UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)))	Docket No. EL14-94-000

MOTION FOR CLARIFICATION, OR, IN THE ALTERNATIVE REQUEST FOR REHEARING OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rules 212 and 713 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM[2] ("Market Monitor"), submits this motion for clarification, or, in the alternative, request for rehearing of a certain holding included in the order issued in this proceeding March 1, 2016 ("March 1st Order").[3]

I. REQUEST FOR CLARIFICATION

The Market Monitor supports the March 1st Order in important respects. The Market Monitor agrees with the finding (at P 51) that "PJM's Tariff is unjust and unreasonable because it allows the cost-based energy offer cap to be used as the sole measure of short-run marginal cost in calculating capacity market offer caps." The specific relief ordered, however, is flawed, because it requires the use of market-based offers as the measure of short run marginal costs when they are higher than cost-based offers. The extent to which a

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1 18 CFR §§ 385.212 & 385.713 (2015).

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

3 PJM Interconnection, L.L.C., 154 FERC ¶ 61,151.

market-based offer exceeds a cost-based offer constitutes markup. Markup is not part of a competitive offer. Markup should not be included as a short run marginal cost ("SRMC") in the calculation of net revenues.

The Commission's order would include markup in short run marginal cost in the calculation of net revenues with two exceptions.

The order finds (at 59) that:

> PJM should use the resource's non-zero market-based offer to reflect marginal costs except in two circumstances, in which the cost-based offer should be used: 1) when the resource is mitigated and its market-based offer is above the cost-based offer cap under PJM's Tariff, as the market-based offer in this circumstance may reflect the exercise of market power; and 2) when the market-based offer is less than its fuel and environmental costs, since the generator is losing money for each MW produced, a reasonable projection of its energy and ancillary services revenue should reflect such a reduction.

There is no support in the record or in economic logic for using a market-based offer that exceeds a cost-based offer. The lower of the cost-based or market-based offer is the most accurate measure of short run marginal cost.

The March 1st Order indicates that the use of the market-based offer when it is greater than the cost-based offer follows the same economic logic as the use of the market-based offer when it is lower than the cost-based offer. But it does not. Voluntary market-based offers less than cost-based offers reveal the generation owners' views about their actual short run marginal cost. Such offers typically exclude, for example, the ten percent adder permitted under the tariff because it is not part of short run marginal costs for coal units. This is the actual observed behavior in PJM markets. Cost-based offers must follow the PJM rules which define short run marginal cost, including fuel costs, short run marginal operation and maintenance expense, the cost of emissions allowances and opportunity cost if appropriate plus the ten percent adder. Cost-based offers reflect all short run marginal costs plus the ten percent adder. Market-based offers above cost-based offers are therefore greater than short run marginal cost by the amount of markup. Markup is not part of short run marginal cost.

If not clarified, the Commission's order would create substantial uncertainty about the definition of a competitive offer, the definition of short run marginal cost and the definition of market power.

For example, if a unit has a market-based offer greater than its cost-based offer, the definition of short run marginal cost would depend on whether it was offer capped. Under the March 1st Order as written, for an hour when the unit is offer capped, the short run marginal cost would be the cost-based offer and in the same hour if the unit were not offer capped, the short run marginal costs would be the market-based offer.

The unit is offer capped to the cost-based offer precisely because the market-based offer is deemed to be in excess of the short run marginal cost and therefore in excess of a competitive offer, by the amount of the markup. Both the cost-based offer and the market-based offer cannot be short run marginal cost at the same time when the market-based offer is greater than the cost-based offer, or when it is lower.

The cost-based offer should be the default offer that reflects short run marginal cost for calculating net revenues, except when the market-based offer is lower than the cost-based offer.

The requirement should state:

> Marginal costs shall be calculated as equal to the lower of (i) market-based offers for the sale of energy or ancillary services from such resource or (ii) cost-based offers as defined in Schedule 2 to the Operating Agreement and in PJM Manual 15 (Cost Development Guidelines) or successor rules. However, marginal costs for a unit shall be calculated as the cost-based offer when the Capacity Market Seller can demonstrate that the market-based offer is less than the fuel and emissions allowances components of marginal cost for the unit.

