

2010 PJM Market Highlights:

A Summary of Trends and Insights

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PJM Interconnection



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Executive Summary

This paper offers six notable insights regarding of the state of PJM wholesale power markets.

Wholesale Power Costs, Inclusive of RPM, Have Returned to 2005 Levels Prior to RPM

In 2010, wholesale power costs -- including Energy Market, Capacity Market, Transmission and Ancillary Services costs -- were slightly below the 2005 costs in which there was little to no capacity market component. In 2010, energy accounted for 73 percent of wholesale market costs.

Energy Market Results Reflect Market Fundamentals and Competitive Behavior

The average load-weighted, real-time locational marginal price (LMP) was \$48.35 in 2010, increasing 23.8 percent over \$39.05 in 2009, but is still at the second lowest level since the last integrations took place in 2005. Prices continue to be driven by market fundamentals -- with changes in demand and fuel prices exerting the biggest impacts within the Energy Market. Prices continue to be set by generators offering at or near their marginal costs of production.

The RPM Capacity Market Provides Consistent Price Signals

Although the RPM market is providing sustained investment signals for new resources are in locations where they are needed most. Developers may be delaying or choosing not to build new generation due to uncertainty about the future. PJM and stakeholders will review ways to improve the RPM Capacity Market later in 2011.

PJM's Markets Appropriately Reflect the Cost of Environmental Regulations

PJM has identified almost 24,000 MW of coal-fired generation in need of significant environmental retrofits due to ongoing and prospective EPA rulemakings, of which approximately half are more than 40 years old and less than 400 MW in size. Retrofit costs are permitted in offers into the RPM Capacity Market, and consequently will likely impact RPM clearing prices which will provide go forward and retirement signals to affected generation.

PJM's Ancillary Service Markets are Competitive and Additional Refinements are Forthcoming

Ancillary Services in PJM account for only 1.25% of wholesale power costs, but only Regulation and Synchronized Reserve are market-based and account for about half of all ancillary service costs. The Regulation Market has experienced improved supply-demand balance, 25 percent lower marginal offers, and lower prices over the last two years. PJM anticipates further refinements to price formation to enhance transparency regarding real-time system conditions if FERC approves PJM's proposal in the shortage pricing proceeding.

FTR Revenue Inadequacy is a Result of Multiple Factors

The leading causes of Financial Transmission Rights (FTR) revenue inadequacy over the last two planning years are planned and unplanned transmission outages which account for almost 70 percent of the revenue inadequacy in total, while loop flows and constraints external to PJM account for the remaining 30 percent. PJM is working to make transparent to market participants the reasons for revenue inadequacy, and working toward resolving revenue inadequacy while balancing the need to ensure as many FTRs as possible are available as a congestion hedge.

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Introduction

This paper highlights key market trends that arose in 2010 and offers observations that should be useful in assessing the state of PJM's competitive wholesale markets, and the markets' ability to meet challenges such as integrating demand response or accommodating emissions reduction policies expected to result in the turnover in aging generation assets.

The key trends covered in this review include:

- The evolution of total wholesale power costs since 2005;
- The key factors influencing load-weighted average LMP in 2010;
- The consistency of new entry price signals from the combined Energy and RPM Capacity Markets since 2007;
- The role of the RPM in signaling the cost of widespread, anticipated environmental retrofits due to forthcoming EPA regulations;
- The competitiveness and efficiency of the Regulation and Synchronized Reserve Markets; and
- The revenue adequacy of Financial Transmission Rights (FTRs).

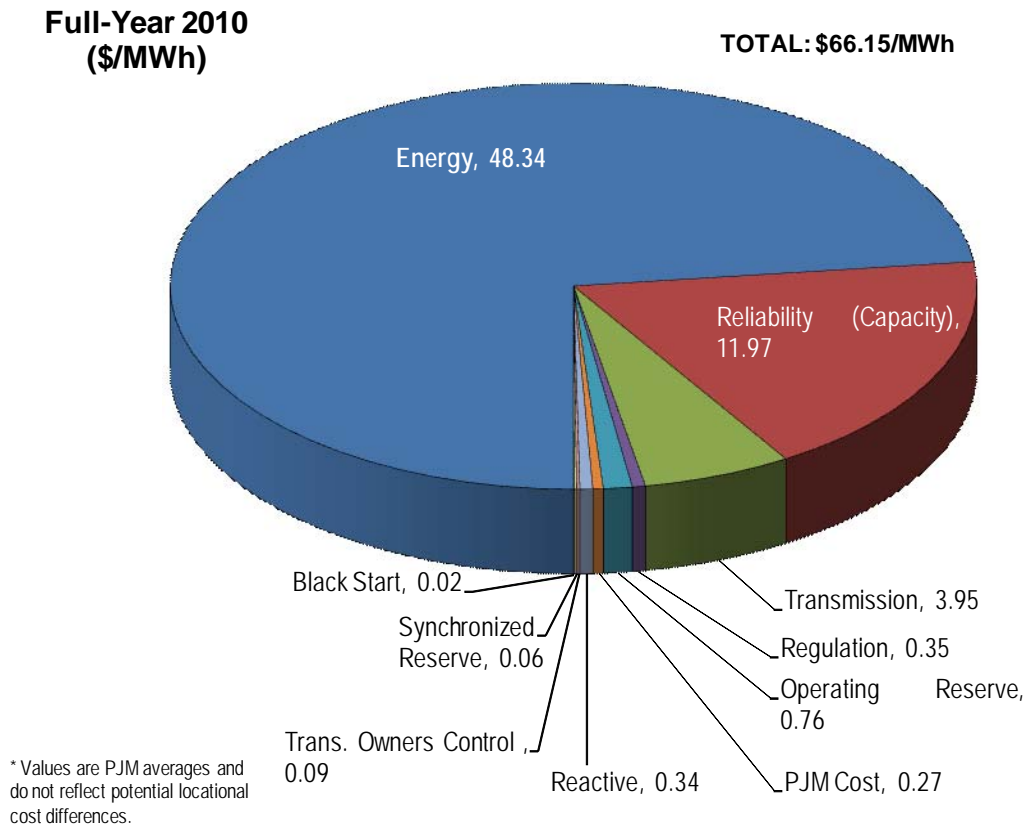
This report complements the information and analysis in the Independent Market Monitor's *State of the Market Report for PJM 2010*.¹ The insights on certain trends are meant to inform further and to emphasize areas that PJM views as significant. In addition, the Appendix includes PJM's responses to the specific recommendations offered in the *2010 State of the Market Report*.

These market trends and insights also serve as a detailed complement to the "Year in Review" session during PJM's Annual Meeting on Tuesday afternoon, May 17, 2011.

Wholesale Power Costs in 2010 are at 2005 Levels Reflecting Lower Fuel Costs

Wholesale power costs consist of PJM Energy Market, Capacity Market, Transmission and Ancillary Services, and other costs associated with PJM's operation of its competitive wholesale electricity markets. Wholesale power costs in PJM were \$66.15/MWh in 2010. The Energy Market, Capacity Market, Transmission and Ancillary Service costs accounted for 73 percent, 18 percent, 6 percent, and 1 percent of wholesale market costs respectively. The components of 2010 wholesale power costs are shown in Figure 1.²

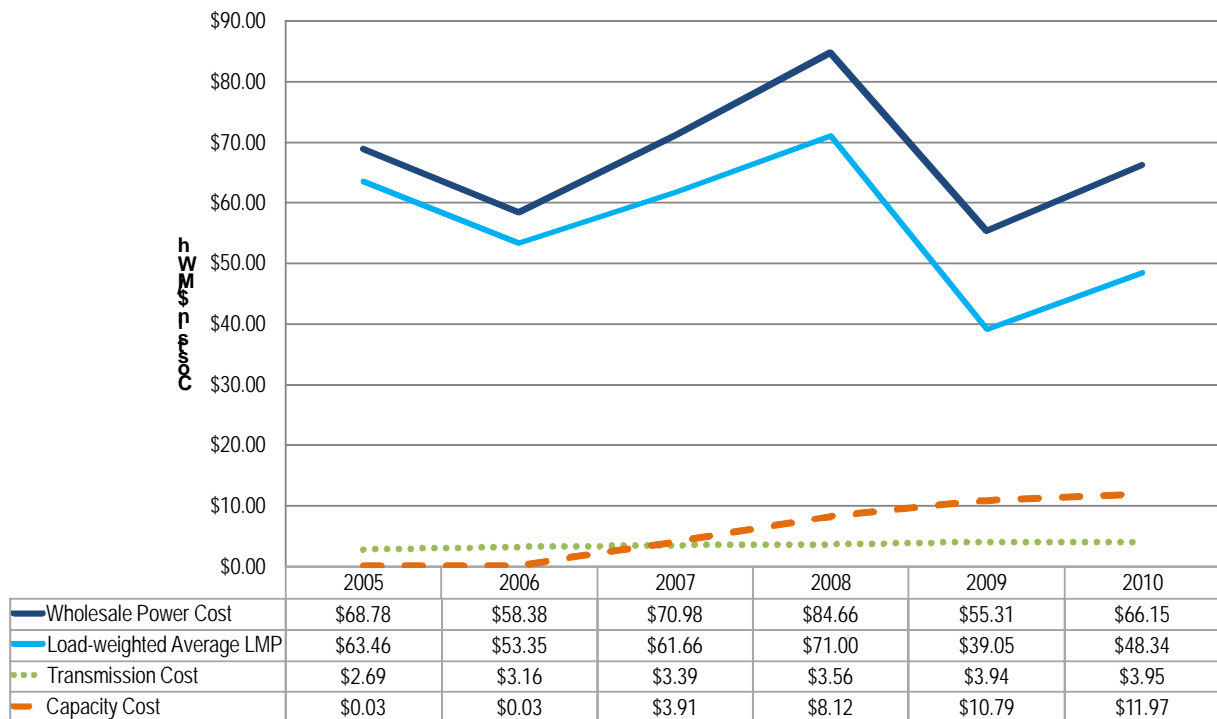
Figure 1: Components of PJM Total Wholesale Power Cost in 2010



2010 wholesale power costs of \$66.15/MWh are slightly below the 2005 costs of \$68.78/MWh. This observation is remarkable for two reasons: 1) in 2005 there was essentially no capacity market component to wholesale costs; and 2) electricity demand was higher in 2010 than in 2005 even in spite of the deep recession. While wholesale market costs were higher during the 2007-2008 period – leading up to and during the first part of the recent recession – the increase in wholesale power cost was due to increasing energy market prices driven by growing demand and increasing natural gas prices.

The five-year trend of total PJM wholesale power costs is shown in Figure 2.³

Figure 2: Evolution of Major Components of PJM Wholesale Power Costs 2005-2010



Notably, there are significant differences between 2005 and 2010. In the Energy Market, load-weighted average LMP is almost \$15/MWh lower largely due to lower natural gas prices. As fuel prices rose in 2007-2008, energy prices followed, and when fuel prices fell in 2009-2010, energy prices also declined. The effect of market fundamentals – fuel and demand – on PJM's Energy Market in 2010 are discussed in detail below.

