Q3

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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PREFACE

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2010 Quarterly State of the Market Report for PJM: January through September*.

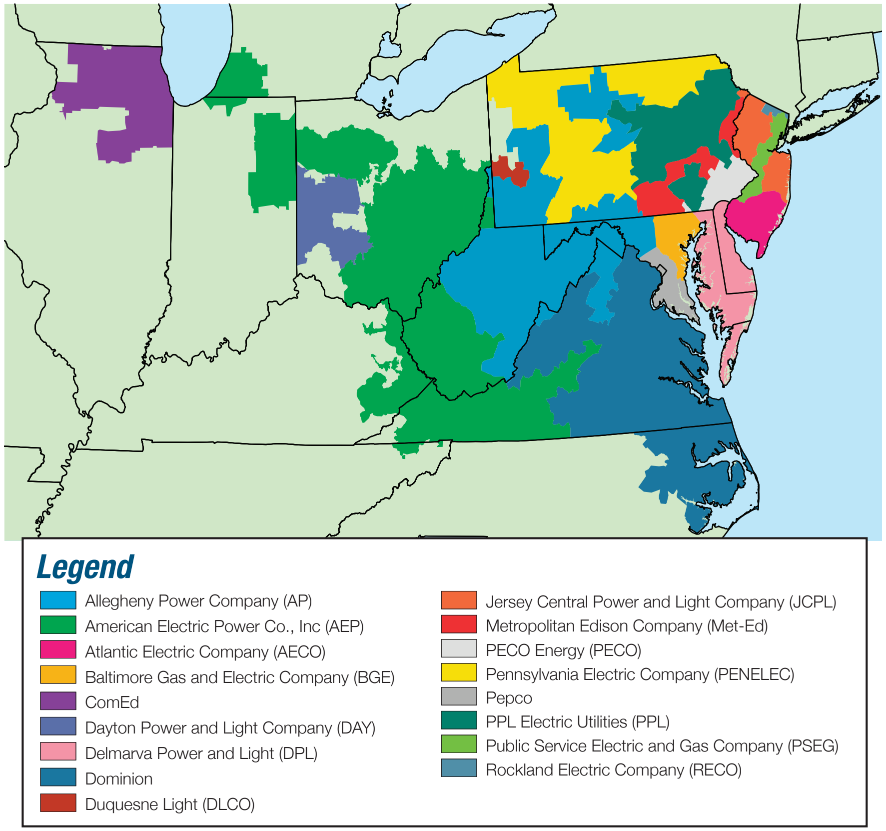
1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal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

2 OATT Attachment M § II(f).

SECTION 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2010, had installed generating capacity of 166,732 megawatts (MW) and more than 500 market buyers, sellers and traders of electricity in a region including more than 51 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. (See Figure 1-1.)[1] Through the first nine months of 2010, PJM had total billings of $26.25 billion. As part of that function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1-1 PJM's footprint and its 17 control zones (See 2009 SOM, Figure A-1)



1 See the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.

PJM Market Background

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 in mid-1999. 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.[2, 3]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine months of 2010, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the independent Market Monitoring Unit (MMU) for PJM.

The MMU introduces a more refined scale for evaluating each PJM market in this quarterly report. The market structure is evaluated, the participant behavior is evaluated and the market performance is evaluated. The outcome of each market, market performance, is evaluated as competitive or not competitive.

2 See also the *2009 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

3 Analysis of 2010 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. 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, see the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

In addition, the MMU introduces an evaluation of 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 assesses the effectiveness of the market design of each PJM market in providing market performance consistent with competitive results.

Market structure refers to the ownership structure of the market. The three pivotal supplier test is the most relevant measure of market structure because it accounts for both the ownership of assets and the relationship between ownership among multiple entities and the market demand and it does so using actual market conditions reflecting both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

Participant behavior refers to the actions of individual market participants. Unit mark up is an important measure of participant behavior. Unit mark up measures the relationship between the offer of a unit and the marginal cost of a unit. The higher the unit mark up, the less competitive the offer.

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. Mark up and net revenue are the most relevant measures of market performance. Mark up measures the relationship between the marginal costs of marginal units and the marginal offers of marginal units and therefore the market clearing prices in the market. The higher the performance mark up, the less competitive the market. Net revenue measures the revenues available from markets in excess of marginal costs, which are available to cover all other unit costs.

