UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION

The Electric Power Supply Association ("EPSA")[1] hereby responds to the Notice of Inquiry issued on November 18, 2021, by the Federal Energy Regulatory Commission ("FERC," or the "Commission") in the above-captioned proceeding with respect to reactive power compensation and market design.[2]

As explained herein and in the affidavit of Adrian J. Kimbrough provided as Attachment A hereto (the "Kimbrough Affidavit"), the *AEP* methodology[3] has been used for over twenty years to determine just and reasonable rates for reactive power. Notwithstanding the questions and concerns raised in the NOI, the *AEP* methodology, as clarified and modified by more recent Commission orders, can be applied to a variety of types of resources and remains an efficient and fair methodology that should continue to

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1 EPSA is the national trade association representing competitive power suppliers in the U.S. EPSA members provide reliable and competitively priced electricity from environmentally responsible facilities using a diverse mix of fuels and technologies. EPSA seeks to bring the benefits of competition to all power customers. This pleading represents the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

2 *Reactive Power Capability Compensation*, 177 FERC ¶ 61,118 (2021) (the "NOI"). As noted in the NOI, "there are two approaches for supplying reactive power to control voltage: (1) installing facilities as part of the transmission system and (2) using generation resources." *Id.* at P 8. For purposes of this pleading, and consistent with the NOI, references to reactive power are to reactive power supplied by generation sources (also referred to as "Reactive Supply and Voltage Control from Generation Sources").

3 This methodology was established in *American Electric Power Serv. Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999) ("*AEP*").

be used to determine the costs of producing reactive power. At the same time, EPSA has been concerned about the significant burden imposed on resource owners in numerous recent cases where reactive power rate filings have been set for hearing and settlement judge procedures, even when no protests have been filed or when the filing complies with Commission precedent. Accordingly, EPSA urges the Commission to provide additional guidance that will help resource owners compile their rate filings and streamline the Commission's review of such filings. In addition, the Commission should re-examine its policies and, consistent with the statutory scheme of, and the Commission's ratemaking obligations under, the Federal Power Act (the "FPA"), ensure that all resource owners have the ability to seek reactive power compensation.

I. COMMENTS

A. The *AEP* Methodology Remains the Best Approach for Establishing Rates for Reactive Power

The *AEP* methodology has been used for more than 20 years to establish reactive power revenue requirements and allows resource owners and the Commission to properly isolate the costs of providing this critical service. The Commission has also refined this methodology in subsequent cases in response to market changes and case-specific disputes. For example, the Commission has held as follows:

- A "needs" assessment is not necessary, because "a generator is 'used and useful' if the generator is capable of providing reactive power," and "[t]he fact that that capability may not be utilized in a given hour does not mean that the reactive power compensation no longer meets the just and reasonable standard."[4]

[4] *Calpine Oneta Power, L.P.*, 119 FERC ¶ 61,177 at P 22 (2007) ("*Calpine Oneta II*") (footnotes omitted), *reh'g denied*, 121 FERC ¶ 61,189 (2007), *reh'g denied*, 124 FERC ¶ 61,193 (2008).

- For purposes of determining the cost of capital, merchant generators may use the Commission-authorized cost of capital of the interconnected utility as a proxy.[5]

- A merchant generator may propose an alternative approach for calculating its cost of capital, such as the Discounted Cash Flow model, Capital Asset Pricing model, or utilizing data regarding publicly-traded companies with comparable risks.[6]

These types of refinements to the original *AEP* methodology have helped address changes in the market and regulatory scheme. Moreover, and as addressed below and in the Kimbrough Affidavit, the *AEP* methodology can be applied to a variety of resources, and is superior to alternative approaches, such as a flat-rate approach that may not fully compensate specific resources for their costs of providing reactive power. Accordingly, Mr. Kimbrough recommends that the Commission continue to permit resource owners to use the *AEP* methodology for purposes of developing their reactive power revenue requirements.

1. The *AEP* methodology is appropriate for both synchronous and asynchronous resources

Although the *AEP* methodology has been successfully used for many years, the NOI now raises concerns regarding the continued use of this methodology, because "the majority of the filings" seeking to establish rates for reactive power are now "made by owners of non-synchronous resources that produce reactive power using different types of equipment than used by synchronous resources."[7] As detailed in the Kimbrough

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5 *See Panda Stonewall LLC*, Opinion No. 574, 174 FERC ¶ 61,266 at P 203 (2021) ("*Panda Stonewall*").

6 *See id.* at PP 178-180. *See also* Kimbrough Affidavit at 8 (discussing Commission guidance on the application of the *AEP* methodology).

7 NOI, 177 FERC ¶ 61,118 at P 2.

Affidavit, however, the *AEP* methodology can and has been used for both synchronous and asynchronous resources.

Mr. Kimbrough explains that "[c]alculating the ARR under the *AEP Method* is the same for all resources regardless of generation technology."[8] The *AEP* methodology begins by segmenting equipment and construction costs into four groups: (1) turbogenerators, (2) generator step-up transformers ("GSUs"), (3) accessory electric equipment ("AEE"), and (4) the balance of plant.[9] Any construction overhead or "indirect" costs are also allocated to these four investment categories.[10] An allocation factor is then applied to each of these cost categories to determine the costs that are deemed to be attributable to real and reactive power production.[11] Mr. Kimbrough further explains that the *AEP* methodology has been successfully applied to both synchronous and asynchronous resources, and that no, or only minimal, adjustments must be made to calculate the allocation factors for each direct cost component to apply the *AEP* methodology to asynchronous resources.[12]

For example, Mr. Kimbrough explains that the *AEP* methodology requires the development of what is typically referred to as a Generator-Exciter Allocation Factor ("GEAF"), but that this name is somewhat misleading because "the GEAF can and should include any additional reactive-related equipment that comprises the turbine."[13] Accordingly, "whereas natural gas-powered turbines rely on generators and *exciters* to

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8 Kimbrough Affidavit at 9.

9 *See id.* at 10.

10 *See id.* *See also Panda Stonewall*, 174 FERC ¶ 61,266 at P 91.

11 *See Panda Stonewall*, 174 FERC ¶ 61,266 at P 4.

12 *See* Kimbrough Affidavit at 10-12.

13 *Id.* at 10.

provide reactive power support, wind-powered turbines typically rely on generators and *converters*," and "[a]lthough the subcomponents may differ by resource technology, the development and application of the GEAF remains the same for all turbine-driven resources and does not require any modification to the *AEP Method*."[14] Similarly, Mr. Kimbrough states that "[b]ecause all power plants require step-up transformers to connect to the transmission system, there is no difference in how synchronous and asynchronous resources account for these costs under the *AEP Method*."[15] Mr. Kimbrough also explains that synchronous resources calculate their Accessory Electric Equipment Allocation Factor ("AEAF") by "dividing their generator-*exciter* auxiliary load to their entire plant auxiliary load," and that "[w]hile asynchronous resources do not use generator-exciters, they do use generator-*converters* or *inverters,* which accomplish the same objective."[16] Accordingly, synchronous and asynchronous resources can calculate the AEAF in a consistent way, with the only difference being what "equipment to include in the numerator."[17] Finally, the Balance of Plant Allocation Factor ("BPAF") is calculated using inputs that are "applicable to all resource types," thereby allowing "synchronous and asynchronous resources [to] develop all [Balance of Plant] calculations in a consistent manner without requiring any modification to the *AEP Method*."[18]

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14 *Id.* (emphasis in original).

15 *Id.* at 10-11.

16 *Id.* at 11 (emphasis in original).

17 *Id.*

18 *Id.* at 12.

2. Merchant generators have been able to provide adequate evidentiary support for their reactive power rate filings

As noted in the NOI, when the Commission issued its *AEP* order, the majority of reactive power rate filings were made by public utilities subject to the Commission's Uniform System of Accounts ("USofA"). By contrast, many reactive power filings are now made by resource owners that have been authorized to make sales at market-based rates, and have received the associated customary waivers and blanket approvals, including waiver of the requirement to maintain their accounts under the USofA.[19] Nonetheless, Mr. Kimbrough explains that merchant generators have been able to adequately support their reactive power revenue requirements based on a variety of documents. In particular, Mr. Kimbrough states that merchant generators have commonly supported their rate filings with "equipment purchase orders, change orders, transaction term sheets, and independent appraisals," which "can provide third party validation of filed cost totals with a high degree of certainty that the costs have already been incurred or will be in the near future."[20] In addition, the cost of resources that have not yet been completed may also be determined with "a high degree of certainty" because engineering, procurement, and construction ("EPC") contracts "are typically priced on a fixed basis that locks in a minimum cost to the project."[21] As a result, while actual costs may ultimately be higher than that set forth in the relevant EPC contract, "it is highly improbable – if not explicitly prohibited under the terms of EPC contracts – that the final costs will be lower

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19 *See* NOI, 177 FERC ¶ 61,118 at P 2.

20 Kimbrough Affidavit at 12.

21 *Id.*

than the initial contracted value," meaning that "reactive rate filings for new projects are more likely to understate their full plant investment costs . . . ."[22]

3. The Commission should provide guidance with respect to future reactive power rate filings

As explained above, resource owners have been able to apply the updated *AEP* methodology to asynchronous resources and have also been able to provide substantial evidentiary support in their reactive power rate filings. Nonetheless, EPSA is concerned that, as noted in the NOI, a large number of reactive power rate filings have been set for hearing and settlement judge procedures, apparently because of concerns regarding these issues.[23] Accordingly, EPSA urges the Commission to provide guidance and clarifications regarding the application of the *AEP* methodology, as described in detail in the Kimbrough Affidavit.

In particular, Mr. Kimbrough explains that the Commission should clarify that, in preparing their rate filings using the *AEP* methodology, resources are permitted to: (1) use an independent engineer to verify their reactive power capability;[24] (2) use original equipment manufacturer ("OEM") support for all equipment costs included in the turbogenerator relating to reactive power;[25] (3) calculate the AEAF numerator using the

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22 *Id.*

23 *See* NOI, 177 FERC ¶ 61,118 at P 17 ("Because the AEP Methodology was designed based on the physical attributes of a synchronous resource and because of this lack of FERC Form No. 1 information for independent power producers (synchronous and non-synchronous alike), customers and the Commission have faced challenges in evaluating proposed reactive power rate schedules submitted pursuant to section 205 of the Federal Power Act (FPA), resulting in the majority of the filings being set for hearing and settlement procedures.").

24 *See* Kimbrough Affidavit at 15-16.

25 *See id.* at 17.

power consumed by all equipment responsible for the production of reactive power;[26] (4) recover costs associated with collector systems;[27] (5) recover all costs that are included under FERC Account 353, rather than just GSU-related costs;[28] and (6) use proxy allocation factors when actual data is not available.[29]

In addition, EPSA also supports the suggestion in the NOI that the Commission could include a standardized template that could be used to prepare reactive power rate filings, and Mr. Kimbrough provides a list of the types of information that could be included in such a template.[30] To the extent that the Commission deems it helpful, the template could also include default allocation factors that could be used by a rate filer.