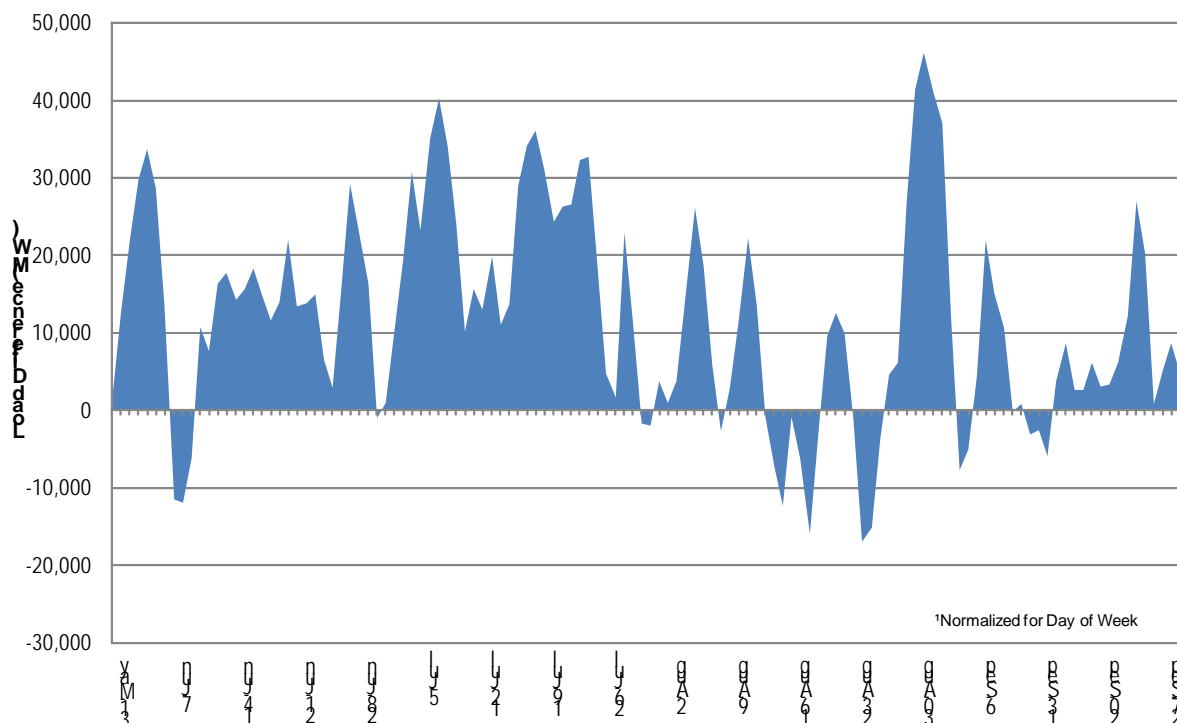
Higher Demand and Fuel Prices Drive Energy Market Results in 2010

The load-weighted average real-time locational marginal price (LMP) was \$48.35 in 2010, increasing 23.8 percent over \$39.05 in 2009.⁴ While this increase is large in percentage terms, this is the second lowest load-weighted average LMP since 2005.⁵ This result was driven by a 4.7 percent increase in average hourly load in 2010 along with slightly higher fuel prices exemplifying yet again the strong correlation between LMP and market fundamentals such as fuel prices and demand.⁶

Weather Drives Electricity Usage

The summer of 2010 was one of record heat. While no individual day marked a new electricity demand peak, the aggregate impact was significant. Records were set for overall energy usage in the PJM region during June and July. There were 38 days with Hot Weather Alerts issued in 2010 for some or all of the RTO, compared with 15 in 2009 and 16 in 2008.⁷ These weather conditions contributed to significantly higher loads in 2010. Figure 3 compares the year-over-year load levels during the summer.⁸ The blue areas above the horizontal axis show increased demand over the prior year's levels. Figure 3 clearly shows the number of days where the load was significantly above the prior year – in many cases tens of thousands of megawatts higher. For much of July alone the peak loads were 10,000 to 30,000 megawatts higher than in 2009. (One thousand megawatts is equivalent of the full output of a large nuclear power plant.)

Figure 3 - PJM Daily Peak Load Comparison: 2009 to 2010



Unusual Conditions in 2009

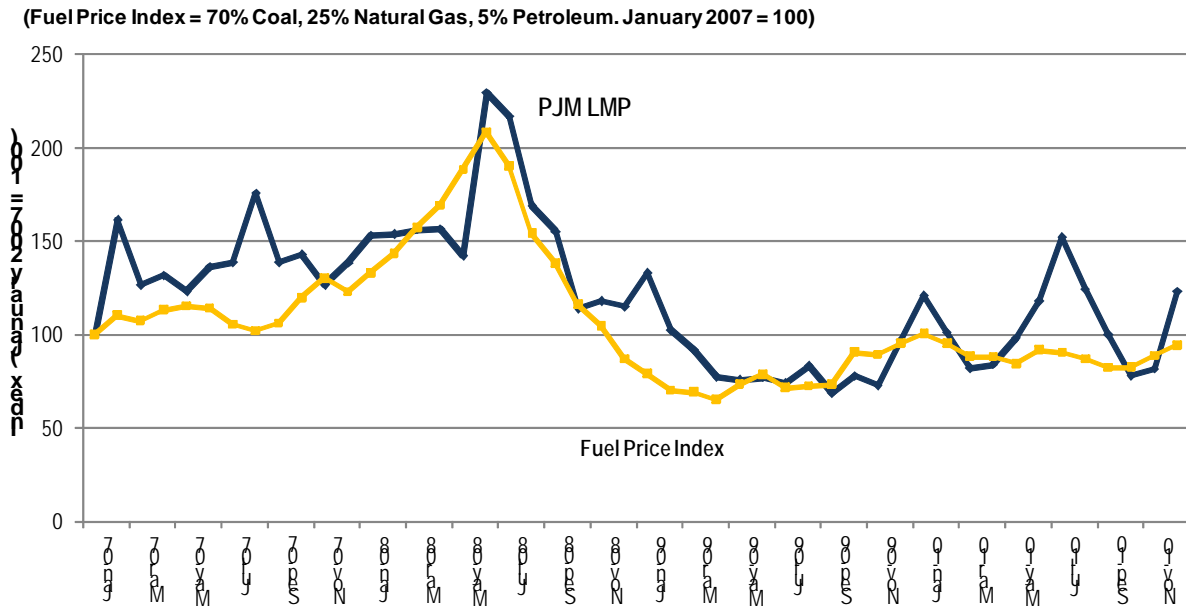
When viewed in isolation, the increases in prices and loads in 2010 compared to 2009 seem startling. However this comparison requires further context. While 2010 saw hot weather and higher demand as the economy was recovering from the recession, 2009 was much the opposite. Mild summer weather and the nascent recovery from the worst recession since the Great Depression combined to mute the demand for electricity. The summer of 2009 was particularly mild (as evidenced by the number of Hot Weather Alerts issued) and energy prices were at notable lows.

Thus, the sharp contrast between 2009 and 2010 is a comparison between extreme weather years, and should not be taken as indicative of an on-going trend.

Fuel Prices and Demand Drive LMP

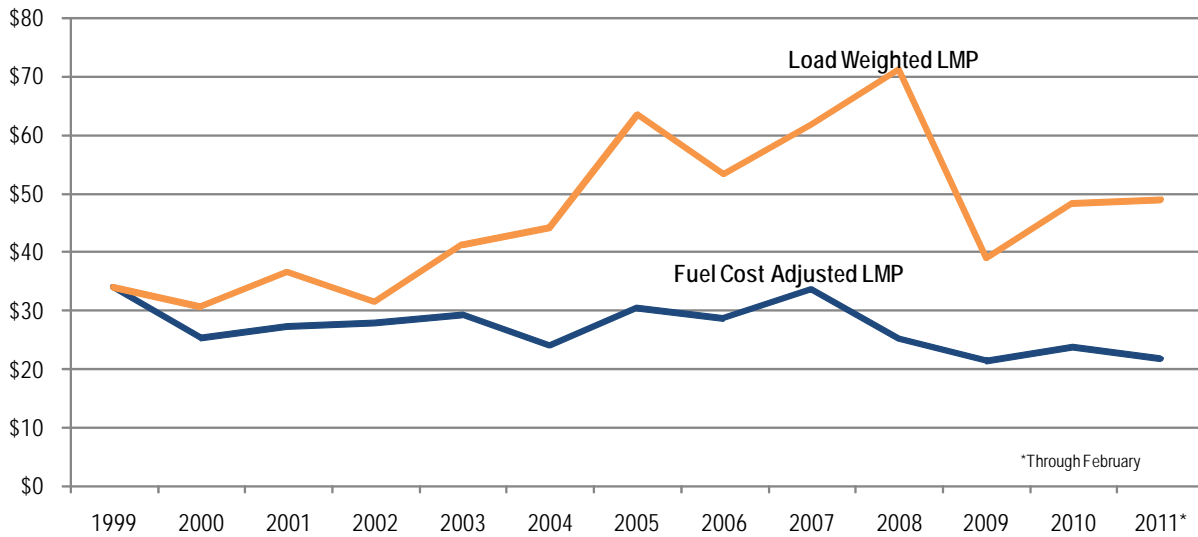
Fuel prices and demand are the primary drivers of electricity prices. Figure 4 below demonstrates the strong correlation between fuel prices and LMP. Some spikes in LMP, such as those during the summer peak months of 2010 and winter peaks such as those in January and February of 2009, demonstrate showing how demand influences prices. Fuel prices in 2010 were generally slightly higher for the marginal fuels in the PJM footprint. This rise in fuel prices has a corresponding impact on LMPs.

Figure 4 - PJM LMP vs. Fuel Price Index



In order to isolate the effect of fuel price changes from other changes in market conditions such as changes in demand, PJM computes a fuel-cost adjusted LMP. The fuel-cost adjusted LMP shown in Figure 5 is a measure of the what the load-weighted average LMP would have been in a given year, holding all other things constant, if fuel prices had been the same on average as they were in 1999.⁹ The fuel-cost adjusted LMP controls for the rise in fuel prices in 2010 and rises slightly to \$23.87, reflecting the increase in price due to increased demand.