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, do 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 that in the first nine months of 2010:

Table 1-1 The Energy Market results were competitive

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

Table 1-2 The Capacity Market results were competitive

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

Table 1-3 The Regulation Market results were not competitive[4]

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

Table 1-4 The Synchronized Reserve Markets results were competitive

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

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

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

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

Table 1-6 The FTR Auction Markets results were competitive

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

Role of MMU in Market Design Recommendations

The PJM Market Monitoring Plan provides under the heading "Monitoring of PJM Market Rules, PJM Tariff and Market Design," in the section setting forth the MMU's function and responsibilities:

> PJM is responsible for proposing for approval by the Commission, consistent with tariff procedures and applicable law, changes to the PJM Market Rules, PJM Tariff and design of the PJM Markets. The Market Monitoring Unit shall evaluate and monitor existing and proposed PJM Market Rules, PJM Tariff provisions, and the design of the PJM Markets. However, if the Market Monitoring Unit detects a design flaw or other problem with the PJM Markets, the Market Monitoring Unit shall not effectuate its proposed market design since that is the responsibility of the Office of the Interconnection. The Market Monitoring Unit may initiate and propose, through the appropriate stakeholder processes, changes to the design of such markets, as well as changes to the PJM Market Rules and PJM Tariff. In support of this function, the Market Monitoring Unit may engage in discussions with stakeholders, State Commissions, PJM Management, or the PJM Board; participate in PJM stakeholder meetings or working groups regarding market design matters; publish proposals, reports or studies on such market design issues; and make filings with the Commission on market design issues. The Market Monitoring Unit may also recommend changes to the PJM Market Rules and PJM Tariff provisions to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[5]

In addition, the PJM Market Monitoring Plan provides, in describing MMU Reports: "In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview."[6]

Recommendations

The MMU recommends retention of key market rules, specific enhancements to those 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 *2010 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2009 State of the Market Report for PJM* and the *2010 Quarterly State of the Market Report for PJM: January through June* are still valid, and the MMU makes the following new recommendations.

- The MMU recommends that the December 1, 2008, modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic. The MMU also recommends that, to the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected. This change would maintain transparent incentives consistent with an effective market design. In the longer run, the proposed modifications to the pricing of regulation by both PJM and the MMU in their scarcity pricing recommendations will result in revenue increases that are expected to exceed any revenue loss from correcting the opportunity cost calculation.[7] The MMU recommends that when the scarcity related modifications are implemented, the margin be reduced to its current level.

- The MMU recommends that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion

5 PJM OATT Attachment M § IV.D.
6 PJM OATT Attachment M § VI.A.
7 *See, e.g.*, PJM compliance filing in Docket No. ER09-1063-004 (June 18, 2010); Protest and Compliance Proposal of the Independent Market Monitor for PJM, Docket No. ER09-1063-004, (July 19, 2010).

charges. The MMU recommends charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service.

- The MMU recommends limiting the use of not willing to pay congestion transactions to wheeling transactions only. It is not possible to control the flow of energy from an external interface to an internal bus within the PJM footprint. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows.

Highlights and New Analysis

The MMU has enhanced this *2010 Quarterly State of the Market Report for PJM: January through September* with the following new analysis since the prior quarterly report:

Section 1, "Introduction"

- Conclusions regarding the competitiveness of each market. (Pages 2, 3)
- New recommendations. (Pages 3, 4)

Section 2, "Energy Market, Part 1"

- Average offered supply increased slightly over Q2, and over Q3 in 2009. (Page 7)
- Peak and average load, and day-ahead and real-time prices increased over Q2, and over Q3 in 2009. (Page 8)
- New analysis: History of locational marginal prices (LMPs) comparing year to date prices to comparable period in prior year. (Table 2-59, Page 40)
- New analysis: Settled Demand-Side Response volume was approximately the same compared to the same period in 2009, while credits were significantly higher in 2010 due to higher price levels. (Page 10)
- New analysis: Preliminary review of Load Management emergency event compliance for the 2010 summer period. (Page 10)

Section 3, "Energy Market, Part 2"

- Net revenues increased from Q3 in 2009. (Page 73)
- Operating reserve charges increased from Q3 in 2009. (Page 74)
- New analysis: New entrant net revenue by market types for combustion turbine, combined cycle, and coal plant unit types, in Figures 3-1, 3-3, and 3-5. (Pages 83, 85, 86)

Section 4, "Interchange Transactions"

- Day-ahead and real-time net exports increased in Q3 over Q2, and over Q3 in 2009. (Page 109)
- New analysis: Summary of marginal loss surplus allocation analysis. (Page 114)
- Enhanced analysis of "not willing to pay congestion" transactions. (Page 115)

Section 5, "Capacity Markets"

- RTO capacity prices for cleared resources in the 2010/2011 RPM Base Residual Auction are increased from the 2009/2010 BRA, and prices for the 2010/2011 Third Incremental Auction are increased from the 2009/2010 Third Incremental Auction. (Table 5-10, Page 151)
- Forced Outage (EFORd) values decreased in Q3 from the corresponding values in Q3 2009. (Page 140)
- New analysis: The results of the RPM 2012/2013 First Incremental Auction are reported. (Page 139)

Section 6, "Ancillary Service Markets"

- Regulation prices increased from Q2 slightly, but remain lower than in 2009. (Page 163)
- Synchronized reserve prices were higher in Q3 than in Q2, and remain higher than in 2009. (Page 165)
- New analysis: History of PJM regulation and spinning market prices. (Table 6-8 and Table 6-13, Pages 170 and 176)

Section 7, "Congestion"

- Congestion costs in Q3 were higher than in Q2, and significantly higher than in Q3 2009. (Page 180)

- New analysis: Review of FERC decisions regarding restructuring responsibility for grid development. (Page 178)

Section 8, "Financial Transmission and Auction Revenue Rights"

- Prices in the Monthly Balance of Planning Period FTR Auctions were down from Q2, and were lower than in Q3 of 2009. (Page 228)

- New analysis: Summary of Tower litigation. (Page 228)

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, transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-7 provides the average price and total revenues paid, by component for calendar year 2009 and for January through September 2010.

