Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Valley Forge Corporate Center
Eagleville, PA 19403
Phone: 610-271-8050
Fax: 610-271-8057

Monitoring Analytics

November 30, 2009

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *PJM Interconnection, L.L.C.*, ER09-13-000

Dear Ms. Bose:

By order issued November 26, 2008 ("November 26th Order"),[1] in the above referenced docket the Commission approved PJM's filing to amend its tariff to apply the Three Pivotal Supplier ("TPS") test to the PJM Regulation Market and to apply mitigation where the results of that test indicated that it was warranted. The Commission also directed (at P 18) "the Market Monitor to submit a report within one year of the date of this order that analyzes changes in regulation market clearing prices, the passage rate of the three pivotal supplier test and the amount of regulation supply offers." Monitoring Analytics, LLC, in its capacity as the Independent Market Monitor for PJM ("IMM"), provides the report included with this letter in satisfaction of this directive ("IMM Report").

The IMM respectfully requests that, should the Commission establish a period for comment on this report, that it allow potential commenters a due date no earlier than December 23, 2008, in order to allow full opportunity for stakeholder review and evaluation.

The IMM filed comments in this proceeding on October 20, 2008[2] in which it outlined its concern with several features of PJM's proposal, including the following: (i) increasing the margin on cost based offers from $7.50 to $12.00 per MW; (ii) modifying the calculation of opportunity costs to use the lower of cost based or price based offers rather than the

1 *PJM Interconnection, L.L.C.*, 125 FERC ¶61,231.

2 Comments and Motion for Leave to Intervene of the Independent Market Monitor for PJM, Docket No. ER09-13-000.

current dispatch schedule as the reference; and (iii) eliminating the netting of regulation revenues from make whole balancing operating reserve payments.

The IMM Report analyzes the impact of each of these three changes to the Regulation Market for the eleven months from December 1, 2008 to October 31, 2009, during which the TPS test has been applied to all suppliers in the Regulation Market. The IMM Report concludes that, taken together, the changes to the tariff related to the Regulation Market resulted in an increase in payments to the providers of regulation of $61.5 million over the period. This represents an increase in total regulation payments of from 13 percent to 76 percent on a monthly basis and an increase of 38 percent for the entire 11 month period.

The market design changes added a substantial cost to those paying for regulation without any evidence that this cost was required for either cost recovery or incentives. If the market design is a good one, there is no reason to make selective and non systematic modifications to the rules in order to enhance returns to the sellers of regulation. The Regulation Market design is a good one and will provide appropriate incentives and returns without these changes. The MMU recommends that the modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed as they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic. The MMU does not recommend that the increase in the margin be reversed at this time as this is an empirical question subject to empirical determination within some limits.

Consequently, consistent with its duties under PJM Open Access Transmission Tariff,[3] the MMU recommends reversal of both the elimination of the offset against operating reserves and the modification to the definition of opportunity cost as they are both inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic.

[3] Attachment M § IV.B.2 & D.

The IMM requests that the Commission carefully consider the analysis in the IMM Report and take appropriate action to address the issues raised therein.

Respectfully submitted,

Jeffrey W. Mayes, General Counsel
Monitoring Analytics, LLC

Monitoring Analytics

PJM Regulation Market: Impact of December 1, 2008 Changes in Market Design December 1, 2008 – October 31, 2009

Monitoring Analytics

The Independent Market Monitor for PJM

November 30, 2009

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Introduction

In 2008, PJM and its stakeholders addressed the issue of market power mitigation for the Regulation Market in the Three Pivotal Supplier Task Force (TPSTF), which was convened pursuant to PJM's 2007 Strategic Report to review market power mitigation issues.[1] The TPSTF voted to support the application of the three pivotal supplier (TPS) test to the Regulation Market, provided that three adjustments to the rules were included, all of which increased margins for units providing regulation. This proposal represented a compromise among the market participants at the TPSTF. PJM filed the proposed revisions on October 1, 2008.[2] A number of parties filed comments, including Market Monitoring Unit (MMU) on October 20, 2008.[3] The MMU welcomed the application of the TPS test to the Regulation Market, but expressed concerns regarding the three adjustments to the regulation market design. The MMU supported the October 1st Filing with the caveat that if the MMU review of the actual impact of the changes "results in a conclusion that these features result in non-competitive market outcomes, the Market Monitor will request that one or more of these provisions be removed or modified." The MMU requested that the Commission direct the MMU to report on the three adjustments to the rules: (i) increasing the margin on cost based offers from $7.50 to $12.00 per MW; (ii) modifying the calculation of opportunity costs to use the lower of cost based or price based offers rather than the current dispatch schedule as the reference; and (iii) eliminating the netting of regulation revenues from make whole balancing operating reserve payments.

On November 26, 2008, the Federal Energy Regulatory Commission (Commission) accepted the proposed changes effective December 1, 2008.[4] The Commission also included the following direction:

> The Market Monitor requests a Commission directive, in this regard, requiring it to submit a report to the Commission addressing PJM's

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1 *See* PJM 2007 Strategic Report at 65 (April 2, 2007). This report is posted on PJM's website at: <*http://www.pjm.com/~/media/documents/downloads/strategic-responses/report/20070402-pjm-strategic-report.ashx.*>

2 PJM submitted its initial filing in FERC Docket No. ER09-13-000 (October 1st Filing).

3 Comments and Motion for Leave to Intervene of the Independent Market Monitor for PJM, Docket No. ER09-13-000. These comments are posted on Monitoring Analytics' website at <*http://www.monitoringanalytics.com/reports/Reports/2008/imm-motion-to-intervene-and-comments.pdf*>.

4 125 FERC ¶61,231.

> proposed revisions, as implemented. A report will help to evaluate the impact of the changes discussed herein to the regulation market, and therefore, we direct the Market Monitor to submit a report within one year of the date of this order that analyzes changes in regulation market clearing prices, the passage rate of the three pivotal supplier test and the amount of regulation supply offers.[5]

This report is provided pursuant to the Commission's directive.

Background

Regulation

Among the six ancillary services identified in Order No. 888, PJM provides regulation, energy imbalance, synchronized reserve, and operating reserve - supplemental reserve services through market-based mechanisms. PJM provides the remaining ancillary services on a cost basis.[6]

Regulation matches generation with very short term changes in load by moving the output of selected resources up and down via an automatic control signal.[7] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by demand side response (DSR). Longer term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve.