Figure 5 - Fuel Cost Adjusted LMP



Competitive Bidding Behavior

The 2010 State of the Market Report illustrates the competitive bidding behavior in the Day-Ahead and Real-Time Energy Markets. In that report, the IMM notes the results of the PJM Energy Markets are competitive and that the offer price versus cost mark-up component of load weighted average LMP of 0.6 percent is strong evidence of competitive behavior.¹⁰ Moreover, the 2010 State of the Market Report shows that the mark-up component of LMP is negative on average at LMP below \$60/MWh (which encompass over 84 percent of all hours in 2010).¹¹

PJM staff has further examined the bidding behavior of coal and natural gas units, regardless of whether they were on the margin or not, to discern how much these units are bidding above or below their allowed cost-based offer. Figure 6 shows the average mark-up of energy supply offers over the maximum allowed cost-based offer.¹²

Figure 6 - Capacity Weighted Markup Index – Calendar Year 2010

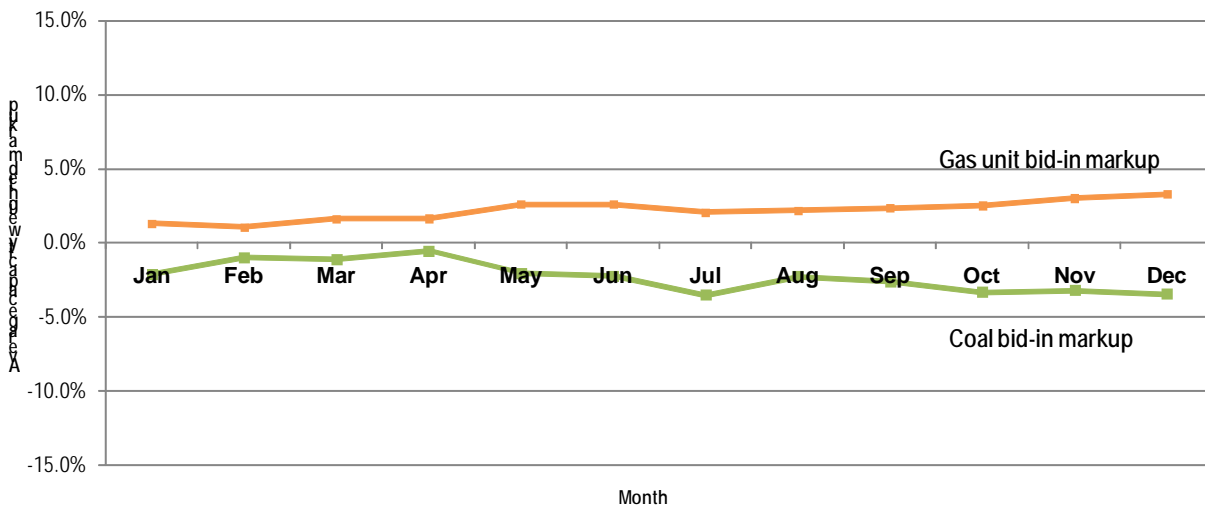


Figure 6 shows that coal units, on a consistent basis, were on average offering just below their allowed cost-based offers. This finding is consistent with the mark-up component of LMP being negative for LMP less than \$60/MWh as in these

hours coal units are most likely to be on the margin and setting price.¹³ Gas units on average are offering at just over their marginal costs. The positive mark-up on average could be attributed to cost-based offers, not including opportunity costs related to run-time restrictions due to hard caps on emissions, starts, or heat input dictated by applicable regulatory rules or restrictions of operating permits. In both cases the overall mark-up bidding behavior of coal and gas units is in a tight band of +/- 0.04, providing strong evidence of marginal cost bidding behavior on the part of all coal and natural gas units, not just those on the margin, further demonstrating that PJM's Energy Markets are highly competitive.

Trends in New Entry Revenue Adequacy: RPM Capacity and Energy Markets

The Reliability Pricing Model (RPM) Capacity Market only accounts for 18 percent of the total cost of wholesale power in PJM, yet it plays a crucial role in helping maintain resource adequacy and reliability. The purpose of the RPM Capacity Market is to ensure on a yearly basis, three years into the future, that resource adequacy requirements can be achieved at the lowest possible cost. The least-cost set of resources could come from the retention of existing resources, entry of demand-side resources or energy efficiency, or the entry of new generation.

The RPM Capacity Market is a necessary component of the overall PJM Market design as revenues from the Energy Market alone are not sufficient to allow all resources necessary to achieve resource adequacy requirements, maintain reliability, and to cover their fixed, going forward costs inclusive of any investment costs. Resource adequacy requirements dictate that PJM strive to maintain sufficient capacity to meet system peak load plus an installed reserve margin.

The competition created in the PJM Energy Market by excess capacity resources and the \$1,000/MWh offer cap have the implication that resources that run only at system peaks will be unable to earn sufficient net energy market revenues to cover their fixed, going forward costs. The only way in which the PJM Energy Market would provide sufficient revenues would be to relax the resource adequacy requirement and allow energy prices to rise sufficiently during system peaks to allow resources the opportunity to earn sufficient revenues to cover their fixed, going forward cost. However the consequence of such a market design choice would be a reduction in the standard of reliability that consumers have enjoyed over time and come to expect going forward.

The RPM Capacity Market works in tandem with the Energy Market to provide price and revenue signals regarding the ability to retain existing capacity, the need for new capacity, and the desired location of retained or new capacity resources. LMP in the Energy Market provide immediate signals to market participants regarding transmission constraints and the need for generation resources to increase or decrease output, or loads to increase or decrease consumption in real-time operation. However the signals provided by RPM Capacity Market and its interaction with the Energy Market are longer term signals that appear over a period of years to signal the need to retain existing capacity resources or for the entry of new capacity resources by location. The need for new entry generation is signaled when over a period of consecutive years, a new entry generation resource would have been able cover its levelized investment costs plus a desired return on that investment. Developers of new generation resources can calculate their estimated return using historical results from the Energy and RPM Capacity Markets. If the revenue is less than this amount, this signals that it is less expensive to retain existing generation resources or to rely on lower cost demand or energy efficiency resources.

The results of the RPM Capacity Market are competitive.¹⁴ This indicates that the appropriate price signals indicating the need for new entry by location is a product of the fundamental supply-demand balance in each Locational Deliverability Area (LDA) and the actual underlying net costs of that new entry. When combined with the competitive results of PJM's Energy Market, these signals are the result of market fundamentals regarding the demand for capacity and its underlying net cost, inclusive of net energy market revenues, in a competitive environment. This should result in the least-cost set of resources providing the combination of capacity and energy services to participants in PJM's Markets.

The next section explains how the RPM Capacity Market along with the Energy Market has generally provided consistent price signals regarding the financial incentive and the need for new generation resources in the eastern portion of PJM, where new entry is most needed for future growth and to help reduce congestion associated with the predominant west-to-east flows of power in PJM.¹⁵

Natural Gas Technologies Received Signals to Enter where Needed in 2010

Without the prospect of revenues from the RPM Capacity Market, new generation would have little or no incentive to enter PJM's markets based on Energy Market revenues alone. According to the analysis of the IMM, a new entry natural gas combined cycle unit entering commercial operation in 2010 would have earned sufficient revenues in the RPM Capacity and Energy Markets in 2010 to have covered its 20-year annualized, levelized cost inclusive of a 12 percent return on equity in four zones: Pepco and BGE in the SWMAAC LDA, and AECO and DPL in the EMAAC LDA.¹⁶ Similarly, a new entry natural gas combustion turbine would have earned sufficient revenues in the RPM Capacity and Energy Markets in 2010 to have covered its 20-year annualized, levelized cost inclusive of a 12 percent return on equity in two zones: Pepco and BGE in SWMAAC.¹⁷ These zones are all on the eastern side of west-to-east flows and congestion – and thus generally experience higher energy and capacity prices.

New Entry Price Signals in the East are Consistent over Multiple Years

Investment decisions on new capacity are not made based only on one year's market results, but on the overall stream of revenues relative to costs over many years. With the implementation of RPM beginning in 2007, one of the key results of the transition auctions has been a history of prices and revenues so that existing resources and potential new entrants have a solid historical foundation upon which investment decisions could be made.

Cost of New Entry

During the 2007-2010 period, the cost of new entry for natural gas combined cycle and combustion turbine generation has increased, but the cost of new entry for potential entrants is somewhat sensitive to their hurdle rate of return on the equity investment they are putting into the new generation facility.

Tables 1 and 2 provide the history of the cost of new entry for combined cycle and combustion turbines respectively as reported in past *State of the Market Reports* for various returns on equity.¹⁸ The reason for thinking about the cost of new entry based on returns on equity is that each individual investor in new generation may have different hurdle rates based on their own unique circumstances and tolerance for risk. These hurdle rates will be relevant in the discussion below.

Table 1: Cost of New Entry for Natural Gas Combined Cycle Facilities by Year and Equity Hurdle Rate

Hurdle Rate Return on Equity	2007	2008	2009	2010
12%	\$143,600	\$171,361	\$173,174	\$175,250
10%	\$133,600	\$158,861	\$160,674	\$162,750
8%	\$123,600	\$146,361	\$148,174	\$150,250

Table 2: Cost of New Entry for Natural Gas Combustion Turbines Facilities by Year and Equity Hurdle Rate

Hurdle Rate Return on Equity	2007	2008	2009	2010
12%	\$90,656	\$123,640	\$128,705	\$131,044
10%	\$84,406	\$114,840	\$119,905	\$122,244
8%	\$78,156	\$106,040	\$111,105	\$113,444

Net Energy Market Revenues Alone over Time are Insufficient to Cover the Cost of New Entry

Consider the decision to build a new combined cycle gas facility or new combustion turbine that would have commenced commercial operation on January 1, 2007 – the first year in which RPM Capacity Market revenues were available. Potential new generation entrants would want to know if it would have made the target hurdle rate of return on equity had such an investment decision had been made. The same is true for an investment decision that went into commercial operation on January 1, 2008 or January 1, 2009. In order to gauge the appropriateness of RPM Capacity Market revenues, it is first instructive to understand whether or not new entry would have been financially viable based on energy market revenues alone.

Table 3 provides the average of the net energy market revenues alone averaged over the 2007-2010, 2008-2010, and 2009-2010 periods as taken from the *2010 State of the Market Report* and adjusted for known commitment and dispatch patterns between Day-Ahead and Real-Time Energy Markets for new entry natural gas combined cycle by zone.¹⁹

In general, it would be expected that most combined cycle units would be committed in the Day-Ahead Energy Market rather than being dispatched in real-time in most instances so that the Day-Ahead Energy Market net revenues may be a more indicative of the need for capacity market revenues.

PJM staff has recently analyzed a simple model of commitment and dispatch patterns of combined cycle units to examine how much revenue would be earned day ahead versus real time. PJM has found net energy revenues to be approximately a combination of 20 to 40 percent real-time net revenues and 60 to 80 percent day-ahead net revenues depending on transmission zone. To reflect this result, Table 3 presents Day-Ahead Energy net revenues alone net revenues based on 25 percent from the Real-Time Energy Market with the remaining 75 percent from the Day-Ahead Energy Market.

Table 3 shows very clearly energy market revenues alone are not sufficient to incent the entry of new combined cycle gas units and that another source of revenues is needed provide incentives for new entry.

