UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION, THE AMERICAN CLEAN POWER ASSOCIATION, EARTHJUSTICE, AND THE NATURAL RESOURCES DEFENSE COUNCIL

Pursuant to the Federal Energy Regulatory Commission's ("Commission"), November 18, 2021 Notice of Inquiry,[1] the Solar Energy Industries Association ("SEIA"),[2] the American Clean Power Association ("ACP"),"[3] EarthJustice, and the Natural Resources Defense Council-Sustainable FERC Project ("Sustainable FERC Project") (collectively, the "Clean Energy Coalition") submit these comments in response to the Commission's questions.

I. RESPONSE TO NOTICE OF INQUIRY

A. Cost-based rates developed in accordance with the AEP Methodology remain the best way to compensate for reactive power.

In 2002, the Commission recommended that all resources seeking to establish a rate for reactive power use the method employed in *American Electric Power Service Corporation*.[4] The *AEP* methodology remains the best approach for determining reactive power revenue requirements. The Commission's long-standing precedent supports using cost-based rates to

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

[2] SEIA is the national trade association of the solar energy industry. As the voice of the industry, SEIA works to support solar as it becomes a mainstream and significant energy source by expanding markets, reducing costs, increasing reliability, removing market barriers, and providing education on the benefits of solar energy.

[3] ACP is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind, solar, energy storage, and electric transmission in the United States. The views and opinions expressed in this document do not necessarily reflect the official position of each individual member of ACP.

[4] *WPS Westwood Generation*, LLC, 101 FERC ¶ 61,290, at P 14 (2002) (citing *Am. Elec. Power Serv. Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999) (Opinion No. 440)).

compensate generators for reactive power services.[5] Since the Commission issued Order No. 888, the types of generators and, therefore, equipment needed to provide reactive power, have evolved. This shift in technologies does not negate the need for just compensation; rather, it demonstrates that a cost-based rate structure is needed to ensure that generators are compensated for acquiring the equipment necessary to provide voltage support.

Voltage support from non-synchronous resources is becoming increasingly critical for maintaining grid stability on the bulk power grid, given the energy mix transition to cleaner energy resources.[6] From a transmission planning and operations perspective, the North American Electric Reliability Corporation's ("NERC") Reliability Guidelines demonstrates that the bulk power system would benefit from inverter-based resources providing additional reactive power voltage support.[7] And, as Sandia National Laboratories has pointed out, the reactive power capability of conventional synchronous generators is more limited than what is often measured for compensation.[8] The reactive power capabilities from non-synchronous resources can resolve voltage disturbances, such as load and generation imbalances and fault-type events, and can provide reactive power when the real power source for the inverter is unavailable (e.g., in the

[5] *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, at 31,720-21 (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) (finding that, in the absence of proof that the generation seller lacks market power in providing reactive power, rates for this ancillary service should be cost-based and established as price caps, from which transmission providers may offer a discount).

[6] North American Electric Reliability Corporation, Reliability Guideline, BPS-Connected Inverter-Based Resource Performance (September 2018) https://www.nerc.com/pa/Stand/Reliability%20Standards/VAR-001-5.pdf (Reliability Guideline).

[7] Reliability Guideline at 36

[8] Sandia NL, Reactive Power Interconnection Requirements for PV and Wind Plants (SAND2012-1098), February 2012, [Online] https://www.esig.energy/wiki-main-page/reactive-power-capability-and-interconnection-requirements-for-pv-and-wind-plants/ (Sandia National Lab).

evening).[9] Providing reactive power capacity, particularly when an inverter-based generator's real power source is unavailable, will require additional costs for equipment upgrades that should be eligible for cost recovery. Further, ensuring that recovery will incentivize resource owners to invest in that equipment, which provide additional benefits to the grid, including when such capability is greater than the minimum capabilities required by the Commission's regulations.

