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March 25, 2024

Debbie-Anne A. Reese
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *PJM Interconnection, L.L.C.*, Docket No. ER24-1387-000

Dear Ms. Reese:

On March 22, 2024, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"), submitted a Protest in the above-referenced proceeding.

The Market Monitor has subsequently discovered that footnote number 17 on page 15 is incorrect. Footnote number 17 is revised as follows:

> See **Monitoring Analytics, L.L.C., 2023 Quarterly State of the Market Report for PJM: January through June, Section 3: Energy Market at Table 3-79 for the calculation method** ~~Table 5 Day-ahead and balancing load payments due to evasion of offer capping~~.

Attached please find a revised version of the Protest, corrected as indicated. The revision does not affect the discussion within the pleading.

If you have any questions regarding this filing, please contact me at (610) 271-8053.

Sincerely,

Jeffrey W. Mayes, General Counsel

Attachment

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket No. ER24-1387-000
	)	

PROTEST OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 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 protest to the proposed revisions to the PJM Interchange Energy Market rules filed by PJM on March 1, 2024 ("March 1st Filing"). In the March 1st Filing, PJM proposes to revise Section 6.4 of Schedule 1 to the OA, to change the offer schedule selection process for clearing the PJM Day-Ahead Energy Market in a way that would permit the widespread exercise of market power in the PJM energy market with potential extremely significant impacts on PJM prices. The March 1st Filing's premise is that PJM must remove schedule selection from PJM's day-ahead market clearing engine to facilitate implementation of expected improvements to combined cycle modeling (the Next Generation Markets project or nGEM). The Market Monitor does not challenge that premise in this filing. The proximate cause has nothing to do with the actual PJM proposal. PJM can meet its defined objective without undermining market power mitigation in the PJM energy market. The very brief March 1st Filing fails to recognize or support the proposed sweeping effort to undo the market power mitigation provisions of PJM's tariff or its impact on the

1 18 CFR § 385.211 (2023).

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

competitiveness of PJM's energy market. The March 1st has not been supported as just and reasonable. The March 1st Filing should be rejected.

I. PROTEST

A. The March 1st Filing Would Effectively Eliminate Market Power Mitigation in the PJM Energy Market

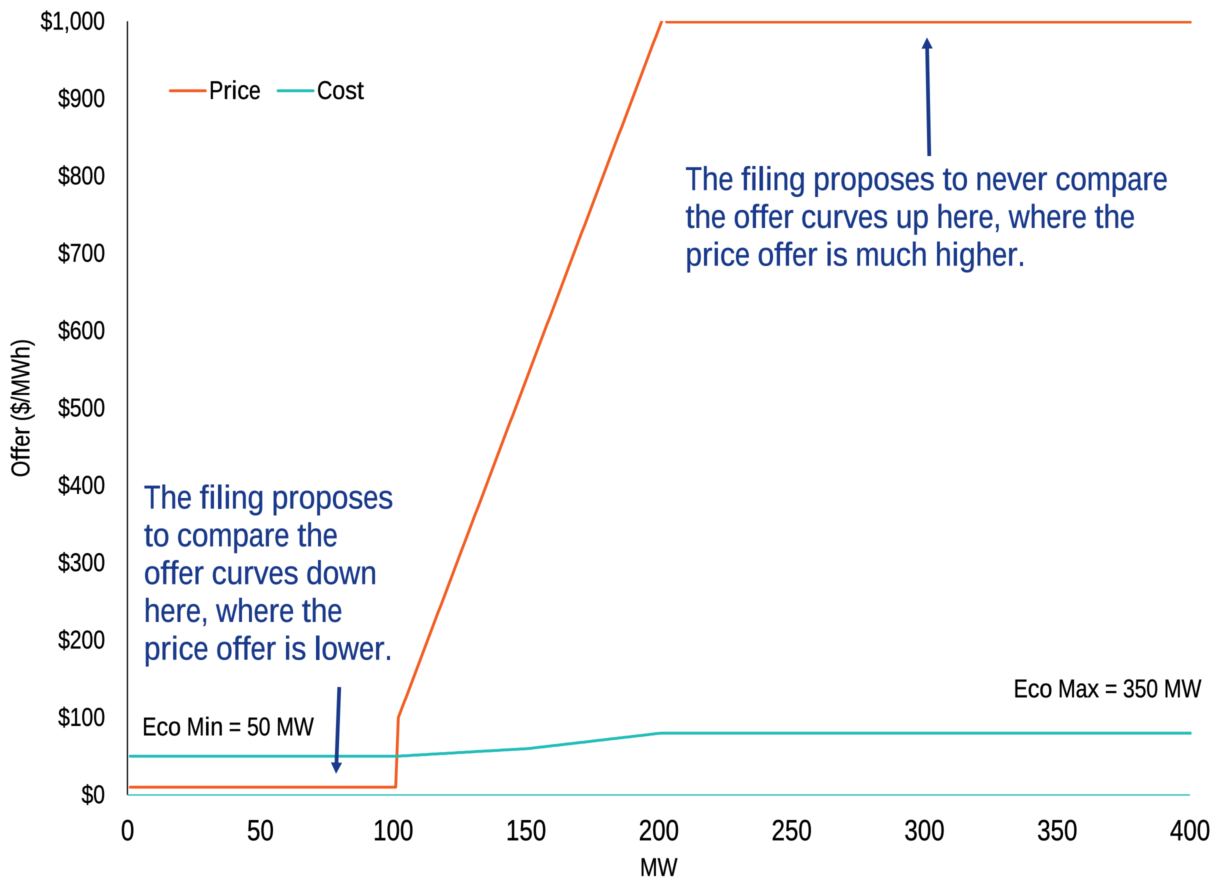
The March 1st Filing fails to address the impacts of its proposed change on the ability to exercise market power. The March 1st Filing fails to explain or even mention key details of the intended implementation. The March 1st Filing proposes an approach to market power mitigation that would define market sellers' offers as competitive, even with markups of up to $1,000 per MWh. Permitting the exercise of market power is inconsistent with using competitive markets to produce just and reasonable rates and it is therefore not just and reasonable. The March 1st Filing's proposal would permit the widespread exercise of market power in the energy market. This would be a dramatic and unacceptable change to market power mitigation and undermine PJM's competitive energy market to the detriment of all market participants including load and competitive generators.