Table 3: Natural Gas Combined Cycle Day-Ahead and Real-Time Net Energy Market Revenues

Zone	Day-Ahead Net Energy Revenues			75 % Day-Ahead/25% Real-Time Net Energy Market Revenues		
	2007-2010	2008-2010	2009-2010	2007-2010	2008-2010	2009-2010
AECO	\$86,760	\$87,765	\$73,661	\$91,251	\$91,787	\$74,930
AEP	\$25,617	\$27,651	\$31,407	\$27,252	\$28,958	\$32,235
AP	\$55,705	\$59,313	\$63,527	\$58,813	\$61,740	\$64,919
BGE	\$95,419	\$95,877	\$84,463	\$99,462	\$98,144	\$85,996
ComEd	\$25,316	\$21,977	\$20,884	\$26,837	\$23,425	\$22,231
DAY	\$24,516	\$26,350	\$29,952	\$26,431	\$27,986	\$31,079
DLCO	\$24,338	\$26,511	\$31,964	\$42,998	\$43,626	\$44,171
Dominion	\$74,160	\$72,106	\$57,529	\$64,068	\$62,632	\$52,373
DPL	\$80,598	\$82,621	\$73,302	\$83,962	\$85,068	\$74,988
JCPL	\$85,440	\$85,470	\$72,052	\$88,453	\$87,545	\$73,360
Met-Ed	\$72,782	\$71,901	\$65,663	\$76,272	\$74,269	\$67,357
PECO	\$72,859	\$73,734	\$67,764	\$75,584	\$75,738	\$68,645
PENELEC	\$45,629	\$49,172	\$53,907	\$46,889	\$49,494	\$53,731
Pepco	\$109,558	\$112,950	\$102,812	\$112,834	\$114,492	\$103,679
PPL	\$65,520	\$65,825	\$59,982	\$68,585	\$68,133	\$61,603
PSEG	\$82,691	\$81,013	\$68,292	\$85,395	\$83,121	\$69,815
RECO	\$76,451	\$73,585	\$62,069	\$79,015	\$75,495	\$63,427

Table 4 provides information similar to Table 3 but for a new entry natural gas combustion turbine and for Day-Ahead and Real-Time Energy markets in isolation.²⁰

In general, combustion turbines are not committed in the Day-Ahead Energy Market, and so the relevant net energy market revenues would likely come from the Real-Time Energy Market. Table 4 shows that if a new entry decision had been made so that commercial operation began in 2007, no new entry combustion turbines would have been able to achieve hurdle rates of return of at least 8 percent. As was the case for combined cycle units, energy revenues alone are insufficient to attract new entry combustion turbines. Thus, other sources of revenue would be needed to provide the consistent new entry price signal in the eastern part of PJM for combustion turbines.

Table 4: Natural Gas Combustion Turbine Day-Ahead and Real-Time Net Energy Market Revenues

Zone	Day-Ahead Net Energy Revenues			Real-Time Net Energy Market Revenues		
	2007-2010	2008-2010	2009-2010	2007-2010	2008-2010	2009-2010
AECO	\$20,610	\$20,597	\$17,895	\$41,730	\$41,645	\$29,945
AEP	\$2,948	\$3,174	\$3,848	\$6,138	\$6,198	\$7,068
AP	\$10,183	\$11,162	\$13,384	\$20,211	\$21,039	\$22,708
BGE	\$23,685	\$24,612	\$23,283	\$45,133	\$41,307	\$38,198
ComEd	\$3,054	\$2,608	\$2,921	\$6,298	\$5,307	\$5,518
DAY	\$2,698	\$2,930	\$3,581	\$5,942	\$5,998	\$6,661
DLCO	\$19,088	\$20,425	\$19,347	\$9,836	\$9,846	\$10,896
Dominion	\$3,118	\$3,551	\$4,613	\$37,594	\$35,575	\$31,630
DPL	\$16,659	\$18,066	\$17,523	\$32,593	\$32,073	\$30,399
JCPL	\$15,468	\$15,264	\$15,815	\$32,249	\$30,387	\$27,997
Met-Ed	\$14,672	\$14,709	\$15,818	\$29,174	\$26,767	\$27,402
PECO	\$13,725	\$14,524	\$15,442	\$26,729	\$26,118	\$25,637
PENELEC	\$6,834	\$7,867	\$9,533	\$11,255	\$11,355	\$14,056
Pepco	\$30,522	\$33,020	\$33,191	\$51,844	\$49,520	\$46,862
PPL	\$11,583	\$12,248	\$13,197	\$23,585	\$22,955	\$23,668
PSEG	\$13,833	\$14,205	\$14,465	\$28,119	\$26,690	\$25,631
RECO	\$12,214	\$12,381	\$12,850	\$25,318	\$22,993	\$22,506

RPM and Net Energy Market Revenues Provide Consistent New Entry Signals Over Time

On average over the 2007-2010 period, a new entry combined cycle gas facility would have earned a stream of Energy Market revenues from the Day-Ahead Energy Market plus capacity market revenues sufficient to cover costs plus at least a 10 percent return on equity in two zones (BGE and Pepco in SWMAAC). This is noted in Table 5 in the green and yellow shaded entries indicating returns of 12 and 10 percent respectively.²¹ New entry in the EMAAC zones of AECO, JCPL, DPL, and PSEG in 2007 and 2008 would have yielded returns of at least 8 percent as indicated by the orange shading. The new entry signal remains consistent in BGE and Pepco for Day-Ahead Energy plus RPM revenues whether new entry would have taken place in 2007, 2008 or 2009 providing a strong indication that RPM together with the Energy Market is working to provide consistent price signals for new entry where it is needed most from a reliability perspective, and under the most conservative of assumptions regarding energy market revenues.

If energy revenues are split 75 percent in day ahead and 25 percent in real time as shown in Table 5, the persistence of the price signal regarding new entry is stronger across EMAAC and SWMAAC, but still begins to diminish somewhat in the 2009-2010 period as the cost of new entry have increased while net energy revenues declined due to lower gas prices and lower demand in 2009. In particular, new entry appears attractive at returns on equity greater than 8 percent in AECO, DPL, JCPL, PSEG and PECO in EMAAC.

Table 5: Natural Gas Combined Cycle Day-Ahead and Real-Time Net Energy Market Revenues plus Capacity Market Revenues

Zone	Day-Ahead Net Revenues			75 % Day-Ahead / 25% Real-Time Net Revenues		
	2007-2010	2008-2010	2009-2010	2007-2010	2008-2010	2009-2010
AECO	\$145,207	\$151,594	\$138,460	\$149,699	\$155,616	\$139,729
AEP	\$58,199	\$68,182	\$77,128	\$59,833	\$69,489	\$77,956
AP	\$96,433	\$110,706	\$125,541	\$99,541	\$113,134	\$126,933
BGE	\$162,824	\$172,301	\$162,288	\$166,867	\$174,568	\$163,821
ComEd	\$57,897	\$62,508	\$66,605	\$59,418	\$63,956	\$67,952
DAY	\$57,098	\$66,882	\$75,673	\$59,012	\$68,517	\$76,800
DLCO	\$106,741	\$112,638	\$103,250	\$96,650	\$103,163	\$98,094
Dominion	\$56,919	\$67,042	\$77,685	\$75,579	\$84,157	\$89,892
DPL	\$139,274	\$146,756	\$138,559	\$142,638	\$149,202	\$140,245
JCPL	\$143,887	\$149,299	\$136,851	\$146,900	\$151,374	\$138,159
Met-Ed	\$113,510	\$123,295	\$127,677	\$117,000	\$125,663	\$129,371
PECO	\$131,306	\$137,563	\$132,563	\$134,032	\$139,567	\$133,444
PENELEC	\$86,357	\$100,565	\$115,922	\$87,617	\$100,887	\$115,746
Pepco	\$176,963	\$189,374	\$180,637	\$180,239	\$190,916	\$181,504
PPL	\$106,248	\$117,219	\$121,997	\$109,313	\$119,527	\$123,618
PSEG	\$141,138	\$144,842	\$133,091	\$143,842	\$146,950	\$134,614
RECO	\$134,898	\$137,414	\$126,868	\$137,462	\$139,324	\$128,226

Table 6 shows new entry combustion turbine revenues from the Real-Time Energy Market plus the RPM Capacity market would have covered costs plus an 8 percent return on a consistent basis in the BGE and Pepco Zones in SWMAAC.²² The new entry signal remains consistent whether new entry took place in 2007, 2008, or 2009 providing a strong indication that RPM together with the Energy Market is working to provide consistent price signals for new entry of combustion turbines where they are needed most from a reliability perspective. Table 6 also shows that Capacity Market revenues plus either Day-Ahead revenue would be insufficient to incent new entry combustion turbines on a consistent basis.

Table 6: Natural Gas Combustion Turbine Day-Ahead and Real-Time Net Energy and Capacity Market Revenues

Zone	Day-Ahead Net Revenues			Real-Time Net Revenues		
	2007-2010	2008-2010	2009-2010	2007-2010	2008-2010	2009-2010
AECO	\$79,057	\$84,426	\$82,694	\$100,177	\$105,474	\$94,744
AEP	\$35,529	\$43,706	\$49,569	\$38,719	\$46,729	\$52,789
AP	\$50,911	\$62,556	\$75,399	\$60,939	\$72,433	\$84,723
BGE	\$91,090	\$101,036	\$101,108	\$112,538	\$117,731	\$116,023
ComEd	\$35,636	\$43,140	\$48,642	\$38,879	\$45,838	\$51,239
DAY	\$35,279	\$43,461	\$49,302	\$38,524	\$46,529	\$52,382
DLCO	\$51,670	\$60,956	\$65,068	\$42,417	\$50,377	\$56,617
Dominion	\$35,699	\$44,083	\$50,334	\$70,176	\$76,106	\$77,351
DPL	\$75,335	\$82,200	\$82,780	\$91,269	\$96,208	\$95,656
JCPL	\$73,915	\$79,093	\$80,614	\$90,696	\$94,216	\$92,796
Met-Ed	\$55,400	\$66,103	\$77,833	\$69,902	\$78,161	\$89,417
PECO	\$72,172	\$78,353	\$80,241	\$85,176	\$89,947	\$90,436
PENELEC	\$47,562	\$59,261	\$71,548	\$51,983	\$62,748	\$76,070
Pepco	\$97,927	\$109,444	\$111,016	\$119,249	\$125,944	\$124,687
PPL	\$52,311	\$63,642	\$75,211	\$64,313	\$74,349	\$85,682
PSEG	\$72,280	\$78,034	\$79,264	\$86,566	\$90,519	\$90,430
RECO	\$70,661	\$76,210	\$77,649	\$83,765	\$86,822	\$87,305

RPM and Energy Price Signals have Attracted New, and Retained Existing Capacity Resources

At the time of the RPM Base Residual Auctions for delivery years through 2010, it was a period of transition and market participants did not have the benefit of matching RPM revenues with Energy Market revenues to reasonably make new entry decisions for combined cycle units or combustion turbines in 2007, 2008, or 2009. The value of these price signals show themselves in how many resources have been retained or attracted to the PJM markets for future delivery years and the consistency of these price signals should trigger increased resources brought into PJM.

