 2014 than in February and March 2013 and marginal loss costs were higher in each of the first six months of 2014 than in the first six months of 2013. The loss component of LMP remained constant, $0.02 in the first six months of 2013 and $0.02 in the first six months of 2014. The loss MW in PJM increased 5.1 percent, from 8,622 GWh in the first six months of 2013 to 9,066 GWh in the first six months of 2014.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $549.0 million or 100.5 percent, from $546.0 million in the first six months of 2013 to $1,095.0 million in the first six months of 2014.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $37.2 million or 72.2 percent, from -$51.6 million in the first six months of 2013 to -$88.8 million in the first six months of 2014.
- **Monthly Total Marginal Loss Costs.** Marginal loss costs in the first six months of 2014 increased compared to the first six months of 2013,

by 310.3 percent in January, 114.4 percent in February, 95.3 percent in March, 7.9 percent in April, 0.9 percent in May and 9.1 percent in June. Monthly total marginal loss costs in the first six months of 2014 ranged from $68.7 million in May to $414.6 million in January.

- **Marginal Loss Credits.** Marginal loss credits are calculated as total energy costs plus total marginal loss costs 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, which is paid back in full to load and exports on a load ratio basis.[122] The marginal loss credits increased in the first six months of 2014 by $163.8 million or 101.6 percent, from $161.3 million in the first six months of 2013, to $325.0 million in the first six months of 2014.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $344.6 million or 103.6 percent, from -$332.6 million in the first six months of 2013 to -$677.2 million in the first six months of 2014.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $596.1 million or 169.2 percent, from -$352.2 million in the first six months of 2013 to -$948.3 million in the first six months of 2014.
- **Balancing Energy Costs.** Balancing energy costs increased by $255.5 million or 1,207.7 percent, from $21.2 million in the first six months of 2013 to $276.6 million in the first six months of 2014.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first six months of 2014 ranged from -$272.5 million in January to -$48.1 million in May.

Section 11 Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 98.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

Overview: Section 12, “Planning”

Planned Generation and Retirements

- **Planned Generation.** As of June 30, 2014, 63,009.4 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 199,948.2 MW as of June 30, 2014. Of the capacity in queues, 6,359.5 MW, or 10.1 percent, are uprates and the rest are new generation. Wind projects account for 16,407.1 MW of nameplate capacity or 26.0 percent of the capacity in the queues. Combined-cycle projects account for 38,793.7 MW of capacity or 61.6 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 25,902.2 MW are, or are planned to be, retired between 2011 and 2019, with all but 2,050.5 MW planned to be retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 23.3 percent, of all MW planned for retirement from 2014 through 2019.
- **Generation Mix.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire.

122 See PJM. “Manual 28: Operating Agreement Accounting,” Revision 65 (April 24, 2014), pp 64-66. Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[123] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.
- The queue contains a substantial number of projects that are not likely to be built. These projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Many feasibility, impact and facilities studies are delayed for reasons including disputes with developers, circuit and network issues, retooling as a result of projects being withdrawn, and an accumulated backlog in completing studies.
- Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of its parent company. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company. Out of 453 projects analyzed, 47 were identified as having the developer and transmission owner being part of the same company.

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that comprises nuclear units at Salem and at Hope Creek. On April 29, 2013, PJM submitted a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. The RFP window closed on June 28, 2013. PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSE&G, and a range of proposals from other non-incumbents. PJM staff recommended that PSE&G be selected to proceed with the Artificial Island project.

  Several market participants and interested parties responded with criticisms of and requests for the reevaluation of the process and of PJM's recommendation. Based on these communications, the PJM Board of Managers decided on July 23, 2014, to defer any selection until they further review and address the issues raised.

123 OATT Parts IV & VI.

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects intended to resolve a wide range of reliability criteria violations and congestion issues and which have substantial impacts on energy and capacity markets. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV.

Section 12 Recommendations

The MMU recommends additional improvements to the planning process.

- There is no mechanism to permit a direct comparison, or competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. The MMU recommends the creation of such a mechanism.
- The MMU recommends that rules be implemented to permit competition to provide financing of transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers.

- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[124]
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation.
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.
- The MMU recommends an analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.

Section 12 Conclusion

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

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

The PJM queue evaluation process should be improved to ensure that barriers to competition are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management.

