UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket No. EL19-58-002,
	)	ER19-1486-000
	)	

COMMENTS 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 ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[2] submits these comments responding to the second filing submitted by PJM Interconnection, L.L.C. ("PJM") on August 5, 2020 ("August 5th Filing") in compliance with the order issued May 21, 2020, in this proceeding ("May 21st Order").[3] The May 21st Order accepted PJM's Operating Reserves Demand Curve ("ORDC"). PJM filed to comply with most of the directives in the May 21st Order on July 6, 2020.[4] The May 21st Order determined (at P 308) "that the reserve market changes implemented herein have rendered PJM's methodology for calculating the E&AS Offset used in its capacity market unjust and unreasonable." The Commission directed (at P 308), pursuant to its Section 206 authority, that PJM file "to implement a forward-looking E&AS Offset" in the MOPR proceeding ("EAS Directive") in calculating MOPR floor prices and

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1 18 CFR § 385.211 (2019).

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.*, 171 FERC ¶ 61,153.

4 The Market Monitor filed comments on the July 6th proposal on July 27, 2020.

other capacity market parameters in the capacity market including the value of Net CONE.[5] Instead of filing a method based on the approach already in use by PJM, PJM requested and obtained a one month extension for compliance with the EAS Directive. PJM submitted a flawed and unnecessarily complicated proposal that fails to comply with the EAS Directive. The August 5th Filing should be rejected, and PJM should be directed to file the method provided by the Market Monitor in the stakeholder process.

Nothing in this filing by the Market Monitor should be cause for delay in running PJM capacity market auctions. The Market Monitor continues to support the expeditious running of the required capacity market auctions. The issues and solutions identified in this filing will make the calculations of the EAS offset easier, not harder.

I. COMMENTS

A. Introduction

In its May 21st Order, the Commission directed PJM to use a forward looking EAS approach in MOPR floor calculations in place of the prior approach using an average of three years of historical net revenues.[6] The forward looking approach is consistent with the way that actual investors evaluate the markets and is clearly preferable to the historical approach. Both the Market Monitor and PJM have been using the essential elements of the forward looking approach for a long time in the calculation of the opportunity costs associated with environmental limits on the operation of generating units. Complying with the Commission's directive to implement a forward looking EAS Offset is not complicated.

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5 *See* PJM Interconnection, L.L.C., et al., Docket No. EL18-178-000, et al. (extended Minimum Offer Price Rule proceeding).

6 PJM defines the term energy and ancillary services revenue offset ("EAS Offset") on page 1 of the August 5th Filing. Although Brattle uses the term E&AS, the Market Monitor will use the term EAS rather than E&AS in this filing. To the extent that the term E&AS appears in tables or figures in this filing, they should both be considered to mean EAS. EAS is also synonymous with the term net revenues.

The Market Monitor recognizes the technical difference between futures prices (exchange traded) and forwards prices (over the counter). In addition, futures prices are frequently shaped in order to provide pricing data to the market for specific hours or days or locations where the market is less liquid. These shaped futures prices are also referred to as forward prices. The Market Monitor uses the generic term forward pricing and forward EAS offset to include futures, shaped futures and forwards prices.

The August 5th Filing states at page 10 that the EAS offset calculation will "rely on futures markets prices." But that is not strictly accurate. The draft tariff language is inadequate. It would not be possible to calculate the forward prices as actually contemplated by PJM based on the tariff language. The August 5th Filing does not clearly recognize the differences between futures and forwards. The August 5th Filing does not specify the forward prices data points and source of such data points. The August 5th Filing draft tariff language states only:[7]

> "For each liquid hub, calculate the average day-ahead on-peak and day-ahead off-peak energy prices for each month during the Delivery Year over the most recent thirty trading days as of 180 days prior to the Base Residual Auction."

The August 5th Filing references prices from the Intercontinental Exchange (ICE) while the Market Monitor uses prices from Platts.

ICE futures data for three plus years forward include trades that cover an entire year, which ICE shows as occurring in individual months at the same price and quantity. Most of the power futures traded on ICE for the future years that are relevant to the capacity market delivery year are annual contracts, not monthly contracts. Platts uses ICE futures data plus a combination of historical forward prices, historical spot prices and ICE

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[7] *See* August 5th filing at 89.

forward data to shape annual prices into monthly prices.[8] Although it is not clear in the August 5th Filing, ICE also shapes the futures price data in similar ways to Platts to get to what ICE refers to as futures settlement prices.[9]

The August 5th Filing does not discuss the reasons for its choice of ICE data over Platts' data. The August 5th Filing does not discuss the shaping methods used by ICE or Platts. The August 5th Filing does not explain why it relies on ICE shaping for some purposes but not for other purposes. The August 5th Filing does not discuss the reasons that PJM chooses to no longer use Platts' data as PJM has used it and approved it for use in the opportunity cost calculator.[10] There should be an explicit choice between the two data sources based on rational criteria. The question of how to address annual futures prices needs to be addressed explicitly. The annual prices must be shaped, either by ICE, by Platts or by a PJM defined method. The Market Monitor recommends that Platts' data continue to be used until it can be established that there is a better option. PJM has access to this data and use of Platts' data will not slow down the capacity market auction process.