Both the Regulation and Synchronized Reserve Markets are cleared on a real time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources,

5 *Id.* at P 18.

6 The Commission defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service. 75 FERC ¶61,080 (1996).

7 Regulation is used to help control the area control error (ACE). See *2008 State of the Market Report for PJM,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2008.

limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

Structural Market Power in the Regulation Market

PJM consolidated its Regulation Markets into a single combined Regulation Market, on a trial basis, effective August 1, 2005. Since that time, the MMU has consistently found that the PJM Regulation Market is characterized by structural market power.[8] This conclusion is based on the results of the TPS test. In addition, the MMU has been unable to conclude that the Regulation Market produced competitive results or noncompetitive results, based on the MMU analysis of the relationship between the offer prices and marginal costs of units that set the price in the Regulation Market, the marginal units, where the MMU has found that prices were set by offers above the competitive level in a substantial proportion of hours, 18 percent of the hours in 2008. The MMU could not reach a definitive conclusion because it had to rely on estimated unit marginal costs in the absence of data submitted by market participants.

The MMU performed an analysis of the Regulation Market and submitted a report on October 18, 2006, in which it recommended "that real time, hourly market structure tests be implemented in the regulation market, that market power mitigation be imposed only for hours in which the market structure is noncompetitive and that market power mitigation be imposed only on the companies failing the market structure tests."[9] Specifically, the MMU recommended "that the three-pivotal supplier test be applied hourly in the regulation market using a market definition of all eligible offers less than or equal to 1.50 times the clearing price and that mitigation be applied to only those regulation owning companies that fail the test in that hour."[10] The MMU also

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8 *See: 2006 State of the Market Report*, Volume II, Section 6 – Ancillary Service Markets, "Conclusion"; *2007 State of the Market Report*, Section 6 – Ancillary Service Markets, "Conclusion"; *2008 State of the Market Report for PJM*, Section 6 – Ancillary Service Markets, "Conclusion"; *2009 Quarterly State of the Market Report for PJM: January through June*, Section 6 – Ancillary Service Markets, "Conclusion"; *2009 Quarterly State of the Market Report for PJM: January through September*, Section 6 – Ancillary Service Markets, " Conclusion"; "Analysis of the Combined Regulation Market: August 1, 2005 through July 31, 2006,"(October 18, 2006) <*http://www.monitoringanalytics.com/reports/Reports/2006/20061018-mmu-regulation-market-report.pdf*>

9 *Analysis of the Combined Regulation Market: August 1, 2005 through July 31, 2006* at para. 35 (October 18, 2006).<*http://www.monitoringanalytics.com/reports/Reports/2006/20061018-mmu-regulation-market-report.pdf*>

10 *Id*.

recommended that mitigation "consist of requiring a cost-based regulation offer including the currently defined margin of $7.50 per MW, plus opportunity costs."[11]

The MMU presented its findings and recommendations to PJM members at stakeholder meetings. Unit owners wanted to be sure that the definition of the marginal cost of regulation was accurate before agreeing that the TPS test should be applied in the Regulation Market. In response, the MMU convened three meetings of the Cost Development Task Force (CDTF) in early 2007 in order to address questions raised by unit owners about whether the costs of providing regulation service were correctly defined in the Cost Development Guidelines, PJM Manual M-15. The three special meetings of the CDTF occurred on February 28, 2007, March 26, 2007 and April 13, 2007. In those meetings, PJM stakeholders, primarily representatives of generation owners, PJM staff and the MMU, developed a modified definition of cost for regulation offers, which was appropriately grounded in economic theory and operational realities. The CDTF definition was approved through the required PJM membership process and by the PJM Board of Managers and was included as Revision 08 to PJM's Cost Development Guidelines Manual (§ 9), effective October 16, 2007.[12]

The potential application of the TPS test issue was transferred to the TPSTF and on November 16, 2007, the charter of the TPSTF was revised to assign that task force responsibility to, among other things "Develop a recommendation by June 13, 2008 as to whether the three pivotal supplier (TPS) test should be implemented in the Regulation Market, and if so, the mechanics by which that implementation should take place."[13] The TPSTF discussed various proposals in four meetings convened between March 31, 2008 and June 5, 2008, and voted to support a proposal in the final meeting. Proposed tariff revisions based on that proposal were accepted through the membership process and PJM filed the revisions on October 1, 2008 in Docket No. ER09-13-000.[14]

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11 *Id*.

12 PJM Manual 15 (Cost Development) at 65 (Revision 08, Section 9).

13 The TPSTF Charter can be found at <http://www.pjm.com/committees-and-groups/closed-groups/~/media/committees-groups/task-forces/tpstf/postings/tpstf-charter.ashx>

14 The October 1st Filing includes, (at 8) the voting history of this proposal in the stakeholder process.

Application of the TPS Test to the Regulation Market, Effective December 1, 2008

On December 1, 2008, the TPS test was implemented in the Regulation Market to address the identified market power problems. The three other market design changes were also implemented on December 1, 2008.

From May 1, 2005 through November 30, 2008, regulation offer prices were provided by the unit owner, applicable for the entire operating day and, with opportunity cost, comprised the total offer to the Regulation Market.[15] The regulation offer price was subject to a $100 per MWh offer cap, with the exception of the two dominant suppliers, whose offers were capped at marginal cost plus $7.50 per MWh plus opportunity cost. All suppliers were paid the market-clearing price. PJM calculated opportunity cost on the basis of the applicable offer in the energy market (i.e. the offer schedule on which the unit is dispatched) and credited net revenue from a unit's offer plus opportunity cost against any operating reserve credits.[16]

Beginning December 1, 2008, as part of PJM's implementation of the TPS test, owners are required to submit unit specific cost based offers which may include up to a $12/MWh margin adder, and owners also have the option to submit price based offers. All offers remain subject to the $100 per MWh cap.[17] All units owned by owners who fail the TPS test for an hour are dispatched at the lesser of their cost based or price based offer.[18] As part of the changes to the regulation market implemented on December 1, 2008, PJM no longer nets regulation revenue above offer price against operating reserve revenue and PJM now calculates opportunity costs using the lower of cost based or price based offers as the reference rather than the cost based offer.[19]

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15 *See PJM Interconnection, L.L.C.*, 111 FERC ¶61,134 (2005); *PJM Interconnection, L.L.C.*, 112 FERC ¶61,129 (2005).