Through the 2013/2014 delivery year, over 33,000 MW of additional capacity resources have been made available to PJM since the inception of RPM as shown in Table 7.²³ Notably, new generation makes up approximately 20 percent of the total with new combined cycle units accounting for 2,425 MW and new combustion turbines accounting for 1,832 MW.

Table 7: Change in Capacity Available to PJM

Change in Capacity Availability	Installed Capacity MW
New Generation	6,376.8
Generation Upgrades (not including reactivations)	4,675.5
Generation Reactivation	529.7
Forward Demand and Energy Efficiency Resources	13,699.9
Cleared ICAP from Withdrawn or Canceled Retirements	3,050.9
Net increase in Capacity Imports	4,757.6
Total Impact on Capacity Availability in 2013/2014 Delivery Year	33,090.4

Other Considerations Affecting New Entry Decisions

Strong historic signals regarding the financial viability of new entry combined cycle and combustion turbines are an essential, but not the only, criteria for making new entry decisions. Potential new entrants also consider: 1) Expectations about the future that may not match with the historic price signals presented; and 2) Uncertainty regarding the future operating environment.

Future expectations that are separate from historic market performance influence investment decisions as much as signals provided by historic performance. For example, the strong, historic new entry price signals that have been observed in the eastern part of PJM do not factor in approved transmission upgrades that are scheduled to go into service beyond 2010. Upgrades such as the TrAIL project will increase transmission capacity in moving power from west to east and thereby reduce congestion and therefore have an impact on future energy prices in the eastern part of PJM. Add other previously RTEP approved projects such as the Susquehanna-Roseland, PATH and MAPP lines, and it is easy to imagine that expectations regarding future energy and capacity revenues would differ from historic market performance.²⁴

Expectations regarding fuel prices also play a considerable role in the new entry decision. If potential entrants believe the price spread between coal and natural gas would remain large, as has been the case historically, then new entry gas technologies may not appear as attractive. Conversely, if potential new entrants believe the recent narrowing of the coal and natural gas price spreads is a long-term trend supported by ever increasing Marcellus Shale gas production, then new entry likely appears more attractive.

Uncertainty also plays a role in the new entry decision for generation. Increasing uncertainty about future operating conditions, such as delays or postponements of previously approved RTEP upgrades, future load growth, or stringency of environmental rules can cause the delay of new investment. In an uncertain future operating environment, delaying a new investment decision is valuable in that the delay allows time for more information to be revealed about the potential profitability of the new generation resource. However, the resolution of uncertainty, such as the recent proposed EPA rules for fossil-fired generation or the announced work schedule on the Mt. Storm-Doubs 500 kV transmission circuit, provides valuable information to potential entrants making the new entry decision less risky as more information is known about future operating conditions and by extension expected profitability.

PJM has retained the Brattle Group to perform an assessment of the RPM Capacity Market, and the examination of the role of future expectations and uncertainty touches almost every issue related to the RPM Capacity Market design.

RPM Design Can Accommodate Retrofit Costs Related to Forthcoming EPA Rules to Ensure Resource Adequacy

The United States Environmental Protection Agency (EPA) has in the last year issued proposed regulations that if finalized, would require the owners of certain generation resources to make capital investments in air pollution control technologies to comply with the proposed regulations and continue operating the resources into the future. These rules include the Clean Air Transport Rule (CATR) issued on July 26, 2010²⁵ and the National Emission Standards for Hazardous Air Pollutants Rule (NESHAP or HAP MACT) issued on March 16, 2011.²⁶ These proposed rules affect primarily coal-fired generation, although other fossil units may be impacted to some degree.

Specifically, the proposed CATR and NESHAP rules indicate the need for coal-fired generation to install sulfur dioxide (SO₂), mercury (Hg), particulate control, and possibly nitrogen oxide (NO_x) control technologies if they have not already done so in response to compliance obligations under previous EPA rules (e.g. Clean Air Interstate Rule) or state environmental rules and laws (e.g. Maryland Healthy Air Act).

Pollution Control Costs can be Included in RPM Offers and Affect the Clearing Price

Capital investment cost associated with pollution control retrofits are easily accommodated into the RPM Capacity Market framework through the Allowance for Project Investment Recovery (APIR) that is a part of the Avoidable Cost Rate (ACR) that goes into determining Market Seller Offer Caps.²⁷ Given the mandatory nature of the NESHAP rule, generating units that must install emission control technologies may chose to include such costs under the Mandatory CapEx Option which expresses the cost of the retrofits in terms of a 4 year recovery period, or units may elect to express these costs under the next highest option for units 25 years and older which allows for the costs to be expressed under a 5 year recovery period.²⁸

The RPM Market Seller Offer Cap then becomes the cost of continuing to operate in the delivery year -- defined as the APIR (inclusive of emission control retrofit costs plus other avoidable costs less) the Expected Net Energy and Ancillary Service Market Revenues (which are based on the previous three calendar years of net revenues).

However, given the long life of emissions control retrofits, it would not be surprising to see RPM offers come in at some level below the calculated offer cap, effectively expressing retrofit costs over a longer time horizon. If the affected units are needed to maintain resource adequacy, then the RPM clearing price will reflect the cost of these emission control retrofits. On the other hand, if it is more cost-effective for demand response or new entry generation to maintain resource adequacy, then affected resources will not clear but the cost of environmental retrofits will still have an indirect effect on RPM clearing prices.

How Much Generation Capacity Requires Pollution Control Retrofits?

The precise number of megawatts requiring emission control retrofits is difficult to identify because CATR is a limited cap and trade rule with some flexibility and the NESHAP rule mandates emission rate standards for acid gases, mercury, and non mercury heavy metals that can potentially be met by different combinations of emissions control technologies. What does seem clear is that some sort of SO₂ and particulate technology would be required to comply with the NESHAP rule that will also provide co-benefits toward meeting the requirements under CATR.

The IMM in the *2010 SoM Report* identifies 14,388 MW of coal-fired capacity without any SO₂ and NO_x control technologies installed.²⁹ Table 8 provides a breakdown of units that PJM has determined do not have any SO₂ controls and do not have a fabric filter baghouse for particulate control according to publicly available EPA and EIA data.³⁰

These are the major kind of controls that would be expected to be installed in response to the NESHAP rule. There are just under 24,000 MW of capacity that do not have these controls, of which only 3,850 MW is in MAAC region in eastern PJM.

PJM has also broken this down by age, size and location. PJM expects older and smaller units would likely have greater costs per unit of capacity for emissions control retrofits and consequently would require higher RPM or Energy Market revenues to continue operating into the future. Additionally, uncontrolled units in the MAAC region may have a greater impact on transmission reliability and congestion than in the rest of the RTO.

Table 8: MW of Capacity without SO₂ Controls and Fabric Filter Baghouse by Age, Size, and Location

	MAAC	Non-MAAC PJM	PJM RTO
Total Coal	3,856	20,006	23,862
Coal > 40 years	3,292	14,438	17,730
Coal < 400 MW	2,192	9,899	12,091
Coal > 40 years, < 400 MW	2,058	9,899	11,957

PJM has also done an analysis of the heat rates and capacity factors from publicly available EIA and EPA data, shown in Table 9.

Table 9: Characteristics of Coal-fired Capacity by Age and Size

Characteristic	2009 Capacity Factor	2009 Gross Heat rate (btu/kWh)
Coal ≤ 40 years	49.25%	9,783
Coal > 40 years	42.4%	10,109
Coal < 400 MW	33.2%	10,367
Coal ≥ 400 MW	69.7%	9,387

Table 9 clearly shows that unit size matters much more than unit age. Units less than 400 MW are more inefficient and run less than half as much as units larger than 400 MW. Based on the information in Table 9, Table 8 shows there are at least 11,957 MW of capacity that require major emissions control retrofits and would require, all else equal, higher RPM prices to continuing operating into the 2014/2015 delivery year and beyond.

In the *2010 SoM Report* the IMM has reported that as many as 14,000 MW of capacity would require in excess of \$300/MW-day in additional revenues just to pay for SO₂ controls assuming capital recovery of 4 years under the Mandatory CapEx option in section 6.8 of Attachment DD.³¹ While PJM agrees that such retrofits will be costly, PJM does not agree with the assumption generation undergoing retrofits will only seek to stay in operation for only four additional years. It is quite likely generation owners making the retrofit decisions will want to continue operating for many more years and will reflect retrofits costs in their RPM offers accordingly.

PJM is in the process of conducting an extensive analysis of the emissions control retrofits that would be required for coal units within the PJM footprint and the implications for the revenues required for these units to continue operating for the 2014/2015 delivery year and beyond.

The RPM Capacity Market has Retained Existing Resources facing Costly Environmental Retrofits

In 2006 the Maryland General Assembly passed the Maryland Healthy Air Act which mandated that all coal-fired units in the state meet stringent annual tonnage limits for nitrogen oxides (NO_x) beginning in 2009 and for sulfur dioxide (SO₂) and emissions reduction targets for mercury beginning in 2010.³²

PJM analysis of the EPA data indicates that 3,759 MW of targeted coal-fired capacity in Maryland installed some kind of SO₂ control technology that can also aid in the reduction of mercury emissions. Almost 3,000 MW installed selective catalytic reduction for NO_x reductions, and just over 1,500 MW installed fabric filter baghouses.³³ Moreover, significant emissions controls have been installed on another 1,200 MW of coal-fired generators in EMAAC in the last two years.³⁴

These are significant pollution control investments that have gone into service and it is quite likely that RPM Capacity Market prices in SWMAAC and EMAAC have been influential for incenting generation owners to undertake these costly retrofits. Conversely, RPM prices were likely influenced to some extent by the costs associated with these retrofits. The experience with retrofits in SWMAAC and EMAAC shows that the RPM Capacity Market can accommodate environmental rules and these will be reflected in RPM Capacity Market prices.

PJM's Ancillary Service Markets are Competitive and Further Refinements are Forthcoming

Ancillary Services in PJM account for only 1.25 percent of wholesale power costs, and not all of these services, such as Reactive Power and Black Start, are market-based. However, market-based services such as Regulation and Synchronized Reserve which account for half of Ancillary Service costs are essential for maintaining real-time, operational reliability by maintaining system frequency at 60 Hertz, or maintaining reserves to meet system contingencies such a loss of generator or major transmission line.

PJM's Regulation Market Remains Competitive with Improved Performance in 2009-2010

In December 2008, PJM implemented stakeholder- and FERC-approved tariff changes to the Regulation Market that implemented the Three Pivotal Supplier Test (TPST) and cost-based offer mitigation for suppliers that fail the TPST.³⁵ Additionally, the stakeholders and FERC approved changes to the adder to the cost-based offer cap, the manner in which opportunity costs are determined for deriving regulation price and opportunity costs payments, and not counting the revenue earned in the Regulation Market toward the offset of Balancing Operating Reserve credits paid to generators. These reforms were designed to enhance competitiveness while increasing supply in the Regulation Market and the Commission agreed.³⁶

Table 10 provides an overview of the state of the Regulation Market two years prior to the implemented changes, 2007-2008, and two years following the implemented changes, 2009-2010.³⁷ Table 10 shows that in the two years since the implemented changes Regulation capability has increased, the average amount and percentage of capability offered has increased, the average hourly eligible megawatts has increased, and the ratio of supply to regulation requirements has increased from a low of 1.9 in 2007 to almost 3 in the last two years.

