UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Fern Solar LLC	)))	Docket Nos. ER20-2186-003 and EL20-62-001

INITIAL BRIEF ON EXCEPTIONS
OF THE INDEPENDENT MARKET MONITOR FOR PJM

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Pursuant to Rule 711 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 this Brief on Exceptions to the Initial Decision issued April 13, 2023.[3]

A filing by Fern Solar, LLC ("Fern"), requesting a revenue requirement under Schedule 2 ("Schedule 2") to the PJM Open Access Transmission Tariff ("OATT") initiated this proceeding. The filing was accepted and became effective solely by operation of law, with no decision on whether any aspect of Fern's revenue requirement is just and reasonable. The Commission set the revenue requirement for investigation of whether it is just and reasonable.

The record developed at hearing supports a finding that the highest just and reasonable rate under supported under Schedule 2 of the OATT is zero dollars. No costs have been identified in this proceeding that are appropriately recoverable from PJM customers. Well settled law rejects Fern's theory of recovery, that it is entitled to recover from PJM customers costs allegedly incurred in connection with Fern meeting its obligation to provide reactive capability as a condition to receive interconnection service.[4]

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1 18 CFR § 385.711 (2022).

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 *Fern Solar, LLC*, 183 FERC ¶ 63,004.

4 *See Midcontinent Independent System Operator, Inc.*, 182 FERC ¶ 61,033 at P 52 (January 27, 2023) (*MISO*) ("We find that MISO TOs' proposed Schedule 2 revisions to eliminate compensation for its own and affiliated generation resources and unaffiliated generation resources and the associated charges to transmission customers, is permitted under, and consistent with Order Nos. 2003 and 2003-A."); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003) ("[T]he Interconnection Customer should not be compensated for reactive power when operating its

The approach relied upon by Fern to calculate its revenue requirement, known as the *AEP* Method, has no valid basis for use in calculating a revenue requirement under Schedule 2. Schedule 2 is the PJM rule that governs filings for the revenue requirements for reactive supply and voltage control. The Market Monitor does not argue for any change to Schedule 2 in this proceeding, only that Schedule 2 be interpreted and applied logically and in conjunction with associated PJM market rules.[5] The record in this proceeding shows

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Generating Facility within the established power factor range, since it is only meeting its obligation."), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28 ("[T]he provision of sufficient reactive power is an obligation of a generator interconnected to the system, and . . . as a general matter, a generator is not entitled to separate compensation for providing reactive power within its deadband."), *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); *California ISO*, 160 FERC ¶ 61,035 at P 19 (2017) ("[T]here is no compensation for any generators for providing reactive power capability inside the standard power factor range… A separate payment for the provision of reactive power capability inside the standard power factor range is not required, and we see no reason to require a separate cost recovery mechanism for reactive power capability…"); *Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 at P 28 (2007) ("[T]he provision of sufficient reactive power is an obligation of a generator interconnected to the system, and that, as a general matter, a generator is not entitled to separate compensation for providing reactive power within its deadband."), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also Public Service Company of New Mexico*, 178 FERC ¶ 61,088, at PP 29–31 (2022); *Nevada Power Co.*, 179 FERC ¶ 61,103, at PP 20-21 (2022).

5 The Market Monitor has argued that Schedule 2 should be removed from the PJM market design. *See, e.g.*, Comments of the Independent Market Monitor for PJM, Docket No. RM22-2-000 (February 24, 2022). Schedule 2 serves no useful purpose. When incorrectly interpreted and implemented, Schedule 2 unjustly, unreasonably and in an unduly discriminatory manner, interferes with the operation of PJM's competitive markets. Removal of Schedule 2 must be accompanied by revisions to other PJM market rules impacted by the removal of Schedule 2 because the rules framework in PJM operates in tandem. No one argues in this proceeding that changes to the PJM market design are within the proper scope of this proceeding. The proper

that it is not just and reasonable to apply the *AEP* Method to determine a revenue requirement for reactive capability under Schedule 2.

Even if Fern had identified valid costs recoverable under Schedule 2, a revenue requirement exceeding the tariff defined energy and ancillary services offset for reactive revenues included in the PJM capacity demand curve (VRR curve) ("EAS Offset") results in over recovery.[6] The Fern Facility participates in a competitive market design that provides an opportunity to recover all its costs, including reactive costs. The capacity market design (VRR curve) anticipates that resources will receive the EAS Offset in compensation for reactive supply capability and sets the market design parameters based on the EAS Offset. To the extent that Fern proposes a revenue requirement exceeding the EAS Offset, it is seeking an unjust and unreasonable excess recovery. If any rate is accepted, no rate under Schedule 2 should be approved that exceeds the EAS Offset.

In the Initial Decision, the Presiding Judge agreed with or made no finding adverse to the merits of the Market Monitor's position. The Initial Decision determines instead (at P 936): "The problems in reactive-capability compensation identified by Dr. Bowring cannot be fixed in this proceeding." This brief seeks exception solely for this determination.

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scope of this proceeding concerns interpreting and implementing Schedule 2 and all associated PJM market rules as they exist, in coordination with each other.

6 The energy and ancillary services offset for reactive revenues included in the PJM capacity demand curve (VRR curve) (EAS Offset) is set forth in Section 5.10(v-1)(A) of Attachment DD to the OATT. Current capacity prices through the 2025/2026 Delivery Year were set using an EAS Offset of $2,199 per MW-Year. The EAS Offset was calculated by the Market Monitor and was based solely on Schedule 2 revenues. Effective December 21, 2022, the EAS Offset was revised to $2,546 per MW-Year for Delivery Years beginning with 2026/2027. *See PJM Interconnection, L.L.C*, 182 FERC ¶ 61,073 (2023). The EAS Offset is based on the total settled reactive revenue requirement for a combined-cycle plant included in the *Q2 State of the Market Report* (August 11, 2022) at 603, Table 10-67. *Id*. at P 135. As a result, starting with the 2026/2027 Delivery Year, the maximum rate consistent with the EAS Offset will be $2,546 per MW-Year.

The problem identified by Dr. Bowring is Fern's excessive revenue requirement, and there is no other forum where that problem can be addressed.

The Market Monitor does not agree that the four rationales provided in the Initial Decision (*id*.) are reasons that the problems identified in this case "cannot be fixed in this proceeding."

The Initial Decision does not dispute the identified problems. The Initial Decision recognizes the substantive merits of the Market Monitor's position and recommends that the problems be addressed with urgency. The Initial Decision errs (at P 936) only in its determination that the problems "cannot be fixed in this proceeding."