If net revenues are calculated as required by the March 1st Order, net revenues will be understated for units with market-based offers that include markup, and market seller offer caps for those units in the capacity market will therefore be too high, inflating capacity offer prices and potentially capacity market clearing prices. The impacts will be incorporated in capacity market prices in upcoming auctions, including the 2019/2020 Base Residual Auction and the 2017/2018 Second Incremental Auction to be conducted beginning on July 11, 2016, unless PJM files to postpone implementation and the Commission accepts.[4] The impacts on capacity market offers will be incorporated whenever the offers are calculated on the basis of Avoidable Cost Rate (ACR) less Net Revenues. Base Capacity Resources directly use ACR less net revenues. Capacity Performance Resources use net revenues to determine when a unit is classified as high ACR and therefore eligible to make an offer greater than Balancing Ratio (B) times Net CONE, the otherwise applicable offer cap.[5] In both cases, the use of artificially reduced net revenues would result in capacity market prices that reflect the noncompetitive energy offers and therefore the noncompetitive capacity market offers. The result would be inefficient even if not the result of conscious actions by market participants to exercise market power.

II. REQUEST FOR REHEARING

If clarification cannot be granted, then the Market Monitor requests that an order be issued on rehearing to determine that the short run marginal cost is the lower of the market-based or cost-based offer except where the market-based offer is less than fuel and environmental costs. It is important that the rehearing order address this issue in a timely manner in order to prevent an inefficient outcome in the 2019/2020 Base Residual Auction to be conducted beginning May 11, 2016, and in the 2017/2018 Second Incremental Auction

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4 PJM stated its intention to implement the March 1st Order starting with the 2017/2018 Second Incremental Auction to be conducted beginning July 11, 2016 and to not implement the March 1st Order in the 2019/2020 Base Residual Auction to be conducted beginning May 11, 2016, but no filing has been made.

5 *See* PJM Interconnection, L.L.C., et al., 151 FERC ¶ 61,208 at PP 336–339 (2015)

to be conducted beginning on July 11, 2016, unless PJM files to postpone implementation and the Commission accepts. The Market Monitor has an April 12, 2016, deadline for determinations on offer caps for this Incremental Auction. The Market Monitor's deadline for determinations on offer caps for the Base Residual Auction have passed.

An inefficient outcome would not be just and reasonable.

A. Market-Based Offers Above Cost-Based Offers Are Not Competitive.

The Commission states (at 56):

> Moreover, we find that PJM's existing tariff is unjust and unreasonable insofar as it uses the cost-based offer whenever the market-based offer exceeds the cost-based offer even in the circumstance in which the resource's offer is not mitigated. As long as the resource is not exercising market power, market-based offers above the cost-based offer also represent marginal cost, based on the same economic principles noted above.

The economic principles are stated (at 53):

> Under conditions where sellers lack market power and a uniform market clearing price is paid to all suppliers, a competitive seller of energy maximizes its profits by offering energy at its short-run marginal cost.

Thus, the assumption underlying the March 1st Order P59 is that in a uniform clearing price auction, all competitive offers will be at short run marginal cost. While this should be correct in a perfect market, this assumption (at 53) is not correct empirically for the PJM markets. It is possible for a unit to not have local market power and to still have an incentive and the ability to not offer competitively. The data show that while marginal units generally offer at or close to short run marginal cost, markups over short marginal cost persist for both marginal units and units that are not marginal. There are generation owners who routinely include high markups in market-based offers on some units. Combustion turbine market-based offers routinely exceed short run marginal cost. There are other generation owners who include high markups on a regular but less routine basis. PJM markets, as a routine matter, demonstrate that it is possible to have competitive results at the same time that not all offers are competitive.

The Market Monitor has demonstrated that cost-based offers frequently exceed short run marginal cost.[6] There is no evidence in this proceeding to show that market-based offers, when they exceed cost-based offers, equal short run marginal cost, or that cost-based offers understate short run marginal cost.

A competitive offer, by definition, does not include a positive markup over short run marginal cost. Market-based offers above cost-based offers include a markup and are not competitive by definition.

The Commission states (at 58):

> We therefore conclude that PJM's current tariff using cost-based offers in all circumstances to reflect marginal cost is at odds with the rest of PJM's market design and is unjust and unreasonable. As noted above, in the energy market, when a generation resource fails the three pivotal supplier test and submits a non-zero market-based offer less than its cost-based offer cap, PJM uses the lower, market-based offer, not the cost-based offer, as the basis for determining the resource's commitment and dispatch. When a resource is not subject to market power mitigation, PJM uses its offer as the basis for the resource's commitment and dispatch. In both cases, PJM's energy market relies on the offer, not the cap, as reflecting the resource's short-run marginal cost. [fn 75: The cost-based rate is an administratively determined marginal cost for the purpose of mitigation. In a well-functioning market, a market-based offer by a company without market power should represent the company's determination of its marginal cost.]