The August 5th Filing adds complexity which is unnecessary and also incorrect in some important ways. The approach to the forward looking EAS Offset should be to make it accurate and as simple as possible, but no more simple. The August 5th Filing fails that test. The August 5th Filing adds multiple elements of unnecessary complexity which fail to make the result more accurate and in some cases make the results less accurate and less transparent. The approach should be transparent so that any participant can replicate the results if they have access to the data on forward prices and historical actual PJM LMPs and

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8 *See* S&P Global Platts "Methodology and Specifications Guide M2MS- Power Methodology," <https://www.spglobal.com/platts/plattscontent/_assets/_files/en/our-methodology/methodology-specifications/m2ms_power_methodology.pdf> . Last updated May 2018.

9 *See* Brattle Affidavit at 16.

10 PJM references the Platts' forward curve in "PJM Manual 15: Cost Development Guidelines," Rev. 35 (April 24, 2020) § 12.7.

the relevant parameters for the technology and can dispatch a unit using the resultant forward prices on a nodal and hourly basis.

In particular, the August 5th Filing's insertion of long term FTRs into the calculation adds unnecessary complexity, has no articulated basis, is not accurate and cannot be implemented as a result of the timing of capacity auctions and FTR auctions.

In particular, the August 5th Filing's use of multiple trading hubs for futures prices adds unnecessary complexity and has no articulated basis.

B. Market Monitor Proposal.

The Market Monitor's proposal is based on the existing approach to the forward looking EAS offset calculations with the minimum complexity required for accuracy.[11]

The Market Monitor's proposed approach to the EAS Offset includes these key components:

Real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years.

Generating costs equal to the short run marginal costs of each technology. The short run marginal cost of gas fired resources is equal to the forward price of gas for the defined zonal gas delivery point multiplied by the heat rate of the resource plus operating costs.

Forward looking net revenues should continue to include bilateral revenues. The August 5th filing omitted (hopefully inadvertently) any reference to bilateral revenues. Bilateral revenues can be a critical source of net revenues.

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11 The existing approach to the EAS offset calculation is defined in Manual 15, for use in the opportunity cost calculator. *See* "PJM Manual 15: Cost Development Guidelines," Rev. 35 (April 24, 2020) § 12.7.

C. The Approach in the August 5th Filing Is Flawed and Unnecessarily Complicated.

The August 5th Filing's approach includes: (i) day-ahead forwards rather than real-time forwards; (ii) multiple trading hubs rather than the most liquid hub; (iii) Long Term FTR prices rather than historical basis differentials; (iv) a 10 percent cost adder for the CT but no other technology; (v) 50 percent of major maintenance in the incremental offer or no load and 50 percent of major maintenance in start costs for the CT and 100 percent of major maintenance in the incremental offer for the CC; (vi) extremely high regulation revenues; (vii) adjustments to gas delivery points based on inconsistent application of judgment.

There are also differences between the Market Monitor's and PJM's approach to default and unit specific EAS offset calculations: the August 5th Filing uses the average RTO price for the VRR curve although no unit faces or could face the average RTO price; PJM includes specific nuclear refueling outages rather than an average equivalent availability factor.

The Market Monitor's approach uses: the average net CONE across zones; and uses class average equivalent availability factor for nuclear plants to ensure that lumpy refueling outages do not skew the results.

D. The Current Calculation of Forward Energy Prices Is Still Correct.

In order to meet the Commission's directive to implement a forward looking energy and ancillary services offset in the capacity market for one year, three years forward, forward energy market prices for slightly more than three years ahead are needed for each generator node in PJM, by hour.

This is a relatively straightforward problem and one which the Market Monitor and PJM have been implementing for years in the calculation of the opportunity costs associated with environmental limits on the operation of generating units.[12] The opportunity cost

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[12] *See* "PJM Manual 15: Cost Development Guidelines," Rev. 35 (April 24, 2020) § 12.7.

calculator uses Platts' data on the prices associated with the PJM Western Hub real-time on peak and off peak futures to develop hourly LMPs for the bus at which specific generators are located. This calculation method is documented in PJM Manuals and can easily be used for the EAS Offset calculation.

Adjustment factors, to account for the basis (locational) differences between the generator's bus and the PJM Western Hub, are computed as the average ratio of the generator's historical LMP to the historical LMP for the PJM Western Hub. Three adjustment factors are computed for each futures contract using three different historical periods which provide three estimates of each monthly forward price at the generator's bus. For example, an adjustment factor for the on peak real-time futures price for November 2020 would be calculated by taking the average of the ratios of the generator's real-time LMP to the PJM Western Hub real-time LMP during the on peak hours during November 2019, November 2018 and November 2017. The same approach is used to calculate zonal prices.

After applying the basis adjustment to the PJM Western Hub real-time futures price, hourly forward LMPs are obtained by multiplying by a second adjustment factor that captures hourly LMP variation. The hourly adjustment factor is the ratio of the generator's historical real-time LMP to the generator's average monthly on peak or off peak LMP by bus or zone.

This approach is still correct and should continue to be applied in the EAS offset calculation.

E. The Approach in the August 5th Filing for Calculating Forward Prices Is Flawed and Unnecessarily Complicated.

The design goal in calculating the forward looking energy and ancillary services offset (EAS) should be to use a market-based method that is as accurate, as simple and as transparent as possible. It should be possible to easily replicate the method. The method should not rely on subjective judgments. The August 5th Filing's approach fails these tests.