Allowing a revenue requirement for Fern above zero dollars is unjust and unreasonable, and cannot be reconciled with the finding in MISO that: "the Interconnection Customer should not be compensated for reactive power when operating its Generating Facility within the established power factor range, since it is only meeting its obligation."[7] This case is about interpreting and applying Schedule 2, but Schedule 2 provides no rules specifying how a rate filed under Schedule 2 should be determined. How Schedule 2 is applied is a matter left for the Commission to resolve.

Contrary to the Initial Decision, the existing and approved PJM market design should determine how Schedule 2 should be applied. No determination on the validity of any aspect of the PJM market design is required to interpret and apply Schedule 2.

The issues raised by the Market Monitor should be resolved in this proceeding, either by order of the Commission, or after remand with appropriate guidance, by the Presiding Judge.

I. PROCEDURAL HISTORY

The Market Monitor incorporates by reference the procedural history provided in Appendix A to the Initial Decision.

[7] *Id*. at P 52, citing Order No. 2003, 104 FERC ¶ 61,103 at P 546.

II. SUMMARY OF ARGUMENT

A. Scope.

In the Initial Decision, the Presiding Judge agreed with or made no finding adverse to the merits of the Market Monitor's position. The Initial Decision determines (at P 936): "The problems in reactive-capability compensation identified by Dr. Bowring cannot be fixed in this proceeding." This brief seeks exception solely for this determination.

The Initial Decision provides (*id*.) four rationales for not making findings on the identified problems:

- "The risk of overcompensation arises not from Fern's filed rate but from that filed rate's interaction with the PJM market design."
- "Adjusting Fern's rate to reflect its interaction with PJM's market design would mean that each reactive proceeding would require an applicant-specific fix."
- "Dr. Bowring's $2,199 per MW-year cap solution is unreasonable because the number is old and has no clear basis in anyone's actual cost of reactive capability."
- "I cannot find that the flaws cited by Dr. Bowring automatically make Fern's filed rate unjust and unreasonable, because the Commission already rejected that automatic conclusion."

The Market Monitor disagrees with each of the stated rationales. The stated rationales all focus on the interaction between the reactive compensation and the PJM market design. This focus ignores the fact that the *AEP* Method at the core of Fern's case has no logical basis.

The risk of overcompensation exists based on the unsupported application of the *AEP* Method by Fern. The risk of overcompensation also exists because Fern fails to recognize that Schedule 2 exists as part of a broader set of PJM market rules which explicitly recognize that reactive costs are not separable from other costs. There is no reason not to recognize that interaction and the implications for this case.

Adjusting Fern's rate to recognize that interaction would actually make all subsequent cases easier because the same solution, the application of a cap equal to the EAS Offset, would apply in all the cases and would not be applicant specific. Every current reactive case is applicant specific and the lengthy process for each case results from a failure to recognize that all reactive revenue requirements should be capped at the EAS Offset.

The EAS Offset is part of the existing capacity market rules, and is therefore the filed rate. The level of the offset in the PJM OATT is not at issue in this case. The existence of the offset in the PJM OATT is not at issue in this case. The fact that the filed rate is based on historical data ("old" data) is irrelevant. Nonetheless, as made clear, the EAS Offset is in the OATT and approved by the Commission was based on the actual data from actual reactive cases also approved by the Commission and is therefore based on units' actual costs.

The *Panda* decision includes a finding "that the issue of double recovery raised by the Market Monitor is a problem the Market Monitor perceives in the methodology for determining the EAS Offset in PJM's capacity market."[8] The *Panda* decision mischaracterized the Market Monitor's position in the *Panda* proceeding, and it is not the Market Monitor's position in this proceeding that the method for determining the offset is flawed or that the offset is now at issue. The issue in *Panda* was not the offset. The issue in this case is not the offset. *Panda* is irrelevant to the Market Monitor's actual position on the level of Fern's revenue requirement. Nothing in the *Panda* decision prevents consideration of the Market Monitor's position in this case.

Finally, none of these rationales are relevant to the MISO decision. None of the rationales explain why the *MISO* decision can be ignored when interpreting Schedule 2.

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[8] *Panda* at P 218.

B. Merits.

The record in this proceeding does not support a revenue requirement under Schedule 2 above zero dollars. A rate exceeding zero dollars would be unjust and unreasonable based on the record.[9]

The arguments on the merits raised by the Market Monitor on brief should have been the basis for a finding in the Initial Decision that Fern's revenue requirement should not exceed zero dollars, or, in the alternative, should not exceed the EAS Offset. A Commission order on the initial decision should require the appropriate result, or, such order should remand the matter to the Presiding Judge.

The record does not demonstrate any cost incurred by Fern in order to provide reactive supply capability unrelated to obligations under its interconnection service agreement with PJM. The record does not demonstrate any cost incurred by Fern in order to provide reactive supply capability. The proposed revenue requirement for Fern should be not be approved. The appropriate reactive revenue requirement for Fern is zero dollars.

If Fern is nevertheless found to be entitled to a revenue requirement under Schedule 2, such revenue requirement should not exceed the $2,199 per MW-Year EAS Offset, because a rate above that level, considered in conjunction with the opportunity to receive market revenues, would result in an over recovery.[10]

Fern participates in a competitive market design that provides an opportunity to recover all of its costs, including reactive costs. Offers by Fern and other capacity resources in the PJM Capacity Market are based on all of their costs and do not exclude costs based on asserted reactive costs. The only reason that there is a reactive net revenue offset in the

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9 *See, e.g.*, *MISO*.

10 *See* FER-0057 (*American Electric Power Service Corporation*, Opinion No. 440, Docket No. ER93-540; 88 FERC ¶ 61,141 (1999), *withdrawal of reh'g granted*, 92 FERC ¶ 61,001 (2000) ("*AEP*")). The "*AEP* Method" refers to the method for allocation generation costs between generation and transmission accounts in testimony provided by Bernard M. Pasternack, Docket No. ER93-540.

capacity market is that all of the units' costs are included in the offers in the capacity market and that there have been separate reactive revenues. If there were zero reactive revenues for all units, there would be no reactive net revenue offset and capacity market prices would be higher. The capacity market design (VRR curve) is explicitly based on the assumption that resources will receive the EAS Offset in revenue for reactive supply capability and sets the market parameters based on the EAS Offset. To the extent that Fern proposes a revenue requirement exceeding the EAS Offset, it is seeking an unjust and unreasonable excess recovery. If any rate is accepted, no rate under Schedule 2 should be approved that exceeds the EAS Offset.