The Market Monitor agrees with the concepts but not the last sentence. The Commission states that, in the absence of offer capping for local market power, the market relies on the offer as reflecting the short-run marginal cost. The footnote adds the condition

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6 *See* 2015 State of the Market Report for PJM, Volume 2, Section 3: Energy Market (March 10, 2016); IMM Reply Brief re Net Revenues, (December 3, 2014) at p. 6.

that this "should" occur in a "well-functioning market." The issue is that, as an empirical fact, market discipline does not always result in market-based offers at short run marginal cost in the PJM market. The PJM market is well functioning and generally produces competitive results, but it is not perfect. The data show that market-based offers do, at times, exceed cost-based offers. The PJM market relies on incentives for competitive behavior. It is rules like those governing the calculation of net revenues that either strengthen or weaken the incentives to make competitive offers. The proposed modification to the rules for calculating net revenues in the March 1st Order would weaken those incentives and serve no positive function. The use of the lower of cost-based or market-based energy offers in the net revenue calculation would strengthen those incentives.

In addition, the March 1st Order (at 58) fails to state that when a generation resource fails the three pivotal supplier test and submits a market-based offer greater than its cost-based offer cap, PJM uses the lower, cost-based offer, not the market-based offer, as the basis for determining the resource's commitment and dispatch.

B. Impact on Incentives of Self Scheduled Units to Offer Competitively in the Energy Market.

Self scheduled units in PJM are an important example of a significant class of units that does not have an incentive to make competitive offers in the energy market. As a result, it is not reasonable to assume that market-based offers equal short run marginal costs for such units. The March 1st Order would further exacerbate the incentive problem for self scheduled units by creating an incentive to offer a high markup in the energy market. The incentive is a result of the fact that high energy offers would, under the March 1st Order, result in lower net revenues and therefore higher capacity market offer caps.

In addition, self scheduled units are not offer capped when they have local market power, so the exception in the March 1st Order would not apply.

Units which are self scheduled to generate fixed output are termed "self scheduled and nondispatchable." Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are termed "self scheduled and dispatchable." Self scheduled and dispatchable units are not offer capped by PJM and are dispatched between their economic minimum and economic maximum on their market-based offers.[7] Self-scheduled units have been able to circumvent the PJM market power mitigation rules. Self-scheduled and dispatchable units have been exempt from application of the market power mitigation rules. Under PJM's current practice, if the self-scheduled resource contributes incremental MW to relieve a transmission constraint, and the owner of the self-scheduled resource fails the TPS test for local market power, the resource is not offer capped and the resource's market-based offer sets price.[8]

Table 1 shows the proportion of MW offers by unit type that were self scheduled and nondispatchable and that were self-scheduled and dispatchable, by unit type and offer range for, for 2015. For example, 15.2 percent of CC offers were self scheduled and dispatchable and in the $0 to $200 price range. The total column is the proportion of all MW offers by unit type that were self scheduled and nondispatchable or self scheduled and dispatchable. For example, 18.8 percent of all CC MW offers were either self scheduled and nondispatchable or self scheduled and dispatchable up to economic maximum, including the 1.7 percent of emergency MW offered by CC units.

Despite this, the current rules require the use of cost-based offers when calculating net revenues for self scheduled units. If market-based offers that are higher than cost-based offers were to be used as a measure of marginal costs for net revenue calculations, resources that self schedule would have an incentive to self schedule with high markups without facing the risk of offer capping or not clearing in the energy market. While self scheduled

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7 *See* 2015 State of the Market Report for PJM, Volume 2, Section 3: Energy Market at 116-117 (March 10, 2016).

8 PJM Interconnection, L.L.C., Docket No. EL15-73-000 Compliance Filing to Implement Hourly Offers, (Docket changed to ER16-372-000) (Nov. 20, 2015). In the November 20th filing, PJM included tariff changes to formalize this inappropriate implementation of the local market power mitigation mechanism as it applies to self-scheduled resources.

resources are not eligible to be made whole in the energy market, the financial risk from self scheduling in the energy market exists only to the extent that revenues from energy market prices in any given hour do not compensate for the actual short run marginal cost of a resource. There is no additional risk in the energy market associated with high markups for self scheduled and nondispatchable units and the risk for self scheduled and dispatchable units would be that the markup resulted in less dispatch. At the same time, the resources benefit from lower net revenues and higher offer caps in the capacity market.

