UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

To: The Honorable Scott Hempling
Presiding Administrative Law Judge

REPLY BRIEF OF THE INDEPENDENT MARKET MONITOR FOR PJM

TABLE OF CONTENTS

Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"), submits this reply brief.

I. ARGUMENT

A. Over Recovery.

Fern attempts (at 98) and fails to rebut the Market Monitor's argument that reactive capability rates exceeding $2,199 per MW-Year result in unjust and unreasonable over recovery under the PJM market rules. Fern argues that there is no over recovery because "[t]he PJM capacity markets do not compensate generators for providing reactive power – they provide a separate revenue stream for separate services."[1] Fern argues (*id*.) that use of a "proxy number" in PJM capacity market calculations "does not change that analysis."[2] Staff makes similar arguments.[3] Fern and Staff attempt to prove too much. The arguments are illogical and should be rejected. The inclusion of the $2,199 per MW-year offset in the PJM Capacity Market is an explicit recognition that reactive capital costs are included in total facility costs and included as part of the capacity market offers. The offset reflects the fact that part of the offer is paid by reactive revenue that covers part of the undifferentiated capital cost.

The Market Monitor's proposed cap is the only approach supported in the record to avoid over recovery when the *AEP* Method is used to allocate costs between a cost of service rate and market prices. Fern and Staff, instead of proposing an alternative, attempt to defend the indefensible. No revenue requirement exceeding $2,199 per MW-Year should be approved.

---

[1] Fern Br. at 98, citing FER 0013 at 51:3-52:4; FER-0001 at 118:5-7.

[2] *Id*., citing FER-0013 at 52:13-54:7.

[3] *See* S-0045 at 25:2–30:7.

Fern and Staff attempt to avoid the substantive arguments raised by the Market Monitor by asserting that they are "out of scope" or are "policy" issues. Neither is correct. Both are evidence that neither Fern nor Staff has a compelling response to the Market Monitor's arguments.

Fern argues that "[t]he Commission in *Panda* rejected the exact same argument… finding that the issue was outside of the scope of the proceeding."[4] Fern explains that "[t]he Commission found in *Panda* that the proper place for such issues to be raised is in challenges to the rate design of the PJM capacity markets."[5] Staff claims (Br. at 99) that the Commission "explicitly rejected the IMM's arguments for a cap in *Panda*." The Commission did not explicitly or implicitly address in *Panda* any of the arguments raised by the Market Monitor in this proceeding. The Market Monitor's arguments are limited to the proper interpretation and implementation of Schedule 2. *Panda* made no attempt to interpret or apply Schedule 2.

Staff argues (Br. at 97) that, "to the extent the IMM bases its arguments on the existence of "distortionary impacts on PJM markets," it is a "policy issue, which should be raised in another forum." Staff explains that the issue is "whether Fern Solar's current ARR is just and reasonable" and "is not evaluating the very existence of cost-of-service compensation." Staff argues (Br. at 99) that the Commission "has never ruled that any sort of cap is permissible," and (Br. at 97) that the issues raised by the Market Monitor should be resolved in the pending Notice of Inquiry.

Staff's arguments have no merit. The Market Monitor's issues concern the interpretation and implementation of Schedule 2. The issues are within the proper scope of this proceeding, regardless of whether Staff would like to characterize them as "policy" issues. Every substantive issue raised by Staff in this proceeding is also a "policy" issue. The decision on any such issue becomes precedential. The Market Monitor's proposal is

---

4 *Id*. at 98, citing *Panda* at P 218.

5 *Id*.

not a cap; it recognizes that the PJM market design explicitly recognizes reactive compensation at a defined level.

There is no basis for the argument that the pending Notice of Inquiry presents a better forum to address the issues. Rulemaking proceedings apply to the whole United States. While the Commission could resolve PJM issues in the Notice of Inquiry, it can also make decisions in the interpretation and application of PJM market rules in PJM proceedings. It is at least arguable that this case presents a better forum to resolve PJM market rules' issues than a Notice of Inquiry. There is no reason to dodge resolution of Schedule 2 issues in a Schedule 2 proceeding like this one.

Staff also argues (*id.*), that "if capacity market costs will increase to offset the lost reactive compensation, this implies that the current reactive compensation does not overlap with capacity market costs." Staff misunderstands the issue. Staff's conclusion is exactly backwards. The increase in capacity market clearing prices would occur if the offset were completely eliminated. Elimination of the offset is not an issue in this case. The issue is how to interpret and apply Schedule 2 in the context of the PJM market design. Current reactive compensation overlaps with capacity market revenues only when reactive revenue requirements are more than $2,199 per MW-Year.

B. *AEP* Method and Power Factor

Fern argues (Br. at 99) that the Market Monitor "appears to advocate for eliminating consideration of the power factor from the calculation of the reactive power revenue requirement." Fern explains (*id.*) that "[t]he AEP Methodology separates costs between AC facilities that receive the reactive allocator and BOP," and that "[t]he power factor is an integral part of the reactive allocator."