If Fern had supported entitlement to any rate above zero dollars, 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 to calculating the CRF should be required. The capital recovery factor ("CRF") calculated by Fern is flawed and should not be approved.

Finally, as the Commission confirmed in *MISO* (at P 52), RTOs and their customers are not required to pay costs that generators are required to incur in order to obtain interconnection service.

III. BACKGROUND

A. The Fern Facility.

This proceeding concerns the proposed annual revenue requirement filed in this proceeding by Fern Solar LLC ("Fern") under Schedule 2 for its 100 MW solar generating facility located in Tarboro, North Carolina ("Fern Facility").[11]

The Fern Facility is an Exempt Wholesale Generator.[12]

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[11] *See* FER-0066 (*Fern Solar LLC*, 172 FERC ¶ 61,160 at P 3 (August 25, 2020) ("Hearing Order")).

[12] *Id*.

Fern is a party to an interconnection agreement among itself, PJM, and Virginia Electric and Power Company, which obligates Fern to produce reactive power ("Fern ISA").[13]

B. Generators' Obligation: Provide Reactive Power Capability.

In order to receive interconnection service from PJM, generation resources must assume certain obligations under an interconnection service agreement (ISA).[14] The Fern ISA is an example of such an interconnection service agreement. It is well settled that a resource's obligation to provide reactive supply capability under an interconnection service agreement does not create an entitlement to receive compensation from the RTO.[15] It is

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[13] *Id.* at P 4.

[14] *See, e.g.*, OATT Attachment O.

[15] *See MISO* at P 52 ("We find that MISO TOs' proposed Schedule 2 revisions to eliminate compensation for its own and affiliated generation resources and unaffiliated generation resources and the associated charges to transmission customers, is permitted under, and consistent with Order Nos. 2003 and 2003-A."); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003) ("[T]he Interconnection Customer should not be compensated for reactive power when operating its Generating Facility within the established power factor range, since it is only meeting its obligation."), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28 ("[T]he provision of sufficient reactive power is an obligation of a generator interconnected to the system, and . . . as a general matter, a generator is not entitled to separate compensation for providing reactive power within its deadband."), *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); *California ISO*, 160 FERC ¶ 61,035 at P 19 (2017) ("[T]here is no compensation for any generators for providing reactive power capability inside the standard power factor range… A separate payment for the provision of reactive power capability inside the standard power factor range is not required, and we see no reason to require a separate cost recovery mechanism for reactive power capability…"); *Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 at P 28 (2007) ("[T]he provision of sufficient reactive power is an obligation of a generator interconnected to the system, and that,

also well settled that customers are not required to pay a separate transmission service charge for reactive supply capability.[16] Fern's reliance on its asserted entitlement to compensation based on meeting obligations it assumed as a condition for receipt of interconnection service from PJM is misplaced.[17]

Schedule 2 does not require or include any method for calculating a reactive revenue requirement, including the *AEP* Method. Schedule 2 refers only to a "monthly revenue requirement as accepted or approved by the Commission."[18] That revenue requirement should be zero.

Any separate compensation for reactive supply capability is determined under a filing submitted by the generation resource directly to the Commission under Schedule 2. Neither PJM, nor the Market Monitor, nor any other entity, makes any prior determination on whether an entity is eligible to submit such a filing or whether any asserted cost requested for recovery under such filing is eligible for recovery. The record in this case does not show a single dollar of cost of the Fern Facility that is not recoverable through PJM markets. The record in this proceeding does not show that Fern was required to incur any incremental cost in order to provide reactive supply capability. Regardless, costs

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as a general matter, a generator is not entitled to separate compensation for providing reactive power within its deadband."), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also Public Service Company of New Mexico*, 178 FERC ¶ 61,088, at PP 29–31 (2022); *Nevada Power Co.*, 179 FERC ¶ 61,103, at PP 20-21 (2022).

16 *Id*. The Presiding Judge and Dr. Bowring discussed this issue at hearing, prior to the issuance of the decision accepting MISO's elimination of the equivalent of Schedule 2 from the MISO market rules. *See* Tr. at 3393:9–3394:13.

17 Tr. 809:20–810:2 ("Q [Presiding Judge] So I think what you're going to say is that because the Commission in Order 827 imposed an obligation to make reactive power available at that location, we now have to compensate for that obligation. And the way that we compensate for that obligation is through this proceeding. Is that fundamentally your reasoning, is that your matching obligations of compensation, Mr. Bethel? A [Fern Witness Bethel] It is. ….").

18 *See* IMM-0002.

incurred in order to receive interconnection service are not properly recovered under Schedule 2.

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 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 capability in Schedule 2. These charges and payments are not at issue.

IV. POLICY CONSIDERATIONS WARRANTING REVIEW

While the Presiding Judge determined that the problems identified by the Market Monitor "cannot be fixed in this proceeding," the Presiding Judge agrees (at P 937) that the problems need to be fixed: "I stress that each of the IMM's points deserves serious consideration, by the full Commission, now." The Presiding Judge supported the need for serious consideration with following specific findings (*id*.):

- Customers are paying hundreds of millions of dollars annually for a service priced via a methodology created not to match cost responsibility with benefit but to allocate sunk costs.

- The standard techniques for addressing a facility that operates in both a monopoly market and a competitive market—cost allocation and revenue credit—have no connection to the AEP method. To comply with the statutory prohibition against undue discrimination, a cost allocation technique should allocate sunk costs based on causation, such as contribution to peak load. Revenue crediting subtracts actual or projected dollars from a sunk-cost-based revenue requirement. Neither technique offers any support to the practitioners of the AEP method.

- Auto-transporting a monopoly-era method into an organized-market context—which is exactly what this proceeding's witnesses do, what dozens of settlements do and what this Initial Decision does—is not regulating based on physical facts.

- In Mr. Pasternack's original testimony, the causal relationship between the $MVAr^2$/ MVA^2 ratio and reactive capability's share of total investment was tersely stated but not explained. In the Commission's *AEP* decision and in all subsequent reactive decisions, the Commission has merely repeated the point without explaining it. The just-and-reasonable standard deserves more.

- The differences among RTOs in reactive compensation methods have no clear connection to differences in cost, terrain, fuel mix, load shape or anything other than tradition and happenstance. For generating companies seeking a national presence, these differences raise costs and lower predictability.

- The non-stop flow of reactive-power filings produces settlements without principle and adversarial proceedings without sufficient policy direction. It diverts thousands of professional hours annually from more useful work. Clear Commission guidance, on the issues addressed in this Decision, will make everyone better off.

