UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mechanicsville Solar, LLC	)))	Docket No. ER21-2091-000, -001

To: The Honorable Matthew Vlissides
Presiding Administrative Law Judge

PRE HEARING BRIEF
INDEPENDENT MARKET MONITOR FOR PJM

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Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"), submits this pre hearing brief. For the reasons explained on brief, Mechanicsville Solar, LLC ("Mechanicsville") has not shown that its facility ("Mechanicsville Facility") satisfies the requirements for eligibility to receive compensation under Schedule 2 to the PJM Open Access Transmission Tariff ("Schedule 2"). The rate schedule should be rejected on that basis alone. If the Mechanicsville Facility is nevertheless determined to be eligible, it should not receive a revenue requirement under Schedule 2 exceeding $2,199 per MW-Year. To the extent that a rate method using a capital recovery factor ("CRF") is permitted, the CRF proposed by Mechanicsville is excessive and unjustified, and it should be calculated instead based on the method proposed by the Market Monitor.

I. SUMMARY

In this brief, the Market Monitor explains its position on four issues:

Whether Mechanicsville Solar, LLC ("Mechanicsville") is eligible to collect reactive power compensation under Schedule 2. Mechanicsville has not established the eligibility of its facility to receive compensation for reactive supply capability under the applicable criteria in Schedule 2.

Whether the level of the rate proposed by Mechanicsville is unjust and unreasonable because it allows for over recovery. The Mechanicsville Facility participates in a competitive market design that provides an opportunity to recover all its costs. The capacity market design (VRR curve) anticipates that resources will receive $2,199 per MW-Year in compensation for reactive supply capability and removes that amount from the market design parameters. To the extent that Mechanicsville proposes a revenue requirement exceeding $2,199 per MW-Year, it is seeking an unjust and unreasonable excess recovery.

Whether Mechanicsville properly uses the *AEP* Method to calculate a cost based revenue requirement under Schedule 2; and whether, if the *AEP* Method generally applies, the AEP Method applies to a solar facility like Mechanicsville. Mechanicsville has not identified any costs that are not already recoverable under the PJM market design and would therefore be includable in a revenue requirement under Schedule 2. The *AEP* Method is not an appropriate basis for calculating a revenue requirement under Schedule 2. Prior decisions allowing the *AEP* Method did not explain how the method operates to identify incremental costs for providing reactive supply capability. The *AEP* Method is a cost of service allocative method that was not designed to implement Schedule 2 or for use in the context of competitive markets.[1] The *AEP* Method was not designed for use with asynchronous resources, and it should not be used for such resources.

Whether Mechanicsville properly calculated its capital recovery factor ("CRF"). The CRF calculated by Mechanicsville is flawed and should be rejected. If it is determined that a method that includes a CRF should be used in this case, the Market Monitor's proposed just, reasonable and nondiscriminatory approach should be required.

II. BACKGROUND

A. Reactive Supply Capability.

Reactive Supply and Voltage Control Service is necessary to ensure a Transmission Provider's reliable operation of the grid. Reactive supply includes the ability of a resource to produce additional reactive power (measured in MVAR) when needed so that the Transmission Provider can provide Reactive Supply and Voltage Control Service. Reactive power is local and cannot be transferred over long distances.[2] PJM procures reactive supply capability from generators located on the transmission system that it monitors and operates.

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1 *See American Electric Power Service Corporation*, Opinion No. 440, 88 FERC ¶ 61,141 (1999), *withdrawal of reh'g granted*, 92 FERC ¶ 61,001 (2000) ("*AEP*").

2 *See Whitetail Solar 3, LLC, et al.*, Initial Decision, 180 FERC ¶ 63,009 at P 24 (2022).

B. Reactive Supply and Voltage Control From Generation or Other Sources Service.

Order No. 888 provided that transmission providers must provide an ancillary service known as Reactive Supply and Voltage Control Service from Generation Resources.[3] Order No. 888 did not define compensation for generators that enable the transmission provider to provide this service.

When PJM serves as the Transmission Provider for its Transmission Facilities, it provides Reactive Supply and Voltage Control from Generation or Other Sources Service under Schedule 2 to the PJM Open Access Transmission Tariff ("Schedule 2").[4] [5] [6]

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[3] See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 75 FERC ¶ 61,080, 61 FR 21540 at 28581–28532, clarified, 76 FERC ¶ 61,009 (1996), modified, Order No. 888-A, 78 FERC ¶ 61,220, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in part and remanded in part sub nom. Transmission Access Policy Study Grp. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

[4] OATT § 1 defines "Transmission Provider" as follows:

> The "Transmission Provider" shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:
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> (a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;
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> (b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and
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> (c) … Transmission Owners shall have the responsibility … to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Schedule 2 states: "In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power." Schedule 2 provides for generation resources to receive a revenue requirement for reactive supply that such resources provide to PJM so that PJM can provide Reactive Supply and Voltage Control Service.

Schedule 2 does not require or include any method for calculating a revenue requirement, including the *AEP* Method. Schedule 2 refers to a "monthly revenue requirement as accepted or approved by the Commission."

Schedule 2 does not assign to PJM any role in evaluating the eligibility of a resource to file revenue requirements. These determinations are the responsibility of the Commission.

