DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM22–2–000; Order No. 904]

Compensation for Reactive Power Within the Standard Power Factor Range

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final determination.

SUMMARY: In this final determination, the Federal Energy Regulatory Commission (Commission) finds that allowing transmission providers to charge transmission customers for a generating facility's provision of reactive power within the standard power factor range is unjust and unreasonable. The Commission, therefore, is revising Schedule 2 of its *pro forma* open-access transmission tariff (OATT), section 9.6.3 of its *pro forma* large generator interconnection agreement (LGIA), and section 1.8.2 of its *pro forma* small generator interconnection agreement (SGIA) to prohibit the inclusion in transmission rates of any charges related to the provision of reactive power within the standard power factor range by generating facilities.

DATES: Effective January 27, 2025.

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SUPPLEMENTARY INFORMATION:

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1. In this final determination, pursuant to section 206 of the Federal Power Act (FPA), the Federal Energy Regulatory Commission finds that allowing public utility transmission providers (transmission providers) [1] to charge transmission customers for a generating facility's provision of reactive power within the standard power factor range is unjust and unreasonable. The Commission, therefore, is revising Schedule 2 of the

[1] Section 201(e) of the FPA, 16 U.S.C. 824(e), defines ''public utility'' to mean ''any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter.'' As stated in the Order No. 888 *pro forma* OATT, ''transmission provider'' is a ''public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.'' *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.,* Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g,* 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 Pol'y Study Grp.* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N.Y.* v. *FERC,* 535 U.S. 1 (2002); *Pro forma* OATT section I.1 (Definitions). The term ''transmission provider'' includes a public utility transmission owner when the transmission owner is separate from the transmission provider, as is the case in regional transmission organizations (RTO) and independent system operators (ISO).

Commission's *pro forma* OATT to prohibit transmission providers from including in their transmission rates any charges associated with the provision of reactive power within the standard power factor range from generating facilities and requiring transmission providers to make compliance filings to update Schedule 2 of their OATTs accordingly.[2] The final determination further revises the Commission's *pro forma* LGIA and *pro forma* SGIA to remove the requirement that a transmission provider pay an interconnection customer for reactive power within the standard power factor range if the transmission provider pays its own or affiliated generating facilities for the same service, and the final determination requires transmission providers to make compliance filings to update their *pro forma* interconnection agreements accordingly. As a result of this final determination, transmission providers will be required to pay an interconnection customer for reactive power only when the transmission provider requests or directs the interconnection customer to operate its facility *outside* the standard power factor range set forth in its interconnection agreement.

2. As discussed below, the Commission has a statutory duty to ensure that transmission rates are and remain just and reasonable. We find that this reform will ensure that transmission providers do not pass onto transmission customers unjust and unreasonable charges that lack a sufficient economic basis or justification and yield no commensurate benefit for ratepayers.

I. Background

A. Historical Framework Including Order Nos. 888 and 2003

3. Almost all bulk electric power is generated, transported, and consumed in alternating current (AC) networks. Reactive power, which is measured in megavolt-amperes reactive (MVAr),[3] is a critical component of operating an AC electricity system and is required to control system voltage within appropriate ranges for efficient and reliable operation of the transmission system. Reactive power supports the voltages that must be controlled to provide for delivery of real power and for system reliability. Reactive power can be produced or absorbed[4] by generating facilities, power electronic equipment such as flexible AC transmission system devices, transmission lines and equipment, and load. As relevant here, generating facilities must either produce or absorb reactive power for the transmission system to maintain voltage levels required to reliably supply real power from generation to load.

4. In Order No. 888, the Commission required that reactive supply and voltage control from generating facilities be offered as a discrete ancillary service by transmission providers and, to the extent feasible, charged for on the basis of the amount required.[5] The Commission explained that there are two ways of supplying reactive power and controlling voltage. One is to install facilities as part of the transmission system, the cost of which is part of the cost of basic transmission service. The second is to use generating facilities to supply reactive power and voltage control, which must be unbundled from basic transmission service.

5. With respect to compensation, the Commission stated that the transmission provider's ''rates for ancillary services should be cost-based.''[6] The Commission expected, however, that transmission customers would be able to change the amount of reactive power service they required. The Commission also identified the possibility that reactive power could potentially be supplied by ''a competitive market for such service'' if ''technology or industry changes'' made such a market possible.[7]

6. The Commission's policy on reactive power compensation has evolved since issuing Order No. 888 in 1996.[8] In Order No. 2003, the Commission adopted a standard agreement for the interconnection of large generating facilities (the *pro forma* LGIA), and specifically addressed the circumstances under which a transmission provider must pay an interconnection customer for reactive power depending upon whether such reactive power was inside or outside the standard power factor range.[9] This standard agreement included the requirement that interconnection customers maintain a composite power delivery at a continuous rate of power output at the generating facility's point of interconnection at a power factor within the range of 0.95 leading to 0.95 lagging when synchronized to the transmission system, unless the transmission provider has established a different power factor range.[10] Order No. 2003 required that a transmission provider compensate an interconnection customer for reactive power when the transmission provider requests that the interconnection customer operate its generating facility outside the established power factor range. With respect to reactive power within the established power factor range, the Commission concluded in Order No. 2003 that the interconnection customer should not be compensated for reactive power when operating within the range established in the interconnection agreement because doing so ''is only meeting [the generating facility's] obligation.''[11] However, in Order No. 2003–A, the Commission clarified that ''if the Transmission Provider pays its own or its affiliated generators for reactive power within the established range, it must also pay the Interconnection Customer.''[12] This standard is generally referred to as the ''comparability standard.''[13]

[2] Operating ''inside the standard power factor range'' refers to a generating facility providing reactive power within the power factor range set forth in the generating facility's interconnection agreement when the unit is online and synchronized to the transmission system. The standard power factor range is sometimes referred to as the ''deadband.'' *Compensation for Reactive Power Within the Standard Power Factor Range,* Notice of Proposed Rulemaking, 89 FR 21,454 (Mar. 28, 2024) (cross-referenced at 186 FERC ¶ 61,203, at P 2 n.1) (NOPR).

[3] MVAr is the typical unit of measurement for reactive power.

[4] A generating facility's leading reactive power indicates its ability to absorb reactive power, and its lagging reactive power indicates its ability to produce reactive power.

[5] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,705–07 & n.359.

[6] *Id.* at 31,720.

[7] *Id.* at 31,707 & n.359.

[8] *Id.* at 31,705–07 & n.359.

[9] *Standardization of Generator Interconnection Agreements & Procs.,* Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103, at P 546 (2003), *order on reh'g,* Order No. 2003–A, 69 FR 15932 (Mar. 26, 2004), 106 FERC ¶ 61,220, *order on reh'g,* Order No. 2003–B, 70 FR 265 (Jan. 4, 2005), 109 FERC ¶ 61,287 (2004), *order on reh'g,* Order No. 2003–C, 70 FR 37661 (June 30, 2005), 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007).

[10] The power factor is the ratio of a generating facility's real power to its apparent power, where apparent power is the total power output of the system (both real and reactive power). Power factors can range from 1.0 to 0.0, with 1.0 representing only real power and 0.0 representing only reactive power.

[11] Order No. 2003, 104 FERC ¶ 61,103 at P 546.

[12] Order No. 2003–A, 106 FERC ¶ 61,220 at P 416. Order No. 2003–A also exempted wind generating facilities from maintaining the established power factor range. *Id.* P 34.