One of the primary reasons for implementing a forward looking EAS offset in the capacity market is to better reflect the way actual investors evaluate the markets. The more that unnecessary complications are added to the calculation of forward prices, the less likely it is that the calculations reflect investors' actual expectations about the future.

The August 5th Filing's approach to calculating forward prices is unnecessarily complicated. PJM uses day-ahead forwards despite the fact that the day-ahead forwards are significantly less liquid than the real-time forwards. The August 5th Filing uses multiple, less liquid, hubs where only one liquid hub is needed. The August 5th Filing uses long term FTR prices in place of actual data on congestion patterns despite the fact that long term FTR prices do not apply to the delivery year for the capacity auction and do not accurately reflect congestion. The August 5th Filing states, but does not specify in the tariff, that PJM will be using data from power futures traded on ICE and not Platts' forward curves. PJM will effectively be calculating its own forward curve rather than using Platts. Although the descriptive language appears detailed, the actual tariff is extremely vague and provides PJM with significant discretion over decisions that can significantly affect PJM markets.

In a well functioning market, the price differentials between any liquid trading hub and a generator node or zone should result in the same forward price at the node or zone. The August 5th Filing does not assert that there are systematic price differentials between different trading hubs and generator nodes or zones. The design goal should be to use the most liquid hub as that is most reflective of market fundamentals and is the least likely to be subject to manipulation. There is no reason to use multiple hubs for forward prices. The August 5th Filing presents no good analytical reason for their proposal to use multiple hubs. PJM should use the most liquid PJM trading hub, Western Hub.[13]

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13 PJM recognizes that (at 11) "… the PJM Western Hub remains one of the most liquid trading hubs in the nation …".

The August 5th Filing proposes to calculate monthly on peak and off peak forward zonal LMPs using day-ahead futures prices from three trading hubs: Western Hub, AEP Dayton Hub, and Northern Illinois Hub for the applicable delivery year. The hub used will depend on the zone for which prices are calculated.

The August 5th Filing uses day-ahead futures from Western Hub, AEP Dayton Hub, and Northern Illinois Hub based on the zone for which the forward LMP is being calculated. Based on PJM's mapping of trading hubs to zones, the August 5th Filing's proposed method results in a forward zonal LMP for some zones to be based on a less liquid product (day-ahead) at less liquid hubs.

The data presented by Brattle show that open interest (the metric used by Brattle) for real-time futures at the Western Hub is about twice that of comparable measures, real-time or day-ahead, at the next most liquid hub and that open interest at Western Hub for real-time prices is about five times higher than open interest for day-ahead prices.[14] PJM plans to use day-ahead futures prices as a basis for forward looking LMPs.[15] The open interest for the Western Hub real-time products, peak and off peak, significantly exceeds the open interest for all day-ahead products at all hubs. The open interest for day-ahead futures prices at the AEP Dayton Hub, the hub with the most day-ahead activity, is approximately one third the open interest for the real-time futures prices at the Western Hub.

The August 5th Filing does not include the name of the relevant hubs in the tariff, referencing only the undefined term liquid hubs. There is no definition of what a liquid hub is, how liquid hubs will be selected in the future, how many liquid hubs will be included or how the hubs will be mapped to specific zones. The hubs are to be identified only in PJM Manuals, providing PJM with inappropriate discretion to affect the calculation in very

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14 *See* August 5th Filing, Attachment C, Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on behalf of PJM Interconnection, L.L.C. ("Brattle Affidavit").

15 *See* August 5th Filing at 14.

significant ways. This adds further unnecessary uncertainty and lack of transparency to the calculations.

PJM should use Platts' Western Hub real-time on peak and off peak forward prices for all zones.

Futures prices, for the relevant capacity market delivery years, at trading hubs are annual or monthly, on peak and off peak. In order to determine hourly nodal prices, the next logical step is to apply historical information on the temporal and locational distribution of prices to the hub prices.

Rather than using the historical information about the actual distribution of LMPs by hour and by location, consistent with the approach currently being used for opportunity cost calculations, the August 5th Filing proposes to use prices from the Long Term FTR Auction. It is unclear why PJM chose to add this complex, superfluous, irrelevant and internally inconsistent approach to the calculation of the forward EAS offset.[16] The August 5th Filing offers no substantive reason.

F. Long Term FTRs are Not a Good Basis for Calculating Locational Price Differences

The August 5th Filing proposes to use Long Term FTR Auction prices to estimate part of the locational differences to apply to the forward prices at the identified hubs. The August 5th Filing proposes to use long term FTR auction results for the wrong year because the long term FTR auction prices will not be available for two years after they are needed. Long Term FTR prices for the relevant delivery year are not available at the time of the capacity market auctions. Because the FTR data are reflective of congestion, but not losses, and do not capture monthly and hourly price variation, this approach requires additional adjustments based on historical LMPs. A simpler process would shape the forward energy

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[16] See August 5th filing.

prices using only historical LMPs, which are a more reliable and more transparent method of calculating locational price differences.