Figure 1 illustrates PJM's approach. This illustration is based on a strategy used in actual unit offers in the PJM energy market. As the example illustrates, PJM's approach would incorrectly select the higher offer as the lower offer. PJM would have the Commission believe that the red curve is lower than the blue curve. Even a casual observer can understand that PJM's assertion is wrong. The blue curve is lower than the red curve. There is no question. The blue curve is the cost offer. The cost offer is the competitive offer, by definition. The cost offer is lower than the price offer.

PJM proposes to define the lower curve based on a comparison at only one MW point, the economic minimum MW. The price offer includes substantial markup above the economic minimum MW point. The price offer is not the competitive offer.

The purpose of the PJM market power mitigation rules at issue is to have a competitive result even in the presence of local market power. The March 1st Filing proposes to completely ignore and never compare the two offers at any point on the offer curve other than the economic minimum, where the price offer is lower than the cost offer. The March 1st Filing will allow the exercise of market power to take place when offers are submitted in this manner.

Figure 1 Which offer curve is lower? (Markup switch)



The competitiveness of the PJM energy market is at issue in the March 1st Filing. PJM's proposal to erode market power mitigation should be rejected. Software changes are not a reason to erode market power mitigation. PJM has not supported or defended or even explicitly acknowledged that the March 1st Filing is the proposed near elimination of local market power mitigation in the PJM Energy Market. There is no defense for the near elimination of market power mitigation. PJM's proposal is not just and reasonable. In fact, PJM's proposal is just not reasonable. The March 1st Filing should be rejected.

B. Regulation Through Competition.

In the nearly three decades that the Commission has pursued its reform of the electric industry, the Commission's principal rationale for its effort has been the promise that the forces of competition can improve efficiency in the industry and lower prices for wholesale electric power.[3] Competition will result in just and reasonable rates that previously required traditional regulation, but only with clear rules, including clear rules on market power mitigation. The Commission's goal is not to deregulate, or to free market participants to conduct themselves as though they operated in an unregulated industry.[4] It follows that to any extent that market power rather than competitive forces are permitted to set the wholesale price of electricity, anywhere or for any time, it compromises the fundamental objective of restructuring for competition and fails to result in just and reasonable rates.[5]

Few have stated this goal as powerfully as Chairman Kelliher:

> Our goal is perfect competition, textbook competition, competition that is so beautiful it would make an economist weep.

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3 *See Entergy Services, Inc.*, 58 FERC ¶61,234 at 61,753 (approving market-based rates for large wholesale power sales because rates set through competitive forces will result in cost savings to ratepayers); *Public Service Company of Indiana, Inc., Opinion No. 349*, 51 FERC ¶61,367 at 61,224–25 (stating that competitive pricing improves efficiency by creating incentives for full utilization of existing capacity and innovation), cited by Joseph T. Kelliher, "Market Manipulation, Market Power, and the Authority of the Federal Energy Regulatory Commission, ENERGY L. J., Vol. 26, No. 1 at 9 n.40 (2005).

4 *See* Kelliher, Market Manipulation at 11 (2005) ("It is important to note that the Commission's policy was never intended to deregulate wholesale power markets. Notwithstanding great debates that have taken place in the United States over deregulation, our economic markets are not truly unregulated in the sense that they are completely free from rules.").

5 *Cf. Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990) ("In a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that price is close to marginal cost, such that the seller makes only a normal return on its investment.").

> I accept that we may not achieve that goal, and that perfect competition may not exist outside the textbook. In our pursuit of perfect competition we may fall short. But if so we will at least have achieved more perfect competition.
>
> …
>
> It is important to appreciate that U.S. wholesale competition policy was not inadvertent. It was a deliberate choice reflected in three major federal laws enacted over the past 30 years. The U.S. consciously embraced competition policy after the comprehensive failure of traditional regulation to assure security of supply at reasonable cost.[6]

The Commission is correct to rely upon the forces of competition to achieve its goals of lower wholesale electric power costs because competitive markets impose discipline on suppliers' behavior.[7] The market power mitigation provisions in the RTO tariff are a key mechanism relied upon by the Commission to achieve competitive markets. Any change to market power mitigation, whether explicit or veiled as a software change, requires careful scrutiny to protect the competitiveness of the market.

C. Current Real-Time Process does not Logically Extend to Day-Ahead.

The March 1st Filing proposes to adapt the real-time process that selects among price-based, cost-based, and parameter limited schedules to the day-ahead market, in place of the current least cost schedule optimization.