[13] In Order No. 2006, the Commission adopted identical power factor and compensation requirements for small generating facilities (those with a capacity of 20 MW or less) and initially exempted small wind generating facilities from the reactive power requirement before Order No. 827 eliminated such exemptions. *Reactive Power Requirements for Non-Synchronous Generation,* Order No. 827, 81 FR 40793 (June 23, 2016), 155 FERC ¶ 61,277, *order on clarification and reh'g,* 157 FERC ¶ 61,003 (2016); *Standardization of Small Generator Interconnection Agreements & Procs.,* Order No. 2006, 111 FERC ¶ 61,220, *order on reh'g,* Order No. 2006–A, 70 FR 71760 (Nov. 30, 2005),

Continued

7. Order No. 661 established technical requirements for interconnecting large wind resources and maintained the exemption from providing reactive power, except where the transmission provider showed, through a system impact study, that reactive power capability was required to ensure safety or reliability.[14] In Order No. 2006,[15] the Commission adopted identical power factor and compensation requirements for small generating facilities (facilities that have a capacity of no more than 20 megawatts (MW)) but exempted small wind generating facilities from the reactive power requirement. Subsequently, in Order No. 827,[16] the Commission eliminated the exemptions for both small and large wind generating facilities, thus requiring those facilities to provide reactive power. The Commission explained that it had previously exempted wind generators from the uniform reactive power requirement because, historically, the costs to design and build a wind generator that could provide reactive power were high and could have created an obstacle to the development of wind generation. But the Commission found in Order No. 827 that, due to technological advancements since the establishment of those exemptions, the cost of providing reactive power no longer presented an obstacle to the development of wind generation, and therefore found that the exemptions had become unjust and unreasonable.[17] The Commission therefore required all newly interconnecting non-synchronous generating facilities to provide reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation transformer as a condition of interconnection.

8. In sum, ''Order Nos. 2003 and 2003–A establish a reactive power compensation policy that, in the first instance, treats the provision of reactive power inside the [standard power factor range] as an obligation of good utility practice rather than as a compensable service and permits compensation inside the [standard power factor range] only as a function of comparability.'' [18] ''Put differently, reactive support by generating facilities operating within the standard power factor range ensures that when these facilities inject real power—the product that their facilities exist to create and sell—onto the grid under normal conditions, they can do their part to maintain adequate voltages and to not threaten reliability.'' [19] By contrast, reactive power provided *outside* of the standard power factor range is considered an ancillary service for transmitting power across the transmission system to serve load,[20] and thus, the Commission has required compensation for such service.

9. Consistent with Order Nos. 2003 and 2003–A and Commission precedent that pre-dated those Orders, the Commission has permitted transmission providers to eliminate separate compensation for generating facilities providing reactive power within the standard power factor range.[21] In these cases, the Commission affirmed its determination that the provision of reactive power within the standard power factor range is not compensable except as a matter of comparability. For example, in *BPA,* the Commission granted a complaint filed by Bonneville Power Administration (BPA) arguing that the rate schedules of certain independent power producers (IPP) for reactive power within the standard power factor range, often referred to as a ''deadband,'' were no longer just and reasonable given BPA's decision to no longer pay its own or affiliated generators for providing this service.[22] The Commission found that ''Commission policy clearly allows BPA to discontinue paying all its merchants for inside the deadband reactive power service,'' explaining that ''[t]he Commission's policy is not new; we confirmed it in Order No. 2003, when we stated that an interconnecting generator 'should not be compensated for reactive power when operating its Generating Facility within the established power factor range, since it is only meeting its obligation.'' [23]

10. The Commission has also found that a transmission provider's decision to end compensation for reactive power within the standard power factor range does not compromise a generating facility's ability to recover costs that it may incur in producing reactive power within this range.[24] For example, the Commission has observed that generating facilities ''may be able to recover the costs for reactive power within the deadband in other ways—such as through higher power sales rates of their own.'' [25] In response to arguments by certain independent power producers that such recovery is infeasible because of competition, the Commission has found that ''since the incremental cost of reactive power service within the deadband is minimal, the infeasibility argument lacks plausibility. The purpose for which generation assets are built (including reactive power capability to maintain voltage levels for generation entering the grid) is to make sales of real power.'' [26]

11. The Commission made similar findings in *MISO,* wherein it accepted an FPA section 205 application by

113 FERC ¶ 61,195 (2005), *order granting clarification,* Order No. 2006–B, 71 FR 42587 (July 27, 2006), 116 FERC ¶ 61,046 (2006).

[14] *Interconnection for Wind Energy,* Order No. 661, 70 FR 34993 (June 16, 2005), 111 FERC ¶ 61,353, *order on reh'g,* Order No. 661–A, 70 FR 75005 (Dec. 19, 2005), 113 FERC ¶ 61,254 (2005).

[15] Order No. 2006, 111 FERC ¶ 61,220.

[16] Order No. 827, 155 FERC ¶ 61,277.

[17] *See also PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097, at P 28 (2015) (finding that, since Order No. 661, the cost of the technology necessary for a non-synchronous resource to provide reactive power has lessened such that the cost of installing equipment that is capable of providing reactive power is comparable to the costs of a traditional generator).

[18] *Bonneville Power Admin.* v. *Puget Sound Energy, Inc.,* 120 FERC ¶ 61,211 (2007) (*BPA*), *order denying reh'g and granting clarification,* 125 FERC ¶ 61,273, at P 18 (2008) (BPA Rehearing Order). *See also* BPA Rehearing Order, 125 FERC ¶ 61,273 at P 15 & n.24 (''[N]either affiliated nor non-affiliated generators have an inherent right to any compensation for reactive power inside the deadband.''). *Accord., Midcontinent Indep. Sys. Operator, Inc.,* 182 FERC ¶ 61,033 (*MISO*), *order on reh'g,* 184 FERC ¶ 61,022, at P 23 (2023) (MISO Rehearing Order); *Sw. Power Pool, Inc.,* 119 FERC ¶ 61,199 (*SPP*), *order on reh'g, Sw. Power Pool, Inc.,* 121 FERC ¶ 61,196, at 61,968 (2007) (SPP Order on Rehearing) (''[R]eactive power is required for an interconnecting generator to deliver its power and reactive power produced within the deadband and is, therefore, generally not compensable.''); *Mich. Elec. Transmission Co.,* 97 FERC ¶ 61,187, at 61,852–53 (2001) (*METC Rehearing Order*) (''Providing reactive power within design limitations is not providing an ancillary service; it is simply ensuring that a generator lives up to its obligations.''); *Consumers Energy Co.,* 94 FERC ¶ 61,230, at 61,834 (2000) (affirming the Commission's rejection of generators' request for reactive power compensation when operating within a facility's reactive power design limitation, stating that as a condition of interconnecting to the transmission provider's system, ''to ensure system security,'' the generator was required to provide equipment, ''*at its own cost,* to meet its reactive power obligations as provided for in [its interconnection agreement].''(emphasis added)); *cf. Dynegy Midwest Generation, Inc.,* 125 FERC ¶ 61,280, at P 16 (2008) (''Reactive power is a localized service that is quickly used by transmission system components and cannot be transported over long distances.'').

[19] MISO Rehearing Order, 184 FERC ¶ 61,022 at P 23.

[20] *See, e.g., id.* at PP 23–24 (citing METC Rehearing Order, 97 FERC at 61,852–53).

[21] *See, e.g., MISO,* 182 FERC ¶ 61,033 at PP 52–53; MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 26–27; *Pub. Serv. Co. of N.M.,* 178 FERC ¶ 61,088, at PP 29–31 (2022) (*PNM*); *Nev. Power Co.,* 179 FERC ¶ 61,103, at PP 20–21 (2022); *BPA,* 120 FERC ¶ 61,211 at P 20; *E.ON U.S. LLC,* 119 FERC ¶ 61,340, at P 15 (2007); *Entergy Servs., Inc.,* 113 FERC ¶ 61,040, at P 38 (2005).

[22] *BPA,* 120 FERC ¶ 61,211 at PP 19–20; BPA Rehearing Order, 125 FERC ¶ 61,273 at PP 10–11.

[23] *BPA, 120* FERC ¶ 61,211 at PP 19–20 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 546); METC Rehearing Order, 97 FERC at 61,852 (''Providing reactive power within design limitations is not providing an ancillary service; it is simply ensuring that a generator lives up to its obligations.'').

[24] *Id.* PP 19–22.