16 Some PJM documents and some MMU documents refer to opportunity cost as lost opportunity cost (LOC). The term opportunity cost will be used in this report.

17 *See* PJM, "Manual 11: Scheduling Operations," Revision 42 (September 24, 2009), p.39.

18 *See* "Regulation cost based offer calculation," <*http://www.pjm.com/~/media/markets-ops/ancillary/regulation-cost-based-offer-calculation.ashx*> accessed October 15, 2009.

19 *See* PJM, "Manual 11: Scheduling Operations," Revision 42 (September 24, 2009), p. 43: "SPREGO utilizes the lesser of the available price-based energy schedule or most expensive available cost-based energy schedule (the "lost opportunity cost energy schedule"), and forecasted LMPs to determine the estimated opportunity cost each resource would incur if it adjusted its output as necessary to provide its full amount of regulation. "

The implementation of the TPS test is consistent with the longstanding MMU recommendation that real-time, hourly market structure tests be implemented in the Regulation Market, that market power mitigation be applied only for hours in which the market structure is noncompetitive and that market power mitigation be applied only to the companies failing the market structure tests. This more flexible and real-time approach to mitigation represents an improvement over the approach to mitigation which had been in place from August 2005 through November 2008, which required cost based offers from the two dominant suppliers at all times. The three pivotal supplier approach to mitigation also represents an improvement over prior methods of simply defining the market to be noncompetitive and limiting all offers to cost based offers. The real-time approach recognizes that at times the market is structurally competitive and no mitigation is required, that at times the market is not structurally competitive and mitigation is required, and that at times generation owners other than the designated two dominant suppliers may have structural market power that requires mitigation. The MMU has also recommended that the overall $100 regulation offer cap remain in effect. The retention of an overall offer cap together with a real-time, TPS test for market structure is consistent with PJM's current practice in the Energy Market.

Table 1 includes a comparison of the prior Regulation Market rules and the new Regulation Market Rules.

Table 1 Summary of changes to Regulation Market design

Prior Regulation Market Rules(effective May 1, 2005 through November 30, 2008)	New Regulation Market Rules (effective December 1, 2008)
1. No structural test for market power. a. Offers from the identified dominant suppliers (American Electric Power Company (AEP) and Virginia Electric Power Company (Dominion)) b. Other offers capped at $100 per MW.	1. The TPS test applied to determine the presence or absence of structural market power in each hour. Units that belong to owners that fail the TPS test are subject to offer capping. 2. Participants must submit a cost-based offer subject to a cap of marginal cost plus a margin of $12 per MW. Cost-based offers must meet specified criteria as part of the market power mitigation process. Participants may also submit a price offer. Price offers are capped at $100/MW.
2. Opportunity cost calculated based on the applicable offer in the energy market. (The offer schedule on which the unit is dispatched.)	3. Opportunity cost calculated based on the lesser of the price-based energy schedule or the most expensive cost-based energy schedule.
3. All regulation net revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.	4. Regulation market revenue above offer plus opportunity cost not netted against operating reserve credits to unit owners.

Analysis of the Three Pivotal Supplier Test As Applied to the Regulation Market

Table 2 shows the results of the three pivotal supplier test in the Regulation Market. The results for the period December 2008 through October 2009 rely upon PJM's application of the TPS test. The units of owners that failed the TPS test during this period were offer capped. The results for the period December 2007 through October 2008 are based on MMU analysis for the eleven month period prior to implementation of the TPS test. The application of the TPS test by PJM allowed the MMU to conclude that, for the first three quarters of 2009, the results of the Regulation Market were competitive because offer capping was applied when structural market power existed. The only caveat to this conclusion is related to the market design changes made on December 1, 2008. While these changes do not mean that participants are exercising market power, the changes are not consistent with an efficient or competitive market design and are not consistent with the way in which the same issues are addressed for other PJM markets in the PJM tariff.

Table 2 Regulation Market pivotal supplier test results: December 2007 through October 2008 and December 2008 through October 2009

Year	Month	Percent of Hours With Three Pivotal Suppliers	Year	Month	Percent of Hours With Three Pivotal Suppliers
2008	Dec	92%	2007	Dec	79%
2009	Jan	84%	2008	Jan	84%
2009	Feb	61%	2008	Feb	83%
2009	Mar	42%	2008	Mar	89%
2009	Apr	40%	2008	Apr	88%
2009	May	31%	2008	May	97%
2009	Jun	37%	2008	Jun	77%
2009	Jul	39%	2008	Jul	75%
2009	Aug	35%	2008	Aug	80%
2009	Sep	47%	2008	Sep	74%
2009	Oct	64%	2008	Oct	89%

Supply of Regulation

The supply of regulation can be measured as regulation capability, regulation offered, or regulation offered and eligible. For purposes of evaluating the Regulation Market, the relevant regulation supply is the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. This is the only supply that is actually considered in the determination of market prices. The level of supply that clears in the market on an hourly basis is called assigned regulation or cleared regulation. Assigned regulation is selected from regulation that is eligible to participate.

Regulation capability is the sum of the maximum daily offers for each unit and is a measure of the total volume of regulation capability as reported by resource owners.

Regulation offered represents the level of regulation capability offered to the PJM Regulation Market. Resource owners may offer those units with approved regulation capability into the PJM Regulation Market. PJM does not require a resource capable of providing regulation service to offer its capability to the market. Regulation offers are submitted on a daily basis.

Regulation eligible represents the level of regulation capability offered to the PJM Regulation Market and actually eligible to provide regulation in an hour. Some regulation offered to the market is not eligible to participate in the Regulation Market as a result of identifiable offer parameters specified by the supplier. As an example, the regulation capability of a unit is included in regulation offered based on the daily offer and availability status, but that regulation capability is not eligible in one or more hours because the supplier sets the availability status to unavailable for one or more hours of that same day. (The availability status of a unit may be set in both a daily offer and an hourly update table in the PJM market software.) As another example, the regulation capability of a unit is included in regulation offered if the owner of a unit offers regulation, but that regulation capability is not eligible if the owner sets the unit's economic maximum generation level equal to its economic minimum generation level. In that case, the unit cannot provide regulation and is not eligible to provide regulation. As another example, the regulation capability of a unit is included in regulation offered, but that regulation capability is not eligible if the unit is not operating, unless the unit meets specific operating parameter requirements. A unit whose owner has not submitted a cost based offer will not be eligible to regulate even if the unit is a regulation resource.