After identifying market power, which includes failure of the Three Pivotal Supplier (TPS) test or reliability commitment, PJM selects the price-based offer, a cost-based offer, or

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6 Statement of Chairman Joseph T. Kelliher State of US Competitive Wholesale Power Markets CERAWEEK 2008—Quest for Security: Strategies for a New Energy Future (February 15, 2008).

7 *See* ALFRED E. KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS at 326 (John Wiley & Sons, Inc. 1971) ("In a competitive industry, firms are motivated to produce efficiently—to find ways to cut production costs—by the hope of increased profits and by the fear that failure to keep costs low will cause more efficient firms to capture their customers by lowering price. In a regulated industry, the stick is usually unavailable.").

the price parameter limited offer if an alert or emergency applies. Each offer is a schedule including hourly offer curves, commitment costs (start-up and no load costs), and operating parameters. The schedule selection is determined by a least cost optimization problem in the day-ahead market.

In the real-time market, PJM uses a simple dispatch cost formula to evaluate the hourly dispatch cost is only at the economic minimum level and not at higher output levels. The simple dispatch model evaluates the cost of commitment of a resource for its minimum run time. Given the ability to submit offer curves with different markups at different output levels in the price-based offer, sellers with market power can evade offer capping by using a negative markup at low output levels, where the dispatch cost formula applies, and a positive markup at higher output levels, which the dispatch cost formula ignores. We term this the markup switch strategy.

Contrary to PJM's assertions, the proposed day-ahead approach is not even close to matching the real-time approach. The real-time commitment process evaluates the dispatch cost for the upcoming one to two hours by summing the sequential hourly offers for the minimum run time of the resource.

The March 1st Filing fails to make any mention of how PJM proposes to actually do the day-ahead comparison of offers and markups. It bears almost no resemblance to the real-time process. The day-ahead comparison makes no sense and is not supported in detail by the March 1st Filing other than the completely unsupported and demonstrably incorrect assertion (at 10-11) that the day-ahead evaluation would be the same as and aligned with the real-time process.[8] In the day-ahead market, there are 24 hours to evaluate

8 March 1st Filing at 10-11.

and offers may vary by hour.[9] The March 1st Filing never states that PJM would not evaluate all 24 hours in the proposed schedule selection process. The details of the actual evaluation can be found in an obscure footnote to PJM's presentations to stakeholders and in a posted spreadsheet.[10] [11] PJM would evaluate only the highest ranked hours where the number of hours evaluated would be equal to the number of hours in the separate minimum run times of the price and cost offers regardless of whether the hours are contiguous. To determine whether the price or cost offer is higher, PJM would add up the dispatch cost at economic minimum for the price and cost offers and compare them. The sum of potentially nonsequential hours is not a meaningful or market relevant number. In real-time, the commitment is evaluating the offers for the actual time period when the resource is expected to operate. The proposed day-ahead calculation has no connection to the expected hours when the resource may operate. A price offer could be deemed lower if the offer were lower at the economic minimum point or the minimum run time for the price offer were relatively short.

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9 In 2023, 346 of 947 PJM units with nonzero offers used hourly differentiated offers in the energy market. *See* Monitoring Analytics, L.L.C., *2023 Annual State of the Market Report for PJM 2023* Vol. 2, Section 3: Energy Market at Table 3-13.

10 *See* PJM Interconnection, L.L.C., "Performance Impact of Multi-Schedule Model on Market Clearing Engine (MCE)," PJM Presentation to the Markets Implementation Committee (August 8, 2023) at 5. The asterisk at the bottom of the slide says, "Total hourly dispatch cost will use the highest hourly cost for equivalent hours as minimum run time."

11 PJM also provided a spreadsheet that demonstrates how the proposed approach would work for the day-ahead market. *See* PJM Interconnection, L.L.C., spreadsheet "Comparison of Design Component 4 Options Offer Selection Approach," PJM Presentation to the Markets Implementation Committee (August 8, 2023), <https://pjm.com/-/media/committees-groups/committees/mic/2023/20230524-special/item-03---comparison-of-design-component-4-options-offer-selection-approach.ashx> , accessed March 21, 2023.

The March 1st Filing does not explain that PJM would not evaluate all offered configurations for combined cycle resources.[12] PJM would only evaluate the highest configuration that could be achieved from an offline state. Highest configuration is not clearly defined. The schedule deemed to be lower would be assumed to be lower in all configurations, even if that is not correct.

Currently, the real-time schedule selection process is only used for short lead time resources, like combustion turbines and engines. It is not used during the market commitment process for combined cycles or coal plants, which occurs day ahead. When the real-time rule was adopted, most of these resources had limited dispatch flexibility and the older ones still do. With the older CTs, there was little risk in only evaluating the offer at the economic minimum point, because it was the only relevant operating point for the real-time committed resources. Currently, a significant number of combustion turbines and engines have a flexible dispatch range. [13] The MW in the offer curve above the economic minimum are relevant and set price. The outdated real-time process should be eliminated, not extended to the more complex and consequential day-ahead market.

D. The March 1st Approach Would Mean that Sellers Would Know With Certainty How to Evade Market Power Mitigation.

Under the March 1st Filing, sellers would know with certainty which schedule PJM will select when they are subject to offer capping and during emergencies and weather alerts. The calculation would not be a function of an optimized day-ahead market but would be a standalone calculation that any seller could do. Negative and positive markup

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12 *See* PJM Interconnection, L.L.C., "Performance Impact of Multi-Schedule Model on Market Clearing Engine (MCE)," PJM Presentation to the Markets Implementation Committee (August 8, 2023) at 15–17.

