UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Reactive Power Capability Compensation	)))	Docket No. RM22-2-000

REPLY COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to the Notice of Inquiry issued in the proceeding on November 18, 2021 ("NOI"),[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 reply comments. The NOI inquires about reactive power capability compensation under the *AEP* Method, alternative methods of compensation, and resources interconnected at the distribution level. The fundamental question is whether market design in the organized wholesale markets requires separate, guaranteed cost of service compensation for reactive capability. The answer is no. No commenter demonstrates any such requirement.

In the PJM market design, investment in resources is fully recoverable through markets. The PJM markets are a complete set of markets that are self sustaining. Unlike some ISO/RTO designs, the PJM market relies on markets rather than cost of service regulation or bilateral contracts to pay for capacity. Generators will invest in markets when the expected revenues provide for the payment of all costs and the return and of capital. That is the way competitive markets work. It would be more equitable, more consistent with the PJM

1 *Reactive Power Capability Compensation*, Notice of Inquiry, 177 FERC ¶ 61,118 ("NOI").

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").

competitive market design, and more consistent with appropriate compensation for all generator costs, including reactive, to rely on PJM markets than to continue the outdated mixing of regulatory paradigms.

I. COMMENTS

A. There is No Good Reason to Mix Market and Cost of Service Paradigms.

There is simply no reason to continue to include cost of service rates in PJM markets. The big picture here is that in PJM, the interrelated and self sustaining markets provide the opportunity for all power plants to recover all their costs, including a return on and of capital, including any identifiable reactive costs. There is no reason that part of those capacity costs should be paid directly in a non market, guaranteed, riskless revenue stream rather than in the market. The existence of the current option creates strong incentives for generators to maximize the allocation of capital costs to reactive in order to maximize guaranteed, nonmarket revenues.

The reactive over recovery issue raised by the Market Monitor arises directly from the fact that the reactive cost of service model continues to be included in PJM markets, and the issue cannot be understood without understanding both markets and cost of service ratemaking. Commenters arguing that there is no issue of over recovery focus solely on cost of service ratemaking. Linking the opportunity to recover revenues in markets to specific costs is based on a confusion about cost of service ratemaking and markets and is therefore irrelevant.

Cost of service ratemaking defines a specific level of revenue requirement based on specific costs. Markets provide an opportunity to recover costs but do not guarantee payment of a defined revenue requirement..

It follows logically that, in a market, the opportunity to recover costs may result in actual market revenue less than costs, equal to costs or greater than costs. The actual level of revenues received by a resource in the markets is irrelevant. The market design does not include a cost of service backstop to ensure recovery of a specific level of revenue. The market design provides the opportunity to cover costs. The actual results depend on competition.

The PJM market rules explicitly recognize and account for the recovery of reactive revenues through a cost of service rate of $2,199 per MW-year because the PJM market rules reduce the opportunity to collect reactive revenues in the market by $2,199 per MW-year by shifting the capacity market demand curve. Capacity market prices are lower as a direct result of this offset. Capacity market prices would be higher if the cost of service approach to reactive revenues were eliminated and the $2,199 per MW year was also eliminated.

The Commission has recognized the relevance of the issue associated with a "resource receiving cost-based rate recovery while concurrently receiving compensation for market-based rate services involves potential double recovery of costs borne by the relevant cost based ratepayers."[3] The Commission states: "the potential for combined cost based and market based rate recovery to result in double recovery of costs" is an issue that "should be addressed."[4] The Commission has evaluated solutions, including but not limited to, "crediting any market revenues back to the cost based ratepayers."[5] [6]

Under market based rates in the PJM markets, unit owners receive revenues but the revenues are not uniquely associated with specific elements of costs. For example, if a unit receives $300 per MW-day in market revenues during a delivery year, the revenue

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3 *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 at P 15 (2017) ("Cost-Based Recovery Policy Statement"); *see also, Transwestern Pipeline Company*, 52 FERC ¶ 61,100 (1990) ("held that Transwestern could not file to recover costs incurred after market-based GIC rates were in effect").

