# REACTIVE POWER COMPENSATION FOR RENEWABLE ENERGY FACILITIES: OPPORTUNITY AMIDST CHANGE

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Reactive power provides synchronous and non-synchronous generators, as well as other forms of non-generation resources capable of providing reactive power, with a potential additional revenue stream. The provision of voltage support to the grid is an ancillary service, compensated in various ways in the various wholesale electricity markets. Renewable developers should familiarize themselves with the opportunities provided by reactive power compensation, even as some of the compensation models may be shifting.

In 2016, the Federal Energy Regulatory Commission ("FERC") began allowing wind and solar facilities to offer reactive power as an ancillary service into wholesale electricity markets. Over the past few years, FERC and the independent system operators ("ISOs") and regional transmission organizations ("RTOs") began to revisit reactive power compensation models and, as a result, there has been a greater focus on reactive power issues in 2022. This article reviews the current status of reactive power compensation in various U.S. regions, as well as possible future changes.

Significantly, inverter-based resources and storage assets are eligible to receive compensation for reactive power produced in most—though not all—markets. While FERC has permitted wide variation in compensation models in the name of "regional differences," some of the models may be unjust and unreasonable by failing to adequately compensate all types of generation and non-generation resources for providing reactive power (measured in volt-amperes reactive, or "VAR" and sometimes expressed as megavolt-amperes reactive or "MVAR").

## I. Background

Reactive power is an ancillary services product that maintains the stability of the electric transmission grid by providing voltage support. As FERC explained:

> 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.[1]

### A. FERC Orders

Nearly three decades ago, FERC recognized that reactive power service could be obtained in one of two ways: (1) by installing facilities as part of the transmission system, or (2) relying on generators. As such, FERC included reactive power purchased from generation resources in Order No. 888 as one of the six ancillary services that transmission owners must include in an open access transmission tariff,[2] and established power factor requirements in interconnection agreements.

In 2003, FERC clarified that if a transmission owner pays its own generation for reactive power, it must also pay interconnected generators for reactive power.[3]

[1] *Reactive Power Capability Compensation*, Notice of Inquiry, 177 FERC ¶ 61,118 at P 4 (2021) ("Reactive NOI").

[2] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,706-07 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *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) ("Order No. 888").

[3] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 546 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 (2004), *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶

This finding kicked off a series of proceedings to determine the just and reasonable rate for reactive power services provided by interconnected generation.

In 2016, FERC eliminated the exemption for non-synchronous generators from the requirement to provide reactive power.[4] As such, non-synchronous generators became required to provide reactive power, but also became eligible to receive compensation for that power.

Most recently, in November 2021, FERC issued the Reactive NOI, requesting industry input on a list of questions regarding the current state of reactive power compensation in wholesale electricity markets, as well as what the most just and reasonable approach may be for different types of resources. The Reactive NOI is discussed in greater depth below.

### B. FERC Staff Reports

Following the August 2003 blackout in New York, the Joint US-Canada task force reviewing the causes found that "insufficient reactive power was an issue in the blackout."[5] Chairman Pat Wood convened a task force to develop "principles for efficient and reliable reactive power supply and consumption," which resulted in a report from FERC Staff outlining the current status of reactive power supply and policies, plus suggestions for change.[6] In 2010, FERC Staff issued a report on the status of reactive power compensation in the organized and bilateral wholesale electricity markets.[7] The report found that a wide variety of compensation methods exists, ranging from treating reactive power as an uncompensated service to fixing a stated rate in the tariff to the so-called AEP Methodology.[8] Under a compensation method that fixes a stated rate in the tariff, the generator is compensated at a flat rate that does not relate to the specific characteristics of the generation facility. The AEP Methodology, by contrast, takes into account the facility's specific characteristics and is explained in more detail below.