EPSA believes that the guidance requested above would help streamline the filing process and lessen the burden on both resources and the Commission. In particular, to the extent that a reactive power rate filing complies with the Commission's guidance, including each of the Commission's standardized assumptions, it should be accepted without additional proceedings. At the same time, EPSA also emphasizes that the Commission should permit owners to propose alternative approaches and deviations from the Commission's standardized assumptions. For example, as stated above, the Commission could establish default allocation factors, but this should only be an option to the extent that rate filers do not propose and adequately support their own, resource-specific allocators. Along the same lines, while the Commission should establish a

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26 *See id.*

27 *See id.* at 18.

28 *See id.* at 19-22.

29 *See id.* at 17-18.

30 *See id.* at 15; *id.* at Appendix.

standard template for reactive power rate filings, this should be optional, as resource owners will need flexibility to adapt their filings based on their specific circumstances.

B. Other Issues Raised by the NOI

1. Concerns regarding degradation may be adequately addressed by periodic reviews

The NOI expresses concern that "the AEP Methodology does not account for the fact that a resource's reactive power capability may degrade," and that "over time the reactive power revenue requirement originally established under the AEP Methodology may no longer reflect the actual reactive power capability of the associated resource(s)."[31]

EPSA understands the Commission's concerns, and believes that the Commission could adopt reasonable measures to periodically review the capability of resources receiving reactive power compensation. Concerns regarding degradation do not mean that there are any problems with the *AEP* methodology itself or that the *AEP* methodology should not be used to set reactive power rates in the first instance; instead, the Commission's concerns simply indicate that there may be a need for periodic review of the reactive power capability of resources receiving reactive power compensation. In particular, Mr. Kimbrough suggests that the Commission should allow a resource to verify its reactive power capability by having a certified independent engineer confirm that the resource "(1) can provide reactive power support to the transmission system; (2) is dispatchable by direction of the transmission provider; and (3) can provide reactive power support consistent with the resource's filed maximum lagging reactive capability."[32] Such

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[31] NOI, 177 FERC ¶ 61,118 at P 21.

[32] Kimbrough Affidavit at 16 (footnote omitted). *See also id.* at n.25 (noting that "it would be reasonable to continue measuring reactive capability at the high-side of the substation and ensure that this applies uniformly to both synchronous and asynchronous resources").

verification would be provided with the initial rate filing, and every five years thereafter.[33] Mr. Kimbrough further explains that this would be preferable to the Commission's current approach of requiring resources to provide reactive capability test results conducted under NERC's verification procedures, because those tests seldom allow resources to demonstrate full reactive capability due to voltage constraints during testing.[34]

2. Any flat rates for reactive power set forth in RTO/ISO tariffs should not preclude resources from filing their own rates based on their specific costs

As noted in the NOI, the various regional transmission organizations ("RTOs") and independent system operators ("ISOs") use different methodologies for reactive power compensation. Resources in PJM Interconnection, L.L.C. ("PJM") and Midcontinent Independent System Operator, Inc. use the *AEP* methodology to establish individualized reactive power rates, while resources in ISO New England Inc. ("ISO-NE") and New York Independent System Operator, Inc. ("NYISO") are compensated under a flat rate set forth in their respective tariffs.[35]

EPSA is not opposed to RTOs and ISOs adopting a flat rate for reactive power but is concerned that current flat rates are not fully compensatory. For example, Schedule 2 of the ISO-NE Transmission, Markets, and Services Tariff sets forth a "Base CC Rate" of \$2.19/kVAR-year.[36] In late 2006, ISO-NE proposed a Base CC Rate of \$2.32/kVAR-year,

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33 *See id.* at 16.

34 *See id.*

35 *See* NOI, 177 FERC ¶ 61,288 at P 12 & n.27.

36 While this is the Base CC Rate, ISO-NE applies an Adjusted CC Rate of approximately \$1.10/kVAR-year or \$0.09/kVAR-month. *See* Kimbrough Affidavit at 13 (citing ISO-NE, 2022 VAR Capacity Cost Rate, https://www.iso-ne.com/static-assets/documents/2021/12/ww_var_cc_rate_iso_2022010100_20211217184006.csv).

which “reflected a proxy value determined by blending two sources of cost data: (1) the average costs for older pre-market (pre-1998) resources built in New England (i.e., $1.38/kVAR-year), and (2) the average cost for newer post-market (post-1998) resources built in New England (i.e., $4.20/kVAR-year based on Commission-approved cost-based filings of gas-fired combined-cycle resources located in [PJM and MISO] for reactive capability compensation).”[37] This proposed rate was subsequently lowered to the existing rate of $2.19/kVAR-year as a result of a settlement, and has not been modified since 2007.[38] Accordingly, it is highly likely that the Base CC Rate does not fully reflect the costs of certain resources in the ISO-NE region, and would not even come close to compensating a new, state-of-the art generating unit being developed in ISO-NE. Similarly, the NYISO flat rate is based on the amount of MVARs expected to be provided in 2002, divided by the costs of reactive power in 1997,[39] and is therefore unlikely to provide adequate compensation for certain resources. Indeed, Mr. Kimbrough explains that the flat rates applied by ISO-NE and NYISO are significantly below recent rates based on the *AEP* methodology in PJM and MISO.[40]

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37 Informational Filing of ISO New England’s Examination of the Base Capacity Cost Rate Under Schedule 2 of the ISO New England Inc. Open Access Transmission Tariff, Transmittal Letter at 3-4, Docket No. ER12-229-001 (filed Oct. 28, 2016) (footnotes omitted) (also proposing no change to the Base CC Rate).

38 *See id.* at 4. *See also ISO New England Inc.*, 122 FERC ¶ 61,056 (2008) (approving settlement).

39 *See* Filing of Amended Rate Schedule 2 for Market Administration and Control Area Services Tariff, to Provide Payments for Voltage Support Service and Request for Expedited Action, and Request for Ratification of Prior Payments, Docket No. ER02-617-000 (filed Dec. 27, 2001). *See also N.Y. Indep. Sys. Operator, Inc.*, Docket No. ER02-617-000 (Feb. 5, 2002) (accepting same).

40 *See* Kimbrough Affidavit at 12-13.

Notwithstanding the above, EPSA recognizes that flat rates may be useful for purposes of reducing the burden on resources that may not want to incur the costs associated with making their own individualized rate filings, and resources should therefore have the option of using them if they prefer. However, the existence of a flat rate should not deprive a resource of its right to file an individualized rate that will fully compensate it for its costs. Furthermore, the Commission must respect the statutory scheme of the FPA, whereby rates are "established initially by the [public utilities],"[41] and the Commission "has no jurisdiction to enter limitations requiring utilities to surrender their rights under [Section] 205 of the FPA to make filings to initiate rate changes."[42] Accordingly, the Commission should make clear that any RTO/ISO flat rates are simply a default option, and that resource owners will retain the right to file their own rates for providing reactive power based on their specific costs.

3. There is no basis for concerns regarding overcompensation

The NOI notes that PJM's capacity market rules assume that the reference resource will receive $2,199/MW-year in reactive power payments, and that the Independent Market Monitor for PJM (the "IMM") has therefore argued that "any separate reactive power capability payments through Schedule 2 [of PJM's Open Access Transmission Tariff (the "PJM Tariff")] that exceed $2,199/MW-year result in

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[41] *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 341 (1956) (interpreting provisions of the Natural Gas Act ("NGA")). *See also Arkansas La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981) (noting that relevant provisions of the FPA and NGA may be cited "interchangeably"); 16 U.S.C. § 824d (2018).

[42] *Atlantic City Elec. Co. v. FERC*, 329 F.3d 856, 859 (D.C. Cir. 2003). *Cf. PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,224 at P 26 (recognizing that "neither the Commission nor PJM has the authority to compel a reactive power supplier to make a section 205 filing" (footnote omitted)).

overcompensation as such costs can and should be recovered through the capacity market."[43] There is no basis for these arguments.

The PJM IMM is, in effect, now arguing that reactive power should no longer be recognized as a separate product and should instead be considered part of the service provided by capacity resources. Mr. Kimbrough explains that the IMM's suggestion makes little sense given that "the capacity market compensates resources for *real* power capability – not *reactive* power capability."[44] As a result, "generators that clear the capacity market may still be unable to recover their costs of investing in their minimum required reactive capability – let alone their full reactive capability."[45] In addressing ISO-NE's market rules, the Commission similarly found that ISO-NE's reactive power payments and capacity payments "compensate two distinct services that are designed to achieve two different purposes."[46] As the Commission explained in that case, "[c]apacity payments are designed to ensure resource adequacy," and as a result, all capacity resources "regardless of type (and whether they are capable of providing reactive power service or not), will receive the same Forward Capacity Auction clearing price."[47]

In fact, the PJM IMM's proposed approach of moving reactive power compensation into the capacity market would have unjust and unreasonable results because some resources that can participate in the capacity market (like demand response resources) are incapable of providing reactive power. Conversely, given that generators are required

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43 NOI, 177 FERC ¶ 61,288 at P 27.

44 Kimbrough Affidavit at 13.

45 *Id.*

46 *Maine Pub. Utils. Comm'n v. ISO New England Inc.*, 128 FERC ¶ 61,012 at P 5 (2009) ("*Maine PUC*").

47 *Id.* (footnote omitted).

under the Commission's interconnection procedures to have reactive power capability regardless of whether they have capacity commitments, it would be unjust and unreasonable to deny those resources reactive power compensation simply because they did not clear in a PJM capacity auction.

There is also no basis for the PJM IMM's arguments regarding potential overcompensation. As the NOI recognizes, PJM's capacity market rules use an energy and ancillary services ("E&AS") offset for purposes of calculating the Net Cost of New Entry ("CONE") of the reference resource. Accordingly, "[t]he result of this offset is that, conceptually, the cost of reactive capability is ***not*** part of Net CONE."[48] Similarly, capacity offers in PJM are subject to a Market Seller Offer Cap, which are based on an Avoidable Cost Rate that also takes into account projected E&AS revenues.[49] As a result, PJM's capacity market rules are already designed to prevent any kind of double-recovery of projected reactive power revenues that the PJM IMM may be concerned about.[50]

More fundamentally, even without these PJM rules, competitive forces will prevent double-recovery. As noted previously, not all resources that are allowed to participate in PJM's capacity market are required to provide reactive power and have the associated costs. Accordingly, in order to effectively compete in PJM's capacity auctions, those resources that are receiving separate reactive power compensation can be anticipated to submit offers that are as low as possible, and that do not provide for double recovery of reactive power costs. In fact, the Commission came to the same conclusion in *Maine*

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48 NOI, 177 FERC ¶ 61,288 at n.46 (emphasis added).

49 *See* PJM Tariff, Attachment DD, § 6.4(a).

50 *See also* Kimbrough Affidavit at 13-14 (providing additional rationales why double recovery is not a concern).

PUC, finding that resources can be expected to act rationally and submit capacity offers that do not provide for double recovery. As the Commission found:

> qualified, VAR-capable generating resources, in fact, have an incentive to reduce their [capacity offers] by the amount of their net revenues from the capacity cost component, given that competing resources—which do not provide reactive power service (*e.g.*, demand resources and imports)—do not need to recover the costs of such reactive service.[51]

As a result, no changes to PJM's rules (or the market rules of any other RTO/ISO) are needed to prevent double-recovery or overcompensation.