Table 1 Distribution of MW for self scheduled offer prices: 2015[9]

	Self Scheduled		Self Scheduled and Dispatchable (Range)							
Unit Type	Must Run	Emergency	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	1.4%	0.5%	0.2%	15.2%	0.1%	0.0%	0.1%	0.0%	1.2%	18.8%
CT	0.4%	0.1%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
Diesel	23.1%	1.0%	0.4%	0.3%	0.1%	0.0%	0.0%	0.0%	0.1%	25.0%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	91.9%	1.1%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	93.3%
Pumped Storage	16.1%	8.4%	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	4.4%	32.3%
Run of River	60.1%	9.9%	2.7%	19.8%	0.0%	0.0%	0.0%	3.5%	3.7%	99.7%
Solar	61.7%	21.6%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	83.6%
Steam	5.4%	1.5%	0.2%	39.6%	0.2%	0.0%	0.0%	0.0%	1.8%	48.7%
Transaction	74.9%	25.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	4.1%	2.9%	25.8%	2.8%	0.0%	0.0%	0.0%	0.0%	4.0%	39.4%
All Self-Scheduled Offers	22.5%	1.3%	0.6%	18.2%	0.1%	0.0%	0.0%	0.1%	1.1%	43.9%

C. Actual Unit Markups in PJM

The Commission's assumption that a resource that is not offer capped always makes market-based offers at short run marginal cost is incorrect as a factual matter. Market-based offers that set energy prices in PJM may include a markup above short run marginal cost. Market-based offers that are not marginal may also include a markup above short run marginal cost.

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9 See 2015 State of the Market Report for PJM, Volume 2, Section 3: Energy Market, Table 3-47 (March 10, 2016).

The Market Monitor presents statistics on the markup component of locational marginal prices (LMP) in the PJM energy market in the State of the Market reports.[10] The Market Monitor's assessments in those reports that the results of the energy market are competitive relies in part on the generally low level of markup by marginal units and the resultant low level of markup reflected in PJM annual average LMP.

The data show that the markup reflected in LMP is generally positive and reaches substantial levels for some hours, for some marginal resources. Table 2 shows that the monthly adjusted markup component of real-time load weighted LMP for all hours in 2014 and 2015 is positive in all months with only one exception.[11] The monthly adjusted markup component of real-time load weighted LMP for on peak hours in 2014 and 2015 is positive in all months and for off peak hours is negative in two months in 2014 and two months in 2015. The evidence shows that some market-based offers can and do include markup over the cost-based offer. For every such unit, the treatment of the market-based offer as the short run marginal cost in the net revenue calculation will result in an understatement of net revenues and an overstatement of capacity market offer caps.

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10 See 2015 State of the Market Report for PJM, Volume 2, Section 3: Energy Market.

11 The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer for coal units. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically exclude the 10 percent adder from their actual offers and offer close to their true short run marginal cost.