### C. The AEP Methodology

The AEP Methodology became the primary way to compensate generators for reactive power in regions that calculate compensation based on the generator's physical characteristics. Under the methodology, the Commission identified three components of a generation plant related to producing reactive power: (1) the generator and its exciter; (2) the generator step-up transformer; and (3) accessory electric equipment that supports the operation of the generator-exciter, plus a fourth category that considers the remaining total production investment required to provide real power and operate the exciter. Because these components produce both real and reactive power, AEP developed an allocation factor to sort the annual revenue requirements of these components between real and reactive power production (the "AEP Methodology"). As described below, FERC recently initiated a notice of inquiry on reactive power compensation and market design that raises new questions about whether FERC will modify the AEP Methodology.

## II. Current Compensation Models and Potential Changes

Compensation models for reactive power vary across the ISO/RTO regions, as well as regions where no ISO/RTO exists. While several models have remained static, others are in flux with potential upcoming changes. The models also differ from one another in levels of technical complexity. The following sections outline each ISO/RTO's approach toward such compensation models.

While the AEP Methodology is the most time-consuming reactive compensation model, as it requires a FERC filing, it also provides the greatest degree of specificity in compensating an individual generator (or fleet of comparable generators) for its actual investment costs, and consistency in the payment. Flat rate compensation methodologies that take lost opportunity costs into account are also beneficial because they recognize that a generator providing reactive power may lose the opportunity to sell real power into the market.

31,171 (2005); *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

[4] *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277, *order on clarification and reh'g*, 157 FERC ¶ 61,003 (2016).

[5] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and* Recommendations at 18 (April 2004).

[6] FERC Staff Report, *Principles for Efficient and Reliable Reactive Power Supply and Consumption*, Docket No. AD05-1 (Feb. 4, 2005).

[7] FERC Staff Report, *Payment for Reactive Power,* Docket No. AD14-7 (Apr. 22, 2014).

[8] *American Electric Power Service Corp.,* Opinion No. 440, 88 FERC ¶ 61,141 (1999) ("*AEP*").

Models that compensate only for the provision of reactive power when called upon provide the least amount of investment recovery to developers, and the greatest potential variability in the actual payment.

### A. PJM

PJM Interconnection, L.L.C. ("PJM") currently relies entirely upon the AEP Methodology. A generator seeking reactive power compensation must file an application with FERC pursuant to Section 205 of the Federal Power Act ("FPA"). The application will most likely be set for hearing and settlement judge proceedings. In the past few years, a number of applicants have sought, and received, reactive power compensation in this market under the AEP Methodology. Table 1 below provides a sampling of requested and settled compensation. Most reactive power compensation applications under the AEP Methodology are settled, with many in a settlement reached between FERC Staff and the applicant generator. Occasionally, the interconnected utility or another interested party may intervene in the proceeding. The parties in several of the applications have been unable to reach settlement and therefore gone to full-blown litigation, taking over two years.

**Table 1. PJM Reactive Power Settled Outcomes.** *(see Table at end of this article)*

In 2021, PJM initiated a Reactive Power Compensation Senior Task Force ("RPCTF"),[9] which was tasked with examining PJM's existing reactive power compensation model and determining whether changes should be made. Following 13 months of meetings, in December 2022, the task force polled whether a change should be made to the current system. Six potential packages were presented to stakeholders, ranging from zero compensation as a separate service, to the *status quo* to various forms of a flat rate. PJM posted the results of the poll on December 23, 2022.[10] 62% of voting members did not believe that a change was needed to PJM's current reactive power construct, while 38% indicated a desire for change. 81% believed that a cost-of-service model should be utilized, and 84% indicated that the AEP Methodology is "a reasonably accurate determination for generator reactive costs." 69% voted no to a flat rate. The only package to receive more than 20-28% support was proposed by the Clean Energy Caucus ("CEC"), and incorporates a flat rate per technology, which would eliminate the need for individual filings at FERC. The RPCTF will reconvene in January 2023 to consider poll results and next steps.