C. The Commission Should Ensure that All Resources Have the Ability to File Proposed Rates for Providing Reactive Power Using the *AEP* Methodology

In re-examining its rules regarding reactive power compensation, the Commission should ensure that all resources have the opportunity to receive compensation for providing this critical service. As noted in the NOI, the Commission has long recognized that reactive power is necessary for the reliability of the grid,[52] and "can also substantially improve the efficiency with which real power is delivered to customers."[53] As a result, in Order No. 888, the Commission identified reactive power as one of the ancillary services that must be provided by a transmission provider to all transmission customers.[54]

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[51] *Maine PUC*, 128 FERC ¶ 61,012 at P 9 (footnote omitted).

[52] *See, e.g., Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 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 relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC*, 535 U.S. 1 (2002); NOI, 177 FERC ¶ 61,118 at P 4.

[53] NOI, 177 FERC ¶ 61,118 at P 6.

[54] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,960.

Nonetheless, the Commission's existing policies put resources at risk of not being fully compensated for their costs of providing reactive power. In particular, in adopting its standard interconnection procedures and *pro forma* Large Generator Interconnection Agreement, the Commission required interconnecting resources to, as a general matter, maintain a power factor range of 0.95 leading to 0.95 lagging,[55] but held that such resources would not be entitled to reactive power compensation for operating within that range unless the transmission provider provides such compensation to its own or its affiliated resources.[56] This "comparability" policy has meant that a transmission provider has the ability to deprive a resource of its right to seek compensation for reactive power.[57] Indeed, the NOI recognizes that there is significant variation in reactive power compensation among the different RTOs/ISOs, with California Independent System Operator Corporation ("CAISO") and Southwest Power Pool, Inc. ("SPP") not paying for reactive power at all.[58] Similarly, outside of the RTO/ISO markets, certain transmission

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55 See *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 542 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 , *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. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

56 *See* Order No. 2003-A, 106 FERC ¶ 61,220 at P 416. *See also, e.g., Bonneville Power Admin. v. Puget Sound Energy, Inc.*, 120 FERC ¶ 61,211 at P 20 (2007) ("*Bonneville*"), *on reh'g*, 125 FERC ¶ 61,273 (2008) ("*Bonneville II*"); *Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282 at PP 26-27 (2006), *on reh'g*, *Calpine Oneta II*, 119 FERC ¶ 61,177.

57 *See, e.g., Public Serv. Co. of N.M.*, 178 FERC ¶ 61,088 at P 29 (2022) ("As the Commission has stated, "[t]he decision to compensate affiliates and non-affiliates [for reactive service capability] rests with the transmission provider." (alterations in original) (footnote omitted)); *id.* at P 30 (finding it unreasonable for a transmission provider to charge customers for reactive power provided by an unaffiliated resource once the transmission provider eliminated reactive power compensation for its own generation).

58 *See* NOI, 177 FERC ¶ 61,288 at P 12 & n.27.

providers do not provide reactive power compensation within the standard power factor range.[59]

The Commission should now revisit its comparability policy. Both the Constitution and the FPA require the Commission to ensure that resource owners are properly compensated for the services that they provide, where rates must be sufficient to provide a return of and on their investments.[60] There is therefore no basis for the Commission to have required resources to provide reactive power without also ensuring that there is adequate compensation for such service. In fact, as the Market Monitoring Unit for SPP (the "MMU") pointed out in its comments in this proceeding, the Commission's assumption that costs of producing reactive power within the deadband are small[61] is not accurate given that extreme weather events are occurring with increased frequency, resulting in price spikes and opportunity costs that will be under-recovered.[62] Accordingly, the MMU states that "[t]he current SPP reactive power compensation approach does not allow generation resources to fully recover costs of providing reactive power," and expresses

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59 *See id.*

60 *See Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 690 (1923) ("Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment."). *See also Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168, 1175 (D.C, Cir. 1987) (holding that the prohibition against confiscatory rates applies under the FPA).

61 *See* Comments of the Market Monitoring Unit of the Southwest Power Pool on Notice of Inquiry at 4, Docket No. RM22-2-000 (filed Jan. 31, 2022) (the "SPP MMU Comments"). *See also Bonneville*, 120 FERC ¶ 61,211 at P 11; *Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 at P 17 ("*SPP*"), *on reh'g*, 121 FERC ¶ 61,196 (2007) ("*SPP II*").

62 *See* SPP MMU Comments at 3-4.

concern that "[t]he market will not get what it does not properly measure, value, or compensate."[63]

In addition, the Commission's existing policy fails to adequately prevent undue discrimination as required under the FPA.[64] Unfortunately, the Commission's comparability policy does not account for the fact that transmission owners and their affiliates may have cost recovery options available to them that are not available to independent power producers. For example, in permitting transmission providers to terminate all compensation for reactive power within the deadband, the Commission found that it was inconsequential that the transmission provider could be a vertically-integrated utility that receives retail rate compensation sufficient to cover all the costs of its generation, while unaffiliated generators have no alternate means of recovering their reactive power costs. The Commission brushed aside this difference, finding that "just as [the transmission provider] may try to recover its lost revenue through higher power sales rates, so the independent power producers may try to recover their lost revenue through their own higher power sales rates."[65] But this argument makes little sense given that independent power producers that need to recover their reactive power costs through market-based rate sales would not be able to effectively compete against resources that have alternative revenue streams or that benefit from affiliate preferences. Indeed, the Commission effectively conceded as much in *Bonneville II*. In that case, independent power producers argued that "non-affiliates do not have a comparable opportunity to

63 *Id.* at 1.

64 *See* 16 U.S.C. §§ 824d, 824e (2018).

65 *Bonneville II*, 125 FERC ¶ 61,273 at P 11 (footnote omitted).

recover their lost revenue through higher power sales rates because rate increases create the possibility of lost sales,"[66] but the Commission held:

> Just as [the transmission provider's] merchant affiliate has an opportunity to recover its lost revenue in its power sales rates, so the independent power producers have an opportunity to seek rates that make up the revenue that they previously might have earned through a separate charge for reactive power inside the deadband; ***comparability does not require that the Commission guarantee that affiliates and non-affiliates will be equally successful in pursuing such opportunities***.[67]

In short, the Commission's comparability policy is only in name, rather than ensuring actual equal treatment with respect to reactive power compensation. Accordingly, in order to ensure that resources have the opportunity to be properly compensated for providing reactive power and consistent with the statutory scheme of the FPA, the Commission should make clear that all resources located in every Commission jurisdictional market have the right to file their own individualized rates for reactive power.

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66 *Id.* at P 15.

67 *Id.* (emphasis added) (footnote omitted).

II. CONCLUSION

WHEREFORE, for the foregoing reasons, EPSA respectfully requests that the Commission take these comments under consideration in taking any further action on the NOI.

Respectfully submitted,

ELECTRIC POWER SUPPLY ASSOCIATION

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Dated: February 22, 2022

ATTACHMENT A
THE KIMBROUGH AFFIDAVIT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PREPARED DIRECT TESTIMONY OF
ADRIAN J. KIMBROUGH

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Adrian J. Kimbrough. My business address is 417 Denison Street, Highland Park, NJ 08904.

Q. WHAT IS YOUR OCCUPATION?

A. I am a Vice President at Gabel Associates, Inc. ("Gabel Associates"), an energy, environmental, and public utility consulting firm.

Q. PLEASE DESCRIBE YOUR FORMAL EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. My formal education includes a B.A. in Political Science from the University of California, Berkeley, and an M.B.A. with concentrations in finance and economics from Harvard Business School. My professional background includes roles as an Energy Industry Analyst with the Federal Energy Regulatory Commission ("FERC" or the "Commission") and as a Cryptologic Linguist with the United States Marine Corps.

Q. HAVE YOU PREVIOUSLY SUBMITTED EXPERT TESTIMONY TO FERC OR ANY OTHER PUBLIC UTILITY COMMISSION?

A. Yes, I have provided testimony to FERC on multiple occasions in my current role as a Vice President with Gabel Associates, as well as in my prior role as an Energy Industry Analyst with FERC. I have also submitted testimony before the Virginia State Corporation Commission. Topics addressed cover a range of subject matters, including, but not limited to, cost-of-service ratemaking for electric utilities and oil pipelines, economic damages analyses, stranded cost analyses, and renewable portfolio standard policy and economic impact analyses.

Q. PLEASE DESCRIBE YOUR REACTIVE POWER RATEMAKING EXPERTISE.

A. I have submitted expert testimony addressing reactive rates in multiple FERC dockets and have negotiated reactive rates for more than 100 individual generation projects encompassing both FERC Section 205 rate filings and Section 206 rate investigations. As part of this process, I have evaluated reactive rates for a range of power generation and storage technologies including solar photovoltaic, wind, battery storage, coal, nuclear, landfill, waste-to-energy, hydroelectric, natural gas, and transmission assets.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to address the Commission's Notice of Inquiry relating to reactive power capability compensation and market design ("Reactive NOI").[1] This affidavit shows that reactive ratemaking under the *AEP Method*[2] continues to be an effective means of determining just and reasonable cost-based rates to compensate compensating resources for their reactive capability, but would benefit from minor enhancements to improve the (1) consistency through which reactive rates are developed; (2) efficiency through which reactive rates can be verified; and (3) accountability of reactive rate filers to ratepayers and system reliability.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Electric Power Supply Association ("EPSA"). EPSA is a national trade association representing competitive power suppliers throughout the U.S. This affidavit reflects my views and not necessarily the views of EPSA or any EPSA member.

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[1] *Reactive Power Capability Compensation*, Notice of Inquiry, 177 FERC ¶ 61,118 (2021).

[2] *American Electric. Power Service Corporation,* Opinion No. 440, 88 FERC ¶ 61,141 (1999) ("*AEP*"), *order on reh'g*, 92 FERC ¶ 61,001 (2000).

II. EXECUTIVE SUMMARY

Q. ARE ALTERNATIVE METHODS TO THE AEP METHOD NECESSARY FOR THE CALCULATION OF REACTIVE POWER CAPABILITY REVENUE REQUIREMENTS?

A. No. Alternative methods are not necessary because the *AEP Method* remains a reasonable approach for calculating an annual revenue requirement ("ARR") attributable to reactive capability and should be maintained because:

- The *AEP Method* is a proven, durable mechanism for developing just and reasonable reactive revenue requirements for many different types of resources with varying cost structures and operating characteristics.
- Calculating the ARR under the *AEP Method* is the same for all resources regardless of generation technology.
- Asynchronous resources like wind farms and solar photovoltaic facilities are increasingly being designed to provide reactive power support even without wind or sunshine.
- Alternative methods are unlikely to provide just and reasonable cost recovery for required reactive capability or a sufficient long-term price signal to invest in additional reactive capability.
- Reactive power capability compensation under the *AEP Method* does not result in double recovery.