[25] *Id.* P 21 (citing *Sw. Power Pool, Inc.,* 119 FERC ¶ 61,199, at P 39).

[26] *Id.*

Midcontinent Independent System Operator, Inc. (MISO) transmission owners to end generator compensation for the provision of reactive power within the standard power factor range.[27] In accepting MISO transmission owners' proposal, the Commission reiterated its longstanding policy ''that the provision of reactive power within the standard power factor range is, in the first instance, an obligation of the interconnecting generator and good utility practice,'' such that ''MISO [transmission owners] do not have an obligation to continue to compensate an independent generator for reactive power within the standard power factor range when its own or affiliated generators are no longer being compensated.'' [28] The Commission also rejected any reliance arguments, reasoning in part that the provision of reactive power within the standard power factor range required little or no incremental investment given that, for both synchronous and non-synchronous generating facilities,[29] the same equipment is used for the production of real power and reactive power.[30] In addition, the Commission found that generating facilities have other opportunities, beyond Schedule 2, to seek to recover their costs of providing reactive power.[31]

12. Consistent with Order Nos. 2003 and 2003–A and other Commission precedent, multiple RTOs/ISOs and non-RTO/ISO transmission providers have elected not to compensate generating facilities for providing reactive power within the standard power factor range under Schedule 2 of their OATTs.[32]

13. Of the six Commission-jurisdictional RTOs/ISOs, only three currently compensate generating facilities for reactive power provided within the standard power factor range. Generating facilities in PJM Interconnection, L.L.C. (PJM) [33] generally use the cost-based AEP Methodology to calculate cost-of-service rates for the production of reactive power.[34] Because the same generation equipment contributes to the production of both real power and reactive power, the AEP Methodology allocates the costs of each piece of equipment to real power service and reactive power service by assigning the cost of each piece of equipment to either real power service, reactive power service, or both. ISO New England Inc. (ISO–NE) [35] and New York Independent System Operator, Inc. (NYISO) [36] compensate generating facilities for reactive power under flat rate designs that are adjusted for inflation.[37]

14. California Independent System Operator Corporation (CAISO),[38] Southwest Power Pool, Inc. (SPP),[39] and MISO [40] do not pay separately for reactive power within the standard power factor range.

15. Outside the RTOs/ISOs, transmission providers that pay for the provision of reactive power within the standard power factor range generally use the AEP Methodology to set reactive power compensation on an individual generating facility basis. Many non-RTO/ISO transmission providers do not pay separately for reactive power provided within the standard power factor range.[41]

[27] *MISO,* 182 FERC ¶ 61,033 at P 53 (''Bearing in mind that the provision of reactive power within the standard power factor range is, in the first instance, an obligation of the interconnecting generator and good utility practice, MISO [transmission owners] do not have an obligation to continue to compensate an independent generator for reactive power within the standard power factor range when its own or affiliated generators are no longer being compensated.'' (citation omitted)); *see also PNM,* 178 FERC ¶ 61,088 at PP 29, 33 (accepting PNM's revisions to eliminate compensation for reactive service under Schedule 2 and rejecting generators' arguments that it is ''just and reasonable for it to be compensated for investments made'' to provide reactive support consistent with interconnection requirements even though PNM elected to no longer pay its own or affiliated generators for such reactive power).

[28] *MISO,* 182 FERC ¶ 61,033 at P 53. The Commission found ''those protests that challenge these well-established policies to be collateral attacks on these earlier determinations.'' *Id.*

[29] Synchronous generating facilities (*e.g.,* coal, gas, nuclear resources) produce electricity in sync with the transmission system at the system frequency. Non-synchronous generating facilities (*e.g.,* solar, wind, battery storage resources) produce electricity that is initially not in sync with the transmission system and use inverters to convert their electrical output to synchronize with the transmission system. *See* FERC, *Payment for Reactive Power,* 7 (Apr. 22, 2014) (2014 Staff Report), *https://www.ferc.gov/sites/default/files/2020-05/04-11-14-reactive-power.pdf.*

[30] MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 29–30 (citing *S. Co. Servs., Inc.,* 80 FERC ¶ 61,318, at 62,091 (1997) (noting also that the primary function of a generating plant is to produce real power; thus, if costs were allocated based on the ''predominant'' function of the equipment, ''all of the costs of generation would thus be assigned to real power production and there would be no basis for any separate reactive power charge''); *BPA,* 120 FERC ¶ 61,211 at P 21 (finding that the incremental cost of reactive power service within the standard power factor range is minimal); METC Rehearing Order, 97 FERC at 61,852–53 (''[R]eactive power provided, not as an ancillary service, but rather as a 'no cost' service within reactive design limitations, may therefore, be provided without compensation.'').

[31] MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 40–42; *SPP,* 119 FERC ¶ 61,199 at P 39 (stating that IPPs ''are free to negotiate rates that they charge their customers for real power that are sufficient to compensate them for any costs that they may incur in producing reactive power within their deadbands, just as affiliated generators may seek to negotiate rates that they charge their customers that are sufficient to compensate them for the costs of any reactive power that they provide within their deadbands.'').

[32] *See, e.g., MISO,* 182 FERC ¶ 61,033 at PP 52–53; MISO Rehearing Order, 184 FERC ¶ 61,022 at P 26; *PNM,* 178 FERC ¶ 61,088 at PP 29–31; *Nev. Power Co.,* 179 FERC ¶ 61,103 at PP 20–21; *BPA,* 120 FERC ¶ 61,211 at P 20; *E.ON U.S. LLC,* 119 FERC ¶ 61,340 at P 15; *Entergy Servs., Inc.,* 113 FERC ¶ 61,040 at P 38.

[33] PJM Interconnection, L.L.C., Intra-PJM Tariffs, OATT Schedule 2, (Reactive Supply and Voltage Control from Generation or Other Sources Service) (4.0.0).

[34] The AEP Methodology derives its name from Opinion No. 440, where the Commission approved AEP's, a vertically integrated utility, method for calculating the costs of synchronous generation equipment associated with the production of reactive power. *See Am. Elec. Power Serv. Corp.,* Opinion No. 440, 88 FERC ¶ 61,141 (1999), *order on reh'g,* 92 FERC ¶ 61,001 (2000). In *WPS Westwood,* the Commission recommended that all generating facilities that have actual cost data and support documentation use the AEP Methodology. *See WPS Westwood Generation, LLC,* 101 FERC ¶ 61,290, at P 14 (2002).

[35] ISO New England Inc., ISO New England Inc. Transmission, Markets and Services Tariff, Schedule 2 (Reactive Supply and Voltage Control Service) (8.0.0).

[36] New York Independent System Operator, Inc., NYISO Tariffs, NYISO OATT, § 6.2 OATT Schedule 2 (Charges For Voltage Support Service) (6.0.0).

[37] Both ISO–NE and NYISO proposed their respective reactive power capability compensation mechanisms pursuant to section 205 filings. *See ISO New England Inc.,* 122 FERC ¶ 61,056, at P 1 (2008) (settling, in part, for a new flat rate in $/kVAR-yr). *N.Y. Indep. Sys. Operator, Inc.,* Docket No. ER02–617–000 (Feb. 5, 2002) (delegated order accepting NYISO's amended Rate Schedule 2 of the Market Administration and Control Area Services Tariff).

[38] CAISO never provided compensation for reactive power within the standard power factor range. *See Cal. Indep. Sys. Operator Corp.,* 160 FERC ¶ 61,035, at P 7 (2017) (explaining that CAISO considered the possibility of compensating generating facilities for reactive power in its stakeholder process, but decided against it, reasoning that the ability to provide reactive power is part of a generator's fixed costs, which are recovered through power purchase agreements).

[39] *SPP,* 119 FERC ¶ 61,199 at P 30.

[40] *MISO,* 182 FERC ¶ 61,033 at PP 52–66; MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 23–55.