The Market Monitor agrees with each of these findings by the Presiding Judge.

If the relief requested in this Brief on Exceptions is granted, the identified problems can be fixed in this proceeding.

The Commission has allowed reactive revenue requirements to become effective in PJM for many years. The few cases that resulted in precedential decisions never considered the fundamental issue of how Schedule 2 filings should be evaluated. The Commission orders do not explain what reactive supply capability compensable under Schedule 2 is. The Commission orders do not explain what the *AEP* Method is, whether it is based on supportable logic, and how or whether it produces a just and reasonable rate. The Commission orders do not explain how Schedule 2 rates exist within the PJM market design and how over recovery is avoided.

In this case, the issues are squarely raised, and they should be squarely decided.

The Commission recognized the serious policy problems related to reactive power compensation in a workshop convened June 30, 2016, and in a notice of inquiry issued in RM22-2 ("NOI").[19] In the NOI, the Commission issued questions that reveal that the Commission is concerned about issues raised by the Market Monitor concerning compensation for reactive supply capability, including the issues raised in this proceeding.

The issues raised in the NOI include:

- Whether cost of service compensation is appropriate for reactive supply compensation.[20]
- Whether the *AEP* Method is a just and reasonable for the development of reactive supply capability rate.[21]
- Whether Schedule 2 rates that exceed the $2,199 offset included in the design parameters of PJM capacity markets result in impermissible double recovery.[22]

While the NOI remains pending, the Commission has approved MISO's elimination of the MISO equivalent of Schedule 2 revenue requirements from its market rules, aligning MISO with CAISO and SPP, which never adopted the defective approach.[23] The Commission's finding in *MISO* was broad, and addressed and rejected most if not all of the policy arguments made by Fern in this case.

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[19] *Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, AD16-17-000; *See Reactive Power Capability Compensation*, Notice of Inquiry, 177 FERC ¶ 61,118 (2021) ("NOI").

[20] NOI at P 26.

[21] NOI at P 28, questions a–q.

[22] NOI at PP 27 & 28, questions r and s.

[23] 182 FERC ¶ 61,033.

The Market Monitor is an active participant in a PJM stakeholder group, the Reactive Power Compensation Task Force ("RPCTF") that is considering reforms to the PJM market rules. In that process, the Market Monitor has advocated the MISO/CAISO/SPP approach. PJM stakeholders have not reached agreement or approved a filing under FPA Section 205, and PJM has not made a filing.[24]

There is no reason to defer action in this proceeding based on deference to the pending rulemaking or based on expectation of a PJM Section 205 filing. Although the Market Monitor supports rule changes, this does not mean that the existing rules, at issue in this proceeding, cannot be interpreted and applied in a manner that addresses the problems. Schedule 2 provides only for filing a revenue requirement within the framework of the PJM market design. Schedule 2 does not guarantee that a requested revenue requirement will be approved. Schedule 2 does not explain how Fern's filing will be evaluated. The issue here is what the Commission determines is unjust and unreasonable.

The fundamental issues should be decided on the merits in this proceeding. Fern's requested revenue requirement should not be approved and the amounts collected since it was accepted should be refunded.

V. ARGUMENT

A. The Issues Raised by the Market Monitor Are within the Proper Scope of this Proceeding, and Should Be Decided in this Proceeding.

The Market Monitor raises two broad issues in this proceeding.

The Fern filing simply ignores the fact that the PJM Capacity Market explicitly recognizes that capacity market offers include all relevant costs including costs related to reactive power. The capacity market design explicitly mitigates the fact that reactive costs are included in offers by incorporating in the capacity market VRR curve EAS Offset

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[24] PJM has the independent authority to submit filings that change rules included in the OATT, including the affected provisions Schedule 2 and Attachment DD.

specified in the PJM OATT. As long as separate reactive payments are less than or equal to the EAS Offset, no excess recovery exists in the reactive revenues.

The Fern filing also simply ignores the fact that the *AEP* Method has no logical basis. The entire foundation of the *AEP* Method was three sentences in the 1993 testimony of Mr. Pasternack. Those three sentences are not logically connected and do not support the *AEP* Method. The *AEP* Method was never based on the actual costs of reactive but was simply an allocation mechanism to allocate more costs for one group and to allocate fewer costs for another group, all in a fully cost regulated environment. As a result, no positive revenue requirement has been supported and there is no need to address whether the level exceeds the EAS Offset.

In the Initial Decision, the Presiding Judge agreed with or made no finding adverse to the merits of the Market Monitor's position. The Initial Decision determines (at P 936): "The problems in reactive-capability compensation identified by Dr. Bowring cannot be fixed in this proceeding." This brief seeks exception solely for this determination.

The Initial Decision provides (*id*.) four rationales for not making findings on the identified problems:

- "The risk of overcompensation arises not from Fern's filed rate but from that filed rate's interaction with the PJM market design."
- "Adjusting Fern's rate to reflect its interaction with PJM's market design would mean that each reactive proceeding would require an applicant-specific fix."
- "Dr. Bowring's $2,199 per MW-year cap solution is unreasonable because the number is old and has no clear basis in anyone's actual cost of reactive capability."
- "I cannot find that the flaws cited by Dr. Bowring automatically make Fern's filed rate unjust and unreasonable, because the Commission already rejected that automatic conclusion [in *Panda*]."

The EAS Offset is part of the existing capacity market rules, and is therefore the filed rate. The fact that the filed rate is based on historical data ("old" data) is irrelevant. Nonetheless, as made clear, the $2,199 per MW-Year EAS Offset was based on the actual data from actual reactive cases and is therefore based on units' actual costs.

The Market Monitor disagrees with each of the stated rationales. The stated rationales all focus on the interaction between the reactive compensation and the PJM market design. This focus ignores the fact that the *AEP* Method at the core of Fern's case has no logical basis.

The risk of overcompensation exists based on the unsupported application of the *AEP* Method by Fern. The risk of overcompensation also exists because Fern fails to recognize that Schedule 2 exists as part of a broader set of PJM market rules which explicitly recognize that reactive costs are not separable from other costs. There is no reason not to recognize that interaction and the implications for this case.

Adjusting Fern's rate to recognize that interaction would actually make all subsequent cases easier because the same solution, the application of a cap equal to the EAS Offset, would apply in all the cases and would not be applicant specific. Every current reactive case is applicant specific and the lengthy process for each case results from a failure to recognize that all reactive revenue requirements should be capped at the EAS Offset.