Q. COULD THE AEP METHOD BE IMPROVED?

A. Yes. While the *AEP Method* remains sound, the Commission should make the following minor clarifications to better achieve the objectives of the *AEP Method* and significantly improve efficiency in the preparation and review of reactive power compensation rate filings:

- Rate filers should be permitted to verify their reactive capability using a sworn statement from an independent engineer.
- Turbine-driven resources should be permitted to rely on original equipment manufacturer ("OEM") support for all reactive-related equipment costs that are included within the turbogenerator unit (rather than having cost recovery be limited to the generator-exciter, which applies only to synchronous resources).
- Rate filers should be permitted to calculate the Accessory Electric Equipment Allocation Factor ("AEAF") numerator using the electricity consumed by all equipment responsible for reactive power production (rather than just the exciter, which applies only to synchronous resources).
- Rate filers should be permitted to recover investment costs associated with collector systems because this asynchronous equipment is

comparable to synchronous equipment such as the isolated phase bus, which is already recoverable under the *AEP Method*.

- Rate filers should be permitted to recover all FERC Account 353 costs that are used to support reactive power production and are not included in a regulated utility's system (in addition to generator step-up transformer ("GSU")-related costs, which are already recoverable under the *AEP Method*).
- Rate filers should be permitted to use proxy allocation factors when actual data is unavailable.
- Rate filers should be permitted the option to use a standardized *AEP Method* template to calculate the reactive revenue requirement with Commission-approved inputs and calculations. The Commission could also consider establishing default allocators that could be used by rate filers. Moreover, the Commission could set for settlement procedures only those components of reactive rate filings that are inconsistent with these standardized inputs and calculations.

Q. ARE THERE ANY OTHER RELATED ISSUES THAT WOULD BE REASONABLE FOR THE COMMISSION TO CONSIDER?

A. In the Reactive NOI, the Commission raises concerns regarding degradation. To address such concerns, resources should be required to verify their reactive capability every five years using a sworn statement from an independent engineer.

In addition, while I strongly support the continued use of the *AEP Method*, if the Commission elects to substantially modify the *AEP Method* or replace it with an alternative method, it would be reasonable to extend "grandfather" rate protections to all existing settled and filed reactive rates. This approach would be consistent with historical Commission precedent and ensure minimal disruption to market participants that have constructed or planned for the development of power generation projects designed to provide reactive power support consistent with the *AEP Method*.

III. BACKGROUND

Q. WHAT IS REACTIVE POWER?

A. In alternating current ("AC") power systems, the production of electric power includes both real power and reactive power. Whereas real power provides the electricity needed to produce active work, reactive power provides the necessary voltage support to supply real power to the grid.[3] In short, reactive power is essential to provide reliable, stable electric power to the end-use customer and plays a critical role in mitigating system emergencies.[4]

Q. HOW ARE RESOURCES COMPENSATED FOR THEIR INVESTMENTS IN REACTIVE CAPACITY?

A. Reactive compensation methods differ significantly across markets, with only PJM Interconnection, L.L.C. ("PJM"), Midcontinent Independent System Operator ("MISO"), New York Independent System Operator ("NYISO"), and ISO New England Inc. ("ISO-NE") providing some form of compensation for reactive capacity. Importantly, however, only PJM and MISO provide fixed, cost-based compensation covering a resource's full operational life. NYISO and ISO-NE, on the other hand, provide a single market-wide rate, which is worth a small fraction of the value of the compensation provided in PJM and MISO, covering a single year. No other market provides any compensation for reactive capacity. Although some resources in these regions may be able to request reactive capacity compensation under limited circumstances, the prospect of succeeding in this pursuit is highly uncertain. Therefore, only PJM and MISO provide reactive compensation that is fully compensatory and that can also produce a bankable price signal for resources to invest in reactive capability beyond the minimum requirements for

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[3] "Reactive power is a critical component of operating an alternating current (AC) electricity system, and is required to control system voltage within appropriate ranges for efficient and reliable operation of the transmission system. At times generators or other resources must either supply or consume reactive power for the transmission system to maintain voltage levels required to reliably supply electricity from generation to load…. Ensuring that reactive power is adequate to support transmission service, whether from transmission system elements, generators, load, distribution system elements, energy storage, or an appropriate mix of these, is one of the transmission planning and operations responsibilities of the transmission planner and operator." *Payment for Reactive Power*, Commission Staff Report, at 4, Docket No. AD14-7-000 (issued Apr. 14, 2014).

[4] "[Reactive power] plays a critical role in maintaining power system reliability, as evident from several blackouts—such as the August 14, 2003 Northeast blackout—that was exacerbated by insufficient reactive power resources. In addition, several voltage stability-constrained flowgates around the world force operators to curtail transactions across these interfaces because of [reactive power] problems." Electric Power Research Institute, https://www.epri.com/research/products/3002005830 (abstract to Voltage Control and Reactive Power Management: Reference Guide - Industry Practices and Tools for Voltage/VAR Planning and Management (VVPM)).

interconnecting to the transmission system, which can be critical for mitigating system emergencies that require higher levels of reactive support.

Q. HOW IS REACTIVE POWER COMPENSATED IN PJM AND MISO?

A. In PJM and MISO, resources may seek cost-based compensation for the ability to provide reactive power support by submitting a resource-specific ARR and supporting expert testimony to the Commission. The revenue requirement calculation must follow the Commission's reactive ratemaking standards known as the *AEP Method*, which allows for the recovery of fixed investment costs ("Fixed Capability Component") and variable heating losses costs ("Heating Losses Component")[5] attributable to reactive capability. I note that, because the Heating Losses Component typically represents a small fraction of the total ARR and because few resources file to recover these costs, the remainder of this affidavit will focus solely on the Fixed Capability Component and use the term "ARR" interchangeably with this component.

After receiving a reactive rate submission, the Commission often sets the rate for hearing and settlement procedures. During this process, which can often last several months if not years, FERC Trial Staff, the rate filing entity, and any participating intervenors in the case will first attempt to validate the reasonableness of the filed rate and negotiate a mutually agreeable settlement outcome. To the extent that the parties are unable to reach an agreement, the rate would be litigated before a FERC Administrative Law Judge. Once determined through settlement or the hearing process, the rate will remain in effect without modification for the operational life of the asset, pending changes in ownership, asset retirements, or other rate review triggers.

Reactive compensation in PJM and MISO is analogous to an option payment, through which the RTO pays resources a fixed monthly sum in exchange for the "option" – or right – to ensure that these resources have the capability necessary to provide reactive power support. This capability allows PJM to mitigate system emergencies and also provides incentives for market participants to build and operate power plants with robust reactive capability needed to stabilize voltage levels across the power grid.

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[5] *Dynegy Midwest Generation, Inc.*, Opinion No. 498, 121 FERC ¶ 61,025, at PP 68-73 (2007) ("*Dynegy*"); *order denying reh'g in part and granting reh'g in part*, 125 FERC ¶ 61,280 (2008) ("*Dynegy II*"); *see also Chehalis Power Generating, L.P.*, 123 FERC ¶ 61,038 (2008) ("*Chehalis*"); *Wabash Valley Power Association, Inc.*, 154 FERC ¶ 61,245 (2016) ("*Wabash*").

Q. HOW HAS REACTIVE COMPENSATION IN PJM CHANGED OVER TIME?

A. Reactive compensation in PJM has been based on the *AEP Method* and remained largely unchallenged and unchanged since its inception in 1999, with the Commission having provided additional guidance in two cases.

First, in *Dynegy*, the Commission clarified several reactive ratemaking issues including but not limited to (1) how to treat general and administrative ("G&A") expenses; (2) how the Balance of Plant Allocation Factor ("BPAF") should be developed for a fleet of generators; and (3) affirming the reasonableness of recovering costs associated with variable heating losses.

Second, in a recent case,[6] the Commission clarified several additional reactive ratemaking issues including but not limited to specifying that (1) cost support should reflect information readily available to rate filers; (2) indirect costs should be allocated to all direct cost groups including Balance of Plant; (3) reactive rates should be based on nameplate capability ratings; (4) the Accessory Electric Equipment Allocation Factor numerator and denominator should reflect consistent measurements; (5) firm fuel transportation costs should be excluded from the fixed operation and maintenance cost component of the fixed charge rate; and (6) the interconnected utility's weighted average cost of capital reflects a more reasonable proxy return than PJM's Net Cost of New Entry ("CONE") assumption.

I note that all explanations and proposed recommendations outlined below are consistent with the *AEP Method* as originally developed and as updated through *Dynegy* and *Panda*, as well as other relevant Commission orders.

Q. WHAT ISSUES DID THE COMMISSION RAISE IN THE REACTIVE NOI?

A. In the Reactive NOI, the Commission raised several questions about the *AEP Method*, ranging from how to account for differences between synchronous and asynchronous resources to whether alternative ratemaking methods should be considered. The following sections of this affidavit address the Commission's questions and explains why the *AEP Method* should be maintained but updated to strengthen the consistency with which it is applied, efficiency through which rates can be verified, and accountability of rate filers to ratepayers and system reliability.

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[6] *Panda Stonewall LLC*, Opinion No. 574, 174 FERC ¶ 61,266 (2021) ("*Panda*").

IV. THE AEP METHOD SHOULD BE MAINTAINED FOR ALL RESOURCE TYPES

Q. IS THE AEP METHOD A REASONABLE APPROACH FOR CALCULATING AN ANNUAL REVENUE REQUIREMENT ATTRIBUTABLE TO REACTIVE CAPABILITY FOR ALL RESOURCE TYPES?

A. Yes. The *AEP Method* is a proven, durable mechanism for developing just and reasonable reactive revenue requirements for many different types of resources with varying investment and operating costs and operating resources with varying operating characteristics. Although the *AEP Method* was originally applied to synchronous resources, it has more recently been successfully used for wind and solar resources. Additionally, as discussed in greater detail below, the differences between synchronous and asynchronous resources with respect to reactive power are decreasing with changes in technology.

Asynchronous resources like wind farms and solar photovoltaic facilities are increasingly designed to provide additional reactive power support even without wind or sunshine. For example, solar resources can use advanced reactive power capabilities such as the "Q at Night" function[7] to pull real power from the grid when there is no sunlight (e.g., at night or during cloudy days), convert this power into reactive power using the resource's inverters, and then send this reactive power back to the grid. Similarly, wind resources can use advanced reactive power capabilities such as the "WindFREE" function[8] to pull real power from the grid when there is no wind, convert this power into reactive power using the resource's converters, and then send this reactive power back to the grid. For each of these reasons as well as those addressed below, the *AEP Method* remains the appropriate mechanism to determine just and reasonable reactive revenue requirements for all technology types and to incentivize efficient investment in technologies that will provide necessary reliability services in the future.

Q. CAN THE AEP METHOD BE APPLIED CONSISTENTLY TO ALL RESOURCE TYPES?

A. Yes. Calculating the ARR under the *AEP Method* is the same for all resources regardless of generation technology. This is evident in comparing how the *AEP Method* treats the various categories of costs that are included in the ARR:

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[7] See SMA Solar Technology AG Q at Night Function, accessed at https://www.sma-america.com/partners/knowledgebase/q-at-night.html.

[8] See GE Energy Presentation on Voltage and Reactive Power Control, accessed at https://www.bpa.gov/doing%20business/technologyinnovation/conferencesvoltagecontroltechnical/voltageandreactivepowercontrolge.pdf.