Annual prices from the Long Term FTR Auction are not a reasonable substitute for the actual distribution of PJM LMPs in the calculation of the EAS offset for use in the capacity auctions, for several reasons. The Long Term FTR Auctions have participation levels only around 50 percent of PJM Annual FTR Auctions. Long term FTRs involving these specific hubs are less than 10 percent of all LT FTRs for the 2017/2020 through 2020/2023 auctions, so broad assertions about the nature of the FTR market are irrelevant. The Long Term FTR Auction was moderately concentrated at two of the three hubs and highly concentrated at one of the hubs for at least one of the last four auction planning years.

Long term FTR prices are a demonstrably poor estimate of actual congestion.[17] Brattle states: "Long-term FTRs of course do not accurately predict the realized congestion in the delivery year due to the uncertainty of the market conditions they serve to hedge."[18]

Even if long term FTR auction results were relevant to the EAS offset, the timing of the FTR auctions means that the results will not be available in time to use for the capacity auction. Capacity market base residual auctions are held in May, three years prior to the delivery year starting on June 1. The EAS calculation for the auctions is done in early January, and participants must submit their offer cap data in January (120 days priors to the start of the Base Residual Auction).

The timing of the capacity market auctions makes it impossible to use the long term FTR data for the relevant capacity market delivery year. The Long Term FTR Auction that includes FTRs for the delivery year is held in five rounds over three years. The first round is

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17 *2020 Quarterly State of the Market Report for PJM: January through June,* Section 13: FTRs and ARRs, Figure 13-33, p683.

18 Brattle Affidavit at para. 55.

in June, three years prior to the start of the third planning year. The June round is after the capacity auction has already cleared. Subsequent rounds are held in August, October, December and the fifth and final round of the FTR auction for the delivery year is in March of the next year, almost a full year after the capacity auction, and more than a year after the data is needed for inclusion in capacity market offers. As a result of the fact that the long term FTR auction prices will not be available for two years after they are needed, the August 5th Filing proposes to use long term FTR auction results for the wrong year, which do not include prices for the delivery year being modeled. Even the prior year's FTR auction results will not be available in time to calculate the EAS offset for the capacity delivery year. For example, the EAS offset for offers for a capacity market auction in May 2021 for the 2024/2025 Delivery Year have to be calculated in January 2021. The Long Term FTR Auction that would cover the 2023/2024 planning year, already a one year mismatch, would not be available until March. The mismatch would be two years.

The August 5th Filing proposes to use long term FTR prices as a measure of price differences rather than actual historical price differences. As a result, the use of long term FTRs requires complex adjustments. The August 5th Filing does not and cannot adjust the FTR results for the two year mismatch. The August 5th Filing does adjust the FTR data to get from the annual results to monthly results and from monthly results to hourly results. The August 5th Filing also does adjust the results to account for losses because FTR prices are for congestion and not losses.

Brattle appears to simply ignore the fact that the long term FTR results are for the wrong year, by two years. The August 5th Filing also ignores the timing mismatch issue. The tariff language proposed in the August 5th Filing simply states: "This differential is developed using the prices for the Planning Period closest in time to the Delivery Year from the most recent long-term Financial Transmission Rights auction conducted prior to the

Base Residual Auction."[19] This means that PJM will adjust forward prices for congestion based on anticipated conditions in a year two years before the capacity market delivery year.

Long term FTRs are an annual product, so that August 5th Filing also makes a monthly adjustment.

The tariff language in the August 5th Filing describes the adjustment:[20]

> The difference between the annual long-term Financial Transmission Rights auction prices for the Zone and the hub are converted to monthly values by adding, for each month of the year, the difference between (a) the historical monthly average day-ahead congestion price differentials between the Zone and relevant hub and (b) the historical annual average day-ahead congestion price differentials between the Zone and hub.

The August 5th Filing then makes a second monthly adjustment to account for losses. Congestion does not include losses.

The August 5th Filing provides for the calculation of what it terms the marginal loss differentials. [21]

> For each month of the year, calculate the marginal loss differential, which is the average of the difference between the loss components of the historical on peak or off peak day-ahead LMPs for the Zone and relevant hub in that month across the three year period scaled by the ratio of (a) the forward monthly average on-peak or offpeak day-ahead LMP at such hub to (b) the average of the historical on-peak or off-peak day-ahead LMPs for such hub in that month across the three year period.

Once the monthly zonal prices have been calculated using long term FTRs and all the associated adjustments, the August 5th Filing calculates hourly zonal prices by applying

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[19] *See* August 5th filing at 89.

[20] *Id*.

[21] *See* August 5th filing at 89-90.

the zonal historical hourly price spread as currently used in the opportunity cost calculator and as recommended by the Market Monitor as a substitute for the entire convoluted process using FTRs.

The August 5th Filing does not provide the details of the FTR calculations or the detailed results.

In summary, PJM should be required to use the straightforward method currently approved by PJM to calculate hourly zonal and nodal LMPs from the monthly on peak and off peak Platts' real-time forward prices. The unnecessary and inaccurate and nontransparent complexity of the approach in the August 5th Filing should be rejected.

G. Selecting the Period for Defining Forward Prices.

The goal in selecting the period during which the forward prices are defined for use in the EAS offset calculation should be to calculate the forwards as close as possible to the auction date and over as short a period as possible to reduce the possibility of manipulation. The goal is to ensure the use of the most current forward information about market prices.

PJM proposes to use forward prices averaged over the 30 day period that ends 180 days before the auction. There is no reason to average the results over 30 days as that results in using data from as long as 210 days prior to the auction, or approximately seven months. That is not as current as it should be.