The EAS Offset is part of the existing capacity market rules, and is therefore the filed rate. The level of the offset in the PJM OATT is not at issue in this case. The existence of the offset in the PJM OATT is not at issue in this case. The fact that the filed rate is based on historical data ("old" data) is irrelevant. Nonetheless, as made clear, the EAS Offset is in the OATT and approved by the Commission was based on the actual data from actual reactive cases also approved by the Commission and is therefore based on units' actual costs.

The *Panda* decision includes a finding "that the issue of double recovery raised by the Market Monitor is a problem the Market Monitor perceives in the methodology for determining the EAS Offset in PJM's capacity market."[25] The *Panda* decision mischaracterized the Market Monitor's position in the *Panda* proceeding, and it is not the

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[25] *Panda* at P 218.

Market Monitor's position in this proceeding that the method for determining the offset is flawed or that the offset is now at issue. The issue in *Panda* was not the offset. The issue in this case is not the offset. *Panda* is irrelevant to the Market Monitor's actual position on the level of Fern's revenue requirement. Nothing in the *Panda* decision prevents consideration of the Market Monitor's position in this case.

Finally, none of these rationales are relevant to the MISO decision. None of the rationales explain why the *MISO* decision can be ignored when interpreting Schedule 2.

The Market Monitor's arguments are properly raised in this proceeding and should be resolved in this proceeding. No other forum exists to resolve them. Revenue requirements for compensating reactive capability is PJM are determined in individual filings under Schedule 2. While alternative exist to address flaws in PJM market rules, no alternative forum exists to address the excessive revenue requirement filed by Fern solar.

The issues raised by the Market Monitor should be resolved in this proceeding, either by order of the Commission, or after remand with appropriate guidance to the Presiding Judge.

B. No Schedule 2 Revenue Requirement Exceeding the EAS Offset Is Consistent with the PJM Market Design.

If a reactive rate exceeding zero dollars is approved in this proceeding, over recovery must be avoided.[26] The Commission has recognized the issue of over recovery specifically in the context of the application of Schedule 2.[27]

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[26] *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.").

[27] *See* NOI at PP 18, 26, 27, 28(j) and 28(s) (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 capability compensation above

While the *AEP* Method does not actually identify the costs of providing reactive supply capability, it was designed to allocate the costs of a coal plant between generation and transmission accounts.[28] In AEP, there was an allocation to two cost of service accounts. In the PJM market design, a dollar allocated for recovery under Schedule 2 is a dollar that is already recoverable in PJM's competitive markets. In PJM, a dollar recoverable through markets is not appropriately included in a revenue requirement for reactive supply capability.

To the extent that Fern Facility receives a revenue requirement exceeding $2,199 per MW-Year, it receives an impermissible over recovery.[29] The Fern Facility's revenue requirement should be capped at $2,199 per MW-Year.

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

[28] *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.").

[29] *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-

The record includes the testimony of Market Monitor Witness Bowring 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.[30] 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.[31] 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.[32] The $2,199 per MW-Year value is close to the average revenues currently received by resources in PJM for reactive supply capability.[33]

C. The AEP Method Is an Arbitrary Method of Cost Allocation Based on Subjective Judgment.

The Presiding Judge has provided in the Bench Question B-2-23 the core statement of the *AEP* Method. Bench Question B-2-23 quotes AEP Witness Pasternack's "terse"

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year through cost-based compensation. But the offset works to prevent overcompensation only if the cost-based price stays below $2,199/MW-year.").

30 *See* IMM -0001 at 4:6–5:16.

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

32 OATT Attachment DD § 6.8(d).

33 *See* IMM-0001 at 3:24–4:1.

explanation of “his chosen reactive power allocator” in his 1993 testimony.[34] The Presiding Judge summarizes Mr. Pasternack’s statement:

> He stated first that the 'size and cost of the generator/exciter and accessory electric equipment are proportional to the MVA rating of that equipment.’ He then presented the basic power triangle relationship, $MVA^2=MW^2+MVAr^2$. Then he concluded: ‘Therefore, the portion of the MVA-based cost related to MVAr production would be $MVAr^2$ /MVA^2.’

But, as Dr. Bowring explained:

> [T]he basic power triangle relationship … has nothing to do with costs. The costs that provide reactive could be 1 percent of a power plant. It could be zero percent, and that relationship would still be true.[35]

The Presiding Judge, while reserving final judgment, identified a related basic logical error:

> While there may be engineering logic to using that ratio to determine, from an engineering—an electrical engineering standpoint, the contribution of equipment to the production of reactive power, that engineering logic doesn't automatically translate into a cost relationship.[36]

But there is no engineering logic that leads to a conclusion about the share or identification of the plant’s physical equipment needed to provide reactive. Dr. Bowring responded that the flaw is more than a failed translation:

> I'm saying that there is no logical relationship, no causal relationship between the basic electrical engineering equation,

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34 *See* FER-0012 (*American Electric Power Service Corporation*, Direct Testimony of Bernard M. Pasternack, Docket No. ER93-540-000 (November 15, 1993)).

35 Tr. at 3391:5–8.

36 Tr. 3391:17–21.

> the definition of power factor, the definition of power factor squared, and the cost to provide real and reactive power.[37]

Put another way, the basic power triangle relationship has nothing to do with actual equipment. The equipment that provides reactive could be 1.0 percent of a power plant. It could be zero percent, and that power triangle relationship would still be true. The power triangle relationship would still be true if it were not possible, as it is not, to identify a single piece of equipment, the sole purpose of which is to provide reactive.

As applied by Fern and other market participants, the *AEP* Method is designed to maximize the allocation of costs to reactive and therefore maximize the level of risk free guaranteed payments for reactive and minimize the costs incorporated in the PJM markets. This also means that, as applied by Fern and other market participants, the *AEP* Method is designed to minimize the allocation of costs to the provision of energy.

As Dr. Bowring explained at hearing:

> [O]ne of the issues with the way reactive is compensated is there is an incentive to maximize the amount of revenue collected from the reactive si[d]e, because it's a cost-of-service guarantee[d] riskless payment that's inconsistent with the basic market design of PJM.[38]

The *AEP* Method unjustly and unreasonably harms competition, harms market efficiency, harms PJM customers and harms the public interest because it arbitrarily forces customers participating in markets to guarantee asserted investment costs that have not been demonstrated to exist and should not be guaranteed, and to assume risks that should not be assumed, with no corresponding benefit whatsoever.

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37 Tr. 3391:23–3392:2.