### B. MISO

Like PJM, the Midcontinent Independent System Operator, Inc. ("MISO") relies upon the AEP Methodology. A generator intending to receive reactive power compensation in MISO must file an application with FERC pursuant to FPA Section 205 and provide notice to MISO.

**Table 2. MISO Reactive Power Settled Outcomes.** *(see Table at end of this article)*

In their comments on the Reactive NOI, the MISO Transmission Owners ("MISO TOs") asserted that MISO should adopt a reactive <u>performance</u> compensation methodology similar to the approach used in Southwest Power Pool, Inc. ("SPP"), rather than a reactive <u>capability</u> compensation methodology. Under a reactive performance methodology, generators are compensated when they are called upon by the ISO/RTO or other transmission provider to actually provide reactive power, rather than being compensated for the ability to provide reactive power in general. Since generators may or may not be called upon to provide reactive power, a reactive performance compensation model results in highly variable and less predictable compensation, as compared to a reactive performance capability model that compensates the generator at a set level (based on expected availability) regardless of how often it is called upon.

On November 11, 2022, the MISO TOs circulated to MISO and its stakeholders a notice that the MISO TOs intend to file with the Commission to eliminate from MISO's tariff the provision allowing for reactive power compensation within the standard power factor range.[11] The MISO TOs indicated that they are providing at least 30 days' notice of their intent to file. On November 30, 2022, MISO and the MISO TOs filed, in Docket No. ER23-523, to remove the obligation for MISO TOs to pay reactive power compensation under Schedule 2 to its own affiliated generators, which therefore terminates the MISO TOs'

[9] *See* PJM Reactive Compensation Senior Task Force, <u>https://www.pjm.com/committees-and-groups/task-forces/rpctf</u>

[10] *See* RPCTF Poll Results (Jan. 6, 2023), *available at* <u>https://www.pjm.com/-/media/committees-groups/task-forces/rpctf/2023/20230106/item-01---rpctf-poll-results-.ashx</u>

[11] Dumais, P., *MISO is filing at FERC to remove reactive power compensation for reactive power provided within the power factor range in the IA* (Nov. 15, 2022), *available at* <u>https://energycentral.com/c/tr/miso-filing-ferc-remove-reactive-power-compensation-reactive-power-provided</u>

obligation to pay reactive power compensation to all generators under Schedule 2, as of December 1, 2022.[12] MISO asserts that if a generator is directed to provide reactive power outside of the standard power factor range, the generator will be compensated based on existing tariff mechanisms.[13] These tariff mechanisms include the make-whole payment mechanisms in Module C and Schedule 27 of the MISO Tariff.[14] MISO claims, however, that manual dispatch for voltage support is rare and has not occurred in the past three years.[15] As of the comment deadline, 15 sets of comments or protests have been filed, many strongly opposing MISO's proposal.

### C. ISO New England

ISO New England, Inc. ("ISO-NE") compensates generators for reactive power capability at a flat rate that is multiplied by the resource's tested reactive power capability. ISO-NE does not require a FERC filing to receive reactive power compensation. Instead, ISO-NE requires that resource owners submit a completed Qualified Reactive Resource ("QRR") Request Form and provide accompanying data, as described below.

To be eligible for reactive power payments under Schedule 2 of the ISO-NE Tariff, a resource must be designated as either a generator or non-generator QRR. A generator is eligible to be designated as a QRR if it meets criteria set forth in the tariff. These criteria include being a market participant interconnected to the ISO-NE system and metered and dispatched by ISO-NE, or otherwise subject to ISO-NE's operational control. The generator must be capable of providing measurable dynamic reactive power voltage support, must meet reactive power testing requirements, and must provide accurate reactive capability data.[16] Non-generator resources may also qualify as a QRR if they are capable of providing reactive power.[17]

Pursuant to Schedule 2 of the ISO-NE Tariff, the flat rate at which QRRs are compensated for reactive power capability is comprised of the following elements:[18]

First, a flat rate for capacity costs ("CC") designed to compensate for fixed capital costs related to providing reactive power. This rate is determined annually based on the formula of Adjusted CC Rate * Min (1, (1.2 * Forecast Peak Adjusted Reference Load for the year/(SUM of all Qualified Reactive Resources' Summer Seasonal Claimed Capability). This rate was $1.1012/kVAR in 2022, and $1.0934/kVAR in 2021.[19]

Second, a variable rate for lost opportunity costs, for generators which are dispatched down by ISO-NE to provide reactive power shall be calculated pursuant to Market Rule 1 of the ISO-NE Tariff.