The Market Monitor recommends use of forward prices averaged over the week that ends 134 days prior to the BRA. Offers are due 120 days prior to the BRA and 14 days gives the participants time to include the latest offset results in offers. The same timing should apply to gas forward data.

H. Open Interest Supports the Use of Forward Prices from the Western Hub.

PJM's liquidity analysis is incomplete. Figure 1 in the August 5th Filing is taken from the Brattle Affidavit and is described as the average open interest on ICE future contracts for calendar year 2024.[22] Market Monitor Figure 1 shows the open interest, or number of contracts currently active, as reported by ICE for the 2023/2024 Delivery Year.[23] [24] The data in Market Monitor Figure 1 is for the period of the 2023/2024 Delivery Year. The total open interest for the PJM Western Hub contracts exceeds the open interest on the hub with the second highest level of open interest, AEP Dayton Hub, by 80.0 percent. The total open interest for the Western Hub contracts exceeds the open interest on the NI Hub, the other hub proposed by PJM, by 146.9 percent.

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22 *See* August 5th Filing, Figure 1 at 13.

23 *See* "End of Day Reports for ICE Futures U.S. – Energy Division," <*https://www.theice.com/marketdata/reports*>.

24 ICE End of Day reports are available for one week on the ICE website after the week occurs. The Market Monitor used End of Day reports for August 27, 2020.

Figure 1 Average monthly open interest on ICE fixed price futures contracts for 2023/2024 Delivery Year (number of contracts)[25]

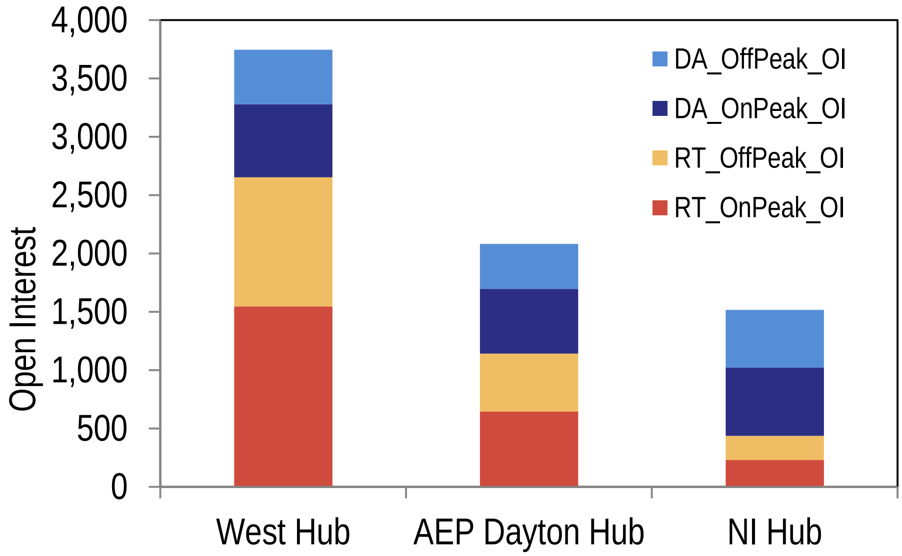
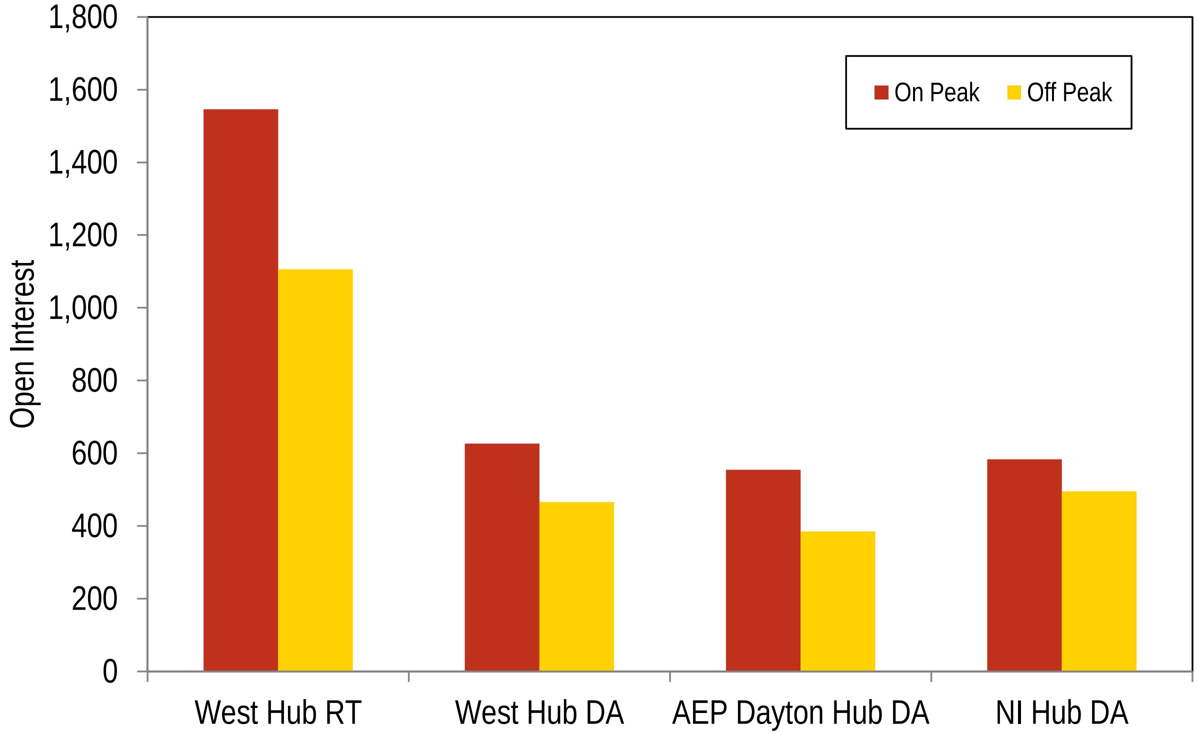