Schedule 2 allows resources to file revenue requirements for reactive capability compensation with the Commission. Schedule 2 makes no provision for how such revenue requirements should be determined. Schedule 2 does not require a cost of service filing, use of the *AEP* Method, or any method, or use of the power factor. The Commission must determine whether a resource filing a revenue requirement has demonstrated a just and reasonable basis to collect the proposed revenue requirement. The record in this case does not show that Fern has identified any cost that it is entitled to receive from PJM or PJM customers in a revenue requirement filed under Schedule 2.

Staff argues that the Commission "has repeatedly blessed reactive compensation in many different contexts."[6] Staff does not identify any context relevant to the proceeding.

One specific context relied upon by Staff is the AEP system in 1993. Staff fails to explain how the *AEP* decision has anything to do with post restructuring competitive markets or PJM's competitive market. The record contains ample evidence that AEP prior to restructuring is not a context relevant to PJM.[7] The Market Monitor has also explained why the alleged logic of the *AEP* Method is unsupported and not relevant to this case.

Another context relied upon by Staff is the decision in *Chehalis*.[8] In *Chehalis*, the Commission interpreted and applied a settlement wherein it was agreed to use the *AEP* Method to calculate reactive capability rates for the Bonneville Power Authority (BPA) system. BPA does not operate a competitive market like PJM.[9] Staff fails to explain how *Chehalis* applies to PJM or to resolution of the issues raised by the Market Monitor.

---

6 Staff Br. at 99, citing *Chehalis*, 123 FERC ¶ 61,038; *Am. Electric Power Serv. Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999); *Am. Transmission Systems*, 119 FERC see¶ 61,020; Hearing Order at P 13, and Order No. 827 at P 52.

7 See IMM-0001.

8 *See Chehalis Power Generating, L.P.*, 123 FERC ¶ 61,038 (2008).

9 *Chehalis* interpreted and applied a settlement approved in *TransAlta Centralia Generation, L.L.C.*, 111 FERC ¶ 61,087 (2005) ("the settlement establishes an agreed-upon methodology and timing for the filing of reactive power service charges by … Chehalis for its generating plant. The settlement leaves open for future inquiry by Bonneville the support used by … Chehalis when applying the methodology for determining reactive compensation sanctioned by the settlement. ... The Commission's approval of the settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding.").

Another context relied upon by Staff is a Midcontinent Independent System Operator ("MISO") case approving a settlement applying Schedule 2 of the MISO market rules.[10] The settlement rate was approved based on the record as a whole, and it did not address the issues raised here by the Market Monitor. Even if the *ATSI* case had addressed any issue relevant to PJM or to the issues raised by the Market Monitor in this case, nothing remains of *ATSI* after the Commission approved the complete elimination of compensation for reactive capability under Schedule 2 of the MISO market rules.[11] *MISO* affirms the finding in Order No. 2003 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."[12] *ATSI* is not valid precedent in this case.

Staff ignores recent precedent in the *MISO* case that undercuts the logic for every Schedule 2 revenue requirement approved for a resource in PJM.[13] *MISO* found that resources are not entitled to revenue requirements for costs incurred to meet obligations to receive interconnection service.[14] Because no other reactive capability costs have been identified, the *MISO* decision eliminates compensation under Schedule 2. The removal of compensation for reactive capability from the MISO rules, brings an end, of course, to the misapplication in MISO of the *AEP* Method. Staff has not shown that any revenue requirement approved prior to *MISO* upon which it would rely is consistent with *MISO* principles.

---

10 *American Transmission Systems, Inc.*, 119 FERC ¶ 61,020 (2007).

11 *See Midcontinent Independent System Operator, Inc.*, 182 FERC ¶ 61,033 at P 52 (January 27, 2023) ("*MISO*").

12 *Id*.

13 *Id*.

14 *Id*.

In contrast to PJM's Schedule 2, the MISO market rules did specify an entitlement to file "cost-based revenue requirements" (as opposed to only "revenue requirements" in PJM's Schedule 2) and the MISO market rules included MISO in a process for continued certification under defined criteria of the resource's eligibility to receive compensation (as opposed to no role for PJM other than collecting the revenue requirement from its customers).[15] The Commission approved MISO's proposal to remove these provisions and specified that MISO would not charge customers for reactive capability, consistent with the Commission's policies on compensation for reactive capability.[16] PJM should remove Schedule 2 to provide clarity. However, PJM's Schedule 2, because it is less extensive than MISO's provisions, can be reasonably interpreted and applied consistent with the Commission's policies by rejecting Fern's proposed revenue requirement because it is unsupported. Fern fails to identify any costs that it did not incur in order to receive interconnection service. In other words, there is no actual conflict between the limited wording of PJM's Schedule 2 and the application and enforcement of well settled Commission policies.

Finally, Staff refers to Order No. 827, at P 52, where the Commission states:

> We will not change the Commission's existing policies on compensation for reactive power. Sections 9.6.3 and 11.6 of the currently-effective pro forma LGIA and sections 1.8.2 and 1.8.3 of the currently-effective pro forma SGIA provide that the transmission provider must compensate the interconnecting generator for reactive power service when the transmission

[15] *See* MISO Filing, Docket No. ER23-523-000, Exhibit II (Revised Schedule 2 Tariff Sheets (Redlined)) (November 30, 2022).