Third, a variable rate for energy consumed (cost of energy consumed, or "CEC") to produce the reactive power. The CEC equals the cost of additional energy to produce or absorb reactive power at zero real power output that would not have been consumed if the resource were not dispatched to provide VAR Service. It is calculated on an hourly basis as follows: CEC= (MWhUnit * (LMP or actual energy cost).

Fourth, a variable rate for costs for the resource to come online or increase its output above its economic loading point, calculated as the Cost of Energy Produced ("CEP") based on the portion of the Net Commitment Period Compensation ("NCPC") to be paid to the resource for the day per Market Rule 1.

### D. New York ISO

Similar to ISO-NE, the New York Independent System Operator ("NYISO") does not require a FERC filing in order to receive reactive power compensation. Instead, compensation requests are processed by NYISO following the submission of a Voltage Support Services ("VSS") Qualification Form and required documentation.

To qualify as a VSS Supplier and receive compensation, suppliers must be able to produce and absorb reactive power within its tested reactive capability range, maintain a specific voltage level, and have

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[12] *Midwest Independent System Operator, Inc. and MISO Transmission Owners*, Tariff Filing, Docket No. ER23-523-000 (Nov. 30, 2022).

[13] *Id*. at 5.

[14] *Id.* at 9, *citing* Tariff, Module C, Sections 40.3.5, 40.3.6; id., Schedule 27.

[15] *Id.* at n. 34, *citing MISO Manual Redispatch Information* (providing reports for manual redispatch instances, which show 723 instances of manual redispatch since November 2019 and no instances of voltage control), *available at* http://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Manual_Redispatch.html

[16] ISO-NE Transmission, Markets and Services Tariff Schedule 2 § II(A).

[17] ISO-NE Transmission, Markets and Services Tariff Schedule 2 § II(B).

[18] ISO-NE Transmission, Markets and Services Tariff Schedule 2 § IV.

[19] *See* VAR Annual Capacity Cost Report, *available at* https://www.iso-ne.com/isoexpress/web/reports/billing/-/tree/schedule-2---var-annual-capacity-cost-rate-report

functioning automatic voltage controlling equipment. Further, the supplier must be under NYISO's operational control, and successfully perform required testing.[20]

NYISO compensates generators at a stated rate. The rate was $3,919/MVAR for 15 years, from 2002 to 2017, but only paid for lagging power. The rate now compensates for both leading and lagging power, resulting in an increase to most generators, and is adjusted annually based on the Consumer Price Index. The 2022 compensation was $2,965.84/MVAR. Generators receiving compensation must demonstrate their leading and lagging reactive power capability annually through a reactive power test or operational data.[21]

### E. SPP

As noted above, SPP compensates generators for the reactive power they provide when called upon, rather than compensating generators for possessing the capability to provide such power. As such, generators in SPP receive a highly variable reactive payment that is dependent on how often they are called upon. A "Qualified Generator" is a generator capable of producing reactive power outside of the 0.95 leading to 0.95 lagging range, able to respond to dispatch instructions, and able to transmit data regarding its provision of reactive power. SPP's definition does not permit non-generation resources, such as storage, to provide reactive power.

SPP compensates in the amount of $2.26 per qualifying MVAR-hour.[22] This rate has not changed in almost a decade. Further, SPP has asserted that generators should not be eligible to recover lost opportunity costs by default as part of reactive compensation. Therefore, if a generator stops producing real power in order to provide reactive power at SPP's request, that generator will be compensated at the tariff-specified rate regardless of the prevailing locational marginal price of power at the time it stops producing real power. This could potentially result in a financial loss at times when market prices are high.