Figure 2 shows a comparison of the open interest on real-time futures at the Western Hub and open interest on day-ahead futures that PJM has proposed serve as the basis for forward LMPs.

[25] Open interest for June 2023 through May 2024 monthly futures contracts on August 27, 2020 as reported in the ICE End of Day report <https://www.theice.com/marketdata/reports>.

Figure 2 Open interest for Western Hub: Market Monitor versus PJM proposal[26]



In addition, the correlation analysis in the August 5th Filing is not enough to support the choice of significantly less liquid hubs based on zone to hub on correlation coefficients.[27] PJM's Table 5 shows that all of their hub to zone associations have a high correlation coefficient. What is missing is a comparison of the correlation coefficients for all hub to zone combinations. PJM did not assert that there was a statistically significant difference in relevant correlation coefficients. Yet the August 5th Filing would give up liquidity in order to obtain a higher zone to hub correlation. That is not an adequate or supported basis for selecting less liquid trading hubs.

[26] Average open interest as of August 27, 2020 for ICE monthly futures contracts with expiration in the 2023/2024 Delivery Year.

[27] *See* August 5th Filing, Table 5 at 17.

I. Forward Natural Gas Prices

The Market Monitor defined criteria for selecting the relevant gas pricing hubs and applied them systematically to determine the gas pricing hubs for each zone. The Market Monitor selected the gas pricing hubs based on the hubs accessible to existing units in each PJM zone where that access is available to new entrants and where that access is not based on firm transportation or location behind a local gas distribution company (LDC).[28] The Market Monitor selected the lowest priced hubs between 2015 and 2017 from the defined accessible hubs within each zone. The August 5th Filing did not follow the same criteria as the Market Monitor and neither PJM nor Brattle defined criteria and applied them.[29]

Table 3 shows the natural gas pricing points used by the Market Monitor. The Market Monitor uses the same pricing point mapping as the August 5th Filing for all but three zones, AEP, PPL and PSEG. However, in the three zones mapped to Tennessee 500L, Transco Zone 5, and Transco Zone 6 NY. The August 5th Filing uses forwards from a different pricing point (PJM Additional Mapping column) to calculate forward gas prices for the three zones.[30]

There is no reason for PJM to estimate forward prices for these three zones because Platts provides the data (as does ICE).[31] The August 5th Filing is inconsistent in its use of forward data. The August 5th Filing uses settlement prices calculated by ICE for some hubs, but not for all hubs. Effectively, the August 5th Filing is substituting Brattle's judgment

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28 Gross CONE calculations do not include the cost of firm pipeline transportation in PJM's approach or in the Market Monitor's approach because the reference unit has dual fuel capability.

29 Protest of the Independent Market Monitor for PJM, Docket No. ER19-105, (November 19, 2020).

30 *See* August 5th filing at 22, Brattle Affidavit at para.67.

31 See S&P Global Platts "Methodology and Specifications Guide M2MS- Gas Methodology," <https://www.spglobal.com/platts/plattscontent/_assets/_files/en/our-methodology/methodology-specifications/m2ms-gas.pdf>. Last updated January 2020.

about prices at these three pricing points for Platts' judgment (or ICE's judgment). This is Platts' core business and the markets use Platts' data. The mapping should use Platts' data.

Table 1 Comparison of natural gas pricing points

	Natural Gas Pricing Point Mapping		
	IMM	PJM	PJM Additional Mapping
AECO	Transco Zone 6 (non NY)	Transco Zone 6 (non NY)	
AEP	Texas Gas Zn 1	Col Gas Appalachia	
APS	Dominion South	Dominion South	
ATSI	Mich Con CG	Mich Con CG	
BGE	Transco Zone 6 (non NY)	Transco Zone 6 (non NY)	
COMED	Chicago CG	Chicago CG	
DAY	Mich Con CG	Mich Con CG	
DEOK	Mich Con CG	Mich Con CG	
DOM	Transco Zone 5	Transco Zone 5	Transco Zone 6 (non NY)
DPL	Transco Zone 6 (non NY)	Transco Zone 6 (non NY)	
DUQ	TX Eastern M-3	TX Eastern M-3	
EKPC	Tennessee 500L	Tennessee 500L	TX Eastern M-3
JCPL	Transco Zone 6 (non NY)	Transco Zone 6 (non NY)	
METED	TX Eastern M-3	TX Eastern M-3	
PECO	TX Eastern M-3	TX Eastern M-3	
PENELEC	Dominion South	Dominion South	
PEPCO	Transco Zone 5	Transco Zone 5	Transco Zone 6 (non NY)
PPL	Tennessee Zone 4 300L	TX Eastern M-3	
PSEG	TX Eastern M-3	Transco Zone 6 (NY)	Transco Zone 6 (non NY)
RECO	Transco Zone 6 (NY)	Transco Zone 6 (NY)	Transco Zone 6 (non NY)