1. Turbogenerators (FERC Accounts 314, 323, 333, 344);
2. Generator Step-Up Transformers (FERC Account 353);
3. Accessory Electric Equipment (FERC Accounts 315, 324, 334, 345);
4. Balance of Plant (FERC Accounts 310-346); and
5. Construction Overhead (Allocated Proportionately to Direct Costs[9]).

The turbogenerator category includes plant costs relating to turbine-driven units used in generating electricity.[10] Under the *AEP Method*, turbogenerator costs must be allocated to isolate the share of the equipment that is responsible for providing reactive power support. The allocation factor used in this step is known as the Generator-Exciter Allocation Factor ("GEAF"). Developing the GEAF is typically necessary because the reactive-related subcomponents of the turbogenerator are seldom priced as standalone pieces of equipment. Instead, an OEM typically prices the entire turbogenerator unit without separately identifying the costs associated with each subcomponent like the generator and exciter. As a result, reactive rate filings often rely on written verification from the OEM to determine the estimated cost-share attributable to the reactive-related turbogenerator subcomponents. While the name "GEAF" suggests this allocation factor relates solely to the generator and exciter, the GEAF can and should include any additional reactive-related equipment that comprises the turbine. For example, whereas natural gas-powered turbines rely on generators and *exciters* to provide reactive power support, wind-powered turbines typically rely on generators and *converters*. Although the subcomponents may differ by resource technology, the development and application of the GEAF remains the same for all turbine-driven resources and does not require any modification to the *AEP Method*.

The Step-Up Transformer category includes plant costs relating to transforming, conversion, and switching equipment used to change the characteristics of electricity in connection with its transmission or controlling transmission circuits[11] specifically associated with the step-up transformers.[12] Because all power plants require step-up transformers to connect to the transmission system, there is no

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[9] "…overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired." 18 C.F.R. § 101 (2021).

[10] 18 C.F.R. § 101 (2021).

[11] 18 C.F.R. § 101 (2021).

[12] *Chehalis*, 123 FERC¶ 61,038, at P 63.

difference in how synchronous and asynchronous resources account for these costs under the *AEP Method*.

The Accessory Electric Equipment ("AEE") category includes plant costs relating to auxiliary generation and conversion equipment used primarily in connection with the control and switching of electric energy other than equipment used for transmission or distribution.[13] Under the *AEP Method*, only the portion of the AEE "that supports the operation of the generator-exciter" is recoverable through the ARR.[14] While the *AEP Method* initially relied on "engineering knowledge"[15] to isolate these costs, more recent cases have relied on an Accessory Electric Equipment Allocation Factor ("AEAF"), which reflects the ratio of the maximum "electricity consumed by the components of the generator responsible for reactive power production" to the whole "auxiliary load of the entire plant."[16] The Commission has found it reasonable for synchronous resources to calculate the AEAF by dividing their generator-*exciter* auxiliary load to their entire plant auxiliary load.[17] While asynchronous resources do not use generator-exciters, they do use generator-*converters* or *inverters*, which accomplish the same objective. As such, asynchronous resources can calculate the AEAF in a consistent manner with synchronous resources without requiring any change to the *AEP Method*. This shows that the only difference between synchronous and asynchronous resources in calculating the AEAF is which equipment to include in the numerator.

The Balance of Plant ("BOP") category includes all remaining direct plant costs (e.g., land, roads, etc.).[18] Because these costs are not responsible for generating or transmitting reactive power but are still necessary for the ability to provide reactive support (e.g., land, which does not produce reactive power but is necessary to build and operate the reactive equipment), the *AEP Method* includes a significantly smaller share of these costs in the ARR. Under the *AEP Method*, BOP costs are allocated using the Balance of Plant Allocation Factor ("BPAF"), which equals the product of two ratios.[19] The first ratio equals the "exciter rating," which

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[13] 18 C.F.R. § 101 (2021).

[14] Pasternack Testimony, Exhibit A-29 at 12, Docket No. ER93-540-000 (filed Nov. 15, 1993) ("Pasternack Testimony").

[15] Pasternack Testimony, Exhibit A-29 at 18.

[16] *Panda Stonewall LLC*, 167 FERC ¶ 63,010, at P 251 (2019).

[17] *Dynegy*, 121 FERC ¶ 61,025, at P 4.

[18] 18 C.F.R. § 101 (2021).

[19] "The remaining production plant investment is allocated to reactive power service using the allocator called the remaining power plant investment allocator (RPPIA) or Balance of Plant (BOP) allocator, which is the product of two ratios. The first ratio is Exciter MW/Generator MW. The second ratio is the maximum MVars/nameplate MVars." *See Dynegy*, 121 FERC ¶ 61,025, at P 4.

is the same numerator from the AEAF, as discussed above,[20] to the total plant real power capability. The second ratio equals the maximum historical reactive output to the nameplate reactive capability rating. Because each of these inputs is applicable to all resource types, synchronous and asynchronous resources can develop all BOP calculations in a consistent manner without requiring any modification to the *AEP Method*.

Q. HAVE RATE FILERS THAT DO NOT USE THE UNIFORM SYSTEM OF ACCOUNTS BEEN ABLE TO PROVIDE SUPPORT FOR THEIR COSTS?

Although many reactive power rate filers do not use FERC's Uniform System of Accounts, this does not mean that they have not been able to adequately support their reactive power costs. Common forms of supporting documentation available to exempted rate filers include equipment purchase orders, change orders, transaction term sheets, and independent appraisals. Each of these forms of support can provide third party validation of filed cost totals with a high degree of certainty that the costs have already been incurred or will be in the near future. I note that new projects that have yet to finalize construction can also have a high degree of certainty with respect to the costs that will be incurred due to the nature of engineering, procurement, and construction ("EPC") contracts, which are typically priced on a fixed basis that locks in a minimum cost to the project. Although the final price of these types of contracts may be higher than the initial contracted value due to unforeseen circumstances such as construction delays and system design changes, among others, it is highly improbable – if not explicitly prohibited under the terms of EPC contracts – that the final costs will be lower than the initial contracted value. This means that reactive rate filings for new projects are more likely to understate their full plant investment costs, resulting in a lower ARR, all else being equal, than rate filings from existing projects, which already have full knowledge of their total plant investment costs. Therefore, it would be reasonable to continue allowing new resources that have yet to finalize construction but that can support their filed costs and system design the opportunity to file reactive rate requests with the Commission on comparable terms with existing resources.

Q. DO ALTERNATIVE METHODS PROVIDE A SUFFICIENT LONG-TERM PRICE SIGNAL TO INVEST IN IMPROVED REACTIVE CAPABILITY WITH ADEQUATE CERTAINTY OF COST RECOVERY?

A. No. As of the date of these comments, only PJM and MISO allow for full reactive capability cost recovery. All other markets either fail to provide any cost recovery or provide significantly lower levels of cost recovery. For example, whereas cost-

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[20] *See Dynegy*, 121 FERC ¶ 61,025, at P 4.

based reactive capacity compensation rates based on the *AEP Method* in PJM and MISO average approximately \$0.56/kVAr-month[21], the flat, market-wide capacity compensation rates in ISO-NE and NYISO equate to just \$0.09/kVAr-month[22] and \$0.25/kVAr-month,[23] respectively.

This disparity demonstrates that comparable resources across these markets achieve drastically different levels of cost recovery, with only PJM and MISO allowing for the possibility of full cost recovery. Because of this disparity, flat, market-wide rates fail to provide the long-term certainty of full cost recovery or a sufficient price signal needed to incentivize additional investments in improved reactive capability. Only the *AEP Method* provides a bankable price signal for resources to improve their reactive capabilities.

Q. DOES REACTIVE POWER CAPABILITY COMPENSATION UNDER THE AEP METHOD RESULT IN DOUBLE RECOVERY?

A. No. Reactive power capability compensation under the *AEP Method* does not result in double recovery because (1) capacity revenues compensate for real power capability – not reactive power capability; (2) the \$2,199/MW-year proxy assumption is unrepresentative of most resources; (3) including reactive revenues in PJM's Net Avoidable Cost Rate ("ACR") calculation can increase the need for additional revenues; and (4) reactive rate settlements already include explicit prohibitions against double recovery.

First, the capacity market compensates resources for *real* power capability – not *reactive* power capability. Resources that clear PJM's capacity market receive capacity revenues in exchange for the right of PJM to call on these resources to provide additional real power support to the grid if needed. While most generators are required to invest in a minimum level of reactive capability to interconnect to the transmission system, certain resources that participate in the capacity market do not have reactive power capability (e.g., demand response). Additionally, the capacity market does not provide a direct incentive or cost recovery mechanism for improvements to reactive power capacity. As a result, capacity revenues are not tied to reactive capability, meaning generators that clear the capacity market may still be unable to recover their costs of investing in their minimum required reactive capability – let alone their full reactive capability.

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[21] See the settled ARR summary table located in the Appendix.

[22] ISO-NE, 2022 VAR Capacity Cost Rate, accessed at https://www.iso-ne.com/static-assets/documents/2021/12/ww_var_cc_rate_iso_2022010100_20211217184006.csv.

[23] NYISO, Open Access Transmission Tariff, Schedule 2, accessed at https://www.nyiso.com/documents/20142/27226617/2022-OATT-MST-Schedule-2-VSS-Rates-Final.pdf/68d6132e-ca0c-9407-ad53-c754abb7a06a.

Therefore, capacity revenues do not compensate for or provide an adequate price signal to invest in improved reactive capability.

Second, the $2,199/MW-year value reflects the assumed reactive revenues corresponding to a proxy new combustion turbine asset. Actual combustion turbine assets and resources using other technology types will have different costs and capabilities, meaning the $2,199/MW-year proxy will reflect lower or higher revenues than those that will actually be realized by most resources. As shown in the appendix of this testimony, recently settled ARRs average $3,450/MW-year and vary widely by resource.

Third, PJM's rules prevent double recovery through the Net Avoidable Cost Rate ("ACR") calculations. As indicated by the name, the ACR only reflects *avoidable* costs, and does not consider fixed costs. The first step in calculating the Net ACR is to identify the Gross ACR, which equals the resource's annual gross operations and maintenance expenses, avoidable project investment costs, and a risk premium for Capacity Performance penalties. Importantly, this means that the Gross ACR framework excludes all fixed plant investment costs, whether applicable to real or reactive power. The next step in calculating the Net ACR is to subtract all projected energy and ancillary service revenues ("E&AS"), *including reactive power compensation,* from the Gross ACR. While this calculation can help improve the competitiveness of supply offers in PJM's capacity market auctions, it can also put downward pressure on clearing prices, meaning the more reactive revenues that are included in capacity offers, the lower capacity revenues will be, all else being equal. Because investors and lenders base their decision to fund the development of new power plants, in part, on the expected revenues earned in the capacity and ancillary services markets, decreasing capacity revenues through the Net ACR framework means that separate, fixed reactive revenues become even more critical to ensuring that these projects can reach their minimum rates of return and debt service obligations.

Fourth, most if not all reactive rate settlements contain explicit provisions prohibiting any double recovery resulting from reactive compensation. While not necessary because of the factors described above, such stipulations provide additional comfort that there will not be double recovery.