Schedule 2 also states the separate compensation that applies to market sellers that increase reactive output at the direction of PJM. Schedule 2 explains that when PJM calls

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Subsection (a) excludes from PJM's role the direction of "those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations."

5 The OATT § 1 defines the "Transmission System" to "mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III."

6 The OA § 1 (Definitions S–T) and OATT § 1 (Definitions–T–U–V) define "Transmission Facilities" to mean: "facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region."

on a resource to increase reactive power output, the resource is paid directly for the resultant energy market lost opportunity costs under Section 3.2.3B of Schedule 1 to the OA. As Schedule 2 states, these charges and payments are separate from the revenue requirement for reactive supply in Schedule 2.

C. The Mechanicsville Facility and Its Location and Terms of Interconnection.

The Mechanicsville Facility is a 25 MW solar generating facility located in Hanover County, Virginia. The Mechanicsville Facility is physically interconnected to the 34.5 kV facilities of Virginia Electric and Power Company ("VEPCO").[7] None of the VEPCO 34.5 kV facilities where the Mechanicsville Facility interconnects are included by PJM as a Reportable Transmission Facility and none are included by PJM as a Monitored Transmission Facility. In other words, PJM does not monitor or operate the grid at the locations where the Generating Facilities are interconnected.

Interconnection service to the Mechanicsville Facility is governed by an Interconnection Service Agreement ("ISA") among PJM, VEPCO and SunEnergy1 ("Mechanicsville ISA").[8] The Mechanicsville ISA imposes an unusual and restrictive requirement on the Mechanicsville Facility's operations. Schedule F of the Mechanicsville ISA requires:

> Interconnected Transmission Owner [i.e., VEPCO] observed voltage violations due to operations of intermittent facility output during the voltage study. A power factor of 0.99 absorbing is needed to correct the violations. Interconnection Customer will be required to maintain the 0.99 absorbing power factor.[9]

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7 *See* MVS-0001 at 5:14–15.

8 *See* Exhibit No. MVS-0001 at 8:6–7; MVS-0019.

9 *See* MVS-0001 at 11:16–20, quoting MVS-0019 at Schedule F.

Mechanicsville Witness Rob Price states: "Thus, as of today, Mechanicsville is operating its Facility at a 0.99 absorbing power factor as directed by VEPCO."[10]

III. ARGUMENT

A. Mechanicsville Has Not Established Its Eligibility for Compensation under Schedule 2.

Eligibility under Schedule 2 requires that a resource "must (1) be under the control of PJM and (2) be capable of providing reactive service to PJM's transmission facilities such that PJM can operate that generation facility to produce or absorb reactive power in order to maintain transmission voltages."[11]

1. Criterion 1: Under the Control of PJM.

Mechanicsville has not established that the resource is under the direct legal or actual control of PJM.

a. Legal Control.

Mechanicsville has not demonstrated that PJM has the legal authority to dispatch the Mechanicsville Facility. Mechanicsville cannot be subject to PJM control because the Mechanicsville ISA, as required by VEPCO and not by PJM, requires that the Mechanicsville Facility "maintain the 0.99 absorbing power factor."[12] Staff Witness Alexander Valle and Joint Customers Witness Gerald Warhol explains why this requirement means that the Mechanicsville Facility does not satisfy the operational

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10 MVS-0001 at 11:22–23.

11 180 FERC ¶ 63,009 at P 118; OATT Schedule 2 ("In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power.").

12 *See id.* at 11:15–23.

capability criterion.[13] The Mechanicsville Facility is not under PJM's control even indirectly through VEPCO because, for reasons identified by VEPCO, the 0.99 absorbing power factor cannot be changed without rising adverse effects on the VEPCO distribution system and distribution customers.[14] The Mechanicsville Facility is unavailable under the terms of the Mechanicsville ISO for dispatch by PJM to maintain voltages on PJM's Transmission Facilities.

b. Actual Control.

Mechanicsville has not shown that the Facility is under the actual control of PJM. No record evidence indicates that PJM has ever actually exercised any control over the Mechanicsville Facility in order to use its reactive capability. PJM could not exercise any control directly because it does not monitor or operate the system where the Mechanicsville Facility interconnects to the grid.

The Mechanicsville ISA requires the Mechanicsville Facility to follow the directives of the "Transmission Provider." The Transmission Provider is unambiguously VEPCO alone.

PJM Manual 3 (Transmission Operations) sets forth the criteria for determining Monitored Transmission Facilities and the criteria for determining Reportable Transmission Facilities.[15] PJM explains that "Monitored Transmission Facilities are monitored and controlled for limit violations using PJM's Security Analysis programs."[16] PJM explains that transmission facilities are "reportable if a change of its status can affect, or has the potential to affect, a transmission constraint on any Monitored Transmission Facility," or "if it impedes the free-flowing ties within the PJM RTO and/or

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13 *See* S-0001 at 22:11–20; JC-0012 at 7:17–9:19.

14 *See* JC-0012 at 8:11–12.

15 *See* No. IMM-0004.

16 See id.

adjacent areas."[17] The Monitored and Reportable Transmission Facilities are included in the Transmission Facilities List. The Transmission Facilities List is located on the PJM website.