13 *See* "CT Rule Removal," (slide 2) PJM presentation to the Markets Implementation Committee. (October 6, 2023) <*https://www.pjm.com/-/media/committees-groups/committees/mic/2022/20221006/item-03a---ct-rule-removal.ashx*>.

and operating parameters could be configured to ensure that price-based offers without parameter limits are selected for market power mitigation with no evaluation of markup in the offer curve above the economic minimum output level.

For example, suppose the resource with the offers shown in Table 6 failed the TPS test. The resource has a minimum run time of six hours on the price-based offer and four hours on the cost-based offer. In this example, offers are the same for all hours of the day.

Table 1 Example Offers for a Hypothetical Gas Combined Cycle

	Price-based Offer	Cost-based Offer
Eco Min	100	100
Eco Max	300	300
Offer Curve MW 1	100	100
Offer Curve Price 1	$9	$20
Offer Curve MW 2	300	300
Offer Curve Price 2	$999	$25
Start Up Cost	$500	$500
No Load Cost	$1,000	$1,000
Minimum Run Time	6	4
Hourly Dispatch Cost	$1,900	$3,000
Total Dispatch Cost	$11,900	$12,500

With equal start up costs of $500 and no load costs of $1,000 on both schedules, the following total dispatch cost calculations would apply:

$$Dipatch\ Cost\ on\ Price = \$500 + (\$1{,}000 + \$9/MWh\ \times 100MW) \times 6\ hrs = \$11{,}900,$$

$$Dipatch\ Cost\ on\ Cost = \$500 + (\$1{,}000 + \$20/MWh\ \times 100MW) \times 4\ hrs = \$12{,}500.$$

The total dispatch cost formula would choose the price-based offer schedule. The amount that the price-based offer is discounted below the cost-based offer at the economic minimum output level could be adjusted as needed to offset the differences in the minimum run time.

The resource would be committed on the price-based offer with its markup to $999 per MWh for points above 100 MW in its offer curve. Given that this resource failed the TPS test, it is likely that the real-time market would dispatch it up if the constraint were binding. LMP for the resource would rise along the offer curve beginning at 100 MW, reaching $999 per MWh if the resource were needed for more than 100 MW. If this were the marginal resource in a load pocket with 5,000 MW of load, the hourly energy cost could be as high as $4,995,000 per hour. If the LMP were based on the cost-based offer at $25 per MWh, the hourly energy cost would instead be $125,000. The difference of $4,870,000 per hour ($116,880,000 per day, $389,600 per MWh-day) would be the impact of the failure of market power mitigation for a single resource and day under the March 1st Filing.

The purpose of market power mitigation is to prevent markups by resources with market power. The tariff should not permit PJM to commit and dispatch units that fail the TPS test on offers that demonstrate a clear intent to economically withhold energy.

E. The Market Impact Could Be Substantial.

The market impact of the status quo markup switch strategy was approximately $246.4 million in 2023 and $418.0 million in 2022. That is based on marginal units failing the TPS test and setting price with markup. Most of these resources were committed on their price-based offers by the current day-ahead schedule selection process. With the March 1st Filing's expansion of the dispatch cost formula to the day-ahead market, these resources would have more flexibility to set higher markups. The markups would never be evaluated in the market power mitigation process. Higher markups would mean higher LMP and higher costs to customers. The Table 6 example, where a pivotal resource sets price at $999 per MWh in a load pocket, shows that hundreds of millions of additional dollars of market impact could accrue each day if a resource required for a constraint could set price at the offer cap in a constrained area. Allowing the possibility that this outcome could occur is unacceptable.

The day-ahead market settles more than 95 percent of PJM load. It includes the majority of resource commitments. The use of the dispatch cost formula for schedule selection in the real-time market currently has limited impact. The March 1st Filing's proposed expansion of its use to the day-ahead market would affect the entire market. The March 1st Filing presents the issue as a simple alignment of the day-ahead and real-time markets, but it is not an alignment. It is simple. It would undo market power mitigation affecting about 95 percent of the energy market.

F. The March 1st Filing Would Also Allow Resources to Avoid Parameter Mitigation on Critical High Load Days.

During PJM market emergencies and when PJM declares a hot or cold weather alert for a region, the schedule selection process evaluates the price-based parameter limited schedule in the same manner that it compares the price and cost schedules when a resource fails the TPS test. If the day-ahead commitment process finds the price-based offer without parameter limits to have a lower production cost for the expected market dispatch when compared to the price-based parameter limited offer, parameter mitigation will not apply. In 2023, only 67.9 percent of all capacity generation resources were committed on offers within their parameter limits during hot and cold weather alerts. The same strategies to combine inflexible parameters with negative markups or negative and positive markups apply to parameter limited schedules. The March 1st Filing would provide a means by which resources that wanted to avoid parameter mitigation could structure their offers so that they would know with certainty that they would not be mitigated. This outcome not only allows for the exercise of market power, but also creates a reliability concern when PJM needs its fleet to operate as flexibly as possible to manage high load conditions.

G. Current Issues with Market Power Mitigation.

The purpose of market power mitigation is to ensure that sellers with market power cannot exercise market power in the PJM energy market. Exercises of market power take the form of economic withholding and physical withholding. Economic withholding occurs through the markup over short run marginal cost of the energy offer, in the incremental energy offer curve, startup cost, or no load cost. Physical withholding includes using inflexible operating parameters that hinder the market from clearing the available energy of a resource.