V. PROPOSED CHANGES

Q. ARE CHANGES TO THE AEP METHOD AND ASSOCIATED PROCEDURES NECESSARY?

A. While the *AEP Method* continues to produce just and reasonable rates, minor clarifications and changes can be made to help support the Commission's efforts to streamline the administrative review process and provide greater transparency into supplier compensation and ratepayer costs. These essential objectives are easily achievable through the following enhancements without significant changes to the overall ratemaking approach.

Q. SHOULD RATE FILERS BE PERMITTED THE OPTION TO USE A STANDARDIZED AEP METHOD ARR TEMPLATE TO CALCULATE THE REACTIVE REVENUE REQUIREMENT?

A. Yes. Providing rate filers with the option to use a standardized *AEP Method* ARR template would reduce unnecessary effort expended in evaluating whether filed rates are consistent with the *AEP Method*. For example, if rate filers were to use either the standardized *AEP Method* template or provide a comparable rate calculation that is consistent with the Commission's approved AEP Method inputs, allocations, and calculations, there would be no need to set the rate filing for hearing and settlement procedures because all information could be immediately validated upon an initial review as either being consistent or inconsistent with the standardized protocols. Please refer to the appendix of this testimony for an example listing of the types of inputs and supporting documentation which could be included in a standardized template.

I note that the Commission's prior efforts to standardize review and approval of requests for Market Based Rate Authority ("MBR") provide an excellent example of the efficiency that this type of standardized approach would provide. The Commission has provided clear guidance on the methodology, specific inputs, and standard of review to be applied to MBR requests, providing little ambiguity about the expectations for filers. It also reduces the administrative burden on Commission staff when auditing MBR requests and supporting analyses.

Q. SHOULD RATE FILERS BE PERMITTED TO VERIFY THEIR REACTIVE CAPABILITY USING A SWORN STATEMENT FROM AN INDEPENDENT ENGINEER?

A. Yes. Given that transmission system constraints often limit the ability of generation resources to demonstrate their full reactive capability, the Commission should replace the requirement to provide reactive capability test results, which are conducted pursuant to North American Electric Reliability Council ("NERC") protocols,[24] with a letter from a certified independent engineer confirming that the resource can provide reactive power support consistent with its filed maximum lagging reactive capability. This change is necessary because reactive capability test results are one of the most contested issues during settlement negotiations precisely because the NERC test results can create a false perception that the tested unit has degraded or is otherwise unable to perform to its design specifications.

I note that reactive capability tests conducted pursuant to NERC protocols are primarily used to validate a resource's *minimum* required reactive capability, as specified in its interconnection agreement, rather than the *maximum* potential reactive capability, as filed through reactive rates under the *AEP Method*. Moreover, NERC reactive capability testing seldom allows for a full demonstration of a resource's reactive potential because system voltage conditions during testing windows are usually too high to allow resources to safely generate their maximum potential reactive output. Instead, resources are usually forced to back down their reactive output to prevent damaging their equipment as they experience increasing transmission system voltage constraints. This is to be expected, however, because lower voltage conditions may indicate a system emergency.

Therefore, it is reasonable to provide an alternative means for the Commission to verify the resource's reactive power-producing capability through an independent engineer certification. The statement should confirm that the resource (1) can provide reactive power support to the transmission system; (2) is dispatchable by direction of the transmission provider; and (3) can provide reactive power support consistent with the resource's filed maximum lagging reactive capability.[25]

In light of the concerns raised in the Reactive NOI regarding degradation, it would be reasonable to require that this information be provided not only upon the initial rate filing, but also once every five years thereafter to validate each resource's reactive capability throughout its operational life consistent with the timing for the NERC tests. Doing so could improve accountability by providing third-party confirmation and a more accurate assessment of a resource's full reactive capability over time without creating a burdensome administrative requirement for both rate filers and Commission staff.

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[24] See NERC MOD-025 and MOD-026, accessed at https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf.

[25] To maintain consistency with current Commission precedent, it would be reasonable to continue measuring reactive capability at the high-side of the substation and ensure that this applies uniformly to both synchronous and asynchronous resources. See *Reactive Power Requirements for Non-Synchronous Generation*, Opinion No. 827, 155 FERC ¶ 61,277, at 1 (2016).

Q. SHOULD TURBINE-DRIVEN RESOURCES BE PERMITTED TO RELY ON OEM SUPPORT FOR ALL REACTIVE-RELATED EQUIPMENT COSTS THAT ARE INCLUDED WITHIN THE TURBOGENERATOR UNIT?

A. Yes. As stated previously, under the *AEP Method*, only the portion of the turbogenerator that is "directly related to the production of VArs" can be included in the ARR.[26] Whereas turbine-driven synchronous resources typically rely on generators and exciters to produce reactive power, turbine-driven asynchronous resources rely on generators and converters to produce reactive power. Regardless of this difference in equipment, however, the process for isolating the portion of the reactive equipment costs remains the same for synchronous and asynchronous resources. Therefore, the Commission could significantly enhance the efficiency of the ratemaking review process by confirming that reliance on OEM cost support is consistent with the *AEP Method* and is a reasonable approach for synchronous and asynchronous resources to justify this portion of the ARR.

Q. SHOULD RATE FILERS BE PERMITTED TO CALCULATE THE NUMERATOR OF THE ACCESSORY ELECTRIC EQUIPMENT ALLOCATOR USING THE ELECTRICITY CONSUMED BY ALL EQUIPMENT RESPONSIBLE FOR REACTIVE POWER PRODUCTION?

A. Yes. As stated previously, under the *AEP Method*, only the portion of the AEE "that supports the operation of the generator-exciter" is recoverable through the ARR.[27] Because asynchronous resource rely on generators and converters or inverters to provide the same function as synchronous generators and exciters, the Commission could substantially improve its administrative processes by expressly affirming that the AEAF numerator should reflect the electricity consumed by *all* equipment responsible for reactive power production rather than just the exciter to recognize these resource-specific differences without significant changes to the *AEP Method*.

Q. SHOULD PLANNED RESOURCES BE PERMITTED TO USE PROXY ALLOCATION FACTORS AND DATA?

A. Yes. Although there is no difference between synchronous and asynchronous resources in calculating the ARR under the *AEP Method*, there is a slight difference between existing and new resources that necessitates clarification from the Commission on the appropriateness of using proxy data when actual data is unavailable. For example, whereas existing resources have historical operating data which can be used to derive the historical peak reactive output component

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[26] Pasternack Testimony, Exhibit A-29 at 12.

[27] Pasternack Testimony, Exhibit A-29 at 12.

used in the Balance of Plant Allocation Factor ("BPAF"), new resources may not have comparable data if they have not yet reached commercial operations or have limited operational history. This discrepancy requires the use of proxy data for the historical maximum reactive output component of the BPAF. As such, it would be reasonable to allow new resources to use a resource-specific assumption for the expected maximum reactive output for their particular resource or a default proxy assumption applicable to all resources.

Similarly, it would also be reasonable to allow rate filers without operational data to use proxy assumptions for the following inputs:

- Operations and Maintenance Expenses;
- General and Administrative Expenses;
- Fuel Expenses;[28] and
- Generation Output.[29]

Q. SHOULD RATE FILERS BE PERMITTED TO RECOVER INVESTMENT COSTS ASSOCIATED WITH COLLECTOR SYSTEMS?

A. Yes. This issue is yet another example where the *AEP Method* is well equipped to correctly allocate costs where synchronous and asynchronous resources use different equipment to achieve the same result. Synchronous resources rely on an isolated phase bus to move power from the turbogenerators to the step-up transformers. Asynchronous resources, on the other hand, rely on a collector system to transfer power from the generators or inverters to the step-up transformers, depending on the resource type. However, unlike the isolated phase bus, which is used *primarily* to support the generator and exciter,[30] the collector system is used *entirely* to support the generator and converter or inverter. Therefore, collector systems are not only comparable to isolated phase bus ducts but can also be incorporated into the ARR under the *AEP Method* in a much more efficient fashion because it is entirely related to the generator-exciter function.[31]

Q. SHOULD RATE FILERS BE PERMITTED TO RECOVER ALL FERC ACCOUNT 353 COSTS THAT ARE USED TO SUPPORT REACTIVE POWER PRODUCTION?

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[28] This component is only necessary for resources that have chosen to file for cost recovery of variable heating losses.

[29] *Id.*

[30] Pasternack Testimony, Exhibit A-38 at 1.

[31] AEE costs fall under FERC Accounts 315, 324, 334, 345, which cover "the cost installed of auxiliary generating apparatus, conversion equipment, and equipment used primarily in connection with the control and switching of electric energy produced…."

A. Yes. Consistent with long-standing precedent, the Commission should affirm that all FERC Account 353 costs[32] that are used to support reactive power production and are not included in a regulated utility's system rates can be recovered through reactive rates under the *AEP Method*. I note that FERC Account 353 covers transmission-related costs such as step-up transformers, substation equipment, and switchyard equipment, among others. However, as of the date of this testimony, only step-up transformer-related costs are recoverable under the *AEP Method* even though other FERC Account 353 costs are necessary for reactive power service.

In the period since the *AEP Method* was initially approved, the Commission has found that to be includable in an ARR for reactive power, "costs must be related specifically to reactive power service, at least by some logical allocation, as with the reactive power capability component of production plant."[33] GSU transformer and related costs are currently includable in the reactive revenue requirement because they "provide a function in support of generation" and reactive power "cannot be provided without reliance upon GSUs."[34]

Although the Commission has previously ruled against including non-GSU-related FERC Account 353 costs such as substation and switchyard equipment, the Commission's rationale was that rate filers had not provided sufficient support for doing so. In *Chehalis*, the Commission affirmed the Initial Decision to exclude transmission-related costs other than those related to the GSU because (1) such costs were not originally included *AEP*; and (2) they did not "see" a rationale for including such costs:

> We affirm the Presiding Judge's finding that the BPA 500 kV switchyard is not properly included in Total Production Plant and Accessory Electric Equipment. As the Presiding Judge explains, and we agree, **the switchyard is a transmission facility whose costs are not included in any of the plant production of accessory equipment accounts that were addressed in AEP**. Significantly, Chehalis does not take exception to this finding. Rather, as Staff points out, Chehalis argues that the costs should be included because, without the switchyard, no reactive power would enter the transmission system. This argument, however, cannot sustain Chehalis's position. Chehalis provides no precedent to support its position, and, moreover,

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[32] FERC Account 353 includes plant costs relating to transforming, conversion, and switching equipment used to change the characteristics of electricity in connection with its transmission or controlling transmission circuits. See 18 C.F.R. § 101 (2021).

[33] *Chehalis*, 118 FERC ¶ 63,009 at P 78.

[34] *Kentucky Utilities Co.*, Opinion No. 432, 85 FERC ¶ 61,274 at 24 (1998) ("Opinion No. 432").