38 Tr. at 3394:14–19.

There is no logical connection among Mr. Pasternack's three steps as stated in his 1993 testimony.[39] The first step is equivalent to a general statement that larger generators cost more. The first step uses MVA rating as a general, but approximate, metric for generator size. The exact nature of the proportional relationship is not specified. The second, and unrelated step, is a statement of the basic power triangle relationship among $(MVA)^2$, $(MW)^2$ and $(MVAR)^2$. The fact that the term MVA appears in both steps does not create a logical link.[40] The third step is not logically related to either of the prior two steps. No support was provided for the fundamental assertion/assumption that the ratio of $(MVAR)^2$ to $(MVA)^2$ is related to the costs of providing real and reactive power. No support is provided for the specific functional form, e.g. the specific relevance of $(1 - PF^2)$ rather than (1 – PF). No support was provided for Mr. Pasternack's inextricably related assertion that the ratio of $(MVAR)^2$ to $(MVA)^2$ is a function of the nameplate power factor rather than the power factor identified in the Interconnection Service Agreement (ISA) and actually required.

Mr. Pasternack's 1993 testimony made explicit that the allocator he proposed was based on subjective judgment.[41] Mr. Pasternack stated that it was fair and equitable to reassign a significant part of the capital costs of generators to transmission customers, including internal and external transmission customers, that had previously been assigned to power customers. Mr. Pasternack stated that his goal was "a fair and equitable cost-based charge to transmission users."[42] The Pasternack testimony was about reassigning costs that were already fully accounted for and not for any asserted costs to provide reactive power that were not recovered elsewhere and not for any asserted additional costs of

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[39] IMM-0008, Attachment: see also FER-0012.

[40] *Id*.

[41] *Id*.

[42] *See* FER-0012 at 9.

providing reactive power.[43] Mr. Pasternack stated that generator costs had not been allocated to transmission customers by AEP prior to the case in which he proposed the allocation. Mr. Pasternack recognized that AEP was "breaking new ground in developing such a VAr charge."[44]

In his 1993 testimony, Mr. Pasternack was engaged in a cost allocation exercise designed to shift a significant level of generator costs from power customers to transmission customers.[45] Mr. Pasternack proposed the use of an allocation approach using one minus the power factor squared ($1 - PF^2$) where the PF was defined to be the nameplate power factor.[46] The reason for the allocation approach was to maximize the allocation of reactive costs to transmission customers rather than power customers.[47] The nameplate power factor is generally lower than the power factor required by the PJM Tariff.[48] A lower power factor means that the PF^2 is also lower and therefore that the allocator ($1 - PF^2$) is higher.[49] The differences in the allocator based on different power factors can be extreme.[50] For example, the allocation of costs to reactive using a nameplate power factor of 0.80 is 36 percent, while the allocation of costs to reactive using a power factor of 0.90 is 19 percent, and the allocation of costs to reactive using the required power factor of 0.95 is 10

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43 *Id*.

44 *See American Electric Power Service Corporation*, Supplemental Rebuttal Testimony of Bernard M. Pasternack, Docket No. ER93-540-000 (October 11, 1998) at 4 ("Pasternack Rebuttal Testimony").

45 *See* IMM-0008; FER–0012.

46 *Id*.

47 *See* IMM-0008, Attachment.

48 *Id*.

49 *Id*.

50 *Id*.

percent.[51] If the choice is between allocating costs to reactive or power generation, it is not logical to use the largest reactive allocator rather than the largest generation allocator.[52] No good reason or any reason, for example based on assertions about cost or function, was provided by Mr. Pasternak for using the largest reactive allocator.[53] Mr. Pasternack never explicitly acknowledged the fact that his proposed allocation method maximized the allocation of unit investment costs to reactive.

In contrast to the Fern Solar case, Mr. Pasternack's cost allocation exercise was in a fully regulated cost of service environment where the regulated utility (AEP) for whom he was working had rates designed to allow recovery of 100 percent of all its costs.[54] In that environment, cost of service exercises were primarily about rate design; what set of customers should pay more or less.[55] In the Fern case, the reactive allocation discussion cannot be separated from the capacity market design.[56] The relationship between the capacity market and reactive revenue is recognized in the PJM market rules.[57] The capacity market explicitly accounts for reactive revenue in the energy and ancillary services offset in defining the capacity market demand curve (VRR curve).[58]

The attempt to maximize the allocation of costs to reactive is inconsistent with the design and functioning of the capacity market. The capacity market includes all the costs

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51 *Id*.

52 *Id*.

53 *See id*.

54 *Id*.

55 *Id*.

56 *Id*.

57 *Id*.

58 *Id*.

of capacity.[59] Critically for the allocation question, when capacity resources sell capacity, they attempt to maximize the amount of capacity in MW of installed capacity (ICAP) that they offer in the capacity market, net of the forced outage rate (UCAP).[60] The ICAP amount is based on tests. Capacity resources are required to offer energy equal to the full ICAP every day in the energy market.[61] Holding aside the more fundamental issue with any positive cost of service payment for reactive, it is not logically consistent to include a reactive allocation factor based on a power factor that assumes power production at less than this full ICAP level, which defines the obligation of the generator to provide real power in MW.[62] That choice, to include a reactive allocation factor that assumes power production at less than ICAP, despite the obligation of resources to offer full ICAP in the energy market every day, is never supported. If done correctly, the allocation of costs to reactive would be zero. The conclusion is that the *AEP* Method is fundamentally inconsistent with the design of the capacity market and the obligations of resources to provide energy.

Cost allocation studies require the creation of allocation factors.[63] Once the judgment has been made to allocate costs, cost allocation studies require that there is some way, regardless of its rationale, to assign costs to customer classes.[64] That is not true in markets.[65] Mr. Bethel, in his uncritical acceptance of Mr. Pasternack's allocation approach, would ignore the underlying reality of the cost of service reactive allocation factors applied

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59 *Id*.

60 *Id*.

61 *Id*.

62 *Id*.

63 *Id*.

64 *Id*.

65 *Id*.

in a market environment.[66] The actual impact is that, in PJM markets, the larger the reactive allocation, the larger the guaranteed, non market revenues received and the less the generator has to rely on markets.[67] The effective function of the proposed reactive allocation approach is to assign risk to customers and away from investors. This is exactly contrary to market principles.[68] In a market, the generation owner is not guaranteed any level of cost recovery.[69] In a market, the concept of cost recovery is not relevant. Investors invest with the expectation of earning a target rate of return from markets, with the associated uncertainty.[70] When PJM introduced markets to replace cost of service regulation, all of the capital costs of generation were included in the PJM markets and no longer subject to cost of service regulation.[71] Mr. Pasternack's approach, which was incorrect even at the time he proposed it, does not apply in markets like the PJM markets.[72]

Reactive power is an ancillary service. It is ancillary to the provision of energy and capacity. It is not intended to supplant or exceed the role of the capacity market.[73] Yet that is exactly the implication of the approach supported by Mr. Bethel.[74] The results of the application of the proposed allocation method, including the proposed use of the nameplate

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66 *Id.*: *see* FER-0001.