1. Status Quo Issues.

Since at least 2015, the Market Monitor has identified the various ways that the market power mitigation process fails to offer cap the resources of market sellers with identified market power. The issues all result from the method used by PJM to select the competitive offer schedule for resources with market power. PJM first identifies when a resource has market power based on failing the Three Pivotal Supplier (TPS) test or when a resource can uniquely solve a reliability issue. Then PJM selects the competitive offer to ensure that the resource cannot exercise market power. The choice is between the price-based offer and the cost-based offer. In addition, when PJM issues an alert or emergency notification, PJM selects between the price-based offer and the price-based offer with flexible parameters (parameter limited offer). Each offer is a schedule including hourly offer curves, commitment costs (start-up and no load costs), and operating parameters.

In the day-ahead market, the schedule selection is based on a least cost optimization over the entire day. Although the current optimization approach is better than the approach in the real-time market, both are susceptible to strategies that permit the exercise of market power.

Some specific strategies in the construction of offer schedules are likely to result in the selection of a price-based offer over a cost-based offer. For example, a shorter minimum run time can be paired with an offer curve markup resulting in the optimization selecting the price-based offer with a markup. Even within the current day-ahead optimization rules, this creates an opportunity for market sellers to exercise market power.

In the real-time market, PJM uses a simple formula to calculate the cost of commitment of a resource only at the economic minimum output level for its minimum run time. The use of this simple dispatch cost formula creates opportunities to exercise market power.

The dispatch cost formula is:

$$\text{Total Dispatch Cost} = \text{Startup Cost } + \textstyle\sum_{\text{Min Run}} \text{Hourly Dispatch Cost},$$

where the hourly dispatch cost is calculated for each hour as

$$\text{Hourly Dispatch Cost} = (\text{Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}.$$

Sellers with market power can evade market power mitigation by using a negative markup at the economic minimum level and a positive markup at higher output levels. We term this the markup switch strategy.

The markup switch is a commonly used strategy, allowing resources to evade market power mitigation. It allows resources with market power to mark up their offer curves in both the day-ahead and real-time markets. Figure 1 provides an example of the markup switch strategy, which is used in the actual observed behavior of units in the PJM energy market.

The data show the extent to which this strategy has been used under the current rules. Table 1 shows the number and percent of unit schedule hours, by unit type, when unit offers included negative markup at the economic minimum output level and positive markup at the economic maximum output level in the PJM Day-Ahead Energy Market in 2022 and 2023. The majority of units pursuing this markup switch strategy are gas-fired combined cycles, with 47.7 percent of gas CCs offering this way in 2022 and 46.1 percent in 2023.

Table 2 Units offered with markup switch in day-ahead market: 2022 and 2023

		2022			2023		
Fuel Type	Unit Type	Number of Schedule Hours with Markup Switch	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Markup Switch	Number of Schedule Hours with Markup Switch	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Markup Switch
Coal	Steam	119,411	859,930	13.9%	75,946	770,846	9.9%
Gas	Steam	40,824	248,405	16.4%	18,511	250,846	7.4%
Gas	CT	359,966	2,359,298	15.3%	367,401	2,363,772	15.5%
Gas	CC	588,251	1,232,957	47.7%	555,190	1,204,047	46.1%
Gas	RICE	108	95,640	0.1%	0	91,271	0.0%
Municipal Waste	RICE	2,903	292,702	1.0%	1,248	260,326	0.5%
Oil	CT	20,781	2,201,586	0.9%	7	2,117,357	0.0%
Oil	CC	4,440	368,422	1.2%	0	290,833	0.0%
Oil	RICE	10,316	159,264	6.5%	0	127,674	0.0%
Wind	Wind	2,442	726,768	0.3%	2,243	756,485	0.3%
Other	Solar	11	834,368	0.0%	1,098	991,388	0.1%
Other	Steam	192	37,273	0.5%	0	43,800	0.0%
Total		1,149,645	9,416,613	12.2%	1,021,644	9,268,645	11.0%

The data show that, even under the current rules, the markup switch is a widely used strategy. The strategy routinely leads to commitments on the price offer rather than the cost offer. Of units that failed the TPS test that used a markup switch, 93.6 percent were committed on their price-based offers in 2022 and 94.6 percent were committed on their price-based offers in 2023. That has had significant impacts on the PJM energy market.

This data is all based on the existing rules in the day-ahead market which, while flawed, are better than the March 1st Filing. The March 1st Filing would make the markup switch strategy much more effective in the day-ahead market with correspondingly large impacts on prices.

2. Impacts.

The status quo results provide a benchmark for considering the effect on the market of unmitigated offers for resources that fail the TPS test. Measuring the impact of the markup switch strategy on prices even under the current rules shows the magnitude of the issue. Significantly weakening the rules, as proposed by PJM, will make matters worse. The schedule selection process also fails to mitigate operating parameters consistently for units with market power and during emergencies and weather alerts. The Market Monitor provided measures of impact to uplift and inflexible parameters in its comments in the Show Cause Order proceeding.[14]

The Market Monitor analyzes the offers and market power of the marginal generating units that determine prices in the energy market.[15] The short run marginal cost of the marginal units is the primary determining factor in the energy market price, LMP. Markup is not part of short run marginal cost. The cost-based offer is defined to be the short

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14 *See* Comments of the Independent Market Monitor for PJM, Docket No. EL21-78 (October 15, 2021) at 16-18.