> following Chehalis's logic would result in all transmission facilities being allocated to reactive power production because, without them, no reactive power would enter the transmission system. In addition, **the fact that Chehalis cannot recover the transmission costs of the switchyard because it is an IPP without an OATT, is no reason to shift these costs to Total Production Plant and Accessory Electric Equipment. Chehalis has simply provided no rationale for such a shift and we fail to see one**.[35]

Therefore, and by the Commission's own logic, it should be possible to include transmission-related costs when supported by precedent or a rationale for deviating from the original AEP cost assignments. Opinion Nos. 440 and 432 provide this support. Opinion No. 440 established the *AEP Method* and specified that transmission-related costs like the GSU could be included in reactive rates:

> In the past, the Commission assigned a utility's entire cost of GSU transformers as transmission-related and allowed the utility to recover these costs through its rolled-in transmission rate. However, in KU we decided to reverse our policy in light of the Commission's unbundling of transmission and wholesale generation services in Order No. 888. As we stated in KU, given our actions in Order No. 888, we believe it is appropriate to reexamine our policy on the functionalization and the recovery of costs associated with GSUs to ensure that unbundled services customers are paying only their appropriate share of the cost of services which they use.
>
> Our reexamination of GSU costs in KU persuaded us that **the costs of a GSU transformer should be directly assigned to its related generating unit, not rolled into transmission rates**. Those same findings are applicable here. We therefore reverse the Initial Decision to reflect our revised policy on the recovery of GSU costs, as more fully articulated in KU.[36]

To understand the Commission's rationale for this determination, it is necessary to examine the arguments presented in *KU* (i.e., Opinion No. 432). In Opinion No. 432, the Commission explained that transmission-related costs like those pertaining to the GSU can be included in reactive rates because they (1) support generation; (2) are necessary for the provision of ancillary services including reactive power; and (3) are not part of a utility's integrated transmission system:

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[35] *Chehalis*, 123 FERC ¶ 61,038, at P 63 (footnote omitted, emphasis added).

[36] *AEP*, 88 FERC ¶ 61,141 at 23 (citing Opinion No. 432) (footnotes omitted, emphasis added).

> Our reexamination of GSU costs in this case persuades us that the costs of a GSU transformer should be directly assigned to its related generating unit, not rolled into transmission rates…[T]his result is appropriate because, given the unbundling of generation and transmission, GSUs serve two functions. First, **GSUs provide a function in support of generation**…. As a result of the unbundling of services offered by utilities in the aftermath of Order No. 888, it has become increasingly important to recognize the role that GSUs perform in support of generation as it pertains to the allocation of costs. In addition, GSUs also perform an important function in the provision of a new category of services we identified in Order No. 888, ancillary services (e.g., Operating Reserve, Regulation and Frequency Response Service, Reactive Supply and Voltage Control). **Ancillary services supplied from generation resources cannot be provided without reliance upon GSUs**, regardless of where power is coming from or going to…We are thus reversing our earlier policy of allowing these costs to be included in the transmission provider's transmission rate base because such a treatment ignores the role these facilities perform in supporting generation and ancillary services. Instead, we find that a more accurate method of cost recovery is to directly assign the costs of each GSU transformer to the generator to which it is connected…This approach also satisfies our comparability requirement because, for example, an independent power producer that wanted service under KU's open access tariff would have the cost of a KU-constructed GSU directly assigned to their generator. We believe that direct assignment of GSU costs is also consistent with our established practice of directly assigning interconnection costs. **GSUs are not part of a utility's integrated transmission grid and should not be charged to transmission-only customers** (except for ancillary services). Instead, GSU costs are incurred because of the installation of a generating unit and should be assigned directly to that unit, so that customers taking service from that unit pay the appropriate costs.[37]

Although Opinion No. 432 addressed the inclusion of GSU-related costs rather than other transmission-related costs, the logic presented by the Commission in this Opinion should be applied to all FERC Account 353 costs for the purposes of reactive ratemaking under the *AEP Method* because these (1) support generation; (2) are necessary for the provision of ancillary services including reactive power; and (3) are not part of a utility's integrated transmission system.

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[37] Opinion No. 432, 85 FERC ¶ 61,274 at 24 (footnotes omitted, emphasis added).

Q. WHAT ISSUES SHOULD BE SET FOR HEARING AND SETTLEMENT PROCEDURES?

A. As stated previously, the Commission should ease the rate filing process by establishing a standardized template that rate filers may (but are not obligated to) use. To expedite the rate review process, the Commission should not set for hearing or settlement any components of reactive rate filings that are consistent with that standardized template. This contrasts with the current practice of setting all issues from all reactive rate filings for hearing and settlement procedures. By allowing uncontested issues to be resolved without requiring protracted rate reviews and settlement negotiations, this change could significantly improve the efficiency with which reactive rates can be validated and free up Commission Trial Staff to pursue contested regulatory proceedings.

Q. ARE THERE ANY OTHER RECOMMENDED CHANGES THAT WOULD BE REASONABLE FOR THE COMMISSION TO CONSIDER?

A. In the event the Commission elects to modify the *AEP Method* or replace it with an alternative method, it would be reasonable to "grandfather" all existing settled and filed reactive rates. This approach would be consistent with historical Commission precedent and ensure minimal disruption to market participants that have constructed or planned for the development of power generation projects designed to provide reactive power support consistent with the *AEP Method*.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

VI. APPENDIX

AEP Method ARR Benchmarks

The following table summarizes recent *AEP Method*-based reactive rates in PJM[38] and MISO[39] since 2020:

Settled AEP Method ARR Benchmarks (2020-2021)							
Project	**Docket**	**Settled $/YR**	**Filed MW**	**Filed PF**	**Est. MVAr at Filed PF**	**Settled $/MW-yr**	**Settled $/kVAr-mo**
Algonquin Energy Services (Sandy Ridge WF)	ER21-1501	180,000	50	0.95	16	3,600	0.91
Algonquin Energy Services, Inc (Great Bay Solar II)	ER20-2108	272,501	44	0.87	24	6,236	0.93
Bitter Ridge Wind Farm, LLC	ER20-2446	597,297	146	0.87	83	4,091	0.60
ConEdison Energy, Inc (Hazelton)	ER20-1210	497,334	232	0.80	174	2,144	0.24
ConEdison Energy, Inc (PA Solar Park II)	ER21-673	55,000	10	0.80	8	5,500	0.61
CPV Fairview, LLC	ER20-287	3,450,000	1,197	0.85	742	2,882	0.39
Crystal Lake Wind Energy I, LLC	ER20-1662	512,418	162	0.90	78	3,163	0.54
Crystal Lake Wind III LLC	ER20-2222	208,763	66	0.90	32	3,163	0.54
Eastern Shore Solar, LLC (Oak Hall)	ER20-707	400,000	80	0.92	35	5,000	0.95
Galt Power, Inc (Ringer Hill Wind)	ER20-2719	155,000	40	0.90	19	3,885	0.67
Garden Wind LLC	ER20-1062	559,000	160	0.90	77	3,494	0.60
Hickory Run Energy, LLC	ER20-490	3,030,000	1,034	0.85	641	2,932	0.39
Hill Top Energy Center, LLC (Greene County)	ER21-1807	2,700,000	646	0.80	485	4,180	0.46
Illinois Municipal Electric Agency (Green River)	ER20-860	182,754	194	0.90	94	941	0.16
Lexington Chenoa Wind Farm, LLC	ER20-2148	550,000	205	0.90	99	2,680	0.46
Lone Tree Wind, LLC	ER20-2953	383,000	89	0.87	50	4,319	0.64
Meadow Lake Wind Farm VI, LLC	ER20-80	570,000	200	0.90	95	2,844	0.50
NedPower Mount Storm, LLC (Greenland Gap)	ER20-2471	737,500	264	0.95	87	2,794	0.71
NextEra Energy Marketing, LLC (Doswell CT)	ER20-263	725,000	199	0.85	124	3,636	0.49
NextEra Energy Marketing, LLC (Lee Dekalb)	ER20-282	671,379	218	0.90	105	3,087	0.53
Paulding Wind Farm IV, LLC	ER20-2503	450,000	126	0.90	60	3,571	0.63
Story County Wind, LLC	ER20-1906	670,000	162	0.90	78	4,136	0.71
Tenaska Power Services Co. (Cordova)	ER20-1455	850,000	611	0.85	379	1,391	0.19
Tenaska Power Services Co. (Westmoreland CC)	ER20-17	2,400,000	1,133	0.85	702	2,118	0.28
Walnut Ridge Wind, LLC	ER20-1936	944,500	212	0.90	103	4,455	0.77
Average						**3,450**	**0.56**

[38] PJM Reactive Supply & Voltage Control Revenue Requirements, January 2022, accessed at https://www.pjm.com/-/media/markets-ops/settlements/reactive-revenue-requirements-table-january-2022.ashx.

[39] MISO, Schedule 2, Reactive Supply and Voltage Control from Generation and Other Sources Service Qualified Generators and Revenue Requirements / Stated Rates, August 2021, accessed at https://cdn.misoenergy.org/Sch.%202%20Qualified%20Generator%20Listing478039.pdf.

Standardized AEP Method Template: Example Components

The following list summarizes example inputs and supporting documentation which can be used in a standardized *AEP Method* ARR template:

1. Project Description
    a. Project Company Name
    b. Facility Name
    c. Technology, Configuration, & OEM Models
    d. Installed Capacity
    e. Resource Location
    f. Commercial Operation Date
    g. Independent System Operator
    h. Interconnection Queue Position
    i. Interconnection Service Agreement FERC Docket
    j. Interconnected Transmission Owner

2. Project Documentation
    a. Interconnection Service Agreement
    b. Market-Based Rate Authority
    c. One-Line Diagrams
    d. Ownership Structure Chart
    e. Useful Life Verification
    f. Project Owner Certification[40]

3. Capability Documentation
    a. Major Equipment Nameplate Photos (as Applicable)
    b. OEM Capability Specification Sheets (as Applicable)
    c. Auxiliary Load Totals and Support
    d. Independent Engineer's Certification of Maximum Reactive Capability
    e. Historical Hourly Real and Reactive Power Output (Existing Resources Only)

4. Cost Documentation
    a. Itemized Capital Costs Supported with Purchase Orders, Term Sheets, Third Party Valuation Reports, and/or Federal Filings

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[40] For example, this could include a notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the resource-specific exception request and that to the best of his/her knowledge and belief: (1) the information used to support its request for an exception is true and correct; (2) the rate filer has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception. Example language based on PJM officer certification for Resource-Specific Exception Process, accessed at https://www.pjm.com/~/media/documents/manuals/m18.ashx.