PJM's criteria for defining Monitored Transmission Facilities and the criteria for defining Reportable Transmission Facilities determine which power lines constitute the PJM transmission system and which do not.[18] A resource interconnected on power lines that fail to meet the criteria defining Monitored Transmission Facilities *and* the criteria for defining Reportable Transmission Facilities are not interconnected to PJM's transmission facilities. PJM is not the Transmission Provider for such power lines and has no actual control over the dispatch of resources interconnected to those lines for voltage control.

None of VEPCO's 34.5 kV facilities, where the Mechanicsville Facility interconnects, are Monitored or Reportable Transmission Facilities. This means that PJM is not monitoring the status of these facilities and does not operate them. PJM is not providing Transmission Service on these facilities. PJM does not consider these facilities to be part of the "PJM transmission system."[19] PJM does not issue a voltage schedule to

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[17] *See* PJM, PJM Transmission Providers Facilities List On-Line Help (Last Updated: May 4, 2017), which can be accessed at: <*trans-fac-help.ashx (pjm.com)*>.

[18] A facility that does not meet the criteria defining Reportable Transmission Facilities but does meet the criteria for defining Monitored Transmission Facilities is also not eligible under Schedule 2. If PJM does not operate the Lines, they are not PJM's transmission facilities. There is no evidence that PJM would rely on a resource to provide Reactive Supply and Voltage Control Service if the resource was located on a portion of the grid that PJM was monitoring but not operating. Coordination with the responsible operator would still be needed.

[19] PJM states: "PJM does not view the generator as directly interconnected with the PJM transmission system. PJM does not have operational control over the distribution line, and any coordination required at the distribution level would need to be done through the Transmission Owner" Responses of PJM Interconnection, L.L.C. to Commission Trial Staff's First Set of Discovery Requests, Discovery

the Mechanicsville Facility.[20] This means that VEPCO and not PJM exercises actual control over the reactive output of the Mechanicsville Facility. In this case, VEPCO has exercised its control through the terms of the Mechanicsville ISA, which requires the Mechanicsville Facility to "maintain the 0.99 absorbing power factor."[21]

Mechanicsville has not shown that the Mechanicsville Facility is under the actual control of PJM. Mechanicsville has not shown that the Mechanicsville Facility is under the direct control of PJM. On the contrary, Mechanicsville Witness Price shows that the Mechanicsville Facility is under the legal, actual and direct control of VEPCO. The Mechanicsville Facility is not under the control of PJM and is not eligible to receive compensation under Schedule 2.

2. Criterion 2: Operationally Capable of Providing Voltage Support to PJM's Transmission Facilities such that PJM Can Rely on that Generation Facility to Maintain Transmission Voltages.

a. Mechanicsville Cannot Provide Reactive Capability

Mechanicsville fails to demonstrate that its facility is operationally capable of providing voltage support to PJM's Transmission Facilities such that PJM can rely on it to maintain transmission voltages. Mechanicsville provides no analysis that even attempts to make this showing and no supporting evidence. Staff provides evidence that the Mechanicsville Facility does not meet this criterion. Mechanicsville Witness Price argues that the Mechanicsville Facility has met its obligation to perform tests under the Mechanicsville ISA and that PJM has entered information from the tests into its system.[22]

Request No. STAFF-PJM-1.1, Dated December 10, 2021, Docket Nos. ER21-2091-001, et al. (December 21, 2021).

[20] *See* S-0001 at 15:8–9.

[21] *See* MVS-0019 at 163.

[22] See MVS-0001.

Mechanicsville's reliance on these facts is misplaced. These facts are not relevant to the required showing.

It is not sufficient to demonstrate that the Mechanicsville Facility can provide reactive power somewhere, it must demonstrate that it can provide reactive supply capability to the PJM transmission grid and that PJM can rely on that capability when it provides Reactive Supply and Voltage Control Service. Given the particular restrictions on the power factor at which the Mechanicsville Facility can operate, the record does not show that the Mechanicsville Facility can provide reactive supply capability anywhere. Reactive supply includes both the ongoing provision of reactive based on the unit's power factor and the ability to respond to a signal from PJM to increase or decrease the power factor to compensate for voltage issues on the system. The Mechanicsville Facility cannot move from its required fixed power factor and therefore cannot provide reactive supply capability.

b. Mechanicsville Cannot Provide Reactive Power to PJM

Unlike real power, reactive power is local and cannot be transferred over long distances. In order for PJM to rely on the Mechanicsville Facility to provide Reactive Supply and Voltage Control on PJM's facilities, Mechanicsville must show that its reactive output can affect reactive power on the 230 kV high side of the Old Church Substation. Such a showing requires an engineering analysis demonstrating that the very small reactive output of the Mechanicsville Facility can overcome the electrical distance and the impact on intervening loads and supplies so that PJM can make use of it to provide service under Schedule 2.

In a recent case deciding the application of the operational capability criterion, the resource owners attempted to provide such an analysis but failed because the analysis did not "establish that the Facilities are operationally capable of providing voltage support to PJM's transmission facilities such that PJM can rely on the Facilities to maintain transmission voltages."[23] The decision also determined that the analysis was "based on unreasonable assumptions" and used a model "beyond its intended design;" that the power flow model" may not accurately reflect the behavior of certain distribution-level voltage control systems" and that "such voltage control systems are one reason that PJM cannot rely on the Facilities for voltage support; and that credible testimony showed the "the modeling results discussed therein contain material errors."[24]

Mechanicsville makes no attempt to provide any analysis at all and automatically fails.