### F. ERCOT

The Electric Reliability Council of Texas ("ERCOT") currently requires generators Energy storage resources to provide voltage support.[23] Generally, this requirement exists for all such resources with a gross generating unit rating greater than 20MVA that are connected to transmission facilities. For inverter-based resources like wind and solar power, the ERCOT Protocols require that reactive power be available at all MW output levels at or above 10% of the facility's nameplate capacity. When an inverter-based resource is operating below 10% of its nameplate capacity and is unable to support voltage at its interconnection point, ERCOT or a transmission provider may require that resource to disconnect from the ERCOT system to maintain reliability. A generator and transmission provider may enter into an agreement in which the generator compensates the transmission provider to provide voltage support on the generator's behalf to meet the reactive power requirements in the ERCOT Protocols.[24]

ERCOT Nodal Protocols Section 6.6.7.1 provides for voltage support service payments. Generators are eligible for reactive compensation only if ERCOT issues a dispatch instruction. If ERCOT instructs a generator to <u>exceed</u> its unit reactive limit and the generator provides reactive power, then ERCOT compensates the unit at a price that recognizes the avoided cost of reactive support resources on the transmission network. If ERCOT directs a <u>reduction</u> in real power to provide additional reactive capability, then that reduction is compensated as a lost opportunity payment.[25]

### G. CAISO

The California Independence System Operator ("CAISO") compensates generators for reactive power produced outside of the standard power factor of 0.95 leading or lagging. Pursuant to its tariff, CAISO may request generators to provide reactive power outside of the standard power factor, and will compensate generators based on the opportunity cost of the foregone sales of real power.[26] Generators must qualify to provide reactive power to CAISO, in the same manner that they qualify to provide other ancillary services.[27] In 2017, FERC agreed with CAISO that further payments for reactive power are

[20] NYISO Tariff, Rate Schedule 2, §15.2.1.1; NYISO Ancillary Services Manual, § 3.2.

[21] NYISO Services Tariff § 15.2; NYISO Manual 2 § 3.6.

[22] SPP Tariff, Schedule 2 § III.A.

[23] Specifically, with certain specified exceptions, ERCOT requires Generation Resources and Energy Storage Resources to provide leading and lagging reactive capability equivalent to a 0.95 power factor. ERCOT Nodal Protocols § 3.15.

[24] ERCOT Nodal Protocols § 3.15(12).

[25] ERCOT Nodal Protocols § 6.6.7.1.

[26] CAISO Tariff §§ 8.2.3.3, 11.10.1.4.

[27] CAISO Tariff §§ 8.4.

not required.[28] No changes are currently pending or proposed to CAISO's compensation model.

## III. FERC Notice of Inquiry

In 2021, FERC issued a notice of inquiry asking for the industry's input on reactive power compensation and market design. In particular, FERC identified several flaws in the current methodologies, including reliance on the AEP Methodology. First, FERC noted that the AEP Methodology is static and does not take into account potential degradation of a facility's production over time. Once a facility is granted a particular cost-based rate for its reactive power, that rate remains in place indefinitely. Second, the AEP Methodology was created to determine the reactive output of a fleet of synchronous generators and does not properly account for non-synchronous resources such as wind or solar. Third, given the requirements of the AEP Methodology and the lack of cost-based data from companies that often operate under market-based rate authority, facilities that sought reactive compensation frequently ended up in time-consuming and expensive litigation.[29]