[41] *See, e.g.,* Arizona Public Service Company, FERC Electric Tariff Vol. No. 2, Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources Service) (6.0.0) (''This service will be provided at no charge until [Arizona Public Service Company] has developed a rate that has been filed with the Commission and allowed to be implemented; however, Transmission Customers taking service at transmission voltage levels shall be responsible for maintaining a power factor of ± 95.0%, and Transmission Customers taking service at distribution voltage levels shall maintain a power factor of not less than 90% lagging but in no event leading, unless agreed to by [Arizona Public Service Company].''); Public Service Company of New Mexico, PNM Open Access Transmission Tariff, Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources Service) (2.1.0) (''As of October 1, 2021, the Effective Date of this Schedule 2, the Transmission Provider is not charging for Reactive Supply and Voltage Control from Generation or Other Sources Service from its own resources. As a result, there will be no separate charge for such service.'').

B. Notice of Inquiry and Notice of Proposed Rulemaking

16. On November 18, 2021, the Commission issued a Notice of Inquiry (NOI) [42] in this proceeding, seeking comment on various issues regarding reactive power compensation and market design as a result of the significant changes that have taken place in the electric industry in the last two decades, including changes in the generation resource mix and a general shift away from cost-of-service rates for generating facilities selling into Commission-jurisdictional markets. Generally, the Commission sought to ''examine whether the current regime for reactive power capability compensation requires revisions to ensure that payments for reactive power capability accurately reflect the costs associated with reactive power capability.'' [43]

17. On March 21, 2024, the Commission issued a NOPR in this same proceeding. Based on a review of the comments submitted in response to the Commission's NOI in the instant docket, as well as the Commission's experience in the years since the issuance of Order Nos. 2003 and 2003–A, the NOPR preliminarily found that where transmission providers require transmission customers to pay for the provision of reactive power within the standard power factor range, transmission rates may be unjust and unreasonable, as they include costs without a sufficient economic basis or justification. In support of such preliminary finding, the NOPR explained that generating facilities provide reactive power within the standard power factor range at no cost or *de minimis* cost, and that providing reactive power within the standard power factor range is already an obligation of the generating facility as an interconnection customer and consistent with good utility practice.[44] The NOPR also stated that current compensation may result in undue compensation or other market distortions. The NOPR proposed, pursuant to FPA section 206,[45] that a just and reasonable replacement rate was to prohibit transmission providers from including in their transmission rates any charges associated with the supply of reactive power within the standard power factor range from a generating facility.

18. Specifically, the NOPR proposed to add the following sentence to the end of Schedule 2 of the *pro forma* OATT: [46] ''However, such rates shall not include compensation to generating facilities for the supply of reactive power within the power factor range specified in its interconnection agreement.'' Second, the NOPR proposed to remove the following clause from section 9.6.3 of the *pro forma* LGIA: [47] ''provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer.'' Third, the NOPR proposed to remove the following sentence from section 1.8.2 of the *pro forma* SGIA: [48] ''In addition, if the Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.''

19. Comments on the NOPR were due on June 26, 2024. Thirty-one parties filed comments.[49] Comments were submitted by RTOs/ISOs and other transmission providers, generating facilities, generation developers, transmission owners, load-serving entities (LSE), Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM (PJM IMM), trade associations representing specific generation technologies, and consumer advocates. Of these, and with few exceptions, transmission owners, LSEs, the PJM IMM, independent filers,[50] and consumer advocates supported or did not oppose the NOPR proposal to eliminate compensation in the standard power factor range,[51] while generating facilities, generation developers, and trade associations representing specific generation technologies oppose the NOPR proposal.[52]

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

[43] *Id.* P 19.

[44] Real power, which accomplishes useful work (*e.g.,* runs motors), is typically measured in MWs.

[45] 16 U.S.C. 824e.

[46] *See pro forma* OATT, Schedule 2.

[47] *See pro forma* LGIA, § 9.6.3.

[48] *See pro forma* SGIA, § 1.8.2.

[49] *See* app. A.

[50] C T Gaunt states that reactive power cannot be delivered and also that it cannot be lost in transmission through a transformer or power system. Thus, C T Gaunt claims that there are no grounds for arguing against the Commission's determination in the NOPR. C T Gaunt Reply Comments at 2–3.

[51] American Electric Power Service Corporation (AEP) (on behalf of itself and its affiliates, including Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, Public Service Company of Oklahoma, Southwestern Electric Power Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., AEP West Virginia Transmission Company, Inc., AEP Oklahoma Transmission Company, Inc., and AEP Southwestern Transmission Company, Inc.); Ameren Service Company (Ameren) (on behalf of Ameren Illinois Company d/b/a Ameren Illinois, Union Electric Company d/b/a Ameren Missouri and Ameren Transmission Company of Illinois); C T Gaunt; New England Consumer Advocates (consisting of the Office of Massachusetts Attorney General Andrea Joy Campbell, the Connecticut Office of Consumer Counsel, the Maine Office of Public Advocate, the New Hampshire Office of Consumer Advocate, and the Rhode Island Division of Public Utilities and Carriers); Joint Consumer Advocates (including the Illinois Attorney General, Illinois Citizens Utility Board, Maryland Office of People's Counsel, the New Jersey Division of Rate Counsel, the North Carolina Utilities Commission Public Staff, the Office of the People's Counsel for the District of Columbia, and the West Virginia Consumer Advocate Division of the Public Service Commission), Joint Customers (including Old Dominion Electric Cooperative, Northern Virginia Electric Cooperative, Inc., and Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company d/b/a Dominion Energy Virginia); Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty (Liberty); MISO; MISO Transmission Owners (including Ameren, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois; Arkansas Electric Cooperative Corporation; City Water, Light & Power; Cooperative Energy; Dairyland Power Cooperative; East Texas Electric Cooperative; Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC; Entergy Texas, Inc.; Great River Energy; Indianapolis Power & Light Company; Lafayette Utilities System; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Services; Montana-Dakota Utilities Co.; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power, Inc.; Southern Indiana Gas & Electric Company (d/b/a CenterPoint Energy Indiana South); and Southern Minnesota Municipal Power Agency); the Ohio Office of the Federal Energy Advocate of the Public Utilities Commission of Ohio (Ohio FEA); Portland General Electric Company (PGE); PJM; the PJM IMM; the Transmission Access Policy Study Group (TAPS) (an association of transmission dependent utilities in 35 states). For convenience, we have listed each commenter and the parties they represent. For brevity, for the remainder of this rule, we will refer to each commenter by their abbreviated names as defined in this footnote.

[52] The American Council on Renewable Energy (ACORE); Calpine Corporation (Calpine); Eagle Creek Reactive Generators (including Mahoning Creek Hydroelectric Company, LLC, York Haven Power Company, LLC, Eagle Creek Reusens Hydro, LLC, Great Falls Hydroelectric Company Limited Partnership, Lake Lynn Generation, LLC, PE Hydro Generation, LLC, Black River Hydroelectric, LLC, All Dams Generation, LLC, and Eagle Creek Hydro Power, LLC); EDP Renewables North America LLC (EDPR); Elevate Renewables F7, LLC (Elevate); Generation Developers (including Vistra Corp. and Dynegy Marketing and Trade, LLC); Glenvale LLC (Glenvale); Indicated Reactive Power Suppliers (including KMC Thermo, LLC, Bitter Ridge Wind Farm, LLC, Guernsey Power Station LLC, Moxie Freedom LLC, Safe Harbor Water Power Corporation, BIF III Holtwood LLC, Brookfield Power Piney & Deep Creek LLC, Erie Boulevard Hydropower, L.P., Carr Street Generating Station, L.P., Bear Swamp Power Company LLC, Brookfield White Pine Hydro LLC, Brookfield Renewable Trading and Marketing LP, and Reworld Waste, LLC

II. Discussion

20. In this final determination, the Commission adopts the NOPR as proposed, except with respect to the timing of the compliance procedures and implementation. Based on our review of the record, we find there is substantial evidence to support the conclusion that allowing transmission providers to charge transmission customers for a generating facility's provision of reactive power within the standard power factor range results in unjust and unreasonable transmission rates. As explained in the NOPR, generating facilities providing reactive power within the standard power factor range are only meeting their obligations under their interconnection agreements and in accordance with good utility practice, and in doing so, incur no or at most *de minimis* variable costs beyond the cost of providing real power. Moreover, providing compensation for the provision of reactive power within the standard power factor range risks overcompensation and market distortion in ways that did not exist prior to the existence of organized markets.