The issues related to the use of gas forward prices are similar to the issues identified by the Market Monitor related to the use of power forward prices. PJM uses futures prices from the Intercontinental Exchange (ICE) while the Market Monitor uses prices from Platts. ICE futures data for three plus years in the future includes trades that cover an entire year, which ICE shows as occurring in individual months at the same price and quantity. Most of the gas futures traded on ICE for the future years that are relevant to the capacity market delivery year are multimonthly or annual contracts, not monthly contracts. Platts uses ICE futures data plus a combination of historical forward prices, historical spot prices and ICE forward data to shape multimonthly and annual prices into monthly prices.[32] The August 5th Filing does not discuss the reasons for its choice of ICE data over Platts' data. The August 5th Filing does not discuss the reasons that PJM chose to no longer use Platts' data as PJM has used and approved for use in the opportunity cost calculator.[33] There should be an explicit choice between the two data sources based on rational criteria. The question of how to address annual futures prices needs to be addressed explicitly. The annual prices must be shaped, by Platts, by ICE or by a PJM defined method. The Market Monitor recommends that Platts' data continue to be used until it can be established that there is a better option. PJM has access to these data, PJM has used these data, and use of Platts' data will not slow down the capacity market auction process.

As with the other elements of the EAS Offset, the choice of gas price data can have a significant impact on the offset and all the market parameters based on the offset.

J. The 10 Percent Cost Adder Should Not Be Included in Operating Costs.

The calculation of net revenues depends both on gross revenue from LMP and the short run marginal costs of operating the unit. Short run marginal costs include primarily fuel but also operating costs. PJM has added 10 percent to the short run marginal costs of CTs but did not add 10 percent to the short run marginal costs of the other unit types for which they are calculating net revenues. There is no good reason for this inconsistent treatment. The 10 percent adder should not be included in costs for any resource type.

The PJM Market Rules allow generators of all types to increase their cost-based offers by 10 percent.[34] The 10 percent adder has been included in the rules for cost-based

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32 *See* S&P Global Platts "Methodology and Specifications Guide M2MS- Power Methodology," <https://www.spglobal.com/platts/plattscontent/_assets/_files/en/our-methodology/methodology-specifications/m2ms_power_methodology.pdf>. Last updated May 2018.

33 PJM references the Platts' forward curve in "PJM Manual 15: Cost Development Guidelines," Rev. 35 (April 24, 2020) § 12.7.

34 PJM OA, Schedule 1, 6.4.2(a), PJM OA, Schedule 2

offers since before the introduction of markets. It was originally intended to address the uncertainty created by ambient conditions that can affect actual costs in real time. But there is no uncertainty in the optimal dispatch used in the EAS calculation. There is no reason to add 10 percent.

In addition, the August 5th Filing's logic proves too much. If PJM adds 10 percent to the cost of a CT because the rules permit the 10 percent adder, by the same logic, PJM should add it to the costs of all units. The PJM Market Rules permit, but do not require, use of the 10 percent adder.

The evidence does not support PJM's inclusion of the 10 percent adder for CTs. Data for offers by CTs show that CTs do not uniformly include a 10 percent adder. Of all the CTs that cleared in the energy market in 2019 and the first two quarters of 2020, between 40 and 50 percent were offered with incremental price-based offers less than their incremental cost-based offers.

The August 5th Filing presents internally inconsistent reasoning. The August 5th Filing's rationale for adding 10 percent to short run marginal costs only for CTs and not for other unit types is that it is "consistent with existing market rules." That is clearly not a distinguishing or logical reason, when the rules are the same for all unit types.

The August 5th Filing attempts to distinguish between gas-fired resources and coal and nuclear resources. But the PJM rules do not make that distinction. In the PJM rules, the 10 percent adder applies to all resources, regardless of fuel type. As the basis for distinguishing gas fired resources, the August 5th Filing asserts that "it is appropriate for the CT to account for increased net costs of matching gas supplies with flexible day-of changes in operations."[35] Again, this is not a distinguishing reason. Even if this assertion were correct, it would apply equally to CC offers, but the August 5th Filing does not apply it to CCs. The assertion is incorrect. In PJM, generators are not allowed to include balancing

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[35] *See* August 5th Filing at 30.

costs in their cost-based offers. Balancing costs are avoidable costs includable in the Avoidable Cost Rate of resources as Avoidable Fuel Availability Expenses.[36] These are not short run marginal costs and should not be included in cost-based offers.

The addition of 10 percent to short run marginal costs artificially reduces CT net revenues. This has significant market impacts because the reduction in CT net revenues artificially increases the default MOPR floor for CTs, the capacity market offer cap which equals the CT net CONE times B, resource specific offer cap values, and the CT net CONE values used in the Variable Resource Requirement ("VRR") curve.