67 *Id.*

68 *Id.*

69 *Id.*

70 *Id.*

71 *Id.*

72 *Id.*

73 *Id.*

74 *Id.*; *see* FER-0001.

power factor, also demonstrate the unreasonable nature of the approach.[75] The nameplate power factor is the power factor at the generator terminals and not the power factor actually provided to the transmission system and not the power factor required by PJM.[76] Mr. Bethel proposes that PJM customers pay more for reactive power from the Fern Facility than the capacity market clearing price in PJM markets.[77] This absurd result demonstrates the practical effect of applying the illogical and unsupported reactive allocation approach to the Fern Facility.[78] The results are particularly disproportionate for inverter based resources like Fern Solar.[79]

The basic math referenced repeatedly in the discussions of reactive allocators is straightforward.[80] The basic math is presented in equation format and all in one place for purposes of clarification:

(1) $MVA^2 = MW^2 + MVAR^2$

(2) $1 = \frac{MW^2}{MVA^2} + \frac{MVAR^2}{MVA^2}$

(3) $\left(1 - \frac{MW^2}{MVA^2}\right) = \frac{MVAR^2}{MVA^2}$

(4) $PF = \frac{MW}{MVA}$

(5) $(1 - PF) = \frac{MVAR}{MVA}$

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75 *Id*.

76 *Id*.

77 *Id*.; see FER-0001.

78 *Id*.

79 *Id*.

80 *Id*.

(6) $PF^2 = \frac{MW^2}{MVA^2}$

(7) $(1 - PF^2) = \frac{MVAR^2}{MVA^2}$

Defined terms:

MVA: Apparent power in megavolt amperes

MW: Real power in megawatts

MVAR: Reactive power in megavolt amperes reactive

PF: Power factor[81]

Equation (1) is the referred to as the power triangle relationship. Equation (2) is equation (1) after both sides are divided by MVA^2. Equation (3) subtracts the term (MW^2/MVA^2) from both sides of equation (2). Equation (4) is the definition of the power factor (PF), MW divided by MVA. Equation (5) is (1 – PF), MVAR divided by MVA. Equation (6) is the PF squared, from equation (4). Equation (7) combines equation (3) and equation (6), showing that ($1 – PF^2$) equals $MVAR^2$ divided by MVA^2. Equation (7), using a nameplate PF value, is the allocation approach used by Mr. Pasternack and Mr. Bethel to assign generation costs to reactive.

In summary, the equations are based on the definition of the power triangle and the definition of the power factor.[82] The rest is just rearranging terms following the rules of algebra.[83] There is no relationship between the power triangle equation or the definition of the PF, and the costs of providing reactive power. These equations do not create or support such a relationship.[84]

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81 *Id*.

82 *Id*.

83 *Id*.

84 *Id*.

This set of equations is the basis for the reactive allocation approach used by Mr. Pasternack.[85] The equations provide a bit more clarity to the relationships identified by Mr. Pasternack but do nothing to change the fact that there is no logical relationship among the three steps listed by Mr. Pasternack as the rationale for his use of $(1 - PF^2)$ as the basis for allocating a significant share of the costs of generating units to reactive power.[86] There is also no basis in these equations for the use of a nameplate PF which significantly increases the claimed allocation of costs to reactive.[87]

D. The AEP Method Is Unsupported in the Record.

The record provides no reasoned support for using the *AEP* Method to assign Fern's reactive costs to customers in addition to market rates for capacity and energy.[88] The record shows that it is not just and reasonable to use the *AEP* Method to calculate a revenue requirement for reactive capability under Schedule 2 and the PJM market rules. Because Fern claims to have calculated its revenue requirement using the *AEP* Method, nothing in the record supports a rate above zero dollars.

Fern never provided any substantive support of the *AEP* Method and never responded to the testimony of the Market Monitor witness Bowring regarding the *AEP* Method.

1. Fern Has Not Supported Use of the AEP Method.

Fern asserts that its proposed reactive revenue requirement is calculated using the *AEP* Method. Fern Witness Horigan claims to have used the *AEP* Method to "isolate the costs incurred by a facility related to the provision of reactive power, through various cost

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85 *Id*.

86 *Id*.

87 *Id*.

88 *See* Fern Solar LLC Initial Post-Hearing Brief (February 15, 2023) at 10–12.

identification and allocation factors."[89] Fern fails to show how it has identified any specific costs related to the provision of reactive power using the *AEP* Method.

Fern does not and cannot demonstrate any specific costs associated with providing reactive supply capability. Fern does not purport to identify specific costs that are required for reactive service. The *AEP* Method simply allocates part of the costs of an integrated generator to reactive. Fern also fails to identify a single cost that is not already recoverable in PJM markets through the sale of energy, ancillary services, or capacity. There are no such costs.

Schedule 2 provides for the recovery of a revenue requirement.[90] Schedule 2 does not define that revenue requirement or how it should be calculated.[91] Schedule 2 does not create a right to recover any cost already recovered or recoverable under the PJM market rules.[92] Schedule 2 does not provide for the allocation of costs between a cost of service generation facilities account and a transmission facilities account.[93] Schedule 2 does not reference the *AEP* Method or any method.[94]

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89 FER-0004 at 2:19–21.

90 *See* IMM-0002 ("Each month, the Transmission Provider shall pay each Generation Owner or other source owner an amount equal to the Generation Owner's or other source owner's monthly revenue requirement as accepted or approved by the Commission.").

91 *Id*.

92 *Id*.

93 *Id*.

94 *Id*.

a. ***The AEP Method Was Not Developed for Use in Competitive Wholesale Power Markets.***

The *AEP* Method was developed and filed in 1993. The *AEP* Method was developed to address issues in the electric industry as it was structured in 1993. The *AEP* Method has been applied without explanation in PJM competitive markets even though it originated prior to the development of the current annual PJM Capacity Market (2006), prior to the development of any PJM competitive markets (1999) and prior to the electric industry restructuring begun in Order No. 888, et seq. (1996).