Even if Mechanicsville had prepared the required engineering analysis, and that analysis showed that the Mechanicsville could physically supply reactive supply capability for use on PJM Transmission Facilities, Mechanicsville would still fail to satisfy the operationally capable criterion.

Because PJM does not monitor or operate the transmission system where the Mechanicsville Facility interacts, PJM cannot directly dispatch the Mechanicsville Facility to maintain transmission voltages on the PJM Transmission Facilities. The unknown impacts on the local system to which the Mechanicsville Facility is connected would prevent PJM from issuing direct dispatch instructions. In this case, the local system is known to be highly sensitive to reactive output. For this reason, the Mechanicsville Facility is required to "maintain the 0.99 absorbing power factor."[25] This restrictive requirement prevents the use of the Mechanicsville Facility to maintain voltage levels within acceptable limits on PJM Transmission Facilities.

Staff provides testimony affirmatively showing that the Generating Facilities are not capable of providing reactive supply capability to PJM's transmission facilities. Staff

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23 180 FERC ¶ 63,009 at PP 108–111.

24 *Id*. at PP 112–114.

25 *See* MVS-0019 at 163.

Witness Valle closely analyzes the Mechanicsville Facility and the intervening VEPCO system and concludes: "Mechanicsville does not and cannot, consistent with good engineering practice, provide reactive service and voltage control to the PJM transmission system."[26] Witness Valle reviews in his testimony confidential analyses that show the engineering limitations on the Mechanicsville Facility.[27] The record demonstrates that Mechanicsville does not meet the operational capability criterion of Schedule 2.

B. Mechanicsville Has Not Demonstrated that Its Proposed Rate Avoids Over Recovery.

The PJM market design allows for the competitive investment in generation resources, including their ability to produce real and reactive power. At the same time, Schedule 2 provides for the recovery of a "revenue requirement" associated with the provision of reactive. Generating facilities use the same equipment to sell real power and capacity in markets and to provide reactive supply capability and this fact creates the potential for over recovery. Over recovery must be avoided.[28] The Commission has recognized the issue specifically in the context of the application of Schedule 2.[29] The

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26 *See* S-0001 at 4:11–13.

27 *See id*. at 18:8–19:18.

28 *See, e.g.*, United Airlines, Inc. v. FERC, 827 F.3d 122, 134 (D.C. Cir. 2016) ("[B]ecause FERC failed to demonstrate that there is no double-recovery . . . we hold that FERC acted arbitrarily or capriciously.").

29 *See Reactive Power Capability Compensation*, Notice of Inquiry, 177 FERC ¶ 61,118 at PP 18, 26, 27, 28(j) and 28(s) (2021) ("NOI") (summarizing the IMM's arguments and asking "Is the existing AEP Methodology appropriate to allocate the costs associated with reactive power revenue requirements of non-synchronous resources? If not, why and can changes be made to the existing AEP Methodology to establish just and reasonable reactive power revenue requirements for non-synchronous resources?" and "Do resources in PJM that receive reactive power

issue was not recognized when Schedule 2 was written because PJM did not have a capacity market at the time.

While the *AEP* Method does not actually identify the costs of providing reactive supply capability, it is designed to split without overlap the costs of a coal plant between generation and transmission accounts.[30] In PJM a dollar recoverable through markets is not appropriately included in a revenue requirement for reactive supply capability. If the PJM market rules made no provisions for revenues received under Schedule 2, cost-based revenue requirements under Schedule 2 would be uniformly zero dollars. The only investment not recoverable through markets is an explicit offset, fixed at $2,199 per MW-Year that accounts for revenues resources are expected to receive under Schedule 2. The offset is the only valid basis for resources to receive any cost-based revenue requirement under Schedule 2.

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capability compensation above $2,199/MW-year effectively receive double-recovery as alleged by the PJM Market Monitor?").

30 *See AEP* at 61,456 ("AEP explained that since generator/exciters and an allocated portion of accessory electric equipment produce active and reactive power, "it was necessary to arrive at an allocation factor to segregate the reactive (VAr) production function from the active power (Watt) production function."); *see also Fern Solar LLC*, Order Denying Motion for Partial Summary Disposition and Motion to Strike, 180 FERC ¶ 63,024 at P 15 (2022) ("The AEP method came into being because one of its creators, AEP's Bernard Pasternack, needed to allocate costs between two cost-based services, generation and transmission. AEP's utility subsidiaries were unbundling regulated transmission service from regulated generation service, making each service available for sale separately. Since each of these regulated services would need its own cost-of-service rate, Mr. Pasternack faced a classic cost allocation problem—how to determine which pieces of equipment serve a transmission function and which serve a generation function; and where some pieces of equipment served both functions, how to allocate their costs between the two functions. But because the price-basis for both services was traditional cost of service set by the same regulatory jurisdiction, there was no possibility of duplicative recovery.").

To the extent that Mechanicsville receives a revenue requirement exceeding $2,199 per MW-Year, it receives an impermissible over recovery. Mechanicsville's rate should be capped at $2,199 per MW-Year.

Mechanicsville does not and cannot demonstrate any specific costs associated with providing reactive supply capability that are not recoverable in PJM markets through the sale of energy, ancillary services, or capacity. There are no such costs.