Order No. 827 requires that non-synchronous resources provide reactive power within a prescribed Power Factor range (i.e. a range of 0.95 leading to 0.95 lagging) to facilitate interconnection to the grid.[10] Grid operators are not required to compensate non-synchronous generators for complying with the Power Factor range requirement, unless the respective transmission owner compensates its own or affiliated generators or requires all generators to meet a Power Factor outside of the range prescribed in the *pro forma* Large Generator and Small Generator Interconnection Agreements ("LGIA" and "SGIA"). Notably, Southwest Power Pool, Inc. ("SPP") and the California Independent System Operator Corporation ("CAISO") do not currently compensate generators complying with the Power Factor requirement. CAISO points to the exemption in Order No. 827, namely that it does not compensate its own or affiliated generators for this capability.[11] However, the transmission owners in CAISO's service territory generally do not own generation, making this exemption inapplicable to the detriment of generators that are required to purchase additional equipment to provide reactive power. There is a trade-off between providing real energy and reactive power at the same time, requiring

[9] Reliability Guideline at 31-32, 34; *see also* PJM Interconnection, LLC, *Energy Transitions in PJM: Frameworks for Analysis*, at 15 (Dec. 15, 2021), https://pjm.com/-/media/library/reports-notices/special-reports/2021/20211215-energy-transition-in-pjm-frameworks-for-analysis.ashx.

[10] *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 (2016).

[11] CAISO, ER17-490-000, December 5, 2016 Transmittal Letter at 7.

generators to forego compensation in the energy markets when they provide reactive power, which can cause financial distress. A utility's cost of service should yield a rate that enables it to "operate successfully, to maintain its financial integrity . . . ."[12] Failing to compensate generators for providing any level of reactive power can be considered a regulatory taking, which supersedes the Commission's jurisdiction to determine whether rates are just and reasonable.[13] The Clean Energy Coalition respectfully urges the Commission to reconsider this compensation exemption in the *pro forma* LGIA and SGIA.

Other compensation methods used by other Regional Transmission Organizations and Independent System Operators (collectively, "RTOs") are inadequate to compensate non-synchronous resources. For example, ISO New England, Inc. ("ISO-NE") and the New York Independent System Operator, Inc. ("NYISO") provide reactive power compensation using a fixed rate per megavar, but the rate does not reflect the costs that each resource incurs to provide reactive power capacity. This is particularly impactful for non-synchronous resources, as inverters used for solar PV and wind plants can provide reactive capability at partial output, but any inverter-based reactive capability at full power implies that the converter would need to be sized larger (at additional costs) to handle both full active and reactive current.[14] Thus, with a fixed rate methodology, the Commission risks overcompensating some resources while undercompensating others, both of which are inconsistent with the cost causation principle. While implementation of the *AEP* methodology might require improvements to relieve the Commission of the administrative burdens stated in the NOI, the other methodologies fail to

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[12] *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591, 602, 605 (1944).

[13] The Fifth Amendment provides that private property shall not be taken for public use, without just compensation. U.S. CONST. Amend. V.

[14] Sandia National Lab at 6.

provide adequate compensation for non-synchronous resources and, therefore, are unjust and unreasonable.

B. Going forward, the Commission should adopt an *AEP* Rate Template, which would be a formulaic approach to compensating resources for reactive power.

The Clean Energy Coalition recommends that the Commission adopt a reactive power compensation template based on the *AEP* methodology (the "*AEP* Rate Template"), which would establish a streamlined, formulaic approach to compensating all resources for the provision of reactive power. Under this approach, the Commission could create, through a rulemaking, a formulaic *pro forma* template that standardizes the *AEP* methodology. Like similar formula rate templates, prior approval of a formulaic *AEP* Rate Template by the Commission would constitute approval of the formula itself.[15] Also like rate templates used for transmission service, the *AEP* Rate Template would set forth the formula used to calculate the revenue requirement pursuant to the *AEP* methodology (or any modified *AEP* methodology) and would include a series of instructional notes that clearly define what inputs may be used.[16]

Each generator owner seeking reactive power compensation would fill out the template to establish a generator-specific stated rate. The generator owner would then submit a filing with the Commission pursuant to section 205 of the Federal Power Act ("FPA") seeking approval for its proposed reactive power revenue requirement.[17] As part of such filing, the generator owner would include a copy of the populated template and any applicable supporting materials. Unlike

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[15] *New England Power Company*, 72 FERC 61,148 at 61,761 (1995); *Boston Edison Company*, Opinion No. 376, 61 FERC 61,026 at 61,145 (1992).