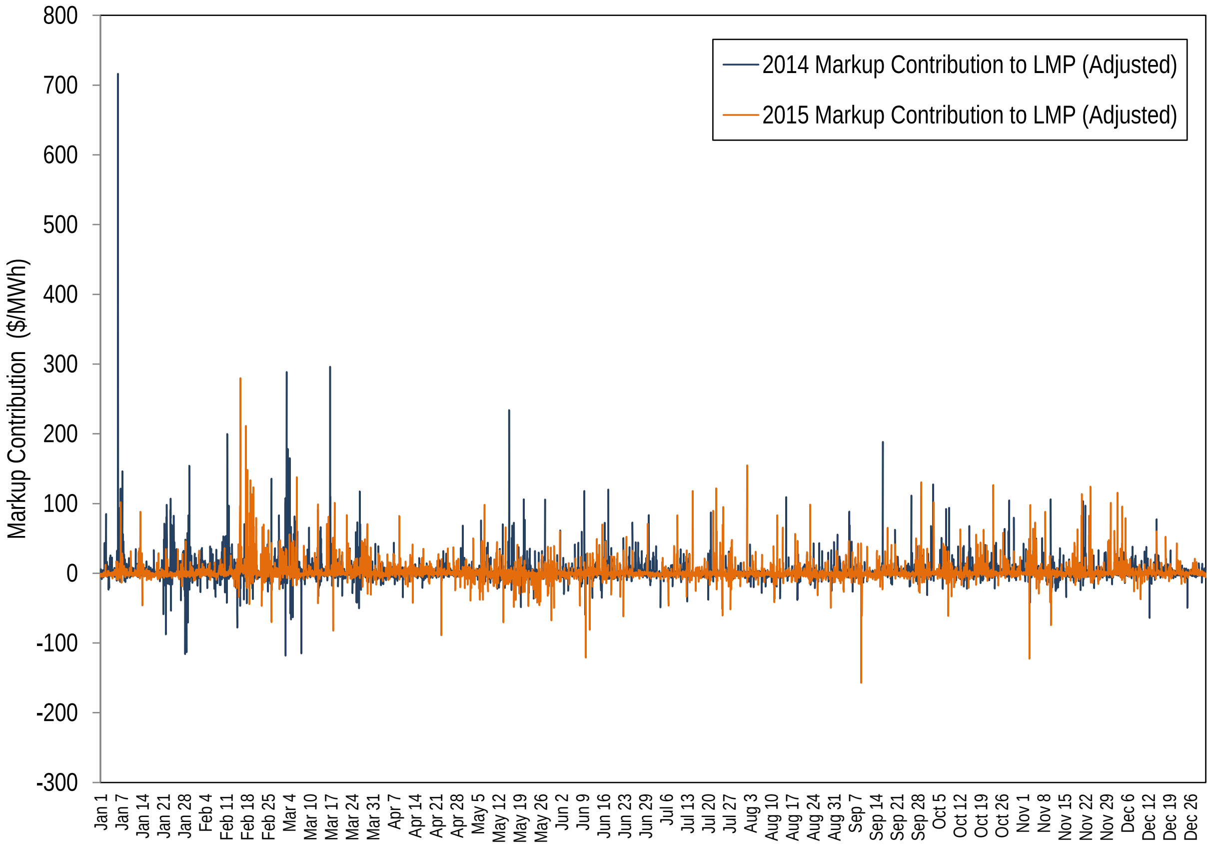
Table 2 Monthly markup components of real-time load-weighted LMP (Adjusted): 2014 and 2015[12]

	2014			2015		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$6.83	$5.48	$8.12	$0.61	($0.61)	$1.90
Feb	$3.94	$1.97	$5.84	$6.44	$3.57	$9.24
Mar	$8.21	$4.59	$12.02	$3.71	$3.69	$3.74
Apr	$0.86	($0.45)	$2.00	$1.22	$0.72	$1.65
May	$2.87	$0.09	$5.54	($0.45)	($2.41)	$1.64
Jun	$3.69	$1.46	$5.62	$1.18	$0.06	$2.10
Jul	$1.48	$0.35	$2.44	$1.17	$0.16	$1.97
Aug	$0.50	($0.29)	$1.25	$0.65	$0.43	$0.86
Sep	$3.18	$1.65	$4.59	$0.86	$0.71	$1.00
Oct	$3.71	$1.06	$5.90	$1.43	$0.91	$1.91
Nov	$1.93	$0.80	$3.25	$2.06	$0.80	$3.39
Dec	$1.65	$0.27	$2.97	$1.79	$0.84	$2.68
Total	$3.32	$1.54	$5.00	$1.75	$0.75	$2.70

Figure 3 shows the adjusted markup contribution to real-time hourly load weighted LMP in 2014 and 2015. Despite the fact that, on average, LMP is a function of marginal units offering at short run marginal cost, the data show that the markup component of LMP is volatile and frequently greater than zero. For example, during times of high relative demand (e.g. January through March, 2014, and February 2015), the markup component increases substantially. For every such unit, the treatment of the market-based offer as the short run marginal cost in the net revenue calculation will result in an understatement of net revenues and an overstatement of capacity market offer caps.

12 See 2015 State of the Market Report for PJM, Volume 2, Section 3: Energy Market, Table 3-50 (March 10, 2016).

Figure 1 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2014 and 2015[13]



D. Impacts of March 1st Order On Net Revenues

The Market Monitor analyzed the impact of the March 1st Order on the calculated net revenues that will apply for the RPM auction for delivery year 2019/2020. The impact on net revenues would be very significant for units with regular markups over short run marginal costs.