Overview: Section 13, "FTR and ARRs"

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can sell FTRs. In the 2014 to 2015 Annual FTR Auction, total participant FTR sell offers were 271,368 MW, down from 417,118 MW in the 2013 to 2014 planning period. In the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period, total participant FTR sell offers were 5,480,676 MW, up from 5,010,437 MW for the same period during the 2013 to 2014 planning period.
- **Demand.** There were 3,270,311 MW of buy and self-scheduled bids in the 2014 to 2015 Annual FTR Auction, down from 3,274,373 MW in the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period increased 27.4 percent from 19,685,688 MW for the same time period of the prior planning period, to 25,088,665 MW.

124 See "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

- **Patterns of Ownership.** For the 2014 to 2015 Annual FTR Auction, financial entities purchased 57.5 percent of prevailing flow FTRs and 80.0 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 78.1 percent of prevailing flow and 87.4 percent of counter flow FTRs for January through June of 2014. Financial entities owned 69.7 percent of all prevailing and counter flow FTRs, including 60.1 percent of all prevailing flow FTRs and 85.7 percent of all counter flow FTRs during the period from January through June 2014.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2013 to 2014 planning period were $1,214,878 for Increment Offers, Decrement Bids and, after September 1, 2013, UTC Transactions.

- **Credit Issues.** People's Power and Gas, LLC and CCES, LLC defaulted on their collateral calls and payment obligations in January 2014. Customers of these members have been reallocated accordingly, and neither company held any financial transmission rights. These two load-serving members accounted for 17 of the total 33 default events. People's Power and Gas, LLC defaulted on three collateral calls totaling approximately $687,000 and then defaulted on four related payment obligations totaling approximately $554,000. CCES, LLC defaulted on two collateral calls totaling approximately $308,000 and then defaulted on eight related payment obligations totaling approximately $2.6 million. On March 6, 2014, PJM filed with FERC to terminate membership of these two companies. The FERC authorized this request effective April 24, 2014 and PJM utilized the default allocation assessment to apply their defaulting charges of approximately $1.9 million (total defaults of these two members less collateral held) to PJM's non-defaulting members in accordance with section 15.2.2 of the OATT to non-defaulting members' March 2014 monthly invoices.[125]

  Of the remaining 16 defaults not from People's Power and Gas, LLC and CCES, LLC, in January through March 2014, 13 were from collateral defaults, averaging $822,493, and three were from payment defaults, averaging $2,328. These remaining defaults were all promptly cured. In April through June 2014, CCES, LLC defaulted again for a total of $59,899. The default allocation assessment was assigned to non-defaulting members resulting in 18 payment defaults in April 2014 totaling $4,017, nine of which were promptly cured. There were no collateral or payment defaults in May or June 2014. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** In the Annual FTR Auction for the 2014 to 2015 planning period, 365,843 MW (11.2 percent) of buy and self-schedule bids cleared. For the 2013 to 2014 planning period Monthly Balance of Planning Period FTR Auctions 3,414,500 MW (13.6 percent) of FTR buy bids and 1,153,835 MW (21.1 percent) of FTR sell offers cleared.

- **Price.** The weighted-average buy-bid FTR price for the 2014 to 2015 Annual FTR Auction was $0.29 per MW, up from $0.13 per MW in the 2013 to 2014 planning period. The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period was $0.17, up from $0.10 per MW in the 2013 to 2014 planning period.

- **Revenue.** The 2014 to 2015 Annual FTR Auction generated $748.6 million in net revenue, up $190.2 million from the 2013 to 2014 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $29.8 million in net revenue for all FTRs for the 2013 to 2014 planning period, up from $23.9 million for the same time period in the 2012 to 2013 planning period.

- **Revenue Adequacy.** FTRs were paid at 72.8 percent of the target allocation level for the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on their portion of FTR target allocations. PJM collected $1,819.5 million of FTR revenues during the 2013 to 2014 planning period and $614.0 million during the 2012 to 2013 planning period. For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were Dominion Zone and

125 *See* Default Allocation Assessment. OATT Section 15.2.2

the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were both the Western Hub.

For the first six months of 2014, total day-ahead congestion was $1,679.2 million while total day-ahead plus balancing congestion was $1,429.5 million, compared to target allocations of $1,965.7 million in the same time period.

Target allocation values are based on FTR MW and the differences between FTR source and sink day ahead CLMPs, not on the actual congestion incurred on FTR paths. Actual congestion incurred is the overpayment by load compared to payments to generation which result from both day-ahead congestion and balancing congestion. Target allocations are therefore not a good measure of congestion incurred on FTR paths and FTR payouts relative to target allocations are not a good measure of the payout performance of FTRs. Target allocations are just a distribution mechanism for congestion collected.