[16] *See e.g.*, PJM Tariff Attachment H; MISO Tariff Attachment O.

[17] 16 U.S.C. § 824d (2020).

a transmission formula rate filing, a resource owner would make a one-time filing. This rate would only be refiled at the direction of the Commission or the RTO, if the RTO imposes a performance paradigm.

Importantly, Commission staff's review would be confined to determining whether the template was correctly filled out and whether sufficient supporting information was included, in accordance with the template's instructions. Failure to fill out the template correctly or provide the appropriate supporting evidence would result in further proceedings or in an outright rejection of the filing.[18] The FPA section 205 proceeding would allow customers the opportunity to dispute any charges arising under the proposed filing, similar to the protections in place when transmission formula rates are adopted.[19]

While the proposed procedure would still require a Commission filing by the generator owner, the review of that filing would more limited than the current process. The current burden on Commission litigation staff and the administrative law judges will be significantly reduced, since the filing would include the information that is usually sought during the hearing and settlement discovery process. Requiring an FPA section 205 filing would still allow affected ratepayers to have the opportunity to review the proposed rate and challenge the proposed inputs

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[18] NOI at P 28(p). *See also Wabash Valley Power Ass'n, Inc.*, 154 FERC ¶ 61,245, P 29 (2016) ("To satisfy this requirement, reactive power revenue requirement filings must include cost information for all equipment used to produce reactive power, including for turbogenerators, generators, exciters, and step-up transformers. Moreover, to support the reactive power allocator used in the AEP methodology, reactive power revenue requirement filings must include reactive power test reports. In other words, the cost figures provided with reactive power revenue requirement filings must be sufficiently detailed for the Commission to be able to evaluate and analyze the proposed revenue requirement.").

[19] *Boston Edison Company*, Opinion No. 376, 61 FERC 61,026 at 61,145 (1992) ("The Commission's audit and complaint procedures provide adequate protection to Towns in the event that disputes arise concerning charges under the formula rate.").

if necessary.[20] For the generator owner, the compensation process is largely moved outside of the hearing and settlement process, saving the generator owner time and money.

Minimizing the prospects of litigation also provides regulatory and rate certainty. Under the current process, when the Commission issues an order setting the reactive power rates for hearing and settlement, it accepts the rate, generally effective the date of the order, *subject to refund*.[21] Following the order, the generator owner, Commission trial staff, and interested intervenors engage in settlement negotiations, and in a growing number of instances hearing. During settlement, which could last as long as a year, ratepayers generally pay a rate that will almost certainly be reduced through settlement. Following the settlement, the generator owner must refund the difference between the filed-rate and the settled rate. Adopting an *AEP* rate template would ensure certainty and transparency. Moreover, the ability for generator owners to rely upon the template would likely enable them to more accurately predict their future reactive power compensation, which in turn would likely enable such owners to lower their overall financing costs and provide a benefit not only to the generator owner, but also to consumers.[22]

[20] *See Delmarva Power & Light Co.*, 145 FERC ¶ 61,055, at P 22 (2013) ("The Commission's acceptance of a formula rate constitutes acceptance of the formula, but not the inputs to the formula. Parties can challenge the inputs to the formula rate in the same way as they can challenge costs in a stated rate case, including by raising prudence issues. In order for formula rates to work properly, they must allow for after-the-fact corrections and updates.") (citations omitted). Notably, to the extent that any litigation is necessary under the proposed formula rate approach, such litigation would almost certainly be much narrower in scope relative to the reactive power compensation-related litigation that occurs today.

[21] *See e.g.*, *Prairie State Solar, LLC*, 178 FERC ¶ 61,072, P 15 (2022); *Glacier Sands Wind Power*, LLC, 178 FERC ¶ 61,070, P 30 (2022); *Oliver Wind I, LLC*, 176 FERC ¶ 61,112, P 15 (2021).

[22] Delta's Edge Solar, LLC, Proposed Revenue Requirement for Reactive Service, Transmittal at 6, Docket No. ER21-1452 (March 16, 2021).