Table 1-7 shows that Energy, Capacity and Transmission Service Charges represent the three largest components of the total price per MWh of wholesale power, contributing 96.7 percent of the total price per MWh for the January through September 2010 period. Of these components, the cost of energy was the most important, making up 73.6 percent of the total price per MWh for the January through September 2010 period, while the cost of capacity contributed 17.3 percent and the cost of transmission service contributed 5.8 percent of the total price per MWh for the January through September 2010 period.

The total per MWh price of wholesale power for the January through September 2010 period, $67.81, was 22.0 percent higher than total per MWh price of wholesale power for the 2009 calendar year, $55.58. This increase in the total per MWh price is largely attributable to the 27.8 percent increase in the price of energy.

The total per MWh price of Energy for the January through September 2010 period, $49.91, was 26.2 percent higher than for the comparable period in 2009, $39.57. The total per MWh price of Capacity for the January through September period, $11.71, was 29.9 percent higher than for the comparable period in 2009, $9.01. The total per MWh price of Transmission Service for the January through September period, $3.93, was 11.1 percent higher than for the comparable period in 2009, $3.54.

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 Load Weighted 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 in the first nine months of 2010.

- The Transmission Service Charge component is the average price per MWh of network integration charges and firm and non firm point to point transmission service.[8]

- The Operating Reserve (Uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[9]

- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[10]

- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[11]

- 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

8 PJM OATT §§ 13.7, 14.5, 27A & 34.
9 PJM Operating Agreement Schedules 1 §§ 3.2.3 & 3.3.3.
10 PJM OATT Schedule 2 and Operating Agreement Schedule 1 § 3.2.3B.
11 PJM Operating Agreement Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; PJM OATT Schedule 3.

through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAILCo and PATH projects.[12]

- 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.[13]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[14]
- The Black Start component is the average cost per MWh of black start service.[15]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[16]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[17]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[18]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[19]

Table 1-7 Total price per MWh by Category and Total Revenues by Category: January through December 2009 and January through September 2010 (See 2009 SOM, Table 1-1)

Category	Totals ($ Millions) Jan-Dec 2009	Totals ($ Millions) Jan-Sep 2010	Jan-Dec 2009 $/MWh	Jan-Sep 2010 $/MWh	Jan-Dec 2009 Percent	Jan-Sep 2010 Percent
Energy	$26,008.22	$26,508.11	$39.05	$49.91	70.2%	73.6%
Capacity	$7,162.71	$6,220.22	$10.75	$11.71	19.3%	17.3%
Transmission Service Charges	$2,664.73	$2,088.31	$4.00	$3.93	7.2%	5.8%
Operating Reserves (Uplift)	$324.15	$406.88	$0.49	$0.77	0.9%	1.1%
Regulation	$203.49	$199.13	$0.31	$0.37	0.5%	0.6%
PJM Administrative Fees	$242.32	$199.05	$0.36	$0.37	0.7%	0.6%
Reactive	$228.18	$189.47	$0.34	$0.36	0.6%	0.5%
Transmission Enhancement Cost Recovery	$63.21	$90.76	$0.09	$0.17	0.2%	0.3%
Transmssion Owner (Schedule 1A)	$56.47	$47.09	$0.08	$0.09	0.2%	0.1%
Synchronized Reserves	$34.27	$31.30	$0.05	$0.06	0.1%	0.1%
NERC/RFC	$8.86	$10.70	$0.01	$0.02	0.0%	0.0%
Black Start	$14.27	$8.40	$0.02	$0.02	0.0%	0.0%
RTO Startup and Expansion	$9.12	$6.84	$0.01	$0.01	0.0%	0.0%
Load Response	$1.62	$3.79	$0.00	$0.01	0.0%	0.0%
Transmission Facility Charges	$1.39	$1.02	$0.00	$0.00	0.0%	0.0%
Total	$37,023.01	$36,011.07	$55.58	$67.81	100.0%	100.0%

12 PJM OATT Schedule 12.
13 PJM OATT Schedule 1A.
14 PJM Operating Agreement Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
15 PJM OATT Schedule 6A.
16 PJM OATT Attachments H-13, H-14 and H-15 and Schedule 13.
17 PJM OATT Schedule 10-NERC and OATT Schedule 10-RFC.
18 PJM Operating Agreement Schedule 1 § 3.6.
19 PJM Operating Agreement Schedule 1 § 5.3b.