K. Major Maintenance Costs Should Not Be in Operating Costs.

Major maintenance costs are not short run marginal costs. About a third of marginal gas fired units and more than half of coal fired units had negative markups in the first halves of 2019 and 2020.[37] Actual competitive offers in PJM cannot be assumed to include major maintenance.[38] Including major maintenance in cost-based offers significantly reduces net revenues. For that reason, the August 5th Filing did not simply include major maintenance costs in cost-based offers as PJM's logic dictates. Rather, the August 5th Filing arbitrarily divides major maintenance between start costs and incremental costs in order to calibrate the impact on net revenues to produce a desired result.[39] The August 5th Filing includes half of major maintenance in start costs and half of major maintenance in operating costs. Nothing in the PJM Market Rules, no experience with actual physical resources, and

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36 PJM OATT, Attachment DD Reliability Pricing Model

37 Markup is defined as the difference between the price-based incremental energy offer and the cost-based incremental energy offer.

38 *See* 2020 Quarterly State of the Market Report for PJM: January through June, Section 3: Energy Market at 206.

39 *See* August 5th Filing at 34–36.

no technical cost information supports this division of maintenance costs in the April 5th Filing.

It is inappropriate for PJM to exercise discretion in the decision about where to include maintenance costs in the energy offer in order to calibrate net revenues to PJM's desired result.

Table 2 Comparison of operating costs

	Operating Cost ($/MWh)	
	IMM	PJM
CT	Fuel + emissions + $0.38 consumables	Fuel + emissions + $1.10 consumables + $0.85 major maintenance + 10% adder
CC	Fuel + emissions + $1.39 consumables	Fuel + emissions + $0.67 consumables + $1.44 major maintenance

Table 3 Comparison of start costs

	Start Cost ($/Start)	
	IMM	PJM
CT	Fuel + emissions	Fuel + emissions + $11,732 major maintenance
CC	Fuel + emissions	Fuel + emissions

The decision to allocate major maintenance between start and incremental costs underscores that these costs are not short run marginal costs. Typically, LTSA agreements allocate maintenance to starts and/or equivalent operating hours depending on how the generator actually operated during a given historical period.

The August 5th Filing argues that the "analysis indicates that splitting the major maintenance 50/50 between starts and run hours is suitable for [their] purposes" because it produces a "more reasonable dispatch simulation."[40]

The correct method is to dispatch the generator using only short run marginal costs and calculate the maintenance cost at the end of the period. The maintenance cost would be calculated based on how the model dispatched the generator. The maintenance cost would not be included in the cost-based energy offer but would be included in the gross CONE.

The addition of major maintenance to short run marginal costs artificially reduces CT net revenues. This has significant market impacts because the reduction in CT net

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40 *Id*. at 73.

revenues artificially increases the default MOPR floor for CTs, the capacity market offer cap which equals the CT net CONE times B, resource specific offer cap values, and the CT net CONE values used in the Variable Resource Requirement ("VRR") curve.

The addition of major maintenance to short run marginal costs also artificially reduces CC net revenues.

L. Ancillary Revenues and Costs are Not Adequately Defined.

The August 5th Filing proposes to model a jointly optimized energy and ancillary services market using historic prices for reserve and regulation products. The August 5th Filing does not clearly specify the resource costs used for synchronized reserves and regulation. Resources are allowed to submit cost-based regulation offers based on defined costs plus a $12.00 per MW margin, but resources rarely submit price-based regulation offers as high as the allowable level because the allowable regulation costs in the PJM market rules are overstated. The August 5th Filing does not explain the determinants of the offers for the reference CT. These details should be specified for transparency of the EAS offset calculation for both the initial calculation and all future quadrennial reviews.

The artificially reduced net revenues for the CT are supplemented by the artificial increase in regulation net revenues in the August 5th Filing. The August 5th Filing includes an artificially high and significant level of regulation revenues for the CT. This level of revenues is inconsistent with the actual behavior of CTs in the regulation market. The August 5th Filing is not clear about how it modeled the regulation market, but the CT regulation revenues do not appear to be consistent with the actual design of the regulation market.[41] The CT regulation market revenues are clearly overstated.

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[41] See Monitoring Analytics, LLC, *2020 Quarterly State of the Market Report for PJM: January through June*, Section 10: Ancillary Service Markets (August 13, 2020).and Monitoring Analytics, LLC, *2019 State of the Market Report for PJM*, Vol. 2, Section 10: Ancillary Service Markets (March 12, 2020).

Simply removing the regulation revenues would not be a solution. The solution to the CT net revenue should be comprehensive and include removal of the 10 percent adder from short run marginal costs, removal of major maintenance costs from short run marginal costs, and elimination of regulation market revenues. The result would a reasonable estimate of the forward looking EAS offset for a CT operating in PJM markets.

M. RTO Net CONE

The average net CONE across all zones should be used for the RTO net CONE for the VRR curve and for the CP nonperformance charge rate. Instead, PJM uses average RTO prices to define the dispatch of and the EAS offset for the reference CT used to define the RTO VRR curve. No actual unit in PJM ever faces RTO average prices. No unit receives EAS revenues based on an RTO average. The PJM RTO calculation is an artifact that has no relevance to actual EAS Offsets and should not be used for any purpose.

For cases in which the RTO net CONE is used for external generation capacity resources (to calculate net CONE times B and MOPR defaults for new external capacity), the net EAS should be based on the zone where the resource is interconnected.

II. CONCLUSION

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

Respectfully submitted,

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Dated: September 2, 2020

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 2nd day of September, 2020.

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