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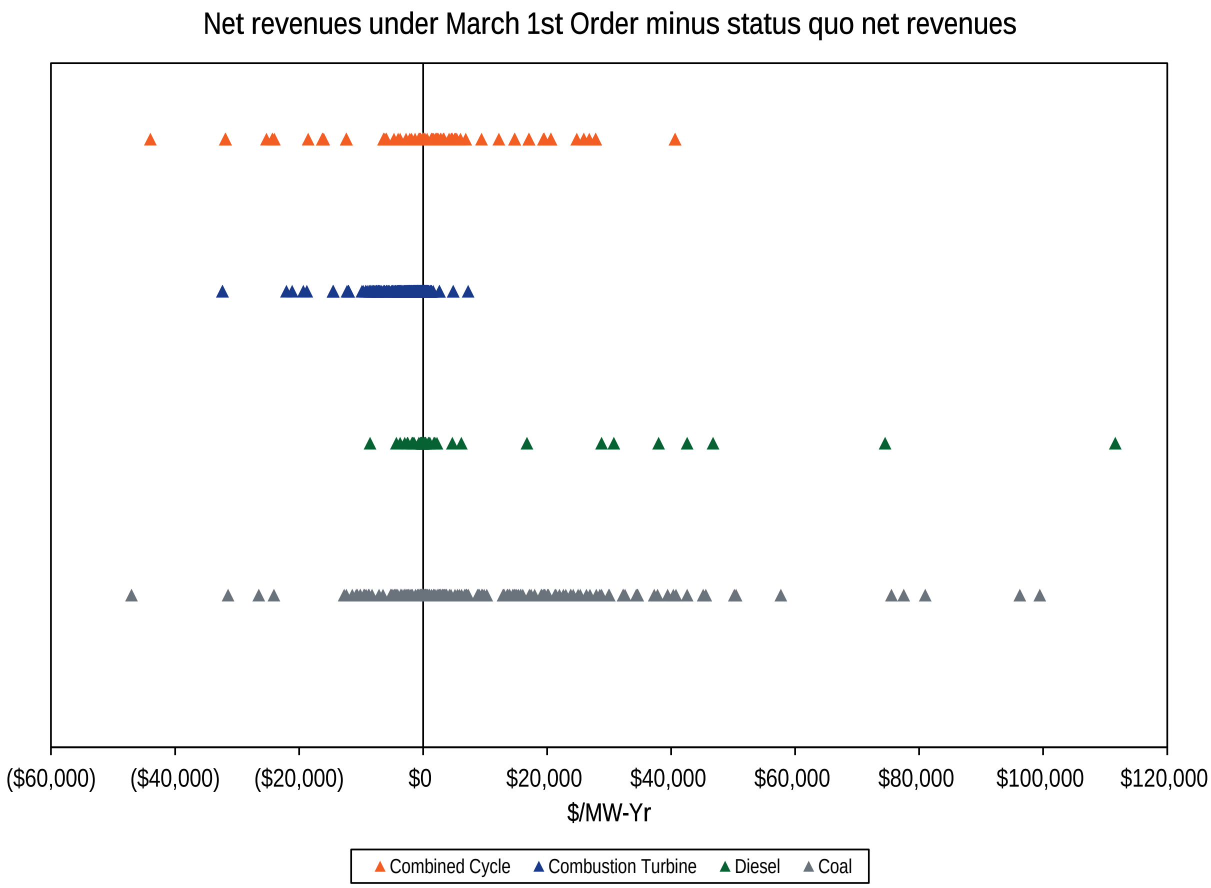
[13] See 2015 State of the Market Report for PJM, Volume 2, Section 3: Energy Market, Figure 3-32 (March 10, 2016). Figure 3-31 shows the markup contribution to real-time hourly load-weighted LMP unadjusted.

Figure 1 shows the distribution of the difference between the net revenues calculated under the March 1st Order and the net revenues calculated using cost-based offers, as required by the current PJM tariff rules (status quo), for the 2019/2020 Base Residual Auction. The results show that 68 percent of coal units have market-based offers lower than cost-based offers. This has been a standard result in PJM markets for some time, reflecting the fact that competitive offers for coal units do not include the ten percent adder. In contrast, 75 percent of CTs have market-based offers higher than cost-based offers. Three quarters of CTs have offers that include a markup over short run marginal cost.