With all the additional supply, the percentage of hours in which at least one supplier failed the TPST has declined. The clear trend of increased supply and competitiveness shows up clearly in the market results as the load-weighted average marginal regulation offer has decreased approximately 25 percent resulting in the lowest average marginal offers since the current Regulation Market has been in operation.³⁸

Table 10: Regulation Market Statistics 2007-2010

	2007	2008	2009	2010
Regulation capability (MW)	7,609	7,326	7,805	8,053
Average Daily Offer (MW)	3,911	4,983	6,343	5,645
% capability offered	51%	68%	81%	70%
Avg. Hourly Eligible (MW)	1,835	2,183	2,537	2,591
% Capability Eligible	24%	30%	33%	32%
Ratio Supply to requirement	1.9	2.39	2.98	2.95
% hours failing TPS Test	80%	83%	52%	73%
LW Avg. Marginal offer (\$/MWh)	\$12.06	\$11.94	\$8.79	\$9.28

PJM is Awaiting FERC Approval of Proposed Changes to Improve Pricing of Ancillary Services

It is important not only that the Regulation and Synchronized Reserve Market results are competitive, but that the prices of Regulation and Synchronized Reserve in real-time operation properly and fully reflect the opportunity cost of not producing energy, which has often not been the case. Marginal offers in the Regulation Market as well as regulation prices are the lowest they have been since 2005 in large measure due to the increased supply-demand balance seen in the last two years and to the fall in energy prices seen in 2009 and 2010 as can be seen in Table 11.³⁹

Table 11: The Price and Cost of Regulation since 2005

Year	Price (\$/MWh)	Cost (\$/MWh)	Price as % of Cost
2005	\$64.03	\$77.39	83%
2006	\$32.69	\$44.98	73%
2007	\$36.86	\$52.91	70%
2008	\$42.09	\$64.43	65%
2009	\$23.56	\$29.87	79%
2010	\$18.08	\$32.07	56%

The Synchronized Reserve Market is cost-based, and prices in this market reflect the overall price trends in the Energy Market resulting in the second lowest overall average price since 2005. An overview of Synchronized Reserve Prices can be seen in Table 12.⁴⁰

Table 12: The Price and Cost of Synchronized Reserve since 2005

Year	Price (\$/MWh)	Cost (\$/MWh)	Price as Pct of Cost
2005	\$13.29	\$17.59	76%
2006	\$14.57	\$21.65	67%
2007	\$11.22	\$16.26	69%
2008	\$10.65	\$16.43	65%
2009	\$7.75	\$9.77	79%
2010	\$10.55	\$14.41	73%

Tables 11 and 12 also show that the actual cost per MWh of Regulation and Synchronized Reserve is greater than the price of each of these ancillary services. From a market efficiency perspective this is not desirable as the price of these

services should reflect the cost of providing them. From a real-time operations perspective, the mismatch in price and cost is the result of having to pay suppliers providing these services their actual opportunity costs (the costs of not providing energy) to ensure suppliers have the incentive to maintain their Regulation and Reserve assignments.

The difference in the price and cost of Regulation and Synchronized Reserve is a result of clearing these markets, and setting market prices, an hour in advance of the actual dispatch. The opportunity costs of forgone energy sales are being calculated based on estimated energy prices. This method of clearing the ancillary service markets and setting prices in advance of dispatch was an artifact of the limits of the computational power available to solve these problems. But with advances in computing power and speed, there is no reason Energy, Regulation, and Reserves cannot be co-optimized in real-time operations and priced together every five minutes to effectively eliminate the mismatch between the price and cost of Regulation and Synchronized Reserves.

The *2010 State of the Market Report* has recommended that the pricing of Regulation and Synchronized Reserve reflect the actual LMP rather than as it is done currently. PJM agrees with these recommendations and has already proposed to simultaneously co-optimize and price Energy, Regulation, and Synchronized Reserve in real-time operations, in the context of shortage pricing under FERC Order 719.⁴¹ PJM filed these changes on June 18, 2010 as part of its Order 719 shortage pricing compliance filing.

FTR Revenue Inadequacy is a Result of a Complex Interaction of Multiple Factors

During the 2009/2010 Planning Period FTR revenue adequacy was 97.3 percent, and in the current 2010/2011 Planning Period through March, FTR revenue adequacy stands at 88.7 percent.⁴² PJM expects that the final revenue adequacy at the end of the 2010/2011 planning period to be over 90 percent but does not expect it to reach the levels typically seen in the past.⁴³

These FTR market results differ significantly from the historical norm where in four of the five previous planning years going back to 2004/2005, revenue adequacy stood at 100 percent.⁴⁴ The current level of revenue inadequacy has understandably caused concern among some PJM stakeholders who rely on FTRs to hedge against congestion costs, and as any revenue shortfalls are spread across FTR holders. In response to concerns from PJM stakeholders, PJM undertook a detailed examination of causes of FTR revenue inadequacy.

Some stakeholders have suggested that too many transmission outages of more than 2 months duration were not appropriately accounted for during the last two Annual FTR Auctions and that these are the main cause of the revenue inadequacy problem. PJM evaluates an average of 46 outages of two months or longer each year to determine which outages, if any, to include in the optimization program for the Annual FTR Auction. In the 2009/10 Planning Period 40 outages lasting longer than two months were evaluated, while 50 outages of the same duration were evaluated for the 2010/11 Planning Period. The historic pattern of FTR revenue adequacy and transmission outages of greater than two months is shown in Table 13 below.⁴⁵ It is certainly true that there is one more major outage of more than two months than any other previous delivery year, but this is not the only cause for the revenue inadequacy.

Table 13: FTR Revenue Adequacy and Major Outages Greater than Two Months in Duration

PJM FTR Revenue Adequacy	FTR Revenue Percentage	Total Outages of Two Months or More	Major Outages of Two Months or More	Description of Major Outages
2004/2005	100%	48	2	AEP Transmission Zone (765 kV line Axton-Jacksons, 500 kV line Nagel- Sullivan)
2005/2006	91%	45	1	AEP Transmission Zone (765 kV Line Jacksons-Wyoming)
2006/2007	100%	60	0	
2007/2008	100%	28	1	GPU Transmission Zone (500 kV line Ewindor-New Freedom)
2008/2009	100%	53	2	PEPCO, Dominion Transmission Zones (Meadowbrook-Morrisville, Burchess Hill-Chalk Point)
2009/2010	97%	40	2	PEPCO, Dominion Transmission Zones (Meadowbrook-Morrisville, Burchess Hill-Chalk Point)
2010/2011	88.7% *	50	3	PEPCO, Dominion, GPU Transmission Zones (500 kV Lines Meadowbrook-Morrisville, Burchess Hill-Chalk Point, 345 kV Line Handsome-Homer City)

FTR Revenue Adequacy is a Delicate Balance of Trade-offs

FTR revenue adequacy can essentially be assured for every planning year by conservatively modeling all major expected outages for the planning year as has been suggested by some stakeholders. However, such conservative modeling of the transmission does come at a cost to those parties who wish to hedge their exposure to congestion costs in the PJM Energy Market. First, not as many Auction Revenue Rights (ARRs) can be allocated and consequently the set of possible FTRs available in the Annual Auction will be more limited meaning that there is a much higher risk that there would be a substantial increase in unhedged congestion in the energy market overall, and especially for parties unable to purchase FTRs that may otherwise have been available.⁴⁶ Second, if it turns out the transmission system was modeled too conservatively, it will be transparent to market participants that more FTRs were available to hedge congestion when the amount of congestion revenues far exceeds the required payouts to FTR holders that will inevitably lead to a call for a less conservative modeling of the transmission system in future FTR auctions.

However, the current situation where FTR payouts are less than 100 percent also leads to some level of unhedged congestion for some individual FTR holders, although total unhedged energy market congestion would be quite small if not zero. Revenue inadequacy then leads bidders in future FTR auctions to attempt to account for any perceived, expected revenue inadequacy in their bids for FTRs to offset expected revenue shortfalls. Moreover, there are likely to be calls for more conservative modeling of the transmission system as is the case currently.

The ideal outcome is that transmission outages are modeled sufficiently to maintain revenue adequacy and market confidence in the value of FTRs, but not have large surpluses or shortage of congestion revenues relative to target FTR payouts. The fact that FTR revenue adequacy has historically been at or near 100 percent reflects the process' overall soundness in modeling system feasibility for the Annual FTR Auction; a process that has been applied the same way without material changes since the inception of ARRs and FTRs in PJM's markets. As there were no significant changes for the past two Annual FTR Auctions, PJM does not believe the process itself led to the current state of revenue adequacy.

FTR Revenue Shortfalls are Dues to Complex Interactions Among Multiple Factors

The analysis undertaken by PJM showed several elements that contributed to the FTR revenue inadequacy. The leading causes of FTR revenue inadequacy are both from planned and unplanned transmission outages which account for almost 70 percent of the revenue inadequacy in total.⁴⁷ Breaking down the outages, construction outages in excess of two months account for only 17 percent of the revenue shortfall while construction and maintenance outages less than two months account for 40 percent of the revenue shortfall, and unplanned de-ratings or outages account for 12 percent of the shortfall. Some stakeholders have expressed concern over the inclusion or exclusion of outages over two months in duration, but such outages have only contributed 17 percent of the total inadequacy. Transmission outages lasting less than two months were the largest factor, representing 40 percent of the inadequacy.

Table 14: Causes of FTR Revenue Inadequacy in the 2010/2011 Planning Period (through February)

Cause	Percentage Contribution
Major construction outages of two months or longer	17%
External flowgates/constraints	12%
Loop flow	19%
Other transmission outages	40%
Unforeseen deratings and outages	12%

Stakeholder Outreach

In order to provide a forum for discussion and promote a common understanding of the FTR revenue adequacy issues, PJM held a technical conference on January 26, 2011.⁴⁸

Through an on-going Task Force, PJM and its members are addressing the FTR revenue inadequacy issue that arose during the 2010/11 Planning Period, and the Task Force anticipates providing input on improvements to the process to address these issues.⁴⁹

Conclusion

PJM's Markets are clearly governed by competitive behavior and by market fundamentals that define supply, such as fuel costs or the cost of building new or retrofitting existing capacity, and define demand such daily or seasonal weather patterns or forecast peak demand driven by economic activity. PJM's Markets are providing consistent price signals regarding the need for new entry by location.

The overall market design in PJM can handle future challenges posed by items such as the forthcoming EPA rules, and this has been tested already by as generators have already faced similar investment decisions in the recent past.