- b. Itemized Fixed O&M Costs Supported with Purchase Orders, Term Sheets, Third Party Valuation Reports, and/or Federal Filings
- c. Itemized Variable O&M Costs Supported with Purchase Orders, Term Sheets, Third Party Valuation Reports, and/or Federal Filings
- d. Itemized G&A Costs Supported with Purchase Orders, Term Sheets, Third Party Valuation Reports, and/or Federal Filings
- e. Itemized Fuel Costs Supported with Purchase Orders, Term Sheets, Third Party Valuation Reports, and/or Federal Filings
- f. Tax Liability and Applicable Tax Rates for Project Income by Upstream Owner
- g. Verification Of Reactive Cost Share of Turbine Costs (Thermal and Wind Resources Only)

5. Cost Assignments
   - a. Direct Costs
     - i. Generation Equipment
       - 1. FERC Accounts 314, 323, 333, 344
         - a. e.g., turbines, generators, exciters
     - ii. Transmission Equipment
       - 1. FERC Account 353
         - a. e.g., step-up transformers, substations, switchyards
     - iii. Accessory Electric Equipment
       - 1. FERC Accounts 315, 324, 334, 345
         - a. e.g., isolated phase bus, collector systems, SCADA
     - iv. Balance of Plant
       - 1. FERC Accounts 310-346
         - a. e.g., land, roads, fencing
   - b. Indirect Costs
     - i. Construction Overhead
       - 1. e.g., engineering, supervision, financing

6. Cost Allocators – Rate filers should have the option of using default allocators established by the Commission or:
   - a. Direct Costs
     - i. Generation Equipment
       - 1. Isolate Reactive Costs
         - a. Apply GEAF
           - i. Apply RPAF[41]
       - 2. Assign Unallocated Costs to BOP
     - ii. Transmission Equipment

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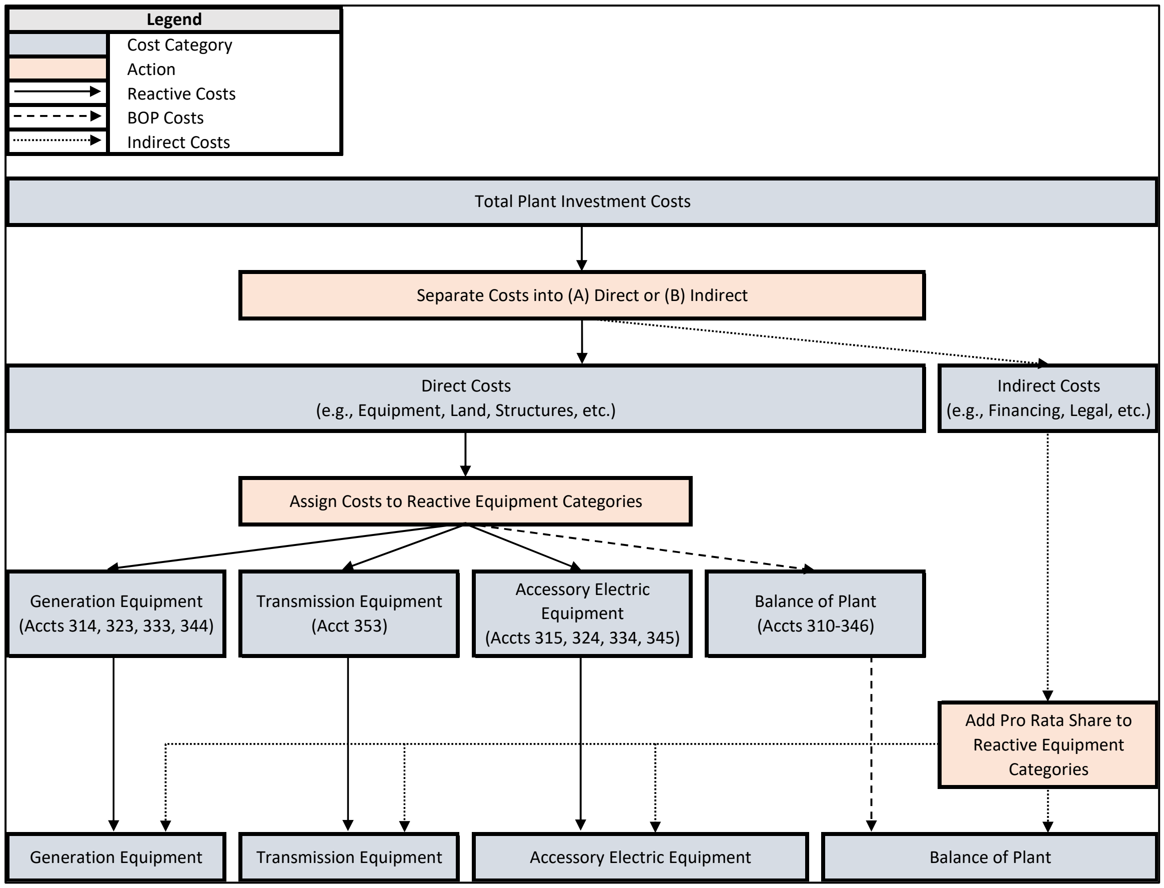
[41] The RPAF refers to the Reactive Power Allocation Factor, which represents the share of the reactive equipment attributable to reactive power and is used to isolate reactive power-related costs from real power-related costs. *See* Pasternack Testimony, Exhibit A-29 at 19-20.

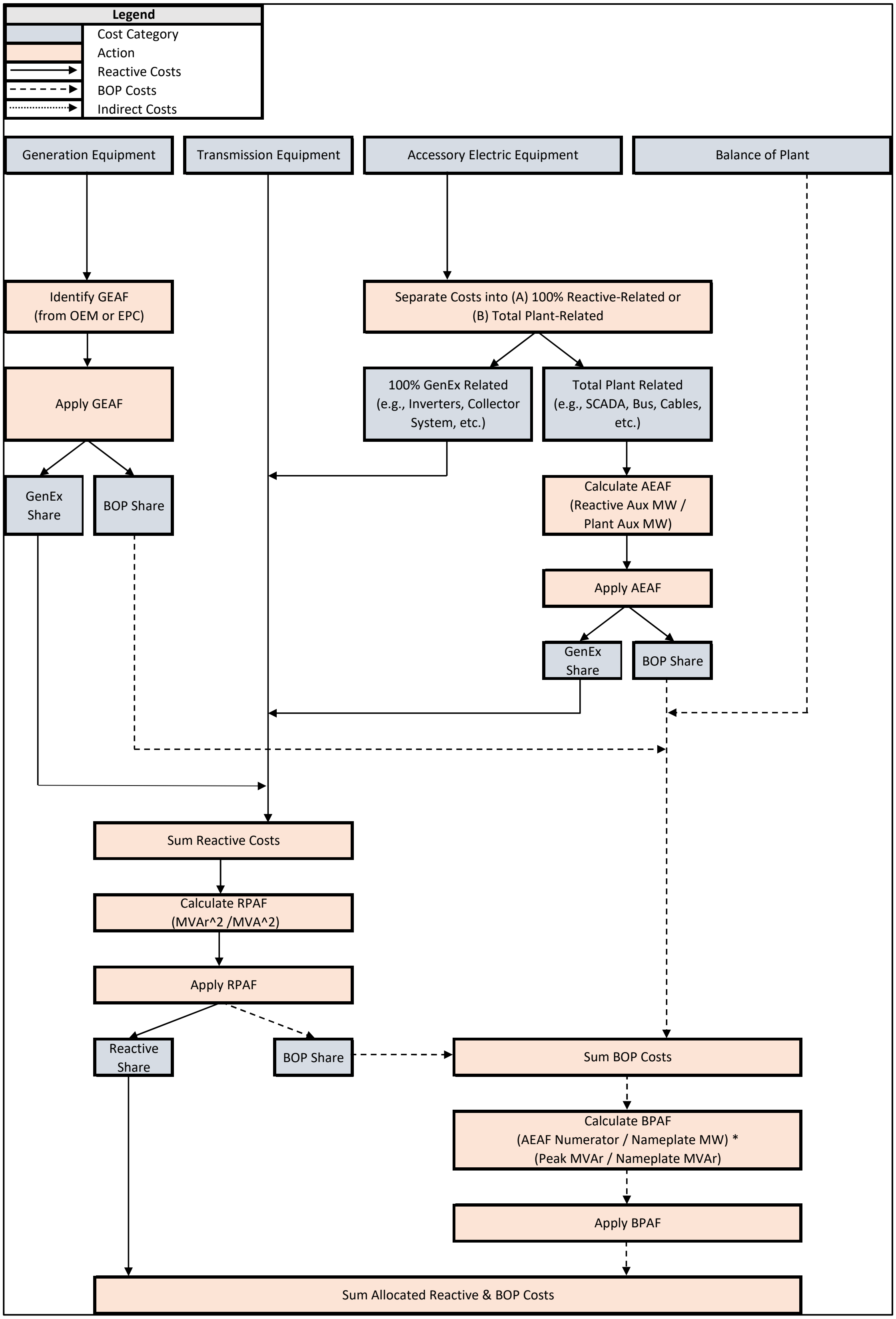
            1. Isolate Reactive Costs
                a. Apply RPAF
            2. Assign Unallocated Costs to BOP
        iii. Accessory Electric Equipment
            1. Isolate Reactive Costs
                a. Apply AEAF
                    i. Apply RPAF
            2. Assign Unallocated Costs to BOP
        iv. Balance Of Plant
            1. Sum All Unallocated Plant Costs
                a. Isolate Reactive Support Costs
                    i. Apply BPAF
    b. Indirect Costs
        i. Assign Proportionately to Direct Costs

Standardized AEP Method Template: Calculation Flow Chart Example

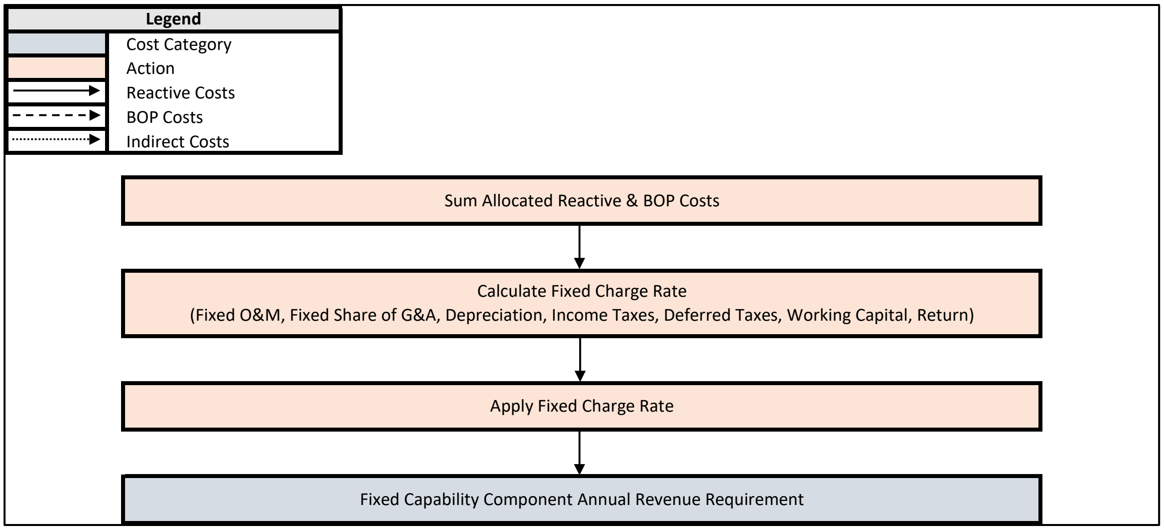
Step 1 of 3: Separate Total Plant Costs into Reactive Ratemaking Categories.



Step 2 of 3: Allocate Reactive & BOP Costs.



Step 3 of 3: Calculate the Fixed Capability Component.



UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

AFFIDAVIT OF ADRIAN J. KIMBROUGH

I, Adrian J. Kimbrough, certify under penalty of perjury that the attached testimony in this proceeding was prepared by me or under my direct supervision or was taken from other sources as noted. The answers contained in my testimony are true and correct to the best of my knowledge, information, and belief.

Executed on the 22nd day of February, 2022

Adrian J. Kimbrough
Adrian J. Kimbrough