The Commission received over 50 sets of initial and reply comments from a diverse set of stakeholders. All of the ISO/RTOs filed an update on their current compensation models, and a variety of developers and other interested stakeholders filed comments regarding potential considerations the Commission should take into account. A group of renewable developers argued that the AEP Methodology is the preferred alternative that permits developers to recover its full investment in the asset, and is readily applicable to inverter-based resources.[30] Similarly, a coalition of clean energy interests argued that the Commission should adopt an AEP Methodology template that would establish a "streamlined, formulaic approach to compensating all resources for the provision of reactive power."[31] Conversely, the PJM Independent Market Monitor argued that the market does not need separate cost of service compensation for reactive power, and resources fully recover their investment in the market.[32]

While a notice of inquiry is frequently a precursor to a potential notice of proposed rulemaking, the Commission has not signaled whether it intends to pursue further consideration of a rulemaking regarding reactive power.

## IV. Conclusion

Reactive power provides synchronous and non-synchronous generators, as well as other forms of non-generation resources capable of providing reactive power, with a potential additional revenue stream. While the various compensation models may be complicated and technical, resources capable of providing this valuable service to the grid should pursue qualification. While revenues may seem uncertain or complicated, particularly as compared to the potential regulatory burden of the qualification process, the potential additional revenue may be valuable in areas where energy and capacity payments are lower.

*(see Table 1 and Table 2 on next page)*

[28] *Cal. Indep. Sys. Operator Corp.*, 160 FERC ¶ 61,035, P 19 (2017).

[29] *See, e.g., Fern Solar LLC*, Docket No. ER20-2186-000 (application for reactive compensation filed June 2020, parties filing testimony in December 2022 in preparation for a hearing in 2023).

[30] *Reactive Power Capability Compensation*, Initial Comments of the Renewable Generation Companies at 6, Docket No. RM22-2-000 (filed Feb. 22, 2022).

[31] *Reactive Power Capability Compensation*, Initial Comments of the Clean Energy Coalition at 5, Docket No. RM22-2-000 (filed Feb. 22, 2022).

[32] *Reactive Power Capability Compensation*, Initial Comments of the PJM IMM at 1, Docket No. RM22-2-000 (filed Feb. 25, 2022).

**Table 1. PJM Reactive Power Settled Outcomes.**

| Applicant | FERC Docket | Size (MWac) | Filed ($) | Resolution |
|---|---|---|---|---|
| Great Bay Solar II, LLC | ER20-2108 | 43.7 | $648,378 | $272,500 |
| Eastern Shore Solar, LLC | ER20-707 | 80 | $857,041 | $400,000 |
| OneEnergy Baker Point Solar, LLC | ER19-62 | 9 | $147,689 | $113,000 |
| Flemington Solar, LLC | ER18-2063 | 9 | $133,346 | $75,000 |
| PA Solar Park, LLC | ER18-1226 | 10 | $241,488 | $95,000 |
| Frenchtown I Solar, LLC | ER18-89 | 3 | $49,966 | $29,217 |
| Frenchtown II Solar, LLC | ER18-90 | 3 | $48,695 | $29,217 |
| Frenchtown III Solar, LLC | ER18-734 | 8 | $94,812 | $37,500 |
| Pilesgrove Solar, LLC | ER17-2415 | 18 | $362,904 | $212,500 |
| Great Bay Solar I, LLC | ER17-2386 | 75 | $2,552,780 | $525,567 |

**Table 2. MISO Reactive Power Settled Outcomes.**

| Applicant | FERC Docket | Size (MWac) | Filed ($) | Resolution |
|---|---|---|---|---|
| Coyote Ridge Wind, LLC | ER22-80 | 97 | $763,171 | $363,000 |
| Tuscola Bay Wind, LLC | ER19-2235 | 120 | $938,561 | $533,000 |
| Assembly Solar I, LLC | ER21-1215 | 50 | $772,999 | $375,000 |
| Oliver Wind I, LLC | ER21-2179 | 50.6 | $313,762 | $190,000 |
| Pioneer Trail Wind Farm, LLC | ER18-1473 | 150 | $826,926 | $493,000 |
| Stuttgart Solar, LLC | ER18-1704 | 81 | $290,779 | $204,000 |