[16] *See id.* ("The Transmission Provider is not charging for Reactive Supply and Voltage Control from Generation or Other Sources Service under this Schedule 2 from Transmission Owner resources or Transmission Owner affiliated resources. As a result, there will be no separate charge to compensate any generation resource for reactive service provided within the standard power factor range.").

> provider requests that the interconnecting generator operate outside of the specified reactive power range.

The Market Monitor's position applies to reactive capability compensation under Schedule 2 to the OATT. Section 3.2.3 of Schedule 1 to the PJM Operating Agreement compensates generation resource for operating at PJM's direction, including outside of the specified power range. The issue in the *Fern* case is reactive capability, not operating in accordance with RTO dispatch instructions. Interpretation and application of Section 3.2.3 is not an issue in this case. The Market Monitor has always agreed with PJM's approach to the application of Section 3.2.3 of Schedule 1 to the PJM Operating Agreement.

That PJM customers have paid and are paying $367 million for revenue requirements that have no rational basis consistent with *MISO* principles (and ample precedent prior to *MISO*) is not a reason to continue unjust and unreasonable practices in this case.[17] Schedule 2 does authorize these revenue requirements. The revenue requirements were approved based on methods and logic that have been repudiated, most recently, in *MISO*. Schedule 2 authorizes the Commission to make determinations on whether proposed revenue requirements are just and reasonable. There is no reason not to make the correct determination in this case.

---

17 *See Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003), *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); *Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 at P 28 (2007), *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).

C. CRF

Staff argues: "[T]o the extent the IMM is proposing that each generator seeking to recover a Reactive Service revenue requirement under Schedule 2 or any other cost-based provision of the PJM Tariff must apply the IMM's CRF formula then such a proposal is beyond the scope of this proceeding and should not be considered."[18] The CRF covers the capital recovery components of the costs included in Fern's proposed fixed charge rate, and is, therefore, plainly within the scope of Fern's proposed cost of service rate. If the Presiding Judge determines that Fern's proposed CRF equivalent is unjust and unreasonable, there is no reason why the initial decision could not approve Fern's revenue requirement on condition that the Market Monitor's proposed CRF applies.

Staff also objects to the Market Monitor's CRF proposal on its substance. Staff claims that the Market Monitor's CRF proposal is "counter to Commission ratemaking principles," because "[t]he depreciation expense recovered in a revenue requirement is based on book depreciation (straight line), not tax depreciation."[19]

Staff ignores the Commission's acceptance of the Market Monitor's CRF for use in developing cost of service rates for black start units within the cost of service framework.[20] The *PJM* CRF case is the best and most recent precedent for calculating a CRF input within the framework of PJM markets. Consistent calculation of CRF promotes efficient markets and logical and consistent market administration.

Staff criticizes the Market Monitors' statement that the "depreciation used in the calculation of the CRF should reflect the depreciation used for taxes purposes" and the Market Monitor's objection that "[t]he sinking fund depreciation factor does not reflect

---

18 Staff Br. at 99; S-0045 at 30:15–19.

19 Staff Br. at 99; S-0045 at 30:19–31:3.

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

actual depreciation used by Fern and therefore should not be used in the revenue requirement for the Fern facility."[21] Fern echoes Staff's concerns.[22]

Staff's objections to the Market Monitor's proposed CRF have no merit. Staff's blanket assertion that depreciation expense recovered in a revenue requirement must be based on straight-line depreciation is illogical on its face when it is inconsistent with the actual accounting used by the project and ignores that tax depreciation is explicitly addressed as part of Staff's calculation. Staff appears to be confusing rate case revenue requirements with this project specific revenue requirement. The Market Monitor's CRF shows the importance of aligning the model assumptions as closely as possible to the actual financial and tax structure for the project. Staff's fixed charge carrying rate is overstated and inconsistent with the actual financial structure of the project. The Market Monitor's CRF is significantly lower than the capital recovery portion of Staff's fixed charge carrying rate. The reason for the difference is Staff's incorrect depreciation assumptions and to a lesser extent, the incorrect treatment of the investment tax credit (ITC). The difference matters because the Market Monitor's CRF reflects reality and Staff's approach does not. The difference between straight-line and MACRS depreciation factors has a significant impact on a CRF and the impact is greatly exacerbated when a capital investment is eligible for bonus depreciation and ITCs. The Market Monitor's CRF results in a lower revenue requirement while providing the necessary and sufficient level of revenue to cover the return on and return of the capital investment and the tax obligations associated with the annual revenue payments.

II. CONCLUSION

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

---

21 *Id.*

22 Fern Br. at 99, citing S-0045 at 30–31.

Respectfully submitted,

Jeffrey W. Mayes

General Counsel
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8053
jeffrey.mayes@monitoringanalytics.com

Joseph E. Bowring
Independent Market Monitor for PJM
President
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8051
joseph.bowring@monitoringanalytics.com

Dated: March 10, 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 10th day of March, 2023.

Jeffrey W. Mayes
General Counsel
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8053
jeffrey.mayes@monitoringanalytics.com