21. We find that these reforms will not adversely impact reliability. We also find that generating facilities have the opportunity to seek to recover any costs associated with providing reactive power within the standard power factor range through their rates for selling real power, including energy or capacity sales, whether in organized or bilateral markets. Given that the primary function of a generating facility is to produce real power and that the provision of reactive power within the standard power factor range is necessary for the provision of real power, we find that the existing means of cost recovery for real power are not only reasonable but also the most logical outcome.

22. Based on more than two decades of experience since Order No. 2003, and the record developed in this proceeding, we find that, even as a function of comparability, charging transmission customers under Schedule 2 for the provision of reactive power within the standard power factor range has become unjust and unreasonable. As explained above and for the reasons discussed below, in Order No. 2003, the Commission found generators should not receive compensation for the provision of reactive power within the standard power factor as it was an obligation of good utility practice. Based on rehearing requests, in Order No. 2003–A, the Commission agreed that where vertically integrated transmission owners continued to have rate schedules providing payment to their affiliated generating facilities for reactive power service within the standard power factor range, such transmission owners were also required to pay non-affiliated interconnection customers for the same provision of reactive power. At the time of Order Nos. 2003 and 2003–A, functional unbundling of transmission service [53] and the development of organized wholesale electricity markets [54] were relatively nascent, and so too was the Commission's experience with the impacts of establishing the comparability standard for the provision of reactive power within the standard power factor range. At the time, establishing the comparability standard appeared consistent with Order No. 2003's stated intent of ''minimiz[ing] opportunities for undue discrimination and expedit[ing] the development of new generation, while protecting reliability and ensuring that rates are just and reasonable.'' [55]

23. Since Order No. 2003, however, many industry changes have occurred. Some vertically integrated utilities have divested their generation. Competitive markets have developed, leading many generators to recover their costs through market-based rather than cost-based rates. The development of competitive markets makes even more challenging any allocation of costs between real power production, under market-based rates, and reactive power service, under cost of service rates.[56] When rates are market-based, challenges in allocation will affect the competitive positions of the entities.[57] New technologies have developed that provide reactive power through different means and to which the AEP Methodology that predates these technologies does not squarely apply. With fewer vertically integrated utilities, the continued development of competitive markets, and new technologies, the initial justification for compensation (*i.e.,* that the Commission required separate compensation on a comparable basis because vertically integrated transmission owners continued to have rate schedules providing payment to their affiliated generating facilities for reactive power service) is no longer broadly applicable. Indeed, the wide-ranging rates for reactive power resulting from cost-of-service proceedings further undermine the principle of comparability as some generating facilities now receive substantially higher rates for the provision of reactive power within the

f/k/a Covanta; Independent Power Producers of New York, Inc. (IPPNY); Indicated Trade Associations (including Electric Power Supply Association, The PJM Power Providers Group the New England Power Generators Association, Inc., Independent Power Producers of New York, Inc., the Coalition of Midwest Power Producers); ISO–NE; Middle River Power LLC (including Coalition of Midwest Power Producers, the Electric Power Supply Association, the PJM Power Providers Group, the New England Power Generators Association, Inc., and the Independent Power Producers of New York, Inc.); National Hydropower Association (NHA) (a national trade association with over 320 member companies); New England Power Generators Association, Inc. (NEPGA); New England Power Pool (NEPOOL); New England States Committee on Electricity (NESCOE); Nuclear Energy Institute (NEI); North American Generator Forum (NAGF); NYISO; Onward Energy Holdings, LLC (Onward Energy); PSEG (including Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC, and each wholly owned, direct or indirect subsidiaries of Public Service Enterprise Group Incorporated) (PSEG); Reactive Service Providers (including CIP, D. E. Shaw Renewable Investments, L.L.C., Invenergy Renewables LLC, Leeward Renewable Energy, LLC, Lightsource Renewable Energy Operations, LLC, NextEra Energy Resources, LLC,1 Ørsted Wind Power North America, LLC, and RWE Clean Energy, LLC); Clean Energy Associations (including Solar Energy Industries Association (SEIA) and American Clean Power Association (ACP)). For brevity, for the remainder of this rule, we will refer to each commenter by their abbreviated names as defined in this footnote.

[53] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,654 (''We conclude that functional unbundling of wholesale services is necessary to implement non-discriminatory open access transmission.'').

[54] *Regional Transmission Orgs.,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999) (cross-referenced at 89 FERC ¶ 61,285) (''We conclude that properly structured RTOs throughout the United States can provide significant benefits in the operation of the transmission grid.''), *order on reh'g,* Order No. 2000–A, FERC Stats. & Regs. ¶ 31,092 (2000) (cross-referenced at 90 FERC ¶ 61,201), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish Cty.* v. *FERC,* 272 F.3d 607 (D.C. Cir. 2001).

[55] *See, e.g.,* Order No. 2003, 104 FERC ¶ 61,103 at P 12 (explaining that standard interconnection procedures and a standard agreement will: ''(1) limit opportunities for Transmission Providers to favor their own generation; (2) facilitate market entry for generation competitors by reducing interconnection costs and time; and (3) encourage needed investment in generator and transmission infrastructure'').

[56] *See* In re Permian Basin Area Rate Cases, 390 U.S. at 804 (''There is ample support for the Commission's judgment that the apportionment of actual costs between two jointly produced commodities, only one of which is regulated by the Commission, is intrinsically unreliable.''); *A.A. Poultry Farms, Inc.* v. *Rose Acre Farms, Inc.,* 881 F.2d 1396, 1400 (7th Cir. 1989) (''How does one allocate the cost of activities that have joint products? Agencies engaged in ratemaking struggle with these problems for years, even decades, without producing clear answers.''); Richard A. Posner, Natural Monopoly and Its Regulation, 21 Stan. L. Rev. 548, 595 (1969) (''where services involve joint or common costs a rational allocation is impossible even in theory. How much of the cost of a telephone handset is assignable to local and how much to interstate telephone service?'').

[57] When both real power and reactive power rates were cost-based, the only effect of the allocation was to change the allocation of costs and the rates for transmission and generation service; the transmission provider would not exceed its total revenue requirement.

standard power factor range than others.[58]

24. All of these changes taken together, coupled with the record developed here, make clear that separate compensation for the provision of reactive power within the standard power factor range results in unjust and unreasonable rates to transmission customers, because such compensation is not necessary for comparability or to ensure continued investment in the capability of generating facilities to provide reactive power within the standard power factor range.[59] We acknowledge that this final determination represents a change in policy,[60] a change we find appropriate based on the record before us, as explained in detail herein.[61]

25. Accordingly, we are modifying Schedule 2 of the *pro forma* OATT, section 9.6.3 of the *pro forma* LGIA, and section 1.8.2 of the *pro forma* SGIA, and we are requiring transmission providers to make corresponding revisions to their OATTs and *pro forma* interconnection agreements, to prohibit transmission providers from including in their transmission rates any charges associated with the provision of reactive power within the standard power factor range from generating facilities.