15 *See* Monitoring Analytics, L.L.C., *2023 Annual State of the Market Report for PJM* Vol. 2, Section 3: Energy Market.

run marginal cost. There are some issues with the definition of the cost-based offer such that it can be overstated, so the markup of price-based offers is an understatement of true markup.[16] The markup as a percent of price is a standard metric for assessing market power in a market, called the Lerner Index. In 2023, the markup component of real-time LMP was $0.72 per MWh, 2.4 percent of price. In 2022, the markup component of real-time LMP was $3.32 per MWh, 4.1 percent of price. Based on day-ahead and balancing energy settlements, markups cost PJM customers $0.7 billion in 2023 and $3.0 billion in 2022.[17]

The contribution of markup to LMP can be broken down into the effects of marginal units using the markup switch in their offer curves and those that fail the TPS test. Table 3 shows, in 2022 and 2023, the markup contribution to real-time LMP of all marginal units, markup switch marginal units, marginal units that failed the TPS test in the day-ahead or real-time market, and marginal units that both submitted markup switch offers and failed the TPS test. The $3.32 per MWh markup contribution to LMP in 2022 means $3.32 per MWh of annual PJM load-weighted average LMP is directly due to markup, and the $0.73 per MWh markup contribution in 2023 means that $0.73 per MWh of the annual load-weighted average LMP is directly due to markup. If market power mitigation were fully effective, the markup contribution for units that failed the TPS test would be zero. But in 2022, $0.59 per MWh of the $3.32 per MWh markup contribution was attributable to units that failed the TPS test. In 2023, $0.33 per MWh of the $0.73 per MWh markup contribution was attributable to units that failed the TPS test. Those effects are almost entirely due to marginal units with markup switching as shown by the $0.54 per MWh out of $0.59 per MWh in 2022 and $0.32 per MWh out of $0.33 per MWh in 2023.

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16 *See* Monitoring Analytics, L.L.C., *2023 Annual State of the Market Report for PJM* Vol. 2, Section 3: Energy Market at 247–254.

17 *See* Monitoring Analytics, L.L.C., *2023 Quarterly State of the Market Report for PJM: January through June*, Section 3: Energy Market at Table 3-79 for the calculation method.

Combined cycle gas units are the majority of marginal units in the energy market. Their markup was $1.71 per MWh or 51.5 percent of the markup contribution of LMP in 2022 and $1.03 per MWh or 141.4 percent of the markup contribution to LMP in 2023. (The amount is greater than 100 percent because other resource types have offsetting negative markup contributions to LMP.) Combined cycle gas units also constitute the majority of the markup contribution to LMP due to markup switching for units that failed the TPS test, with contributions equaling 100 percent of the markup contribution in both years. Marginal coal units also contributed a positive amount in both years.

Table 3 Real-time markup contribution of marginal units with markup switching

		2022				2023			
Fuel Type	Unit Type	All Units	Markup Switch	Failed DA or RT TPS Test	Markup Switch and Failed DA or RT TPS Test	All Units	Markup Switch	Failed DA or RT TPS Test	Markup Switch and Failed DA or RT TPS Test
Coal	Steam	$1.70	$0.75	$0.15	$0.15	($0.40)	($0.06)	$0.01	$0.01
Gas	CC	$1.71	$0.98	$0.60	$0.54	$1.03	$0.91	$0.35	$0.32
Gas	CT	$0.07	($0.38)	($0.16)	($0.16)	$0.36	($0.05)	($0.01)	$0.00
Gas	RICE	($0.02)	$0.00	$0.00	$0.00	($0.01)	$0.00	$0.00	$0.00
Gas	Steam	($0.03)	$0.01	$0.01	$0.01	($0.10)	($0.05)	($0.02)	($0.02)
Municipal Waste	RICE	($0.00)	$0.00	$0.00	$0.00	$0.02	$0.00	$0.00	$0.00
Oil	CC	($0.02)	($0.00)	($0.00)	($0.00)	($0.03)	$0.00	$0.00	$0.00
Oil	CT	($0.06)	$0.00	$0.00	$0.00	($0.10)	$0.00	$0.00	$0.00
Oil	Steam	($0.06)	$0.00	$0.00	$0.00	($0.07)	$0.00	($0.00)	$0.00
Other	Solar	$0.01	$0.00	$0.00	$0.00	$0.01	$0.01	$0.00	$0.00
Other	Steam	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Wind		$0.02	($0.01)	($0.00)	($0.00)	$0.01	$0.00	$0.00	$0.00
Total		$3.32	$1.35	$0.59	$0.54	$0.73	$0.76	$0.33	$0.32

At $0.54 per MWh and with 778,624,300 MWh of load, the effect of resources that failed the TPS test and set price based on markup switching was $418.0 million in 2022 based on real-time prices.[18] At $0.32 per MWh and with 775,052,750 of load, the effect of resources that failed the TPS test and set price based on markup switching was $246.4 million in 2023 based on real-time prices.

18 *See* Monitoring Analytics, L.L.C., *2023 Annual State of the Market Report for PJM* Vol. 1, Table 9 for total load for the year.