- **ARR and FTR Offset.** ARRs and FTRs served as an effective, but not total, offset to congestion. ARR and FTR revenues offset 98.2 percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.
- **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 $720.4 million in profits for physical entities, of which $355.1 million was from self-scheduled FTRs, and $495.1 million for financial entities. FTRs were undervalued in the auctions compared to their returns from congestion revenue, despite the fact that the payout ratio was less than 1.0. Not every FTR was profitable. FTR profits were high for the first six months of 2014 due in large part to very high January congestion prices and higher than normal congestion prices in February and March.

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 2013 to 2014 planning period planning period PJM allocated a total of 15,417.5 MW of residual ARRs with a total target allocation of $4,683,134.
- **ARR Reassignment for Retail Load Switching.** There were 52,825 MW of ARRs associated with $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 64,086 MW of ARRs associated with $382,100 of revenue that were reassigned for the 2013 to 2014 planning period.

Market Performance

- **Revenue Adequacy.** For the 2013 to 2014 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $520.0 million while PJM collected $593.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2012 to 2013 planning period, the ARR target allocations were $587.0 million while PJM collected $653.6 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.
- **ARRs as an Offset to Congestion.** ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market for the 2013 to 2014 planning period and for the 2012 to 2013 planning period.

Section 13 Recommendations

- Report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants.
- Eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs.
- Eliminate geographic cross subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate the over allocation of ARRs in the Annual ARR Allocation process.
- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.

Section 13 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.

After the introduction of LMP markets, financial transmission rights (FTRs) permitted the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the facts that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source of the funds available to offset congestion costs in an LMP market. In other words, load payments in excess of generation revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs to pay back to load the difference between the total load payments and the total generation revenues associated with congestion.

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.

For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested.[126] One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach would ignore the fact that loads must pay both day ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system, would have to continue paying in excess of generator revenues and not have balancing congestion included in the calculation of congestion in order to increase the payout to holders of FTRs who are not loads and who therefore did not receive an allocation of ARRs. In other words, load would have to continue providing all the funding of FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths.

126 See "FirstEnergy Solutions Corp. Allegheny Energy Supply Company, LLC v PJM Interconnection, LLC" EL13-47(February 15, 2013).

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reporting, distribution of and quantity of funding in the FTR Market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. ARR holders do have those rights based on their payment for the transmission system. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and balancing 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 modeling differences between the day-ahead and real-time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

Reported FTR revenue sufficiency uses target allocations as the relevant benchmark. But target allocations are not the relevant benchmark. Target allocations are based on day-ahead congestion only, ignoring the other part of total congestion which is balancing congestion. The difference between the congestion payout using total congestion and the congestion payout using only day-ahead congestion illustrates the issue. For the first six months of 2014, total day-ahead congestion was $1,679.2 million while total day-ahead plus balancing congestion was $1,429.5 million, compared to target allocations of $1,965.7 million in the same time period.

The market response to the revenue adequacy issue has been to reduce bid prices and to increase bid volumes and offer volumes. Clearing prices have fallen and cleared quantities have increased.

In the 2010 to 2011 planning period, the clearing price for an FTR obligation was $0.71 per MW, and in the 2013 to 2014 planning period the clearing price was $0.30 per MW, a 57.7 percent decrease. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, and in the 2013 to 2014 planning period was $0.05 per MW for, a 340 percent decrease.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions increased from 287,294 MW in the 2010 to 2011 planning period to 420,489 MW in the 2013 to 2014 planning period, an increase of 133,095 MW or 115.9 percent. The volume of cleared sell offers increased from 10,315 MW in the 2010 to 2011 planning period to 37,821 MW in the 2013 to 2014 planning period, an increase of 266.7 percent.

In June 2010, which includes the Annual, Long Term and monthly auctions, the bid volume was 3,894,566 MW, with a net bid volume of 3,177,131 MW. The net bid volume is the buy bid volume minus the sell bid volume. In June 2014, the bid volume was 9,600,316 MW (a 405.7 percent increase) and the net bid volume was 8,631,332 MW (a 368.1 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.90 in June 2014, indicating an increase in the ratio of sell offers to buy bids.

The monthly payout ratio reported by PJM is understated. The PJM reported monthly payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs on a monthly basis. PJM's reported monthly payout ratios are based on an estimate of the results for the entire year. The reported monthly payout ratio should be the actual monthly results including all revenue. The MMU recommends that the calculation of the monthly 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. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge. The FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the portfolio subsidy would be a good first step in that direction.

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

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

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

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

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR over allocation would increase the payout ratio to 94.6 percent.

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