26. We discuss below the issues raised in the comments.

A. Need for Reform

27. The NOPR preliminarily found that where transmission providers require transmission customers to pay for generating facilities' provision of reactive power within the standard power factor range, transmission rates may be unjust and unreasonable, as such rates may include costs without a sufficient economic basis or justification and such costs may not result in transmission customers receiving commensurate reliability benefits.[62] In support of the need for reform, the NOPR preliminarily found that generating facilities providing reactive power within the standard power factor range are only meeting their obligations under their interconnection agreements and in accordance with good utility practice, and in doing so, incur no or at most a *de minimis* increase in variable costs beyond the cost of providing real power.[63] The NOPR also highlighted various adverse impacts of the Commission's policy on reactive power compensation, which have been exacerbated by the increasing volume of filings for reactive power compensation and in turn, increasing reactive power-related costs to transmission customers.[64] For example, in many regions, generating facilities are sited without regard to where there is a geographic need for reactive power, which is significant given that unlike real power, reactive power cannot be efficiently transmitted long distances.[65] Additionally, adjudicating cost-of-service reactive power rates has become increasingly administratively burdensome and may result in inconsistent rate treatment across generating facilities.[66] Furthermore, in regions where generating facilities may seek to recover their costs by participating in organized competitive wholesale markets, providing separate compensation for the provision of reactive power within the standard power factor range risks overcompensation and market distortion in ways that did not exist prior to the existence of organized markets.[67] Finally, as explained in the NOPR, the costs to transmission customers have increased substantially without any commensurate increase in benefits.[68]

28. The NOPR also preliminarily found that cessation of payments for reactive power within the standard power factor range for generating facilities does not compromise a generating facility's ability to recover costs–if any–that it may incur in producing reactive power within such range because generating facilities have the opportunity to seek to recover such costs in other ways, such as through energy or capacity sales.[69]

1. Comments

29. AEP, Ameren, Joint Consumer Advocates, Joint Customers, MISO Transmission Owners, New England Consumer Advocates, Ohio FEA, PGE, PJM, the PJM IMM, and TAPS agree there is a need for reform and, accordingly, support the NOPR proposal to eliminate compensation for reactive power within the standard power factor range.[70]

30. Many commenters argue that there is substantial evidence to support the conclusion that allowing transmission providers to charge transmission customers for a generating facility's provision of reactive power from within the standard power factor range results in unjust and unreasonable transmission rates.[71] They also agree that current generator compensation for the provision of reactive power within the standard power factor range lacks sufficient economic basis or justification,[72] and that customers may

[58] The PJM IMM notes that total settled reactive power revenue requirements for oil-fueled steam units average $993/MW-year whereas other units have settled reactive power revenue requirements as high as $18,750/MW-year. IMM Initial Comments at 5.

[59] *See, e.g.,* PJM IMM Initial Comments at 11–12 (''The salient difference between PJM and CAISO, SPP, and MISO is that PJM customers paid $388,044,837.00 in out of market payments for reactive capability in 2023, and customers in CAISO, SPP and MISO, paid $0.00''); For Schedule 2 service in 2023, PJM paid $388 million, NYISO paid $75 million, and ISO–NE paid $18 million. *See* PJM 2023 Annual Report at 5, *https://services.pjm.com/annualreport2023/*); 2023 NYISO Voltage Support Service Rates, *https://www.nyiso.com/documents/20142/35126567/2023-OATT-MST-Schedule-2-VSS-Rates-FINAL-for-posting.pdf/f59317b0-41c6-9f41-5d61-e7f502af82c2*); 2023 Annual Markets Report at 154, *iso-ne.com/static-assets/documents/100011/2023-annual-markets-report.pdf.*

[60] *See* Order No. 2003–C, 111 FERC ¶ 61,401 at P 42 (finding that because providing reactive power within the established range is an ''important service,'' payment for such service does not constitute a ''windfall'').

[61] *PJM Power Providers Grp.* v. *FERC,* 88 F.4th 250, 271–72 (3d Cir. 2023), *amended sub nom. PJM Power Provisers Grp.* v. *FERC,* No. 21–3068, 2024 WL 259448 (3d Cir. Jan. 24, 2024) (''An agency may alter its 'view of what is in the public interest.' The fact that contrary agency precedent exists 'gives us no more power than usual to question the Commission's substantive determinations.' The agency need not establish that 'the reasons for the new policy are better than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency believes it to be better.' '') (citing *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009)); *In re Permian Basin Area Rate Cases,* 390 U.S. 747, 784 (1968) (*Permian Basin*); *see also Motor Vehicle Mfrs. Ass'n of U.S., Inc.* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 42 (1983) (''[W]e fully recognize that regulatory agencies do not establish rules of conduct to last forever.'') (internal quotations omitted); *Greater Bos. Television Corp.* v. *FCC,* 444 F.2d 841, 852 (D.C. Cir. 1970) (an agency may change its course as long as it ''suppl[ies] a reasoned analysis indicating that prior policies and standards are being deliberately changed, not casually ignored.''), *cert. denied,* 403 U.S. 923 (1971)).

[62] NOPR, 186 FERC ¶ 61,203 at PP 25, 40.

[63] *Id.* PP 28–33.

[64] *Id.* PP 34–40.

[65] *Id.* P 35.

[66] *Id.* PP 36–38.

[67] *Id.* P 39.

[68] *Id.* P 40.

[69] *Id.* P 42.

[70] AEP Initial Comments at 1–2; Ameren Initial Comments at 2–3; Joint Consumer Advocates Initial Comments at 1; Joint Customers Initial Comments at 2; MISO Transmission Owners Initial Comments at 1, 5; New England Consumer Advocates Initial Comments at 6; Ohio FEA Initial Comments at 3; PGE Initial Comments at 1; PJM Initial Comments at 1, 3; PJM IMM Initial Comments at 2; TAPS Initial Comments at 1.

[71] *See, e.g.,* Joint Customers Reply Comments at 10–11 (''Standing on its own, the record in this proceeding is sufficient to justify the conclusion that compensating generators, any generators, for reactive service within the standard power factor range is not just and reasonable. Through the NOI comments, the development of the NOPR, and comments to the NOPR, the Commission has supported its conclusions and addressed potential concerns.'').

[72] Joint Consumer Advocates Initial Comments at 1, 5; Joint Customers Initial Comments at 5–6; Joint Customers Reply Comments at 1–2; MISO Transmission Owners Reply Comments at 2; PGE Initial Comments at 5; TAPS Initial Comments at 3.

not be receiving commensurate reliability benefits.[73]

31. Joint Customers maintain, for example, that the NOPR builds on longstanding Commission policy, reaffirmed since Order No. 2003, that no compensation is appropriate for reactive service within the standard power factor range and that challenges to the sufficiency of the record or the process are unfounded.[74] Joint Customers explain that ''[t]he only *change* the Commission is making in the NOPR is to determine that transmission providers no longer should have the option to compensate, affiliate and non-affiliate alike. And for that discrete change, that the *exception* to the general rule on compensation should be closed, the Commission has plainly created a sufficient record.'' [75]

32. PJM supports the NOPR and asserts that it would largely eliminate the problems with the current reactive power compensation regime in PJM, including the resource-intensive administrative burdens of reactive power rate proceedings and the ''black box'' settlements that ''seem[ ] at odds with the Commission's general precedent on efficient energy and ancillary service price formation.'' [76] MISO explains that it has not experienced reliability concerns since eliminating compensation for reactive power within the standard power factor range in December 2022 [77] and that it would not expect to see any effect on reliability through eliminating compensation for reactive power within the standard power factor range.[78]

33. MISO Transmission Owners support the need for reform, arguing that the current framework for reactive power compensation is neither just nor reasonable given that it results in transmission customers being required to pay for a service that generators already are required to provide and that costs them little or nothing to provide.[79]

34. Many commenters agree that the current reactive power framework does not result in commensurate reliability benefits.[80] First, many commenters agree that compensation for providing reactive power within the standard power factor range is unnecessary to maintain reliability.[81] Second, many commenters also agree with the NOPR that under the current framework, compensation for reactive power within the standard power factor range is not tied to whether there is a particular geographic need for reactive power.[82] TAPS, for example, contends that the existing approach to reactive power capability compensation does not adequately consider a generator's actual contribution to reliability or lack thereof and thus requires consumers to pay excessive charges for reactive power that may not be needed or is in the wrong location.[83] Similarly, Joint Customers contend that ''[t]his incentive structure to provide payment based on reactive capability results in the building of unnecessary capabilities in locations it is not or may not be needed and does not allocate the costs associated with reactive capability in a manner that is at least roughly commensurate with the benefits received.'' [84]