Yet, there remain incremental improvements that can be made such as with the pricing of Regulation and Synchronized Reserves and revenue adequacy for FTRs as discussed above.

PJM endeavors to work with its members and other stakeholders in continually improving the market design to meet new challenges and improve upon what is already a highly efficient, transparency, and reliability wholesale power market.

APPENDIX

Appendix: PJM Response to the 2010 State of the Market Report Recommendations

The Independent Market Monitor (IMM) makes a number of recommendations in the 2010 State of the Market Report. PJM generally either supports the recommendations or supports the recommendation with some modifications.

Energy Market Recommendations:

1. **IMM Recommendation** — The IMM recommends that changes be made to simplify and improve the Emergency Demand Response (DR) program. The IMM recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The IMM also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

PJM Response — PJM believes that demand response resources should have the opportunity to express their economic dispatch desires in a manner similar to that available to other resources such as generation resources, and does not believe that the elimination of the minimum dispatch price option is appropriate at this time. The Emergency Program Energy Only option is a program that has historically generated very little interest among participants. PJM is not opposed to the removal of this option in principle.

2. **IMM Recommendation** — The IMM recommends that there be substantial improvement in measurement and verification methods be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. The IMM makes a number of detailed recommendations regarding ways to improve the measurement and verification process for demand response activity. PJM is currently engaged in a pilot study to evaluate measurement and verification methods.

PJM Response — PJM established the Load Management Task Force in early 2010 specifically to look into these issues. PJM is conducting a pilot study to evaluate measurement and verification (M&V) methods. PJM notes that the results provided by curtailment service providers (CSPs) are subject to audit under current practices. PJM also notes that the submittal and verification process is not dissimilar to the test results and practices used for generation resources. Also, PJM notes that many of the M&V issues currently being debated become moot with the implementation of Price Responsive Demand.

3. **IMM Recommendation** — The IMM recommends resolution of the double counting issue in the Emergency Load Response Program. The double counting issue can be directly resolved by not permitting the over compliance which results from the interaction between peak load contribution (PLC) management and the PJM DR Program. A simple way to achieve this result would be to revise Attachment A to PJM Manual 18 (Load Forecasting and Analysis) to cap the baseline for measuring compliance under Guaranteed Load Drop (GLD) at the customers' PLC. The IMM recommends action on this issue prior to the 2011/2012 delivery year.

PJM Response — PJM agrees with this recommendation and notes the "double counting" issue stems from business rules that allow demand resources, for M&V purposes, to count load reductions from actual consumption that may be larger than the PLC of the resource. For example, a demand response site that has managed its peak load with a PLC of 40 MW, which is its capacity obligation. But without managing its peak load, would have a load of 100 MW. When demand response is called and the resource drops from 100 MW to 20

MW, it would get credit for 80 MW of M&V compliance purposes, but this is more than its capacity obligation. PJM has proposed action in the stakeholder process to either credits for reductions be capped at the PLC value (40 MW), or that the load forecast be increased to reflect the higher claimed reduction. PJM notes that the IMM event compliance analysis shows that almost half of all sites only performed to 50 percent or less of their committed MW, but this was offset by over-compliance from double counting.

4. **IMM Recommendation** — The IMM recommends that the limits on operational parameters apply to both price- and cost-based schedules in order to prevent the exercise of market power.

PJM Response — PJM has concerns about extending limitations on operational parameters to market-based and cost-based schedules as it is not clear whether or not this is infringing upon FERC authority to grant market-based rate authority. The IMM has made this proposal to PJM stakeholders but it has not received support.

5. **IMM Recommendation** — The IMM recommends incorporating startup and notification times as additional parameters subject to limits in order to ensure the reliability of the grid, as well as to deter market manipulation by offering artificially lengthy startup and notification time parameters to withhold generation from the market.

PJM Response — PJM is open to introducing limits on start-up and notification times. PJM notes that balancing operating reserve charges were much higher in 2010 than they had been in previous years and that in December there were many units using 24 hour start-up and notification times to ensure they would run even though they were otherwise uneconomic. PJM believes the IMM's recommendations stem from these observations and market results.

6. **IMM Recommendation** — The IMM recommends that renewable energy credit markets be brought into PJM markets as renewable energy credits (RECs) are an increasingly critical component of regulated wholesale energy prices.

PJM Response — PJM disagrees with this recommendation and believes such a proposal is not workable. Moreover, RECs only have an impact on market prices in a limited number of cases when a wind resource is on the margin and submitting negative offers that might reflect compensation received from RECs. PJM notes the Generation Attribute Tracking System (GATS) is used by jurisdictions to auction renewable energy credits. In fact, GATS functions only as tracking system and has no auction functionality.

Interchange Transactions Recommendations:

7. **IMM Recommendation** — The IMM recommends that PJM modify a number of its transaction related rules to improve market efficiency, reduce operating reserves charges, reduce gaming opportunities and to make the markets more transparent. The IMM recommends changing the not-willing-to-pay congestion product to eliminate uncollected congestions charges, eliminating internal source and sink bus designations for external energy transactions, eliminating or modifying the dispatchable transactions and up to congestion transactions products to reduce or eliminate gaming opportunities associated with the products.

PJM Response — PJM Stakeholders are currently discussing changes to the rules related to these transactions rules in the Stakeholder process.

8. **IMM Recommendation** — The IMM requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.

PJM Response — PJM agrees that additional information is required on an hourly basis to provide greater transparency with respect to the sources of flows on the power grid. PJM is committed to working with other ISOs /RTOs and neighboring control areas to seek sharing of real-time transaction tag information and hourly flow information regarding power flows on key flowgates that result from hourly generation dispatch to meet control area. Currently, such hourly flow information is not available on an interregional basis.

9. **IMM Recommendation** — The IMM recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.

PJM Response — PJM is aware that arrangements between neighboring balancing authorities will require refinement as experience dictates and has committed to working together to continually identify areas that require improvement or could benefit from further enhancement. To this end, PJM's experience with the dynamic schedule approach will be continuously evaluated to ensure that it continues to represent a reasonable, and practical, approach to address congestion management which meets the particular operational characteristics of PJM and neighboring entities. It has already been recognized by the FERC that it represents a just and reasonable methodology to address congestion on the PJM and neighboring systems.

Capacity Market Recommendations:

10. **IMM Recommendation** — The IMM recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity.

PJM Response — PJM has requested that an independent consultant (The Brattle Group) consider the IMM recommendations as part of its report on the performance of RPM in meeting its design goals.

PJM agrees in theory that more granular LDAs and price signals in RPM would be desirable, but the implementation of such a concept seems impractical. The idea may stem from the concept that more granular LDAs would eliminate the need for reliability must run (RMR) contracts. But PJM believes these situations are more the exception than the rule as only very localized transmission problems have led to RMR contracts.

With respect to energy recall procedures, PJM notes that the ability recall of system sales from capacity resources exists in Manual 13: Emergency Operations and does not believe other procedures are necessary.

11. **IMM Recommendations** — The IMM recommends that the obligations of capacity resources be more clearly defined in the market rules.

PJM Response – PJM does not believe that capacity resources should be required offer in the energy market at short-run marginal cost. First, PJM believes this would circumvent the FERC's clear authority to grant market-based rates. Second, PJM notes that short-run marginal costs are difficult to define and this has been recognized

by the FERC many times over. Third, there is no indication that there is an incentive or market power problem as offer behavior in the energy market clearly shows offers at or near short-run marginal cost.

12. **IMM Recommendation** — The IMM recommends that the performance incentives in the RPM Capacity Market design be strengthened.

PJM Response — PJM has commissioned an independent consultant (The Brattle Group) to study the performance of RPM in meeting its design goals and has requested the consultant to consider the IMM recommendations. Following that report, PJM Stakeholders will consider improvements to the RPM Capacity Market design.

13. **IMM Recommendation** — The IMM recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized.

PJM Response — PJM believes that standard procedures already exist in the tariff governing RMR contracts. If the amount of investment required exceeds a relatively low threshold, then the matter goes to FERC to determine the justness and reasonableness of the RMR contract submitted for approval. To the extent the IMM believes RMR contracts are recovering costs they should not, PJM believes the IMM should submit its comments to the FERC as it is a matter for the FERC to decide. Moreover, PJM notes the conditions leading to the need for an RMR contract are unit specific and standardization can only go so far.

Ancillary Service Recommendations:

14. **IMM Recommendation** — The Regulation Market design and implementation continue to be flawed and require a detailed review to ensure that the market will produce competitive outcomes. Some of the flaws identified by the IMM were addressed by PJM in 2010, but some remain. The IMM recommends a number of market design changes designed to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the lost opportunity cost (LOC) calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO.

PJM Response — PJM believes that the Regulation Market continues to operate in a competitive manner consistent with PJM's FERC-approved tariff, and that further design changes are not required at this time. PJM will continue periodic evaluation of potential improvements in the design of all PJM markets, taking into account the need to balance theoretically perfect competition with the costs and complexity that can arise in overdesigning market constructs, so that these markets remain robust, fair and workably competitive in both design and outcome.

15. **IMM Recommendation** — The IMM recommends that the single clearing price for synchronized reserves be determined based on the actual LMP. This consistent with PJM's recommendation on this topic in the scarcity pricing matter. The IMM also recommends that documentation of the Tier 1 synchronize reserve deselection process be published.

PJM Response — PJM generally agrees with this recommendation but believes that it is more practical to implement this in the shortage pricing model currently filed with the FERC.

16. **IMM Recommendation** — The IMM recommends that the Day-Ahead Scheduling Reserve (DASR) Market rules be modified to incorporate the application of the three pivotal supplier test (TPST) in order to address potential market power issues.

PJM Response — PJM is not opposed to the use of the TPST and marginal cost offer capping in the DASR Market with appropriate adjustments to fit the DASR Market context. PJM notes that the average market clearing price in the DASR market was \$0.16/MWh in 2010.

17. **IMM Recommendation** — The IMM recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which Black Start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

PJM Response — As a need for new Black Start Service is identified due to the retirement of an existing Black Start unit, PJM does conduct an open and transparent RFP process as outlined in Manual 14D, and this is also noted and recognized by the IMM. PJM notes that the PJM Members Committee recently approved tariff provisions to be filed with FERC permitting the recovery of NERC Critical Infrastructure Protection for Black Start units so as to provide incentives for Black Start units to remain in-service rather than leaving the Black Start program. Several other changes to compensation for Black Start Service are currently being considered in the stakeholder process.

Congestion Recommendations:

18. **IMM Recommendation** — The IMM recommends that PJM continue its efforts to find ways to modify the generation and transmission interconnection process to minimize the uncertainty for potential market entrants.

PJM Response — PJM remains committed to the on-going improvement of the interconnection processes and has recently created a new stakeholder body to examine potential improvements in these areas.

19. **IMM Recommendation** — The IMM recommends that PJM propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables. These issues are currently being considered in the PJM stakeholder process.