Figure 2 Comparison of net revenues under the March 1st Order vs status quo[14]



14 Net revenues are the three year average of 2013, 2014 and 2015 net revenues used in the offer cap calculation for the 2019/2020 Base Residual Auction.

Under the March 1st Order, the net revenues for coal units would be correctly calculated when the market-based offers are less than the cost-based offers. But under the March 1st Order, the net revenues for combustion turbines would be understated as a result of using market-based offers with markups included as the definition of short run marginal costs.

For example, for the last four RPM Base Residual Auctions, the average offer cap for CTs ranged from $5.30/MW-day, or $1,935/MW-year for the 2018/2019 BRA, to $11.34/MW-day, or $4,150/MW-year for the 2015/2016 BRA.[15]

The March 1st Order would result in a large average decrease in net revenues for CTs of $2,074/MW-year compared to the status quo, raising the offer caps for CTs by from 50 percent to 107 percent.

Using the lower of cost-based and market-based offers would result in a smaller average increase in net revenues for CTs of $255/MW-year compared to the status quo, reducing the offer caps for CTs by from 6 to 13 percent.

Application of the Commission's March 1st Order would lead to lower class average net revenues for all four unit types (Coal, Combined Cycles, CTs and Diesels) compared to the method using the lower of cost-based and market-based. Figure 2 shows net revenues by technology class for the 2019/2020 Base Residual Auction under the three methods: the March 1st order; the status quo using cost based offers in all cases; the lower of cost-based and market-based offers. Net revenues calculated using the lower of cost-based and market-based offers are higher than net revenues calculated using the method in the March 1st Order. The differences are: 2 percent for diesel; 4 percent for coal; 16 percent for combined cycles; and 27 percent for combustion turbines.

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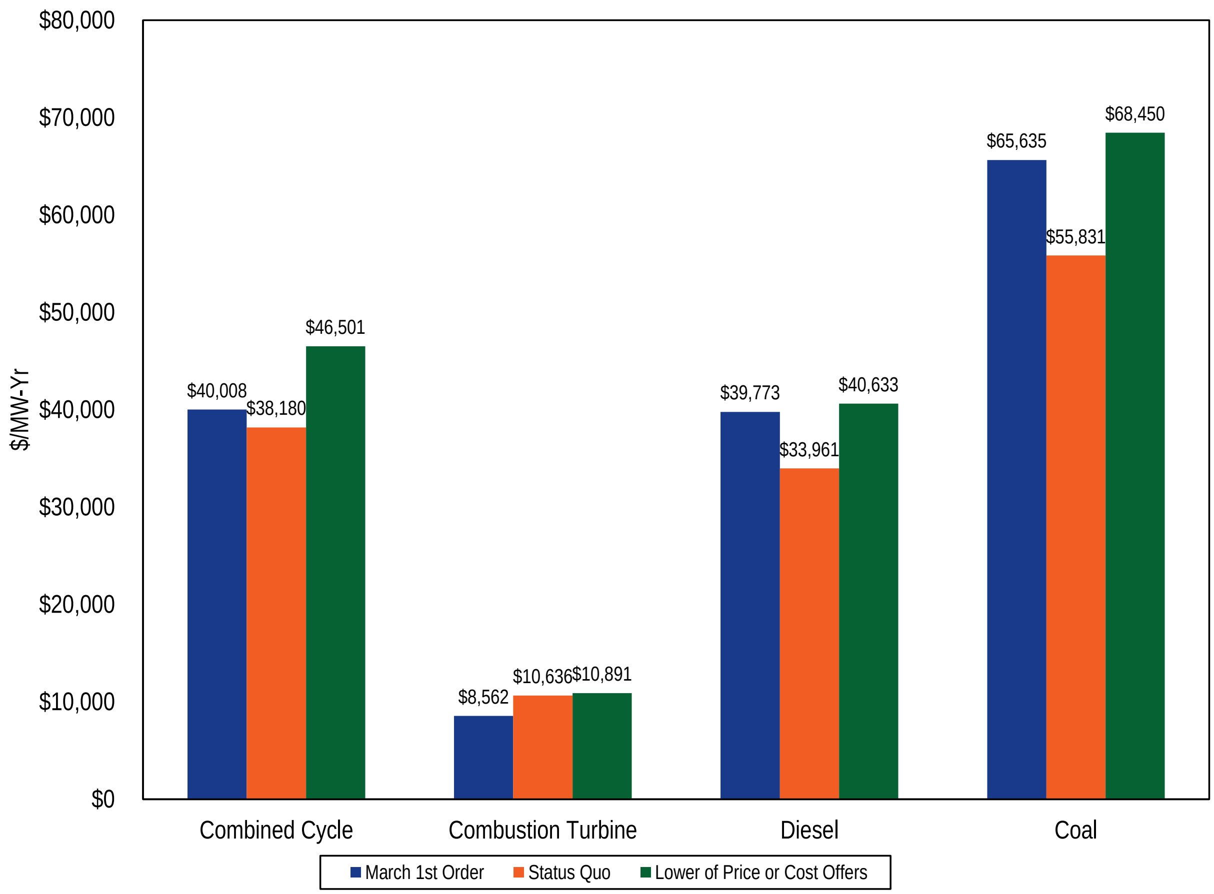
15 See 2015 State of the Market Report for PJM, Volume II, Section 5: Capacity Market, Tables 5-17 to 5-20 (March 10, 2016). The estimated impact on net revenues is calculated for units that do not incur an Avoidable Project Investment Recovery cost, for confidentiality reasons.