35. Further, like PJM, many commenters agree with the NOPR regarding the administrative burden for all parties to determine Schedule 2 rates.[85] Joint Consumer Advocates argue that ''the existing compensation framework for generators that supply reactive power has led to unjust and unreasonable rates'' and note that ''[d]ue to limited resources, the [Joint Consumer Advocates] have generally been unable to participate in the numerous reactive proceedings and assist the Commission with the review and scrutiny of generator submissions. But such review and scrutiny are essential given the sheer number of filings and the absence of standardized accounting for the costs claimed in them by generators.'' [86]

36. AEP states that it supports the Commission's proposal to prospectively terminate reactive power compensation to generators for maintaining the ability to produce reactive power within the standard power factor range because it ''will more equitably balance the interests of customers and generators, ensure that reactive power will continue to be provided as a requirement of interconnection, and significantly decrease the administrative burdens associated with individualized, opaque, and inconsistent cost-of-service reactive power rate proceedings.'' [87]

37. Similarly, New England Consumer Advocates state that ''[t]ransmission rates have been rising in recent years and costs are only expected to increase in the near term to accommodate projected future transmission system

[73] Joint Customers Initial Comments at 13–17; MISO Transmission Owners Reply Comments at 8, 19; New England Consumer Advocates Initial Comments at 4–6; TAPS Initial Comments at 3.

[74] Joint Customers Reply Comments at 10–11.

[75] *Id.* at 11 (emphasis in original).

[76] PJM Initial Comments at 1–3.

[77] MISO Initial Comments at 2.

[78] *Id.*

[79] MISO Transmission Owners Initial Comments at 5.

[80] Joint Customers Initial Comments at 12; MISO Transmission Owners Initial Comments at 19; MISO Transmission Owners Reply Comments at 3–5; New England Consumer Advocates Initial Comments at 4–6; TAPS Initial Comments at 3–5.

[81] *See, e.g.,* PJM IMM Initial Comments at 11–12 (''There will be no adverse reliability impacts in PJM (or other similarly situated regions) for the same reasons that . . . there have been no observable impacts in regions that do not compensate generating facilities for the supply of reactive power with the standard power factor range. As in the case of CAISO, SPP and MISO, new and existing generating facilities in PJM are required to provide reactive power within the standard power factor range as a condition of obtaining and maintaining interconnection service. There is no evidence that expanding the just and reasonable approach to compensation already in place in CAISO, SPP and MISO to PJM will have any adverse impact on reliability in PJM.''); MISO Transmission Owners Initial Comments at 13 (''When the MISO Transmission Owners proposed to eliminate compensation for producing reactive power within the deadband, the most common protest from generators was that it would impact the reliability of the grid. However, such claims are not supported by evidence and distract from the underlying fact that generators are obligated to provide reactive power within the deadband whether or not they are compensated for it.'' (citations omitted)).

[82] *See, e.g.,* Ohio FEA Initial Comments at 5 (''As a result, in areas like PJM, generators currently receive compensation regardless of proximity to locations on the transmission system where there is an actual need for additional reactive power.''); Joint Customers Initial Comments at 17 (''Further, the failure to account for transmission system needs or grid geography in the current regime in regions like PJM undermine the reliability benefits of generators that interconnect to the system with reactive capabilities, whether meeting or exceeding their baseline interconnection requirements. The current paradigm has resulted in the development and deployment of generator based reactive capability that is ill-suited to the needs of the transmission system, and specifically that is well in excess of needs. Eliminating the incentive to overbuild reactive capability will not negatively impact reliability.'').

[83] TAPS Initial Comments at 4–5.

[84] Joint Customers Initial Comments at 12 (citing *Ill. Com. Comm'n.* v. *FERC,* 576 F.3d 470, 477 (7th Cir. 2009)).

[85] AEP Initial Comments at 4–6; Joint Customers Initial Comments at 1–5; PJM IMM Initial Comments at 9.

[86] Joint Consumer Advocates Initial Comments at 7. *See also* PJM IMM Initial Comments at 9 (''Applying cost of service rules is costly, burdensome and unnecessary. Most reactive proceedings for generators in PJM are resolved in black box settlements that require substantial time and resources from all parties, fail to address the merits of the cost support provided, result from an unsupported split the difference approach, and that produce a wide, unreasonable and discriminatory disparity among the rates per paid per MW-year for the same service.''); Joint Customers Initial Comments at 7 (''As well documented in comments to the NOI and described in the NOPR, the current individualized consideration of reactive filings purporting to apply the *AEP* [M]ethodology places a heavy burden on customers, Transmission Providers, and the Commission while resulting in customer charges with dubious connection to any clear benefits to the customers paying those charges. This combination created an intolerable condition necessitating Commission action to reform the compensation structure.'').

[87] AEP Initial Comments at 4–5.

needs. At this time of increasingly onerous retail energy costs, particularly in New England, the Commission must ensure that transmission providers are passing on to consumers only those costs which are just and reasonable, and for which consumers receive commensurate benefit.'' [88]

38. The PJM IMM argues that opposing comments come largely from generation owners opposed to the removal of subsidies that have benefited them, even though such subsidies are primarily the result of the ''nonsensical, wasteful and unworkable'' attempts to allocate a portion of costs recoverable in markets to a guaranteed reactive payment based on an outdated and arbitrary cost-of-service approach referred to as the AEP Methodology.[89]

39. Other commenters opposed the NOPR, arguing that existing reactive power rates remain just and reasonable.[90] Reactive Service Providers argue that ''changes to cost allocation'' following Order No. 888 (*i.e.,* functional unbundling) do not warrant a change to reactive power compensation.[91] Reactive Service Providers contend that reactive power supply being unaffected in regions where transmission providers no longer pay for reactive power is not evidence that reactive power compensation is unjust and unreasonable,[92] that the ''comparability'' policy cannot be used as a basis to end compensation,[93] that administrative burden is not a basis to find that compensation is unjust and unreasonable,[94] and that inconsistent rate treatment across generating facilities does not mean that compensation is unjust and unreasonable.[95]

40. Reactive Service Providers argue that the Commission should study individual generating facilities to determine if reactive power is still needed.[96] Reactive Service Providers also argue that the Commission must ensure that compensation for providing reactive power outside the standard power factor range is adequate.[97]

41. Indicated Trade Associations assert that the NOPR would grant transmission providers unlawfully preferential treatment, creating a preference for higher cost transmission solutions, and suggest that the Commission should withdraw the NOPR proposal and refocus its efforts on improving the methodologies used to determine reactive power rates.[98] Further, Indicated Trade Associations assert that concerns raised about the AEP Methodology being burdensome and a lack of refund protections for customers do not justify eliminating reactive power compensation within the standard power factor range altogether.[99]

42. ISO–NE argues that ISO–NE's Schedule 2 VAR compensation program should not be disturbed.[100] ISO–NE asserts that its treatment of reactive power is distinct from its energy and capacity markets.[101] ISO–NE further states that its VAR service is not based on cost-of-service and is different from the standard AEP Methodology but is instead based on a resource's capability to provide reactive power. ISO–NE explains that its VAR service compensates resources at a uniform payment rate (*i.e.,* a single rate for reactive power provided within and outside of the standard power factor range) and is not resource-intensive to calculate.[102] ISO–NE adds that total VAR payments amounted to 0.25% of the total energy, ancillary services, and capacity markets combined (or approximately 18–20 million dollars) for the same given period. NEPOOL argues that one of the reasons Schedule 2 has worked well for New England is that it provides a simple fixed rate for the main component of VAR service, which pays part of the costs of a reactive power resource's capability to provide VAR service to the transmission system when needed. NEPOOL explains that this same fixed rate is provided to all qualified resources without further analysis of, or dispute about, resource-specific costs.[103] NEPOOL argues that one of the reasons Schedule 2 has worked well for New England is that it provides a simple fixed rate for the main component of VAR service, which pays part of the costs of a reactive power resource's capability to provide VAR service to the transmission system when needed, without further analysis of, or dispute about, resource-specific costs.[104]