Witness Bowring provides testimony explaining that the PJM market design explicitly accounts for and excludes from the capacity market design $2,199 per MW-Year in order to account for revenues received under Schedule 2.[31] The rules that account for recovery of reactive revenues are built into the auction parameters, specifically, the VRR Curve. The PJM market rules explicitly account for recovery of reactive revenues of $2,199 per MW-year through inclusion in the Net CONE parameter of the capacity market demand (VRR) curve.[32] The Net CONE parameter directly affects clearing prices by affecting both the maximum capacity price and the location of the downward sloping part of the VRR curve. In addition, market sellers, when submitting offers based on net avoidable costs must account for revenues received through cost of service reactive capability rates in the calculation.[33] The $2,199 per MW-Year value happens to be close to the average revenues received by resources in PJM for reactive supply capability.[34] The $2,199 per MW-Year offset included in the PJM market design provides the only valid basis for a revenue requirement under Schedule 2.

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31 *See* IMM Exhibit -0001 at 4:6–5:16.

32 *See* OATT Attachment DD § 5.10(a)(v)(A).

33 OATT Attachment DD § 6.8(d).

34 *See* IMM-0001 at 3:24–4:1.

To the extent that Mechanicsville proposes a revenue requirement exceeding the $2,199 per MW-Year offset, it is seeking an impermissible over recovery.[35] Mechanicsville proposes a revenue requirement of $20,645.84 per MW-Year, creating an overlap of $18,446.84 per MW-Year. The $18,446.84 per MW-Year overlap of the proposed revenue requirement under Schedule 2 and the opportunity for participation in PJM markets not subject to any offset should not be approved as just and reasonable. Mechanicsville has the burden in this case to demonstrate that its proposed rate is just and reasonable, and it has not done so.

C. Mechanicsville Has Not Justified the Basis for Calculating Its Revenue Requirement.

1. The *AEP* Method Does Not Calculate the Incremental Costs for Providing Reactive Supply Capability and Should Not Be Used to Calculate Revenue Requirements Under Schedule 2.

Schedule 2 provides for the recovery of a "revenue requirement." Schedule 2 does not define that revenue requirement or how it should be calculated. Schedule 2 does not create a right to recover any cost already recovered or recoverable under the PJM market rules. Schedule 2 does not provide for the allocation of cost between a cost of service generation facilities account and a transmission facilities account.

Market Monitor Witness Bowring explains why the *AEP* Method and the misplaced reliance of that method on the power factor are not suitable for developing a cost-based revenue requirement under Schedule 2:

> The *AEP* Method assigns costs between real and reactive power based on a unit's power factor. This is effectively an

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[35] *See* 180 FERC ¶ 63,024 at P 17 ("The PJM capacity market design does aim to prevent duplicative recovery. It does so through its Variable Resource Requirement (VRR) curve, which has a reactive power "offset"; specifically, a leftward shift to reflect PJM's assumption that each reactive providing generator will recover $2,199/MW-year through cost-based compensation. But the offset works to prevent overcompensation only if the cost-based price stays below $2,199/MW-year.").

allocation based on a subjective judgment rather than actual investment. There are few if any identifiable costs incurred by generators in order to provide reactive power. Separately compensating resources based on a judgment based allocation of total capital costs was never and is not now appropriate in the PJM markets. Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation.

The *AEP* Method originated with a regulated utility assigning costs between two sources of regulated revenue requirement. The practice persists in PJM only because it provides a significant, guaranteed stream of riskless revenue. Generation owners have an incentive to maximize such guaranteed revenue streams.

There is no logical reason to have a separate fixed payment for any part of the capacity costs of generating units in PJM. If separate cost of service rates for reactive continue, they need to be correctly integrated in the PJM market design.

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The *AEP* Method never accurately reflected the investment costs of providing reactive power, nor was it intended to do so. The *AEP* Method is a cost of service allocation approach designed to assign the regulated revenue requirement for generating units to a regulated generation function and a regulated transmission function. The *AEP* Method was designed to split that cost recovery for generating units in a reasonable way, based on a judgment about what is reasonable. The *AEP* Method was never about actually identifying specific capital costs associated solely with the provision of reactive power. Cost of service approaches apply allocation factors to accounting line items based on assumptions. The assumptions are that X percent of a type of equipment at a generating plant is associated with reactive power while (1-X) percent is associated with real power. The false precision of the *AEP* Method is entirely based on arbitrary assumptions. Even proponents of the *AEP* Method do not assert that the goal is to recover only the costs associated with a specific portion of a power plant required for the production of reactive power, or, in most cases, that such identification is even possible. That is not what the *AEP*

Method was intended to do or is intended to do. The *AEP* Method does not define costs that are uniquely associated with the production of reactive power.

The *AEP* Method is based on the incorrect premise that the capacity costs of an integrated power plant are separable. The capacity costs of an integrated power plant are not separable.