Figure 3 Class average net revenues values using various methods to estimate costs[16]



E. The Lower of Market-Based and Cost-Based Offers Are the Best Estimate of Short Run Marginal Cost in All Circumstances.

The Market Monitor recommends that the tariff language provided here be adopted to ensure a just and reasonable outcome in this proceeding.[17] This is a redline against the current tariff language:

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16 Net revenues are the three year average of 2013, 2014 and 2015 net revenues used in the offer cap calculation for the 2019/2020 Base Residual Auction.

17 *See* Reply Brief of the Independent Market Monitor for PJM, Docket No. EL14-94-000 (December 3, 2014) at 12–13.

> Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of marginal costs for providing such energy ~~(i.e., costs allowed under cost-based offers pursuant to Section 6.4 of Schedule 1 of the Operating Agreement)~~ and ancillary services from such resource. Marginal costs shall be calculated as equal to the lower of (i) market-based offers for the sale of energy or ancillary services from such resource or (ii) cost-based offers as defined in Schedule 2 to the Operating Agreement and in PJM Manual 15 (Cost Development Guidelines) or successor rules. However, marginal costs for a unit shall be calculated as the cost-based offer when the Capacity Market Seller can demonstrate that the market based offer is less than the fuel and emissions allowances components of marginal cost for the unit. … [T]he calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

III. STATEMENT OF ISSUES AND SPECIFICATION OF ERRORS

In accordance with Rule 713(c)(2) of the Commission's Rules of Practice and Procedure, the Market Monitor submits the following statement of the issue and specification of the error on which it seeks rehearing: the March 1st Order erred in holding, without explanation or citing to any basis in the record, that market-based offers that exceed cost-based offers reflect short run marginal cost because offers can be assumed to be competitive whenever mitigation is not applied.

Ample precedent supports reversal of the contested holding. In reaching the contested holding, the March 1st Order is arbitrary and fails to consider an important aspect of the problem at issue.[18] The March 1st Order fails to support the contested holding with

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18 *See* 5 U.S.C. § 706(2)(A); Pac. Coast Fed'n of Fishermen's Ass'ns, Inc. v. Nat'l Marine Fisheries Serv., 265 F.3d 1028, 1034 (9th Cir. 2001) ("[An agency action is arbitrary and capricious if the agency has:] relied on factors which Congress has not intended it to consider, entirely failed to consider an

substantial evidence.[19] The contested holding cannot be sustained without an "articulated [] rational connection between the facts found and the conclusions made."[20]

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important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise.) (quoting Motor Vehicle Mfrs. Ass'n v. State Farm, 463 U.S. 29, 43, (1983)).

19 *See* Dickinson v. Zurko, 527 U.S. 150, 162 (1999).

20 Pac. Coast Fed'n of Fishermen's Ass'ns, 426 F.3d at 1090.

IV. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to this pleading and grant the motion for clarification, or, in the alternative, rehearing of the March 1st Order as requested.

Respectfully submitted,

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Dated: March 28, 2016

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 28th day of March, 2016.

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