1. The *AEP* Rate Template would not rely on the FERC Uniform System of Accounts.

The Commission originally designed the *AEP* Methodology for a resource owned by a public utility that used the Uniform System of Accounts ("USofA") and annually submitted a FERC Form No. 1. In earlier reactive power cases, utility owners of thermal resources could rely on USofA accounting structures and the sworn and attested-to accounting entries in their FERC Form No. 1 to support their proposed reactive power rates.[23] However, as the Commission notes in the NOI, the vast majority of resource owners now applying for reactive power compensation have waivers of the Commission's accounting and reporting requirements.[24] Accordingly, "it is difficult for the Commission and affected customers to easily verify that the proposed rates accurately reflect the AEP Methodology."[25]

The proposed *AEP* Rate Template would not rely on the FERC USofA. Instead, the template would include a series of instructional notes that clearly define what inputs a generator owner may use to support their reactive rate filing. The generator owner would then include that supporting documentation as part of its filing to recover a reactive rate. The information Commission staff would need to verify the rate would be included in the filing.[26]

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[23] NOI at P 25. Recently, though, even in instances where a utility that follows the USofA files for reactive revenues, Commission staff does not appear to rely on the accounting structures and attested-to accounting entries in the FERC Form No. 1. *See Otter Tail Power Co.*, 175 FERC ¶ 61,178, P 24 (2021).

[24] NOI at P 25.

[25] NOI at P 25.

[26] NOI at P 28(q)(ii).

2. Interconnection Service Agreements and Transmission Owner oversight provide for protections against inadequate testing and reactive power capability degradation.

The *AEP* methodology compensates resources for their capability to provide reactive power.[27] Resources that seek reactive power capability compensation under the AEP Methodology are required to submit test reports.[28] The Notice of Inquiry states there are several flaws with the testing data: the tests are not upgraded and may not reflect any degradation of the facilities;[29] the tested capabilities are not tied to compensation in certain regions;[30] and the testing data may be incomplete.[31]

There is another flaw in this testing requirement that the NOI did not recognize: Rarely will a system operator create the system conditions necessary to test the reactive power capabilities of a new inverter-based resources. Reactive power is compensated on the maximum capability to provide the service and based on the nameplate power factor of the facility.[32] That maximum capability information is generally included in the manufacturers' inverter specifications. Testing can be done to confirm those specifications, but for inverter-based resources it is difficult to confirm the *maximum* capability unless the right weather and grid conditions are present. For example, if a test of a solar resource is conducted in the fall, there is

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[27] *Am. Elec. Power Serv. Corp.*, 80 FERC ¶ 63,006, at 65,071 (1997), *aff'd in part, rev'd in part*, Opinion No. 440, 88 FERC ¶ 61,141 at 61,437 (establishing the AEP Methodology); *see also WPS Westwood Generation, L.L.C.*, 101 FERC ¶ 61,290 at P 14 (recommending that all resources seeking to recover reactive power capability costs pursuant to individual cost-based revenue requirements use the AEP Methodology).).).).).

[28] NOI at P 21; *see also Wabash Valley Power Ass'n, Inc.*, 154 FERC ¶ 61,245, at P 29 (2016); *Wabash Valley Power Ass'n, Inc.*, 154 FERC ¶ 61,246, at P 28 (2016).

[29] NOI at P 21.

[30] NOI at P 13.

[31] NOI at P 21.

[32] *Panda Stonewall LLC*, 174 FERC ¶ 61,266, at PP 99, 107-109 (2021).

insufficient sun to ensure maximum generating capability, and as a result, that resource may end up being undercompensated.

Similarly, with respect to resource degradation, the Commission raises a theoretical concern that in practice is not an issue.[33] Standard Commission-jurisdictional Interconnection Service Agreements require that interconnection customers maintain a power factor range of 0.95 leading to 0.95 lagging.[34] The utility to which that interconnection customer is connected has visibility into whether a resource is maintaining a power factor within that range.[35] If an interconnection customer fails to maintain that range, it may be liable for a violation of its Interconnection Service Agreement, contractually incentivizing that interconnection customer is to maintain its resource. There is an additional, practical protection against reactive capability degradation for inverter-based resources. Specifically, inverters are fast-changing technology that require regular updates. As a matter of regular maintenance, inverter-based generation owners routinely replace and upgrade their inverters. The degradation issue flagged by the Commission is addressed in the course of regular resource maintenance.