PJM Response — As noted, these issues are already under consideration in the PJM stakeholder process.

20. **IMM Recommendation** — The IMM recommends continued efforts to incorporate transmission investments into competitive markets. Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities, and the lack of existing transmission, can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area.

PJM Response — PJM remains committed to the on-going improvement of the transmission planning and has recently created a new stakeholder body to examine potential improvements in these areas.

Financial Transmission Rights and Auction Revenue Rights Recommendations:

21. **IMM Recommendation** — The IMM continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the IMM's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members.

PJM Response — PJM believes that credit policies must strike a prudent balance between risks and high transaction costs and barriers to entry. The nature of the FTR markets, with their long forward commitments and the potential for changes both in the transmission system and to market participants in the market, represented a strong candidate for the elimination of unsecured credit. With the introduction of weekly settlements for shorter-term products, PJM feels that there can still be a place for unsecured credit, reducing barriers to entry and keeping transaction costs low, while still providing mitigation for the risks associated with it.

22. **IMM Recommendation** — The IMM recommends that when load switches among load serving entities (LSEs) during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do.

PJM Response — PJM disagrees with this recommendation. The ARR functions as the allocated right, and should therefore move in conjunction with load switches. The use of FTRs however is a business decision left to the market participant and it is therefore inappropriate for this to be reallocated along with load switches. To do so would create discriminatory treatment between FTRs that were self scheduled versus those that were just executed at a high clearing price.

23. **IMM Recommendation** — The IMM recommends that PJM provide more comprehensive explanations to members regarding the reasons for FTR underfunding.

PJM Response — PJM is committed to transparency and providing information for stakeholders to make informed decisions. PJM has presented detailed information regarding the reasons for FTR underfunding to PJM stakeholders on several occasions and is committed to continuing this practice in the future.

Endnotes

- ¹ See *2010 State of the Market Report for PJM: Volume 2 Detailed Analysis*, March 10, 2011 (*2010 SoM Report*) at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml. The report can also be found on PJM's website at <http://www.pjm.com/documents/reports/-/media/documents/reports/state-of-market/2010/2010-som-pjm-volume2.ashx>.
- ² See "Markets Report" presentation to the PJM Member's Committee, January 27, 2011 at 2 <http://www.pjm.com/-/media/committees-groups/committees/mc/20110127/20110127-item-14a-market-report.ashx>.
- ³ Source: PJM Settlements data 2005-2010. 2008 and 2009 data can be verified in the "Markets Report" presentation to the PJM Member's Committee, January 27, 2011 at 2, <http://www.pjm.com/-/media/committees-groups/committees/mc/20110127/20110127-item-14a-market-report.ashx>.
- ⁴ See *2010 SoM Report* at 11.
- ⁵ *Id.* at 74, Table 2-38.
- ⁶ *Id.* at 11.
- ⁷ Source: https://emergproc.pjm.com/ep/guest_login.htm and search under "Hot Weather Alert".
- ⁸ Source: PJM load data found at <http://www.pjm.com/markets-and-operations/energy/real-time/loadhryr.aspx>. The year-over-year comparison was adjusted by one day such that similar days of the week were being compared, (e.g. Monday compared to Monday).
- ⁹ See "Markets Report" presentation to the PJM Member's Committee, January 27, 2011 at 20, <http://www.pjm.com/-/media/committees-groups/committees/mc/20110127/20110127-item-14a-market-report.ashx>.
- ¹⁰ See *2010 SoM Report* at 28.
- ¹¹ *Id.* at 53, Table 2-21.
- ¹² Cost-based offers consist of defined marginal running costs as defined in PJM Manual 15 plus an adder of up to 10 percent that accounts uncertainty in the measurement of costs and has been reiterated by FERC in various orders. For examples, refer to 52 FERC ¶ 61,241 at 61,840 (1990). The mark-up indices for coal and gas units below were computed for coal- and gas-burning units at their maximum economic output, and weighted by the MW quantity of their offer.
- ¹³ This kind of bidding behavior is not surprising for coal units. Such units want to ensure they run through off-peak hours because there are opportunity costs for shutting down and starting up again that can be avoided by running a few hours just below cost. See *PJM's Comments Regarding the 2007 State of the Market Report Issued by the PJM Market Monitoring Unit* April 11, 2007 at 11-12.
- ¹⁴ See *2010 SoM Report* at 349.
- ¹⁵ Due to potential future reliability violations due to west-to-east flows, the TrAIL Project is scheduled to go into service on June 1, 2011. Other projects such as the PATH and MAPP, despite having been delayed into the future, indicate a need for capacity resources to be located in EMAAC and SWMAAC to maintain future reliability. See *PJM 2010 Regional Transmission Expansion Plan* (2010 RTEP) at 7-9, at <http://www.pjm.com/documents/reports/rtep-report.aspx>.
- ¹⁶ *Id.* at 181, Table 3-24.
- ¹⁷ *Id.* at 177, Table 3-22.
- ¹⁸ See *2010 SoM Report* at 176 and 188, Tables 3-20 and 3-27. See also *2007 State of the Market Report* at 144, Table 3-29, *2008 State of the Market Report* at 156, Table 3-29, and *2009 State of the Market Report* at 170, Table 3-28. Cost of New Entry at 8 percent and 10 percent hurdle rates estimated by linear interpolation from the tables. 2010 estimates at 8 and 10 percent based on 2009 linear interpolation.
- ¹⁹ See *2010 SoM Report* at 166, Table 3-6 for Real-time Net Energy Market revenues, and at 172, Table 3-15 for Day-ahead Net Energy Market revenues. PJM derived the split of 75 percent day-ahead and 25% real-time revenues examining the frequency with which combined cycle units are committed Day-ahead versus remaining uncommitted Day-ahead and then dispatched in Real-time.
- ²⁰ *Id.* at 165, Table 3-5 for Real-time Net Energy Market revenues, and at 172, Table 3-14 for Day-ahead Net Energy Market revenues.
- ²¹ *Id.* at 163, Table 3-4 for Capacity Revenues by zone, at 166, Table 3-6 for Real-time Net Energy Market revenues, at 172, Table 3-15 for Day-ahead Net Energy Market revenues. PJM derived the split of 75 percent day-ahead and 25% real-time revenues examining the frequency with which combined cycle units are committed Day-ahead versus remaining uncommitted Day-ahead and then dispatched in Real-time.
- ²² *Id.* at 163, Table 3-4 for Capacity Revenues by zone, at 165, Table 3-5 for Real-time Net Energy Market revenues, and at 172, Table 3-14 for Day-ahead Net Energy Market revenues.
- ²³ See "2013/2014 Base Residual Auction Report" at 20, Table 9, <http://www.pjm.com/markets-and-operations/rpm/-/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx>.
- ²⁴ See *2010 RTEP* at 6-9.
- ²⁵ *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, EPA-HQ-OAR-2009-0491, (CATR) *Federal Register*, Vol. 75, No. 147, August 2, 2010, pp.45210-45465.

- ²⁶ 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-HQ-OAR-2009-0234, (NESHAP or HAP MACT), issued March 16, 2011, <http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposal.pdf>.
- ²⁷ PJM Open Access Transmission Tariff (PJM Tariff), Attachment DD, Section 6.8.
- ²⁸ *Id.*
- ²⁹ *2010 SoM Report* at 200.
- ³⁰ For EPA data go to <http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard>. For EIA data, see "2009 PJM EIA 411 Report found at <http://www.pjm.com/documents/reports/-/media/documents/reports/2009-pjm-eia-411-data.ashx>.
- ³¹ *2010 SoM Report* at 202.
- ³² Code of Maryland Regulations, Title 26, Subtitle 10, Chapter 27, "Emission Limitations for Power Plants" (Maryland Healthy Air Act)
- ³³ <http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard>. One can search the data base by year to see emissions rates and controls as some of these retrofits were installed.
- ³⁴ *Id.*
- ³⁵ 125 FERC ¶ 61,231 Order Accepting Tariff Revisions
- ³⁶ *Id.* at p 16, "We also accept, as appropriate, PJM's proposed package of price incentives. Specifically, we agree with PJM that, on balance, these incentives, when used in conjunction with the three-pivotal-supplier test, strike a balance reasonably calculated to both deter market power and ensure sufficient generator participation in the market."
- ³⁷ Sources: *2007 State of the Market Report* at 283, Table 6-1, at 285, Table 6-4, at 287; *2008 State of the Market Report* at 308, Table 6-2, at 310, 312; *2009 State of the Market Report* at 364, Table 6-2, at 366, 369; *2010 State of the Market Report* at 433, Table 6-5, at 435, 438.
- ³⁸ PJM has provided to the Commission, through 2009, its analysis of the Regulation Market. See "Comments of PJM Interconnection, L.L.C. to the Report of Independent market Monitor" in docket ER09-13, December 30, 2009.
- ³⁹ *2010 SoM Report* at 442, Table 6-12.
- ⁴⁰ *Id.* at 462, Table 6-18.
- ⁴¹ PJM Interconnection, L.L.C. Docket No. ER09-1063-006 (Compliance Filing), June 18, 2010, Transmittal Letter at 19-20, <http://www.pjm.com/-/media/documents/ferc/2010-filings/20100621-er09-1063-006.ashx>.
- ⁴² Percent FTR Credit by Month (June 2003 – March 2011) , <http://www.pjm.com/markets-and-operations/ptr/-/media/markets-ops/ptr/ptr-credit.ashx>
- ⁴³ High level study conducted by PJM staff at the request of a PJM member. Analysis used historical congestion, outages, and cleared FTRs. Estimate should not be used for market decisions, as too many unknown variables exist. PJM FTR Revenue Discussion; November 9, 2010; p. 7; <http://www.pjm.com/-/media/%20committees-groups/committees/mic/20101109/20101109-item-05-ftr-revenue.ashx>
- ⁴⁴ *Id.*, Percent FTR Credit by Month (June 2003 – March 2011)
- ⁴⁵ Answer of PJM Interconnection, LLC. To PPL Energy Plus, LLC's Complaint, Request for Fast Track Proceeding and Request for Summary Disposition; 3/16/2011; p. 38 <http://www.pjm.com/-/media/documents/ferc/2011-filings/20110316-EL11-25-000.ashx>;
- ⁴⁶ See "FTR Technical Meeting: FTR Revenue and Modeling" January 26, 2011, at 20-21, <http://www.pjm.com/-/media/committees-groups/committees/mic/20110126/20110126-mic-ftr-technical-meeting.ashx>.
- ⁴⁷ Answer of PJM Interconnection, LLC. To PPL Energy Plus, LLC's Complaint, Request for Fast Track Proceeding and Request for Summary Disposition; 3/16/2011; at 43, <http://www.pjm.com/-/media/documents/ferc/2011-filings/20110316-EL11-25-000.ashx>
- ⁴⁸ *PJM Financial Transmission Rights Task Force (FTRTF)*, <http://pjm.com/committees-and-groups/task-forces/ftrtf.aspx>
- ⁴⁹ *Id.*