Only those offers eligible to provide regulation in an hour are part of supply for that hour, and only eligible offers are considered by PJM for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the regulation market clearing mechanism to provide regulation service for a given hour.

The average ratio of eligible regulation supply to the regulation requirement (demand) in the PJM Regulation Market during 2008 was 2.39. In other words, the amount of regulation offered into the hourly markets was 2.39 times the actual demand for regulation in each hour, on average.

During the December 2007 through October 2008 period, the PJM regulation market total capability was 7,305 MW.[20] Table 3 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours. Total capability is a theoretical measure which is never actually achieved. The level of regulation resources offered on a daily level and the level of regulation resources eligible

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20 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

to participate on an hourly level in the market were lower than the total regulation capability. For this period, the average daily offer level was 6,016 MW or 82 percent of total capability while the average hourly eligible offer level was 2,210 MW or 30 percent of total capability. Although regulation is offered daily, eligible regulation changes hourly and the hourly eligible offers are the only offers relevant to clearing the Regulation Market.

Table 3 PJM regulation capability, daily offer and hourly eligible: December 2007 through October 2008

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percentage of Capability Offered	Average Hourly Eligible (MW)	Percentage of Capability Eligible
All Hours	7305	6016	82%	2210	30%
Off Peak	7305			1919	26%
On Peak	7305			2521	35%

During the December 2008 through October 2009 period, the PJM regulation market total capability was 7,717 MW.[21] Table 4 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours. For this period, the average daily offer level was 6,016 MW or 82 percent of total capability while the average hourly eligible offer level was 2,210 MW or 30 percent of total capability.

Table 4 PJM regulation capability, daily offer and hourly eligible: December 2008 through October 2009

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percentage of Capability Offered	Average Hourly Eligible (MW)	Percentage of Capability Eligible
All Hours	7717	6363	82%	2497	32%
Off Peak	7717			2181	28%
On Peak	7717			2844	37%

21 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

During the first ten months of 2009, the ratio of eligible regulation offered to regulation required averaged 2.98 throughout the first nine months of 2009, an increase from the 2008 ratio of 2.39.[22]

The ratio of eligible regulation to regulation required is a function both of the supply of and demand for regulation. The demand for regulation decreased on August 7, 2008. From January 1 through August 7, 2008, PJM calculated the regulation requirement for all hours of the day as 1.0 percent of the peak load forecast for the operating day. This requirement was established in August 2006. Beginning August 7, 2008, PJM began to calculate on-peak and off-peak regulation requirement. The on-peak requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day while the off-peak Regulation Requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in the first nine months of 2009 was 863 MW, compared to 947 MW for the first nine months of 2008.[23]

Logic for Tariff Modifications

While PJM did support the implementation of the TPS test in the Regulation Market, PJM did not advance any specific arguments for the three modifications to the market design. The broad rationale advanced for the three market design changes was that the proposal "includes mechanisms to ensure adequate cost recovery and avoid creating any disincentives for suppliers to continue offering regulation into the market."[24] As the MMU noted in comments filed in this matter, "there is no factual basis for this assertion."

PJM also stated in its filing: "Recognizing that institution of market power mitigation in this market could decrease the incentives for suppliers to offer regulation into the market, PJM stakeholders explicitly considered and included elements in this proposal that are intended to ensure full cost recovery by regulation suppliers and maintain adequate incentives to offer the service."[25]

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[22] *See 2009 Quarterly State of the Market Report for PJM: January through September,* Section 6 – Ancillary Services, at 111.

[23] *See 2009 Quarterly State of the Market Report for PJM: January through September,* Section 6 – Ancillary Services, at112.

[24] October 1st Filing in ER09-13-000 at 7.

[25] October 1st Filing at 5-6.

In the course of developing the compromise proposal, no analysis was provided to the TPSTF supporting the need for such mechanisms or incentives to ensure adequate cost recovery or to successfully procure regulation.[26]

Market power mitigation plays a central role in ensuring competitive outcomes in PJM markets generally, even in the presence of structural market power. The assertion that the inclusion of market power mitigation in the market design means that there must be some additional, not clearly defined, incentive payments is antithetical to the fundamental PJM market design.

With respect to the cost recovery issue, the assertion that the market design changes were required in order to provide "full cost recovery" is not supported by any evidence or even any assertions of evidence. In fact, as a direct result of the discussion about the TPS test in the membership process, special meetings of the CDTF were convened to address the issue of the definition of costs for regulation service because the cost issue was raised in the membership process. The CDTF agreed unanimously with a series of changes to the definition of costs, which were implemented effective October 16, 2007. These changes were based on recommendations by generation owners and the generation owners agreed with the changes. The outcome was a definition of the costs of regulation developed by PJM stakeholders and incorporated in Section 9 of PJM's Cost Development Guidelines Manual. Thus, the issues of the definition of the costs of regulation had been explicitly resolved prior to the October 1st Filing. There is nothing in the filing that relates in any way to cost recovery or the definition of the costs of regulation.

With respect to the incentive issue, PJM's only support was the assertion, based on a single graph provided by PJM to a TPSTF meeting, that owners of regulation capacity offered "only 30 – 40%" of that capability and that the offer capped owners, AEP and Dominion, offered only "15 – 30%" of their capability.[27]

The relationship between the level of regulation capability offered into the Regulation Market on an hourly basis and the level of actual hourly eligible regulation has been repeatedly established by the MMU in its reports on the Regulation Market. Eligible regulation has been less than half of regulation capability since the establishment of the regulation market and, in fact, since the start up of PJM markets on April 1, 1999. More importantly, the MMU reports have documented that the hourly offers of eligible regulation have been substantially in excess of the levels of regulation required for

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26 PJM posts materials for the March 31, April 17, May 19 and June 5, 2008 meetings of the TPSTF at < http://www.pjm.com/committees-and-groups/closed-groups/tpstf.aspx >.

27 October 1st Filing at 5.

reliability. The tables in this report show comparable results for the periods under review.