H. Market Based Rates and Show Cause Order Proceedings

The Commission relies on the market power mitigation provisions in the RTO tariffs in its approval of Market Based Rates ("MBR").[19] All market sellers must have MBR approval to participate in the PJM market. Therefore, the Commission's finding that the market power mitigation provisions in the tariff are sufficient to ensure a competitive market are critical to the continuing functioning of the PJM Energy Market. For this reason, the Market Monitor has routinely intervened in the triennial review MBR filings for market sellers in the PJM region to inform the Commission that there are loopholes in PJM's market power mitigation provisions that allow sellers to exercise market power.

On June 17, 2021, the Commission issued an Order to Show Cause requiring PJM to demonstrate that its parameter mitigation rules remained just and reasonable given the possibility that resources can offer in such a way that their parameters are not mitigated even when they have market power and even during weather alerts and emergencies.[20] The Commission found that the Market Monitor did not provide sufficient evidence to find the current tariff unjust and unreasonable.[21]

PJM's reliance on that order related to real-time as a justification for modifying market power mitigation in the day-ahead market is misplaced. More than 95 percent of load payments are from the day-ahead market. Undoing market power mitigation in the day-ahead market would effectively remove market power mitigation from the PJM energy

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19 *See, e.g.*, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 119 FERC ¶ 61,295, at P 4 (2007); Independent Market Monitor for PJM v. PJM Interconnection, L.L.C., 178 FERC ¶ 61,121, at PP 96, 106, 112–13 (2022) ("In RTO/ISO markets, the Commission has long held that these market rules must be paired with an effective framework for monitoring and mitigating market power to ensure that the markets produce just and reasonable rates.").

20 *See* 175 FERC ¶ 61,231 (2021).

21 *See* 185 FERC ¶ 61,158 (2023).

market. The results presented in this filing, including Table 1 and Table 3, show why the March 1st Filing should be rejected and provide new evidence connecting the issues in the offer capping process to specific market outcomes, specifically higher LMP and increased costs to customers above the competitive level.

I. nGEM

PJM's asserted reason for revisiting its schedule selection process is the nGEM project. nGEM is a joint project with other RTOs to streamline and upgrade software to facilitate additions to the market software like enhanced combined cycle modelling and storage resource modelling. Streamlining the software means making the software more similar across the RTOs. A key difference between PJM's energy market offer structure and that of the other RTOs is the connection between the three part offer (energy offer curve, start up, and no load) and operating parameters. The other RTOs do not tie them together in an offer schedule like PJM. The others can separately apply mitigation to the three part offer and to the operating parameters.

PJM's basic assertion is that continued inclusion of the schedule selection process in the market clearing software would unacceptable slow down the day-ahead market clearing software. The Market Monitor does not challenge that premise in this filing.

Selecting the competitive offer schedule requires choosing among packages of offers and parameters, where some parts of the package may be offered competitively while other parts are not. The only way to ensure that market power is mitigated while preserving the offer schedule structure is to always choose the cost-based offer for resources with market power and to always choose a parameter limited offer (cost-based or price-PLS) for emergencies and weather alerts.

J. The November 30th Order Does Not Provide Support for the March 1st Filing.

On November 30, 2023, the Commission issued its order in the Show Cause proceeding on PJM's parameter mitigation process.[22] The November 30th Order provided arguments supporting the status quo schedule selection process, mostly repeating arguments made by PJM in defense of the status quo day-ahead market least cost schedule optimization process. Those arguments do not extend to the March 1st Filing, because it proposes to remove the status quo day-ahead market process. The November 30th Order makes limited arguments in defense of the real-time process, describing it as perhaps the best PJM can do given the limitations in real-time. Clearly, such arguments do not extend to the day-ahead market.

1. Removing the Least Cost Schedule Optimization Will Increase Costs (P31).

The November 30th Order (at P 31) emphasizes that removing the day-ahead least cost schedule optimization, which is the purpose of the March 1st Filing, would likely increase costs to consumers without associated benefits. Removing the day-ahead least cost schedule optimization is the exact purpose of the March 1st Filing. The day-ahead market commitment process would no longer optimize the schedule selection to minimize costs. The removal of the optimization would, by definition, increase costs to consumers. Maintaining lower costs was the argument in defense of the status quo, despite the possibility of exercises of market power due to inflexible parameters. The November 30th Order states (at P 31):

> [T]he Market Monitor alleges that, because the Tariff requires PJM to commit and dispatch resources based on their lowest cost schedule, sellers can strategically offer higher markups on their market-based parameter-limited offer to ensure that PJM chooses the market-based offer, without parameter limits, and thus avoid

[22] *See* 185 FERC ¶ 61,158 (2023).

> mitigation. However, we agree with PJM that the fact that a particular seller's market-based offer, without parameter limits, is lower cost than its cost-based offer does not in and of itself demonstrate that a seller is attempting to exercise market power. The cost-based offer, which as P3 notes can include a 10% adder, functions as a cap and does not preclude sellers from submitting offers below that cap. Furthermore, PJM explained that changing its current commitment and dispatch practices would likely *increase* costs to consumers without an associated benefit.

2. The Status Quo Least Cost Schedule Determination Considers Uplift. The March 1st Filing Removes Uplift Consideration (P33).