The fundamental flaw in the *AEP* Method approach is the assumption that the costs of providing reactive power are a function of the power factor. The power factor is the ratio of real power (expressed as megawatts or MW) to the total output (apparent power) of a generator (expressed as megavolt-amperes or MVA). The remaining output is reactive power (expressed as megavolt amperes reactive or MVAR). The allocator typically used by proponents of the *AEP* Method to assign costs to reactive power generation is (1 – $(\text{PowerFactor})^2$). The power factor has superficial attraction as an appropriate allocator. The power factor is the core determinant of the reactive allocation factor in the *AEP* Method. Small changes in the power factor have large impacts on the costs allocated to reactive power. For a power factor of .95, the allocator is 9.75 percent while for a power factor of .90, the allocator is 19.00 percent, and for a power factor of .70, the allocator is 51.00 percent. For a resource claiming a power factor of .70, does that mean that more than half of the generator's costs were incurred in order to provide reactive power? Does this mean that 51 percent of the costs of the generator, exciter, and electrical equipment should be recovered through a cost of service rate? The answer to both questions is no. But resources have filed for guaranteed reactive revenue requirements on that basis.

The power factor has taken on somewhat mythical significance in the discussion of reactive power. There are frequently long discussions of power factors in reactive cases. The ratio of real to reactive power can vary significantly. The typical actual operating power factor of generators in PJM is determined by their voltage schedule and is usually between .97 and .99. The resultant *AEP* Method power factor allocator consistent with this actual reactive output of PJM generators and the actual tariff defined reactive output to generators is 5.91 to 1.99 percent. The nameplate power factor of thermal generating units is typically .85. But the nameplate power

> factor stamped on the generator at the factory and not based on actual operation on an actual grid. The nameplate power factor is meaningless for the actual operation of the power plant. The nameplate power factor does not mean that 27.75 percent of the power plant capital costs are associated with reactive power, although many resources have made that request because that is the power factor allocator based on the nameplate rating.
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> The power factor is not an appropriate allocator and does not reflect the actual capital costs associated with producing reactive power. The power factor has taken on a disproportionate significance in reactive rate cases because it is the single most important allocator in the *AEP* Method. That significance illustrates the fundamental flaws in the *AEP* Method.[36]

The power factor does not identify costs associated with reactive capability or provide a reasonable basis for allocating those costs to reactive or real power production.

In the past, the Commission has approved rates for reactive supply capability using what was described as the *AEP* Method.[37] No prior case explains how the *AEP*

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36 *See* IMM-0001 at 5:21–8:4.

37 The decision cited by Mechanicsville (transmittal letter at 5 n.17) in support of use of the *AEP* Method states, "In Opinion No. 440, the Commission approved a method for American Electric Power Service Corp. (AEP) to recover costs of reactive power (AEP methodology)." *Dynegy Midwest Generation, Inc.*, Opinion No. 498, 121 FERC ¶ 61,025 at P 3 (2007), *order on reh'g*, 125 FERC ¶ 61,280 (2009) ("*Dynegy Midwest*"). *Dynegy Midwest* immediately proceeds to describe how the method operates: "Since these groups of production power plant investment involve both reactive and real power, under the AEP methodology, an allocation factor is developed to sort the annual revenue requirements of components between real and reactive power production."). *Id.* The logical connection between asserted purpose and operation is unexplained, and cannot be explained. The asserted purpose is incorrect. Opinion No. 440 does not concern recovery of the costs of reactive power. The issue was assignment of costs already in rate base to particular accounts without, of course, allowing double recovery of the same costs. *Dynegy*

Method properly calculates a cost-based revenue requirement for reactive supply capability. No prior case properly explains how the *AEP* Method properly applies to rates for reactive supply capability to be used within the framework of the PJM market rules, including a capacity market, or the rules applicable to any organized wholesale electric market. Use of the *AEP* Method was not challenged. Unexplained, rote application of the *AEP* Method does not create issue preclusion.[38] Arguments against the use of the *AEP* Method in Schedule 2 proceedings are valid unless and until the issue is both actually litigated and actually decided.[39]

It is appropriate to raise this issue in any specific proceeding that seeks to establish a revenue requirement under Schedule 2. Schedule 2 operates specifically in support of the PJM market design. Other markets address the costs of reactive supply capability differently. California Independent System Operator Corporation; Southwest Power Pool, Inc.; and some non-RTO/ISO transmission operators, including Bonneville Power Administration, Arizona Public Service Company, Southern Companies, do not pay separately for reactive supply.[40] A case under Schedule 2 may present a better forum for

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Midwest does not explain why the AEP method is appropriate for developing a revenue requirement under Schedule 2.

38 *See, e.g.,* Texas Employers' Ins. Asso. v. Jackson, 862 F.2d 491, 500 (5th Cir. 1988) ("Collateral estoppel, or "issue preclusion," requires, among other things, that the allegedly precluded issue have been "actually litigated and determined" in the prior action."); citing, *e.g.,* Lawlor v. National Screen Service Corp., 349 U.S. 322 (1955) ("collateral estoppel . . . precludes relitigation of issues actually litigated and determined in the prior suit"); Montana v. United States, 440 U.S. 147 (1979); Liona Corp. v. PCH Assocs. (In re PCH Assocs.), 949 F.2d 585, 593 (2nd Cir. 1991) ("With respect to issue preclusion, it must be remembered that for the doctrine to be properly invoked the particular issue currently in dispute must have been "both actually litigated and actually decided.").

39 *Id*.

40 *See* NOI at P 12 & n.27.

a decision on how Schedule 2 should be applied than a general rulemaking for the industry. The Commission can decide where and how to address the issue.