In *Wabash*, the Commission required all resources to submit test reports when seeking a reactive power revenue requirement.[36] In this proceeding, the Commission should revisit that testing requirement and instead require submission of the manufacturers' specifications of the resource to support the capability requirement. There are sufficient safeguards in place, through

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[33] *See* NOI at P 28(f)-(i).

[34] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, 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).

[35] *See e.g.*, Prepared Answering Testimony of Jason Ausmus at 28:13-29:4, Docket No. ER20-714 (Jan. 19, 2022).

[36] *See* NOI at P 21 (citing *Wabash Valley Power Ass'n, Inc.*, 154 FERC ¶ 61,245, at P 29 (2016); *Wabash Valley Power Ass'n, Inc.*, 154 FERC ¶ 61,246, at P 28 (2016) (together, *Wabash*)).

both transmission provider control and through the interconnection service agreement to ensure that a resource is providing the necessary levels of reactive power.

C. Any changes to the *AEP* methodology or cost-of-service ratemaking associated with reactive power capability should apply prospectively only and with sufficient notice.

If the Commission opts to change the *AEP* methodology, it should do so with caution, for three reasons. First, the *AEP* methodology has enabled reactive power compensation to become a key revenue stream for non-synchronous resources; in turn, it has helped finance these resources, and lowered the prices reflected in power purchase agreements ("PPAs") and elsewhere, benefiting consumers. Second, *if* the Commission were to change the *AEP* methodology, it should not revisit existing reactive rates, barring extraordinary circumstances. Finally, the *AEP* methodology is long-standing Commission policy and the Commission should not amend this ratemaking method without sufficient notice.

Since the issuance of Order No. 827, dozens of non-synchronous resources have received reactive compensation under the *AEP* methodology for their successful provision of a key reliability service. For these resources, and for other non-synchronous resources, reactive power compensation represents an important, stable revenue stream. This is a revenue stream that resource owners can rely upon when determining how to finance, design, and construct their projects. Being able to estimate and rely upon stable reactive power revenues has provided benefits to consumers because resource owners can reduce energy prices that they offer to buyers in PPAs (either on a bilateral basis or via requests for proposals issued by the buyer) and can also lower financing costs associated with a particular resource. This, in turn, lowers overall energy prices and helps save consumers money.

While the costs of reactive power—which is an essential reliability service—flow through to consumers, those costs would exist *with or without* new non-synchronous generators. The need for reactive power is an aspect of the electric grid as a whole. The Commission's orders approving compensation for non-synchronous generators to provide this service can not only reduce the revenue requirements of resources such as solar and wind under PPAs, but also allow these resources to rely less on other non-PPA (*i.e.*, merchant) revenue streams, such as revenues from energy and capacity markets administered by RTOs. This in turn can help lower RTO energy and capacity market prices and provide additional benefits to consumers. Similarly, reactive power revenue compensation helps reduce the cost of compliance with state procurement requirements, and benefits consumers, without actually creating any extra costs for reactive power. Accordingly, amending the *AEP* methodology to reduce reactive power compensation would require resource owners to rely upon other potential revenue streams in order to finance and construct their projects, meaning that all else equal, the costs to consumers associated with these other revenue streams would rise.[37]

Furthermore, *if* the Commission changes the *AEP* methodology it should refrain from initiating any section 206 proceedings against already-filed rates, barring extraordinary circumstances like a unit's failure to perform. Doing so would contravene long-standing principles of the Commission's role in electricity markets, and its long-standing interest in ensuring that rates are sufficiently predictable to attract investment.[38] It would also stand on

[37] As a simple example, if a resource owner can lower the price it offers to a buyer under a PPA due to the fact it can rely on reactive power revenues, if it no longer can rely upon such reactive power revenues, it will have to increase the PPA price that it offers to that buyer.

[38] *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591, 602, 605 (1944).

weak legal footing and could entangle any new requirements on reactive power revenue in lengthy litigation.