4 *Id*. at P 13.

5 *Id*. at P 15.

6 *Id*. P 19, citing The *Nev. Hydro Co. Inc.*, 122 FERC ¶ 61,272 at P 83 (2008) ("allowing LEAPS to receive a guaranteed revenue stream through CAISO's [Transmission Access Charge] would create an undue preference for LEAPS compared to these other similarly situated pumped hydro generators"); *Western Grid Dev.*, LLC, 130 FERC ¶ 61,056, *reh'g denied*, 133 FERC ¶ 61,029 (2010).

contributes to covering all costs, including fixed and variable costs, and cannot be identified as covering a specific element of costs. This is particularly true for reactive costs as the same generating equipment produces both real and reactive power. If the unit's total costs are $400 per MW-day, the shortfall cannot be assigned to reactive costs or all other costs.

B. The *AEP* Method Is an Allocation Method Premised on Avoiding Over Recovery.

Contrary to the views of EPSA and some other commenters, the potential for over recovery is a fundamental premise of Opinion No. 440, which approved the *AEP* Method.[7] The *AEP* Method recognizes that the same plant is used to provide real (MW) and reactive (MVAR) power.[8] As a result, the *AEP* Method allocates a portion (X percent) of the cost of the plant to MVAR production and the balance (1 – X percent) to MW production. In a pure cost of service world, the allocators add to 100 percent and there can be no over recovery, regardless of the value of X. But that is not true when the units operate in a competitive wholesale power market.

Comments dismissing the over recovery issue are rooted in cost of service logic that ignores how markets operate. EPSA asserts that over recovery does not result from the use of the *AEP* Method in the PJM markets. EPSA's arguments are incorrect. [9]

There is no distinction between the equipment required for real and reactive power. Sellers of power generating equipment do not define or charge for separate reactive capability equipment. Power plants are integrated machines. The PJM markets, including

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7 *See American Electric Power Service Corp.*, 80 FERC ¶ 63,006 (1997), *aff'd*, Opinion No.440, 88 FERC ¶ 61,141 (1999). The *AEP* Method refers to the approach developed by AEP Witness Pasternack for calculating a cost of service rate for a vertically integrated coal fired power plant. *See American Electric Power Service Corporation*, Direct Testimony of Bernard M. Pasternack, Docket No. ER93-540-000 (November 15, 1993) at 14:24–15:24 & Exhibit A-34.

8 *See id. mimeo* at 32.

9 Comments of the Electric Power Supply Association, Docket No. RM22-5-000 (February 22, 2022) ("EPSA"), Attachment A (The Kimbrough Affidavit) at 13:14–20.

energy, ancillary services and capacity markets, provide the opportunity to be paid for 100 percent of the cost of capacity, but currently with an offset for reactive revenue in the capacity market demand curve. Without the offset, the PJM markets would provide the opportunity to be paid for 100 percent of all costs. In actual practice, PJM markets may pay less than, more than or 100 percent of total costs, depending on market conditions.

There is no basis for asserting that the $2,199 per MW-year is unrepresentative of most resources. The actual average payment for reactive capability is actually less than $2,199 per MW-year. The fact that black box settlements have resulted in excess payments for some technologies to which the *AEP* Method does not apply is not precedential or relevant to defining the costs of reactive capability. Most fundamentally, there is no separately identifiable cost for reactive capacity costs. The $2,199 is the current offset in the capacity market demand curve but that number was based on historic reactive settlements under the *AEP* Method and not based on a definition of the costs of reactive.

EPSA misunderstands the implications of removing the $2,199 per MW-year offset. The result would be to increase capacity market prices and not decrease capacity market prices. The result would not be to increase the need for additional revenues.