Dr. Bowring summarized at hearing the mismatch between AEP's situation in 1993 and PJM markets today:

> [T]he problem with this entire exercise, and the Pasternack assertions from the very beginning, because what he was doing was assigning costs between two sets of customers, both of whom guaranteed payment of 100 percent of whatever they are allocated. And that's not what's happening here. What's happening is we are dividing revenues between markets and non-markets. And the fact is that the power factor approach is designed, at least as it's proposed by Fern, to maximize the amount of revenues assigned to the risk-free cost-of-service recovery, rather than markets.[95]

Even in the context of AEP in 1993, the *AEP* Method had only superficial appeal. The *AEP* Method did not then and does not now actually provide a sound logical basis for cost allocation.

In this case, indifference to the consequences of the using the *AEP* Method is not just and reasonable. Use of the *AEP* Method has harmful impacts on policy, fairness and efficiency. A logical evaluation of the *AEP* Method reveals that it does not support a revenue requirement under Schedule 2.

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95 Tr. at 3404:3-13.

E. Compensation for Reactive Power Capability Should Occur through PJM Markets.

The Market Monitor's position is that reactive revenue requirements for generation resources providing reactive supply capability under Schedule 2 should be eliminated. Reactive revenue requirements should be eliminated in PJM for the same reason that they were eliminated in MISO, and are not included in the CAISO and SPP rules.[96]

Unlike the MISO, CAISO and SPP rules, the PJM rules recognize under Schedule 2 that a resource may file to receive revenue requirement with the Commission.

Schedule 2 recognizes that a resource may file a revenue requirement and how such a revenue requirement would be billed to PJM customer if accepted or approved. Schedule 2 says nothing about what is required for acceptance or approval. Schedule 2 does not specific any rate or revenue requirement. Schedule 2 does not require PJM or PJM customers to pay any revenue requirement. PJM customers are only required to pay a revenue requirement under Schedule 2 unless and until it is "accepted or approved" by the Commission.

The scope of this case is now limited to the whether a proposed revenue requirement file under Schedule 2 should be approved. This case does not provide an opportunity to revise the PJM market rules to eliminate Schedule 2. A rate of zero dollars is appropriate in this case because the record in this case does not support a higher revenue requirement.

The answer must be zero dollars for the same reasons that the Commission has eliminated the reactive supply capability rate in *MISO*, and approved the CAISO and SPP tariffs excluding such payment.

Fern's filed revenue requirement should be found unjust and unreasonable, and terminated subject to refund.

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96 *See, e.g.*, 182 FERC ¶ 61,033.

F. Any Cost Based Compensation Should Include a Correctly Calculated Capital Recovery Factor (CRF).

If a rate exceeding zero dollars is approved in this proceeding, the revenue requirement should be calculated using an appropriate capital recovery factor (CRF). The equivalent CRF proposed by Fern is flawed and should be rejected as unjust and unreasonable.

The Market Monitor proposes an alternative method for calculating the CRF, defined in a technical reference ("CRF Technical Reference").[97] The CRF Technical Reference explains in detail the how to accurately and consistently calculate 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 reactive capability rates.[98] 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.[99] 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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97 *Id*. at 8:21–11:24; IMM-0003 (Capital Recovery Factor (CRF) Technical Reference); IMM-0004 (CRF and Annual Payment–Capital Reduced for ITC) and IMM-0005 (CRF and Annual Payment-not reduced for ITC).

98 *Id*. at 9:28–29.

99 *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.[100]

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.[101] 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 Fern.

For a 25 year cost recovery period, the Market Monitor's CRF is 0.085862 and the corresponding annual revenue payment is $860,321.[102] The formula for the CRF is equation (1.4) in the CRF Technical Reference.[103] 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 in order to protect Fern's confidential information.

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

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100 *See* IMM-0001 at 10:1–11.

101 The capital cost values in Exhibits Nos. IMM-0004 and IMM-0005 are from the Clayton Testimony (Exh FS-3). The amount was later revised by Witness Horigan (FER-0006).

102 *See id*. at 10:15–17.

103 *See id*. at 10 n.10.

reactive capital cost to account for an investment tax credit (ITC). Fern's filed rate inappropriately fails to reflect ITCs.[104]

Witness Horigan's inexplicably asserts that the manner in which the ITC is used or accounted for by the recipient of the tax credit is not relevant to the calculation of the capital recovery payments to the recipient.[105] It is clear, of course, that the ITC is relevant.[106] Whether it is a direct offset to the tax liability or a payment or series of payments from third party tax equity financing, the capital cost is reduced.[107] As Dr. Bowring explains, reducing capital costs is the reason for the ITC mechanism: "[The ITC] provides an incentive to the project by reducing the cost."[108] Dr. Bowring explains the distortion what would result from accepting Witness Horigan's view: "If recovery of the value of the ITC in a capital recovery payment is allowed, as suggested by Witness Horigan, the incentive would be doubled."[109]

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 the 100 percent bonus depreciation provisions of the tax code that allow generators placed in service after September 27, 2017, to fully depreciate the capital investment in the first year of operation.[110] Fern's failure to use the 100 bonus depreciation in their calculations also results in an overstatement of their calculated revenue

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104 *See* S-0013 at 29:3–31:20.

105 *See* FER-0004 at 41:7–10.

106 *See* IMM-0007 at 6:27–7:2.

107 *See id*.

108 *See id*. at 6:31–32.

109 *See id*. at 6:32–7:2.

110 *See* IMM-0001 at 11:1–3.

requirement. 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 25 years. For example, the Market Monitor's CRF for a 40 year cost recovery period is 0.075600.[111] The corresponding annual payment is $257,172 under the assumption that the reduction of the reactive capital cost by an ITC is applicable.

Neither Witness Clayton nor Horigan has explained why a 25 year life rather than a 30 or 40 year life is appropriate for the Fern Facility. A 25 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 25 years. Such longer life should be reflected in the CRF.[112]

Staff Witness Kevin Pewterbaugh provides detailed testimony supporting the use of a 30 year life.[113]

Witness Horigan never explained the actual cost of capital for the Fern facility or explained why the actual cost of capital should not be used in the calculation of the CRF.

In the event that a cost of service rate including a CRF is used to calculate the revenue requirement for Fern, the CRF proposed by Fern should be found unjust and unreasonable. In its place a CRF based on the approach included in the CRF Technical Reference should be calculated and used to determine a just, reasonable and nondiscriminatory revenue requirement.

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111 *See* IMM-0004 & IMM-0005.

112 *See* IMM-0001 at 11:12–14.

113 *See* Exhibit No. S-0008 REV at 4:8–10.

VI. CONCLUSION

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

Respectfully submitted,

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Dated: May 15, 2023

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 15th day of May, 2023.

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