There are a variety of possible explanations for the actual offer behavior, but there is no evidence that regulation supply had been withheld by any supplier including AEP or Dominion, or that the levels of regulation offers were a result of less than competitive compensation, or that the levels of regulation offers have ever been even close to the levels required for reliability. Regulation offer behavior varies widely by company.

The evidence from the first eleven months of the new rules does not support the need for the three modifications to the design of the Regulation Market. There was an increase in regulation capability in 2009 over 2008 of 412 MW, or 5.6 percent, and a corresponding increase in average hourly eligible offers of 287 MW, or 13 percent. The ratio of eligible supply to required regulation in the first 10 months of 2008 was 2.90. The ratio of eligible supply to required regulation in 2008 was 2.39. The increase in the ratio was the result of both the increase in eligible offers and the reduction in demand for regulation. The increase in supply came entirely from owners that had not previously been subject to offer capping, but were subject to offer capping under the new rules. For the owners that had been subject to offer capping 100 percent of the time, but were subject to less frequent offer capping, regulation capability decreased by 64 MW or about 3 percent, while average hourly eligible offers increased by 3 MW or less than 1 percent.

Increase in the Margin

The tariff modifications included an increase of the margin included in cost-based regulation offers from $7.50 to $12.00 per MW. The average cost based regulation offer is less than $10.00 per MW, so this margin represents a substantial adder to costs. While there was no specific rationale advanced for the increase in the margin, the only logical argument would be that this margin is somehow part of marginal costs. The Cost Development Manual defines the marginal costs of providing the identified services. While the MMU is unconvinced that such an increase is required, the MMU does not now recommend reducing the margin to the prior level of $7.50 per MW. While there is no support provided for the margin, the appropriate margin is, in concept, subject to empirical determination within some limits. This is in contrast to the other two modifications to the Regulation Market design, which are incorrect conceptually and are inconsistent with the treatment of the same issues elsewhere in the PJM tariff.

The Impact of Increasing the Margin on Cost-Based Offers from $7.50 to $12.00 Per MWh

Table 5 shows the additional revenues that are paid as a result of the rule change that increased the margin on cost based offers from $7.50 to $12.00 per MWh. The first column shows how often the marginal unit's cost based offer was greater than cost plus

$7.50. The second column shows how often the additional margin affected the Regulation Market Clearing Price (RMCP). A unit may be marginal with an offer above cost plus $7.50 but the higher margin on cost based offers does not impact the price because the unit's effective offer is price based rather than cost based. The third column shows the total regulation credits. The fourth column shows the additional revenue paid as a result of the higher margin. The fifth column shows the percent increase in total credits paid. Note that the percent increase in column four refers to total regulation credits.

This calculation is an estimate and is not based on reclearing the Regulation Market with modified offers. The calculation assumes that the clearing price is reduced by the full amount of the difference between the actual margin and the prior $7.50 margin. This approach may result in an overestimate when there are other units with offers between the two offers of the marginal unit and those offers are either cost based with a margin of $7.50 or less, or price based.

The increase in the margin resulted in an estimated increase in payments to the providers of regulation of $6.5 million over the 11 month period from December 2008 through October 2009. This represents an increase in total regulation payments of from one percent to six percent on a monthly basis and 2.9 percent for the 11 month period.

Table 5 Impact of $12 adder to cost based regulation offer: December 2008 through October 2009

Year	Month	Number of Periods When Marginal Unit Offer Greater Than Costs Plus $7.50	Number of Periods When Marginal Unit Offer Greater Than Costs Plus $7.50 Impacts Price	Total Regulation Credits	RMCP Credits Attributable to Marginal Units Cost Offer > Costs Plus $7.50	Percent Increase in Total Credits Due to Marginal Unit With Offer > Cost Plus $7.50
2008	Dec	629	286	$25,609,796	$1,072,284	4%
2009	Jan	612	237	$26,614,050	$847,740	3%
2009	Feb	595	237	$21,455,212	$773,856	4%
2009	Mar	670	120	$17,853,025	$369,684	2%
2009	Apr	659	122	$12,172,449	$340,555	3%
2009	May	637	112	$21,180,526	$306,988	1%
2009	Jun	596	116	$24,664,652	$364,863	1%
2009	Jul	574	131	$20,237,959	$436,178	2%
2009	Aug	566	146	$23,049,672	$518,021	2%
2009	Sep	550	226	$15,251,640	$649,811	4%
2009	Oct	538	296	$13,587,330	$785,454	6%
Total				$221,676,311	$6,465,434	2.9%

Change in the Definition of Opportunity Cost

The tariff modifications included a change in the definition of opportunity cost. Offers in the Regulation Market consist of the direct offer price and the opportunity cost, which is calculated by PJM based on forecast LMP for the next hour. The tariff change to the definition of opportunity cost is the most significant, because the opportunity cost is, on average, more than half the total offer price. Any modification to the measurement of opportunity cost will have a significant impact on the Regulation Market.

In general, opportunity cost refers to the value of an opportunity that cannot be pursued because a resource is being used for another opportunity. For example, if a unit reduces its generation output in order to be able to provide regulation, the opportunity cost of providing regulation is the value of the foregone opportunity to generate MWh and sell them at LMP.

The change to the tariff is inconsistent with the definition of opportunity cost, is inconsistent with the way in which opportunity cost is calculated elsewhere in the PJM tariff and is inconsistent with the way in which opportunity cost has been calculated for regulation under the PJM tariff for approximately ten years. The MMU recommends that this modification be reversed and that the correct definition of opportunity cost be reinstated for regulation. In addition, to getting the price right, the concept and application of opportunity cost is critical to ensuring an efficient allocation of resources between the energy market and the ancillary services markets. The goal is to hold generators neutral to the decision whether to sell MWh in the energy market or to regulate, in order to ensure that the energy markets and the ancillary markets all clear in an efficient manner.

The opportunity cost of providing regulation is the value of the foregone opportunity to generate MWh and sell them at LMP. However, the opportunity cost is not the gross revenues which would result from the sale of the MWh. Selling MWh requires that resources be used and the value of those resources must be offset against the gross revenues when calculating the opportunity cost of providing regulation. Under the prior method of calculating opportunity cost for regulation, opportunity cost was calculated by subtracting the unit's accepted offer, on which the unit was simultaneously dispatched, from the LMP to determine the level of energy net revenue foregone in order to provide regulation. That is the correct method because the generation owner has offered to provide energy at this specific price, which reflects the owner's marginal costs or the owner's view of their marginal costs. If that is not the case, either the owner is irrational or is attempting to exercise market power.