The fact that reactive rate settlements include explicit prohibitions against double recovery despite the fact of ongoing over recovery is direct evidence that the prohibitions are not well defined and not meaningful, particularly in black box settlements.

Likewise, arguments that intermittent resources have limits on the amount of capacity that they can offer, and therefore, are limited in their ability to receive compensation for reactive capability, are misplaced.[10] Market sellers receive the same locational market prices per MW of capacity and per MWh of energy regardless of resource type. There is no

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10 *See* Initial Comments in Response to Notice of Inquiry of EDF Renewables, Inc., Docket No. RM22-2-000 (February 22, 2022) at 10–11; Comments of Vistra, Docket No. RM22-2-000 (February 22, 2022) at 18.

guarantee of cost recovery for any resource type. Resources in PJM markets have to opportunity to cover all their costs based on all market revenues.

Some commenters argue that it is discriminatory to provide for recovery through capacity market revenues when some units do not participate in capacity markets or fail to clear the capacity market.[11] But that is not the argument. The incentives for investment in PJM are based on all revenues received from all PJM markets. Whether or not a unit participates in the capacity market or clears a capacity market auction is not relevant to the question of whether market revenues are sufficient. This argument is based on the misunderstanding that capital costs are uniquely recovered in the PJM Capacity Market. That is not correct. The actual share of total costs recovered in different PJM markets depends on how units operate. Some units recover most of their fixed and variable costs in the energy market.

Some commenters complain that capacity markets are discriminatory because resources compete against demand resources that do not have reactive capability obligations.[12] Such commenters claim that this means the investment in reactive capability cannot be recovered. This argument is a red herring. Flawed rules for the participation of demand resources have an effect on market outcomes but the impact has nothing to do with reactive power. If anything, it is discriminatory to allow generators to be provided a guarantee of cost recovery through reactive cost of service guarantees when that option is not available to demand resources.

The Market Monitor has focused on the capacity markets because changes to the capacity market rules would be necessary if the provisions for cost of service ratemaking in Schedule 2 to the OATT were removed as is recommended. The $2,199 per MW-Year ancillary services offset would need to be removed along with Schedule 2. Focus on the capacity

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11 *See, e.g.*, EPSA at 13.

12 *Id*.

market does not mean that revenues from other PJM markets are not relevant. The energy market is the largest source of revenues for resources in PJM.

C. A Flat Rate for Reactive Capability Is Just a Simplified Cost of Service Method.

A number of commenters support the development of a flat rate for reactive capability compensation, noting that flat rates have been adopted in other markets.[13] But a flat rate is just a simplified version of the current cost of service method and is incorrect for all the same reasons. A flat rate should be rejected for all the reasons that the cost of service approach should be rejected.

A flat rate removes a large part of the administrative burden associated with cost of service proceedings. A flat rate would not avoid the wide disparity in the rates paid in PJM for reactive capability if the flat rates vary by technology, as some have proposed. There is no reason for PJM customers to pay different prices to different technologies for the same product.

D. Allowing Remote Attendance at Hearings and Settlement Conferences Would Facilitate Greater Participation by Customers.

The Market Monitor has an additional comment concerning the inquiry in the NOI (at page 24) about the level of participation by customer representatives in reactive cost of service rate proceedings. During the past two years, the ability to remotely participate in hearings and settlement conferences has significantly reduced the cost of participation. Before Covid, participants were required in some cases to attend settlement conferences and other proceedings in person, even to address only administrative matters. Ensuring that all participants, including customer representatives, can attend proceedings remotely would avoid the need to incur travel expenses, to need to incur the opportunity cost related to travel

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[13] *See, e.g.*, Comments of American Electric Power Service Corporation, Docket No. RM22-2-000 (February 22, 2022) at 2–3; Comments of Ameren Services Company, Docket No. RM22-2-000 (February 22, 2022) at 19–21.

time, and/or the need to incur legal expenses for counsel in Washington, D.C. The ability to participate remotely should be extended to all future reactive related cases.

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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