The November 30th Order also points (at P 33) to the current day-ahead schedule selection process in arguing that higher uplift is not sufficient evidence of a problem with the status quo market power mitigation:

> [T]he Market Monitor argues that some sellers that fail the TPS test are able to collect uplift payments with operating parameters that are less flexible than their unit-specific parameter limits. The Market Monitor states that generators committed on their inflexible market-based offers after failing the TPS test received the majority of day-ahead uplift in 2020. PJM explained that its day-ahead market software considers uplift payments when selecting among offers to minimize overall system production cost. As such, we are not persuaded that the collection of uplift, in and of itself, demonstrates that mitigation after the failure of a TPS test is ineffective.

The March 1st Filing would remove the consideration of uplift payments in PJM's process for selecting the offer schedule for resources that fail the TPS test. Uplift payments are a function of total production costs for a resource commitment, including the area under the offer curve up to the point of dispatch. The status quo least cost offer schedule determination does in fact minimize production costs, at least to the extent that it accurately mirrors the final commitment and dispatch of the resource. The March 1st Filing does not consider the area under the offer curve, because it only evaluates the offer curve at the economic minimum point. The November 30th Order's uplift argument does not extend to the March 1st Filing as defense of a just and reasonable schedule selection process.

3. Uncertainties Inherent in Real-Time (P34)

The November 30th Order (at P 34) acknowledges that the real-time schedule selection process based on the dispatch cost formula does not consider all the costs of dispatching a resource, citing uncertainties and unknowable costs in real time:

> [T]he Market Monitor argues that PJM's response does not address real-time uplift or the process for selecting the least cost offer in the real-time market. Tariff provisions regarding the TPS test also require PJM to select the least cost offer in real-time, as measured by the resource's dispatch cost, among several schedules, including the real-time cost-based offer. PJM's least-cost algorithm for real-time dispatch does not take into account the full cost of dispatching a resource, which is unknowable at the time of unit commitment given the uncertainties inherent in real-time. However, PJM's current real-time commitment and dispatch process appears to use all of the information available to select offers that minimize total expected costs in real-time. We find that there is insufficient evidence in the record to show that PJM's current method of addressing mitigation in the real-time market is unjust and unreasonable.

This argument does not extend to using the dispatch cost formula for the day-ahead schedule selection process. The March 1st Filing would extend the real-time process, which does not consider all the relevant costs of commitment and dispatch, to the day-ahead market. The cited unknowable costs and inherent uncertainties are specific to real time. The March 1st Order (at 6) cites this very paragraph as justification, but the argument clearly does not extend to the day-ahead market.

4. Commissioner Clements Explains the Status Quo Failure to Mitigate Market Power and to Minimize Costs, as Well as the Problems with the Real-Time Process.

Commissioner Clements points out, in her dissent to the November 30th Order (at P 6), that PJM's current process attempts to both mitigate market power and minimize costs, but may fail to do both:

> PJM layers a second objective into its mitigation rules: curb the exercise of market power but also minimize costs by selecting among mitigated and unmitigated offers. While this sounds good

> in theory—two birds, one stone—the Market Monitor presents evidence that in trying to do both things, PJM may at times be failing to do either. That is, the Market Monitor asserts that PJM's tariff rules for selecting among mitigated and unmitigated offers fail to account for all relevant costs and therefore may commit and dispatch resources on offers that reflect the exercise of market power on the part of the seller. That claim calls into question the very basis on which the Commission has found that energy market rates in an RTO like PJM are just and reasonable.

The March 1st Order would no longer attempt to minimize costs, yet it would still fail to consistently mitigate market power—zero birds, one stone. Market benefit achieved by the status quo cost minimization would be lost with no associated benefit of more effective market power mitigation. In fact, it would result in less effective market power mitigation. In ceasing to use the least cost schedule optimization in the nGEM context, PJM has an opportunity to ensure that market power mitigation is effective. The March 1st Filing fails to take that opportunity with no asserted justification for the decision.

Commission Clements (at P 9) also points out the flaws in PJM's real-time schedule selection process and the lack of defense for it:

> With respect to the real-time market, the Market Monitor argues PJM's offer-selection formula is flawed because it takes a myopic view of offer prices across the seller's offers. A seller's offer includes not a single offer price but a curve of prices at varying quantities of output. But PJM's real-time offer-selection formula looks only at a single point on each offer curve: the economic minimum quantity, or EcoMin. Should a seller wish to make its non-parameter-limited market offer more attractive under the formula in order to have PJM select it, the seller need only submit a low offer price at EcoMin while potentially submitting much higher prices at quantities above EcoMin. The Market Monitor argues that when PJM selects this offer based on the EcoMin offer price but dispatches the resource above EcoMin, a seller found to possess market power can set the market price based on an unmitigated offer. In addition, the Market Monitor asserts a seller can earn uplift due to inflexible operating parameters in its market offer that it would not have earned had PJM dispatched it on its cost-based (parameter-limited) offer. This is why the Market Monitor states that "the offer with the lowest dispatch cost as

> defined by PJM is not necessarily the least cost offer at output levels greater than the economic minimum MW."

The flaws and limitations of the dispatch cost formula approach to schedule selection are acknowledged. PJM acknowledged the problem in the stakeholder process and offered a remedy to it.[23] The March 1st Filing has no defense to offer for extending the flawed real-time process to the day-ahead market.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to this protest as the Commission resolves the issues raised in this proceeding.

Respectfully submitted,

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23 *See* PJM Interconnection, L.L.C., Performance Impact of Multi-schedule Model on the Market Clearing Engine, PJM Presentation to the Markets and Reliability Committee (December 20, 2023) at 12.

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Dated: March 22, 2024

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 22nd day of March, 2024.

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