In the simplest case, the unit is offered at its marginal cost and the calculation results are the same, regardless of method. However, if the unit is offered at a price greater than marginal cost and is dispatched based on that price, the use of the new method will result in a higher calculated opportunity cost. The difference between the LMP and the cost based offer is greater than the difference between the LMP and the price offer on which the unit is dispatched. Effectively, the new method assumes that the unit will not respond to dispatch even when LMP exceeds its marginal cost as defined by its cost based offer. Under the new method, the market accepts the price offer but the regulation opportunity cost calculation uses the marginal cost from the cost-based offer.

The correct way to calculate opportunity cost and maintain incentives across both markets is to treat the offer on which the unit is dispatched as the measure of its marginal costs for both the energy market and the Regulation Market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher opportunity cost. This gives the generation owner a non-efficient incentive to provide regulation rather than generation. It also provides the owner an incremental incentive to exercise market power in the energy market. Under the appropriate definition of opportunity cost, as the price offer for energy increases, opportunity cost decreases. Under the new definition of opportunity cost, as the price offer for energy increases, the opportunity cost does not change.

Opportunity Costs in the PJM Tariff

The calculation of opportunity costs is addressed in several places in the PJM tariff including opportunity costs related to synchronized reserves, reactive services, synchronous condensing for post-contingency operation, and PJM directed reduction in output by units for reliability reasons.[28] In every case, including the definition of opportunity cost for regulation prior to the December 1 change, the definition of opportunity cost uses the current dispatched energy offer as the basis for the calculation.[29]

For synchronized reserves, the tariff defines the relevant portion of opportunity cost as: "the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the synchronized reserve set point for the resource) in the PJM Interchange Energy Market."[30] The opportunity cost for synchronized reserves is calculated using the difference between the LMP and the offer price for energy of the resource. This is the actual offer price used in the dispatch as further indicated by the fact that the actual set point is used to determine the exact offer

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28 PJM Operating Agreement (OA) Schedule 1 §§ 3.2.2, 3.2.2A (Regulation), 3.2.3A (Synchronized Reserve), 3.2.3B (Reactive) & 3.2.3C (Synchronous Condensing).

29 *See Id.*; PJM OA Schedule 1 § 3.2.2(e), Sixth Revised Sheet No. 109 (effective May 1, 2006).

30 *See* PJM OA Schedule 1 § 1.11.4A.

price from the offer curve. This is the way in which PJM has applied the calculation of opportunity costs to synchronized reserves.

Opportunity cost for units providing synchronous condensing for post-contingency operation are compensated in the same manner when such units also provide synchronized reserve.[31]

For reactive services, the tariff defines the opportunity cost as the difference in MW output required to provide reactive service multiplied by the difference between LMP and the offer price for energy of the resource.[32] The tariff states that this offer price: "equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule." This is the actual offer price used in the dispatch. In the case of the tariff language for reactive services, the logic is further clarified by requiring the use of the cost-based offer in place of the price-based offer when the cost-based offer is higher.

The PJM tariff provides for the payment of opportunity costs to units which reduce output at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue.[33] The tariff states that the payment will equal the difference in MW output required to provide the requested reliability, multiplied by the difference between LMP and the offer price for energy of the resource. The tariff states that this offer price: "equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for that unit, in which case the offer for the unit will be determined from the cost-based schedule." This is the actual offer price used in the dispatch.

For regulation, prior to the tariff change, the opportunity cost was defined in the tariff in the same way that it is defined for all other applications of opportunity cost, as the difference between the LMP that would have been received and the offer price based on the actual offer curve used in dispatch. The previous tariff language defined opportunity cost as the difference in MW multiplied by the difference between LMP and the offer price of the unit. Specifically: "the absolute value of the difference between the expected

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31 *See* PJM OA Schedule 1 § 3.2.3C.

32 *See* PJM OA Schedule 1 § 3.2.3B(c).

33 *See* PJM OA Schedule 1 § 3.2.3(f))

Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market."[34]

The Impact of Modifying the Definition of Opportunity Costs

Table 6 compares the impact on the regulation market clearing price of the old and new methods of calculating opportunity cost. The Regulation Market is cleared using a supply curve based upon each unit's offer plus opportunity cost. For the current method, the opportunity cost is based on forecast LMP and the lesser of the price-based energy schedule or most expensive cost-based energy schedule. For the prior method, the opportunity cost is based on the current energy dispatch schedule. The results show a higher regulation market clearing price (RMCP) using the new method compared to the prior method. The current method is in the column labeled "Load Weighted RMCP Using Lesser Schedule for LOC."

Table 6 Impact to regulation market clearing price of using lesser of price-based energy schedule or most expensive cost-based energy schedule vs. current dispatch schedule: December 2008 through October 2009

			New Rule		Old Rule		Additional Credits	
Year	Month	Average Regulation Required (MW)	Load Weighted RMCP Using Lesser Schedule for LOC	Using Lesser Schedule For LOC, Total Charges	Load Weighted RMCP Using Current Dispatch Schedule for LOC	Using Current Dispatch Schedule For LOC, Total Charges	Additional Regulation Credits Paid Using New Rule	Percentage Increase in Regulation Credits
2008	Dec	912	$24.79	$25,609,796	$22.50	$24,039,842	$1,569,954	6%
2009	Jan	970	$21.04	$26,614,050	$17.62	$24,136,240	$2,477,810	9%
2009	Feb	905	$25.83	$21,455,212	$17.10	$16,257,318	$5,197,894	24%
2009	Mar	819	$19.90	$17,853,025	$16.34	$15,645,792	$2,207,233	12%
2009	Apr	762	$16.84	$12,172,449	$13.93	$10,569,368	$1,603,081	13%
2009	May	738	$32.41	$21,180,526	$24.63	$16,514,576	$4,665,950	22%
2009	Jun	884	$32.59	$24,664,652	$23.08	$17,198,351	$7,466,301	30%
2009	Jul	908	$24.10	$20,237,959	$15.33	$12,992,257	$7,245,702	36%
2009	Aug	998	$23.89	$23,049,672	$14.18	$15,047,460	$8,002,212	35%
2009	Sep	803	$20.09	$15,251,640	$13.72	$10,656,302	$4,595,338	30%
2009	Oct	744	$17.20	$13,587,330	$13.62	$11,167,730	$2,419,600	18%
Post-Change Total				$221,676,311		$174,225,236	$47,451,075	21%

Note that total charges are the sum of Regulation Market charges and post market opportunity cost charges. Post market charges are incurred when the actual opportunity cost of a unit exceeds the opportunity cost included in the clearing price. The change to clearing price affects the Regulation Market charges but has no impact upon post market

[34] PJM OA Schedule 1 § 3.2.2(e), Sixth Revised Sheet No. 109 (effective May 1, 2006).

opportunity cost charges. Thus, the clearing prices differ by a greater percentage than total charges.