Lastly, any prospective change should also provide stakeholders with sufficient notice. In this instance, sufficient notice would be a period of time long enough that it would minimize market disruptions and would not undermine projects that are already in advanced stages of development. As discussed above, many projects rely on stable revenues provided under the current reactive power construct using *AEP*. Amending it, and especially if that might include potentially significantly reduced projected revenues, could mean that some projects with low power factors that are already in development could become uneconomic. This may lead to serious market disruptions, as resource owners and buyers would likely have to renegotiate and reprice PPAs, or resource owners would need to find new buyers all together. Significant market disruptions due to a sudden change to the current reactive power construct would likely delay the development of many renewable energy projects, which in turn would thwart states from achieving their clean energy goals. As construction of late-stage projects can take as long as two years, the Commission should consider delaying implementation of any new reactive power rules for at least 24 months from the date of any final order in this proceeding.

D. Recovery of reactive power revenues in capacity market offers is not feasible.

Requiring resources to recover the costs of their investment in reactive power capability by embedding those costs in their capacity market offers is not a feasible approach to reactive power compensation.[39] Capacity and reactive power are two different services serving two

[39] NOI at P 32 (g).

different functions. Capacity can be used throughout region (MW), whereas reactive (VARs) stay local.

The PJM Independent Market Monitor ("IMM") has not articulated any reason why reactive supply capability should be commingled with the capacity market, aside from an alleged double-recovery due to some resources having a Commission-approved reactive annual revenue requirement above the standard reactive capability offset included in the Net Cost of New Entry calculation. The IMM has failed to provide any evidence that "double-recovery" issue exists.

However, assuming for a moment that the issue of double-recovery *does* exist, the IMM ignores another potential solution, which is to examine changes to how reactive revenue offsets might be used in the Net Cost of New Entry calculation or otherwise impact other capacity market parameters. The IMM's approach of compensating reactive power only through the capacity market may solve a theoretical double-recovery issue, but it introduces another, more substantial issue. Namely, this proposal ignores that there may be resources that are fully capable of effectively providing reactive capability but that choose to not participate in the capacity market or do not clear in a capacity auction. There are numerous reasons why a resource may be unable or unwilling to participate in the capacity market, and yet the resource could be a critical reactive power source for the grid and should be properly incentivized to provide its reactive capability. It is also the case that there is nothing that makes a capacity resource more effective at providing the reactive supply service than non-capacity resources. Therefore, capacity and reactive capability should continue to be compensated separately, and any unnecessary tying of the two services, like the IMM's proposal, would produce an unduly discriminatory outcome.

E. Distribution-Connected Resources should be compensated for the reactive power they provide to the transmission grid.

In the 2002 *Otter Tail Power Co.* proceeding, the Commission held that transmission providers are not required to compensate generators for reactive power if the generator is not under the transmission provider's control.[40] Schedule 2 of the *pro forma* Tariff similarly requires that generation facilities and non-generation resources capable of providing reactive power be "under the control of the control area operator." Schedule 2 of the MISO Tariff limits reactive compensation to resources "connected to" the transmission system. Currently, the Commission has pending before it several cases contemplating the issue of whether a transmission provider controls a distribution-level generation resource, which would entitle that resource to compensation.[41] Through these cases, several facts were established that demonstrate that distribution-connected resources should be compensated for supplying reactive power.

First, a transmission provider is able to direct the dispatch of reactive power by a distribution-connected resource.[42] In the *Whitetail Solar* proceeding, a witness for Whitetail Solar demonstrated that PJM directed the distribution-connected resource to provide reactive power.[43] Second, even though the resources at issue in the current-Commission cases are distribution-connected, they have Commission-jurisdictional interconnection agreements with an

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[40] *Otter Tail Power Co.*, 99 FERC ¶ 61,019, 61,093 (2002).

[41] *See, e.g.*, *Ingenco Wholesale Power, LLC*, 173 FERC ¶ 61,247 (2020; *Whitetail Solar 3, LLC*, 173 FERC ¶ 61,288 (2020); *Whitetail Solar 2, LLC*, 174 FERC ¶ 61,238 (2021); *Elk Hill Solar 2, LLC*, 175 FERC ¶ 61,188 (2021); *Mechanicsville Solar, LLC*, 176 FERC ¶ 61,076 (2021).