Accordingly, the Market Monitor here challenges whether the *AEP* Method reasonably identifies incremental costs required for a generator to provide reactive. The Market Monitor challenges whether the *AEP* Method reasonable applies in the context of the PJM market rules, which provide for resources to participate in competitive markets, including a capacity market. Schedule 2 provides only for a revenue requirement for costs not otherwise recoverable through PJM markets.

Mechanicsville fails to identify any incremental costs associated with the provision of reactive supply. Mechanicsville fails to identify any cost associated with the provision of reactive supply that are not recoverable through participation in PJM markets.

2. The *AEP* Method Should Not Be Used to Develop Revenue Requirements for Asynchronous Resources.

Mechanicsville fails to demonstrate that application of the *AEP* Method is appropriate for its asynchronous solar Mechanicsville Facility. The *AEP* Method was developed for use with a fleet that consisted primarily of steam plants.[41] No decision has determined that *AEP* Method should apply to asynchronous facilities. The Commission has identified the issue, and it is under consideration in a pending rulemaking proceeding.[42] *Panda Stonewall*, a recent case involving the *AEP* Method, specifically

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[41] NOI at P 17 ("[T]he AEP Methodology was designed based on the physical attributes of synchronous resources owned by a public utility that utilized the USofA and annually submitted a FERC Form No. 1.").

[42] *See id*. at P 28, question j ("Is the existing AEP Methodology appropriate to allocate the costs associated with reactive power revenue requirements of non-synchronous resources? If not, why and can changes be made to the existing AEP Methodology to establish just and reasonable reactive power revenue requirements for non-synchronous resources? If so, please provide detailed descriptions of any potential changes and explain why they are necessary.").

explicitly limits its holding on the appropriate power factor to synchronous facilities, indicating the potential significance to the differences between synchronous and asynchronous facilities.[43]

Mechanicsville Witness Dennis Bethel provides testimony attempting to demonstrate how the *AEP* Method can be applied to a solar facility like the Mechanicsville Facility.[44] Witness Bethel does not explain how the *AEP* Method produces an accurate cost-based revenue requirement for reactive supply capability for an asynchronous resource, or any type of resource. Identifying the *AEP* Method's formula and drawing analogies between equipment at synchronous facilities and asynchronous facilities does not substitute for the core showing required, that the *AEP* Method identifies the incremental costs for providing reactive supply capability.

Staff and Intervenors have submitted evidence showing that the *AEP* Method does not properly apply to the Mechanicsville Facility.[45]

Application of the *AEP* Method to the asynchronous Mechanicsville Facility should not be accepted.

D. Mechanicsville Has Not Justified Its Approach to Calculating Its Capital Recovery Rate.

If the *AEP* Method applied to any resource for establishing a cost-based revenue requirement under Schedule 2, it is important to establish an accurate and consistent method for calculating the capital recovery factor ("CRF"). The CRF is a rate, multiplied

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43 *See Panda Stonewall LLC*, Opinion No. 574, 174 FERC ¶ 61,266 at P 109 (2021) ("For these reasons, we affirm the Initial Decision's finding that Panda's reactive power capability should be based upon a power factor of 0.85 since the facility is a new synchronous generator facility and degradation of its reactive power output is not an issue.").

44 *See* MVS-0050, MVS-0068.

45 *See* S-0007; JC-0001 and JC-0014.

by the relevant investment, which defines the annual payment needed to provide a return on and of capital for the investment over a defined time period. CRFs include as inputs the weighted average cost of capital and its components, including the rate of return on equity and the interest rate on debt and the capital structure, in addition to depreciation and taxes.[46]

Mechanicsville's proposed method for calculation of its form of CRF, which it refers to as the "annual carrying cost percentage," results in an excessive value that inflates its proposed revenue requirement.[47] The Market Monitor objects to the calculation of a cost of service revenue requirement in this proceeding, but if such an approach is used, then an accurate calculation of the CRF component should be required.

The Mechanicsville CRF was initially presented in the prepared direct testimony of W. Wade Horigan on June 7, 2021, and then modified by Witness Horigan on February 11, 2022.[48] Witness Horigan derives a fixed charge carrying rate which is the sum of a CRF and a fixed operating expense rate. The latest CRF presented by Witness Horigan is the sum of a sinking fund depreciation factor and the before tax weighted average cost of capital. Witness Horigan's updated derivation removed the income tax factor that was included in Witness Horigan's original derivation.

The Market Monitor's Witness, Dr. Joseph Bowring, in his testimony filed April 25, 2022 (Exhibit No. IMM-0001), reviewed Witness Horigan's testimony and concluded: "Neither derivation accurately reflects the tax liability and the return on and the return of the capital investment."[49] Specifically, Dr. Bowring stated: "Witness Horigan did not account for the actual tax treatment of the facility and did not adequately

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[46] *See* IMM-0001 at 8:18–22.

[47] *See* MVS-47 at 32:10–38:14.

[48] *See* Exhibit No. MVS-3 (June 7, 2021); Exhibit No. MVS-47 (February 11, 2022).