This calculation is an estimate based on reclearing the Regulation Market with the revised opportunity cost inputs for each offer. The MMU does not have access to the PJM market software (SPREGO) for the Regulation Market and thus used an approximation. For every hour, the MMU calculated the opportunity cost of each unit using the prior regulation market rule. The MMU constructed new supply curves and did a recalculation of the clearing price for each hour assuming the same synchronized reserve dispatch and the same unit availabilities.

The change to the definition of opportunity cost resulted in an estimated increase in payments to the providers of regulation of $47.5 million over the 11 month period from December 2008 through October 2009. This represents an increase in total regulation payments of from 6 percent to 36 percent on a monthly basis and 21 percent for the 11 month period.

Eliminate Offset Against Operating Reserve Credits

The tariff modifications included eliminating the offset of the net revenues earned in the Regulation Market against operating reserve credits. There was no specific rationale advanced for this change. This tariff modification is directly counter to the fundamentals of the PJM markets and the purpose of operating reserve credits. The MMU recommends that this modification be reversed and that the net revenues earned in the Regulation Market be offset against operating reserve credits in the same manner that all net revenues from all other PJM markets are offset against operating reserve credits and in the same manner that regulation market credits were offset against operating reserve credits prior to December 1, 2009.

Operating reserve credits are provided to the owners of generating units in order to ensure that unit owners are never required to run their units without full recovery of marginal costs. For example, if a unit with an offer of $100 per MWh runs at PJM's request for four hours during which the average LMP is $50 per MWh, then the unit will be paid its full offer amount, including start costs. The difference between the total payment and the market revenues resulting from LMP payments are the operating reserve credits. If the unit were also providing reactive service, the revenues from reactive service would be included in the total market revenue when calculating operating reserve credits. This is also true for revenues from the provision of synchronized reserves and was true for revenues from the provision of regulation service prior to this tariff change.

The logic of including all market revenues in the calculation of operating reserve credits is clear. The goal is to ensure that unit owners are never required to run their units without compensation of all marginal costs, but all market compensation is included when determining whether there is a shortfall. The exclusion of the regulation revenues is arbitrary and results in an increase in operating reserve charges and a shift of revenues to the owners of regulating units from those who pay operating reserve charges. There is no reason to modify a fundamental market rule in order to provide greater incentives in the Regulation Market. This argument is reinforced by the appropriately increased scrutiny paid to operating reserve in recent years, and given the overall goal to reduce these non market payments. No need for additional incentive has been established. If there actually were a need for greater incentives, it should be established directly and the incentive payment made directly. The total increase in operating reserve credits to date has been fairly small.

Offsets to Operating Reserve Credits in the PJM Tariff

The PJM tariff applies a clear logic to the calculation of operating reserve credits to be paid to generation resources. The logic is that any generating resource required to run at PJM's request will be made whole to its marginal costs, after accounting for all market revenues. All market revenues include revenues from the energy market, from the provision of synchronized reserves, and from the provision of reactive services. These revenues also included revenues from regulation prior to this change.

The PJM Manual 28: Operating Agreement Accounting makes this clear at page 29:

> "The total resource offer amount for generation, including startup and no-load costs as applicable, is compared to its total energy market value for specified operating period segments during the day (including any amounts credited for day-ahead scheduling reserve in excess of the day-ahead scheduling reserve offer, any amounts credited for synchronized reserve in excess of the synchronized reserve offer plus opportunity cost, and any amounts credited for resources providing reactive services). If the total value is less than the offer amount, the difference is credited to the PJM Member."

The Impact of Eliminating the Netting of Net Regulation Revenue Against Operating Reserve Credits

Table 7 includes the regulation credits eligible for offset, and actually offsetting balancing operating reserve under the prior market rules and the new rules. There was a reduction in the offset against operating reserve credits over the December through October period of $7.6 million. This was an increase in net revenue received by generating unit owners compared to what would have occurred under the prior market rules.

Table 7 Impact on regulation credits of eliminating the netting of net regulation revenue. (Data is September 2008 through October 2009; totals include only December 2008 through September 2009.)

Year	Month	Load Weighted Regulation Market Clearing Price	Regulation Credits Before Offset	Regulation Credits Eligible to Offset Operating Reserves	Actual Credits Offset Against Operating Reserves	Credits Offset Against Operating Reserves Under Old Rule	Final Regulation Credits Under Old Rule	Percentage of Credits Offset Under Old Rule
2008	Sep	$39.99	$36,137,028	$13,551,211	$297,125	$297,125	$35,839,903	1%
2008	Oct	$29.58	$23,801,880	$7,976,251	$214,423	$214,423	$23,587,457	1%
2008	Nov	$29.48	$25,335,642	$9,202,784	$172,452	$172,452	$25,163,190	1%
2008	Dec	$24.71	$25,609,796	$7,436,447	$0	$305,602	$25,304,194	1%
2009	Jan	$21.04	$26,614,050	$4,740,510	$0	$196,840	$26,417,210	1%
2009	Feb	$25.83	$21,455,212	$7,912,596	$0	$248,663	$21,206,549	1%
2009	Mar	$19.90	$17,853,025	$5,103,398	$0	$261,539	$17,591,486	1%
2009	Apr	$16.84	$12,172,449	$3,739,354	$0	$193,303	$11,979,146	2%
2009	May	$32.41	$21,180,526	$14,123,960	$0	$1,176,340	$20,004,186	6%
2009	Jun	$32.59	$24,664,652	$18,197,004	$0	$1,389,399	$23,275,253	6%
2009	Jul	$24.10	$20,237,959	$12,769,702	$0	$1,078,174	$19,159,785	5%
2009	Aug	$23.89	$23,049,672	$11,709,264	$0	$803,008	$22,246,664	3%
2009	Sep	$20.09	$15,251,640	$7,916,634	$0	$822,891	$14,428,749	5%
2009	Oct	$17.20	$13,587,330	$5,856,272	$0	$1,107,098	$12,480,232	8%
Total: Dec-Oct			$221,676,313	$99,505,141	$0	$7,582,857	$214,093,456	4%

This calculation is based on a comparison of the net revenues for each unit from the Regulation Market to the actual operating reserve credits for each unit.