[42] NOI at P 36(a). Prepared Answering Testimony of Jason Ausmus at 30:11-31:22, Docket No. ER20-714 (Jan. 19, 2022).

[43] NOI at P 36(a). Prepared Answering Testimony of Jason Ausmus at 30:11-31:22, Docket No. ER20-714 (Jan. 19, 2022); *Whitetail Solar 3, LLC*, 173 FERC ¶ 61,288, P 9 (2020).

RTO.[44] As part of those agreements, the resource is required to maintain reactive voltages at 0.95 leading and lagging.[45] Third, those resources were required to conform with RTO testing requirements.[46] As NERC has found, reactive power is a critical part of planning and operating the bulk power system.[47] Failure to maintain proper voltage control can result in cascading effects across the bulk power system,[48] and in the Northeast in 2003, it did result in such effects.[49] However, reactive power cannot be transported over long distances.[50] It is an inherently local service. That is why NERC recommended focusing on smaller areas of the bulk power system when evaluating that service.[51] Whether a resource is under the "control of" PJM or "connected to" only the distribution system in MISO, *distribution-connected* resources can, and in some instances, have, provide reactive supply to the *transmission* system. They should be compensated accordingly.

Compensating distribution-connected resources would be consistent with Commission policy. In Order No. 2222, the Commission directed each RTO to remove the barriers to participation of distributed energy resources in the capacity, energy, and ancillary services

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[44] NOI at P 36(a); *Ingenco Wholesale Power, LLC*, 173 FERC ¶ 61,247, P 10 (2020); *Whitetail Solar 3, LLC*, 173 FERC ¶ 61,288, P 9 (2020).

[45] *Pro forma* ISA.

[46] NOI at P 36(d); Prepared Answering Testimony of Jason Ausmus at 30:11-31:22, Docket No. ER20-714 (Jan. 19, 2022).

[47] NERC, Essential Reliability Services, at 18 (Dec. 2016), https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf (Reliability Services).

[48] Reliability Services at 18; *see also* PJM Interconnection L.L.C., Reactive Reserves and Generator D-Curves, at 7-9 (Oct. 8, 2018) https://www.pjm.com/-/media/training/nerc-certifications/gen-exam-materials-feb-18-2019/training-material/02-generation/6-2-reactive-reserves-and-generatord-curve.ashx.

[49] FERC Staff, August 14, 2003 Outage Sequence of Events (Sept. 12, 2003) https://www.ferc.gov/sites/default/files/2020-05/09-12-03-blackout-sum.pdf.

[50] Reliability Services at 18.

[51] *Id*.

markets.[52] Compensating distribution-connected resources for providing an essential reliability service would be consistent with that policy and ensure that these resources are treated comparably to their utility-scale counterparts.

II. CONCLUSION

Reactive power is a valuable service that helps ensure grid reliability.[53] However, the process for receiving reactive power compensation has become onerous—onerous for RTOs tracking these proceedings, onerous for Commission staff processing and litigating these cases, and onerous for the generator owner that spends significant time and money filing and litigating reactive power revenue requirements for individual resources. The issues surrounding the compensation of reactive supply are complicated and technical. These issues, though, are most often addressed in the hearing room, are subject to confidentiality, and are not discussed in the public records.[54] Typically, individually litigated reactive power cases are resolved through "black-box" settlement agreements, which cannot be cited as precedent. This means that each subsequent project cannot rely on past reactive power rates. In addition to considering these comments, the Clean Energy Coalition urges the Commission to establish a technical conference in this proceeding to engage in these discussions openly and on the record.

In revising the compensation methodology, the Commission has the opportunity to strike a reasonable balance between encouraging the proper design of inverter-based resources and

[52] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197 (2021).

[53] Reliability Guideline.

[54] 18 C.F.R. 385.606 (2021).

reducing the regulatory burdens of the current *AEP* methodology filing process. Providing clear guidance and a consistent framework for reactive power compensation would increase certainty, ensure provision of a vital reliability service, and reduce unnecessary burdens on the Commission, resource owners, and transmission providers.

Sincerely,

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of this pleading has been served this day upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 22nd day of February 2022.

/s/ Melissa Alfano