[49] *See* IMM-0001 at 8:16–17.

explain his tax treatment, did not account for the actual expected life of the facility, did not adequately explain or support his depreciation method, and did not account for the actual cost of capital of the facility."[50]

The Market Monitor proposes an alternative method, including the method in the form of a technical reference ("CRF Technical Reference") for calculating the CRF.[51] The CRF Technical Reference explains in detail the components for accurately and consistently calculating a CRF. The CRF Technical Reference is designed for, and should be required for use in, all cost based revenue requirement provisions used in PJM, which now include black start service rates and, improperly, reactive capability rates.[52] The Commission accepted the approach included in the CRF Technical Reference for black start service and directed PJM to include the CRF formula in the PJM tariff.[53] Consistent use of the CRF would ensure that accurate, just, reasonable and nondiscriminatory values are applied. Accurate and consistent values promote efficient markets and just and reasonable, competition based rates.

Witness Bowring explains:

> The CRF as proposed by the Market Monitor provides the necessary and sufficient level of revenue to pay the annual tax liability and the return on and return of the capital investment. The CRF approach proposed by the Market Monitor is based on the weighted average cost of capital (WACC) capital budgeting method. Under the WACC approach, the after tax cash flow is discounted at the after tax WACC rate and the payback of the investment in each cost recovery year reflects

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50 *Id*. at 8:28–31.

51 *Id*. at 9 and IMM-0003 (Capital Recovery Factor (CRF) Technical Reference).

52 *Id*. at 9:8–9.

53 *PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,080 at PP 43–44 (2021).

> the defined capital structure. This approach can be efficiently reduced to a single formula for the CRF.[54]

The Market Monitor used the CRF approach to determine an annual revenue requirement based on the capital cost data and financing structure provided in the Horigan Testimony.

The Market Monitor provides the results in Exhibit Nos. IMM-0004 and IMM-0005. Exhibits Nos. IMM-0004 and IMM-0005 illustrate the implications of the issues with the company's CRF calculations for the annual revenue requirement, assuming the company's allocation of costs to reactive are correct. The Market Monitor does not advocate using the annual revenue requirements in Exhibits Nos. IMM-0004 and IMM-0005, but includes the calculations solely for the purpose of showing the implications of the incorrect CRF calculations proposed by Mechanicsville.

For a 20 year cost recovery period, the Market Monitor's CRF is 0.094192 and the corresponding annual revenue payment is $320,329.[55] The formula for the CRF is equation (1.4) in the CRF Technical Reference.[56] The calculation assumes the half year convention for the timing of revenue and tax payments. This value reflects the capital cost recovery and does not include fixed operating expenses to protect confidential information.

The Market Monitor's CRF is lower than the CRF proposed by Witness Horigan. The Market Monitor's annual revenue requirement in Exhibit IMM-0004 reflects a

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54 *See* Exhibit No. IMM-0001 at 9:10–17.

55 *See id*. at 9:23–25.

56 See Exhibit IMM-0003 at 7.

reduction to the reactive capital cost to account for an investment tax credit (ITC). Mechanicsville's filed rate inappropriately fails to reflect ITCs.[57]

The Market Monitor's payment is lower than the payment proposed by Witness Horigan. The Market Monitor's CRF calculations in Exhibits Nos. IMM-0004 and IMM-0005 reflect 100 percent bonus depreciation that allows generators placed in service after September 27, 2017, to fully depreciate the capital investment in the first year of operation. In order to provide information in this matter, Exhibit No. IMM-0005 shows the Market Monitor's proposed capital cost recovery assuming no reduction for an ITC.

Exhibit Nos. IMM-0004 and IMM-0005 also show the CRFs and corresponding capital recovery payments for recovery periods exceeding 20 years. For example, the Market Monitor's CRF for a 40 year cost recovery period is 0.075621. The corresponding annual payment is $257,172 under the assumption that the reduction of the reactive capital cost by an ITC is applicable.

Witness Horigan has not explained why a 20 year life rather than a 30 or 40 year life is appropriate for the Mechanicsville Facility. A 20 year life is not appropriate, and should not be used to calculate the CRF. Dr. Bowring testified:

> It is my experience that comparable solar units frequently assert that they have useful life well in excess of 20 years. Such longer life should be reflected in the CRF.[58]

Staff Witness Kevin Pewterbaugh provides detailed testimony supporting the use of a 30 year life.[59]

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[57] *See* Responses of Mechanicsville Solar, LLC to Commission Trial Staff's First Set of Discovery Requests, Discovery Request No. STAFF-MVS-1.55, Dated December 10, 2021, Docket Nos. ER21-2091-001, et al. (December 27, 2021).

[58] *See* Exhibit No. IMM-0001 at 10:18–20.

[59] *See* Exhibit No. Staff-0016 at 4:2–4.

Witness Horigan has not explained the actual cost of capital for the Mechanicsville facility or explained why the actual cost of capital should not be used in the calculation of the CRF.

In the event that, over the Market Monitor's objections, a cost of service rate including a CRF is used to calculate the revenue requirement for Mechanicsville, then CRF proposed by Mechanicsville should be rejected as deficient. In its place a CRF based on the approach included in the CRF Technical Reference should be calculated and used to determine and just, reasonable and nondiscriminatory revenue requirement.

CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these arguments on brief as the Commission resolves the issues in this proceeding.

Respectfully submitted,

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Dated: August 19, 2022

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 19th day of August, 2022.

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