Table 7 shows total regulation revenues (regulation market credits) and net regulation revenues (regulation credits above offer plus opportunity cost). Under the prior market rule net regulation revenues would have been used to offset any operating reserve credits. Regulation Market revenues that would actually offset operating reserve credits are limited by the amount of operating reserve credits to offset. Table 7 also shows: the actual net regulation revenues that were offset against operating reserve credits for September, October and November 2008 under the prior market rule; the net regulation revenues that would have been offset against operating reserve credits under the prior market rule for December 2008 through October 2009; and the total regulation revenue that would have remained after the offset against operating reserve credits. Under the prior rule, regulation market credits would have been reduced by the percents shown in the last column. Under the new rules, this reduction no longer occurs, so the last column represents an increase in total regulation market revenues that resulted from the new rules.

The elimination of the offset to operating reserve credits resulted in an increase in payments to the providers of regulation of $7.6 million over the 11 month period from December 2008 through October 2009. Table 7 shows that total regulation payments are from 1 to 8 percent higher on a monthly basis and 4 percent higher for the 11 month period, as a result of this change to the market design.

Summary and Conclusion

Table 8 summarizes the additional regulation credits paid by PJM market participants as a result of each of the three rule changes that went into effect on December 1, 2008.

Together, the changes to the tariff related to the Regulation Market resulted in an increase in payments to the providers of regulation of $61.5 million over the 11 month period from December 2008 through October 2009. This represents an increase in total regulation payments of from 13 percent to 76 percent on a monthly basis and 38 percent for the 11 month period. While these results are based on estimates of how the market would have worked in the absence of the changes in market design, the calculations reflect detailed hourly data about the individual units in the Regulation Market supply curve. There is no question that the changes in market design significantly increased the payments for regulation service.

Table 8 Additional charges paid as a result of December 1, 2008 changes to Regulation Market rules: December 2008 through October 2009

Year	Month	Additional RMCP Credits Attributable to Marginal Units Cost Offer > Costs Plus $7.50	Credits No Longer Offset Against Operating Reserves Under New Rule	Additional Regulation Credits Paid Using New Rule	Total	Percentage Increase in Regulation Credits as a Result of December 2008 Rules Changes
2008	Dec	$1,072,284	$305,602	$1,569,954	$2,947,840	13%
2009	Jan	$847,740	$196,840	$2,477,810	$3,522,390	15%
2009	Feb	$773,856	$248,663	$5,197,894	$6,220,413	41%
2009	Mar	$369,684	$261,539	$2,207,233	$2,838,456	19%
2009	Apr	$340,555	$193,303	$1,603,081	$2,136,939	21%
2009	May	$306,988	$1,176,340	$4,665,950	$6,149,278	41%
2009	Jun	$364,863	$1,389,399	$7,466,301	$9,220,563	60%
2009	Jul	$436,178	$1,078,174	$7,245,702	$8,760,054	76%
2009	Aug	$518,021	$803,008	$8,002,212	$9,323,241	68%
2009	Sep	$649,811	$822,891	$4,595,338	$6,068,040	66%
2009	Oct	$785,454	$1,107,098	$2,419,600	$4,312,152	46%
Total		$6,465,434	$7,582,857	$47,451,075	$61,499,366	38%

The MMU supported the October 1st Filing with the caveat that if the MMU review of the actual impact of the changes "results in a conclusion that these features result in non-competitive market outcomes, the Market Monitor will request that one or more of these provisions be removed or modified." The three modifications to the market design were: (i) increasing the margin on cost based offers from $7.50 to $12.00 per MW; (ii) modifying the calculation of opportunity costs to use the lower of cost based or price based offers rather than the current dispatch schedule as the reference; and (iii) eliminating the netting of regulation revenues from make whole balancing operating reserve payments.

The market design changes added a substantial cost to those paying for regulation without any evidence that this cost was required for either cost recovery or incentives. If the market design is a good one, there is no reason to make selective and non systematic modifications to the rules in order to enhance returns to the sellers of regulation. The Regulation Market design is a good one and will provide appropriate incentives and returns without these changes. The MMU recommends that the modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed as they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic. The MMU does not recommend that the increase in the margin be reversed at this time as this is an empirical question subject to empirical determination within some limits.

PJM's rationale for these changes does not support the changes to the market design. The logical steps of the rationale are: regulation is necessary for reliability; market power mitigation could reduce incentives to supply regulation; full cost recovery should be ensured; adequate incentives should be maintained; maintaining or increasing the amount of regulation will increase competition and reduce the requirement for market power mitigation.[35]

Regulation is necessary for reliability. In a competitive market, regulation owners will offer regulation at marginal cost. The application of the TPS test results in the same competitive offer behavior by regulation owners even in the presence of structural market power. The presumption that market power mitigation reduces incentives below the competitive level is incorrect. Therefore the conclusion that extraordinary measures must be taken to increase incentives to provide regulation has no basis. While it may be correct that paying in excess of the competitive price could incent additional regulation, that would be an inefficient result, particularly given that demand for regulation is fixed. Full cost recovery is ensured by the changes to Manual 15 that were designed and agreed to by PJM members. The assertion that maintaining or increasing the amount of regulation will necessarily increase competition is also not correct. For example, increasing the amount of regulation offered by a dominant supplier or a group of dominant suppliers will not increase competition. Increasing the number of competitors is more likely to increase competition, but it is also less likely given the ownership structure of generation assets in PJM.

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[35] October 1st Filing at 5-6.