43. NYISO challenges the Commission's preliminary conclusion that compensating generating facilities for providing reactive power within the standard power factor range has resulted in unjust and unreasonable transmission rates and urges the Commission to allow NYISO to maintain its current reactive power compensation program.[105] NYISO states that it supports the NOPR's objective to avoid administratively burdensome processes and procedures to determine individualized cost-of-service reactive power rates for generation facilities. NYISO adds that NYISO's existing reactive power and Voltage Support Service (VSS) compensation structure, which uses a flat dollars per MVAr-year structure, is just and reasonable.[106] NYISO maintains that this structure aligns costs directly with services provided, ensures reliability benefits

[88] New England Consumer Advocates Initial Comments at 3–4. *See also* PJM IMM Initial Comments at 5 (''Most recent cases settled prior to issuance of the NOPR have settled for costs well in excess of the average cost and well in excess of the ARR offset amount. The issue is growing in significance.''); MISO Transmission Owners Initial Comments at 5 (''The Commission's preliminary findings that led to the changes proposed in the NOPR are accurate. The current framework for reactive power compensation can result in transmission customers being required to pay for a service that generators already are required to provide and that costs them little or nothing to provide. Therefore, the current framework allows for compensation that is neither just nor reasonable.'').

[89] PJM IMM Reply Comments at 1–2.

[90] Clean Energy Associations Initial Comments at 2–3; Indicated Trade Associations Reply Comments at 16; NEI Initial Comments at 1.

[91] Reactive Service Providers Initial Comments at 4, 29–34.

[92] *Id.* at 41–43.

[93] *Id.* at 43–48.

[94] *Id.* at 48–52.

[95] *Id.* at 53–54.

[96] *Id.* at 76–77.

[97] *Id.* at 77.

[98] Indicated Trade Associations Reply Comments at 16–17.

[99] *Id.* at 8–9.

[100] ISO–NE Initial Comments at 1–2, NESCOE Reply Comments at 2; NEPGA Reply Comments at 6–7; NEPOOL Reply Comments at 6–7. ISO–NE explains that its VAR service consists of four components: (1) the fixed Capacity Cost (CC) rate, under which Qualified Reactive Resources are eligible to receive VAR payments for their measurable capability to provide VAR service to the New England Transmission System; (2) the variable Lost Opportunity Cost, which compensates for the value of a resource's lost opportunity in the wholesale energy market in situations where a resource that would otherwise be economically dispatched is directed by the ISO to reduce real power output to provide more reactive power; (3) the variable Cost of Energy Consumed, which compensates for the cost of energy consumed by the resource solely to provide reactive power; and (4) the Cost of Energy Produced, which compensates for the difference between the locational marginal price and a resource's offer price, if the locational marginal price is lower than the offer price, for each hour the resource provides reactive power. ISO–NE Initial Comments at 3–4. ISO–NE notes that the components other than the CC component may occur infrequently and are far less than the CC rate component. ISO–NE Initial Comments at 4 n.5.

[101] ISO–NE Initial Comments at 1–2.

[102] *Id.* at 3–5, 14. The ISO New England Ancillary Service Schedule 2 Business Procedure is available on the ISO–NE website: *https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/gen_var_cap/schedule_2_var_business_procedure.pdf.* Operating Procedures include primarily: ISO New England Operating Procedure No. 12—Voltage and Reactive Control, available at *https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op12/op12_rto_final.pdf*; and ISO New England Operating Procedures No. 23—Generating Resource Auditing, available at *http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op23/op23_rto_final.pdf.*

[103] NEPOOL Reply Comments at 6–7.

[104] *Id.* at 6–7.

[105] NYISO Initial Comments at 1.

[106] *Id.* at 2; IPPNY Reply Comments at 1–2.

commensurate with expenses,[107] provides market-like incentives, and encourages resources to offer reactive power cost-effectively by rewarding increased capability and maintaining necessary equipment,[108] which reduces the need for complex, individualized cost-based payments and integrates reactive power support efficiently into the broader market framework, promoting economic efficiency and reliability.[109] NYISO contends that a uniform implementation approach is not suitable given the varying regional needs and existing effective compensation frameworks.[110]

44. Indicated Trade Associations, Generation Developers, NEI and PSEG raise constitutional claims with respect to the NOPR proposal. Indicated Trade Associations argue that the proposed rule violates the Takings Clause of the Fifth Amendment to the United States Constitution.[111] They argue that public utilities have the statutory and constitutional right to compensation for the services they provide, including reactive power, and the Commission cannot deprive public utilities of just and reasonable compensation simply by characterizing the provision of reactive power as a condition of interconnection, particularly where it was the Commission that established this condition. Similarly, Generation Developers argue that forcing generators to supply an identifiable portion of the reactive power they generate, without any compensation, as a condition of interconnection to the transmission system, falls squarely within the kinds of takings prohibited by the Takings Clause.[112] PSEG states that, in accordance with the FPA and the Supreme Court precedent in *Hope,* the Commission has a duty to protect public utilities from rates that are confiscatory.[113] PSEG argues that the proposed rule, not unlike the Commission denying transmission owners the opportunity to earn a return on network upgrades in *Ameren,* essentially compels generators to provide a service without the ability to recover their fixed associated costs, which is unjust and unreasonable, unduly discriminatory, and confiscatory and in violation of the FPA and judicial precedent.[114]

45. MISO Transmission Owners disagree with commenters arguing that the NOPR proposal constitutes an unconstitutional taking.[115] They contend that the commenters' claim that the Order No. 2003 requirement for generators to provide reactive power within the standard power factor range violates the Takings Clause of the U.S. Constitution is a collateral attack on Order No. 2003. They contend that, while some contractual rights are considered ''property'' within the meaning of the Takings Clause of the Fifth Amendment, the contractual relationship entered into when a generator interconnects with a transmission system does not implicate a taking that must be compensated.[116] MISO Transmission Owners state that the Commission determined in Order No. 2003 that generators ''should not be compensated for reactive power when operating [their] Generating Facilit[ies] within the established power factor range, since [they are] only meeting [their] obligation.'' Moreover, they state that ''as 'legislation [that] readjust[s] rights and burdens is not unlawful solely because it upsets otherwise settled expectations,' the Commission's action implementing the changes in the NOPR would not constitute an unconstitutional taking just because the changes would 'impact the benefits and burdens' of the agreement entered into by generators interconnecting with the Transmission System.'' [117] They contend that ''[g]enerators have only a unilateral expectation of payment for the provision of reactive power and not a legitimate claim of entitlement to compensation.'' [118]

46. Eagle Creek and the NHA both assert that existing reactive service rates enjoy the Mobile-Sierra presumption. The NHA asserts that, in order for the Commission to disallow the existing reactive service rates, each rate on-file must be demonstrated by the Commission to ''seriously harm the public interest.'' [119] Eagle Creek and the NHA both note that, given the highly localized nature of reactive power, it is unclear how the Commission could assess these individual contracts without conducting a case-by-case analysis through individual section 206 proceedings.[120] Eagle Creek and the NHA claim that absent such proceedings, generating facilities would be deprived of their current just and reasonable compensation and previous investments made by generating facilities would be compromised.[121] The NHA and Eagle Creek assert that, by relying on a generic rulemaking to effectively cancel all reactive power rates, the NOPR is an ''act of convenience'' and ''an indirect attempt to strip the value of existing rates without facing the legal challenge that the Mobile-Sierra doctrine presents.'' [122]

47. Joint Customers disagree with Eagle Creek and the NHA's argument that the Commission cannot eliminate compensation within the standard power factor range without initiating individual rate proceedings.[123] Joint Customers explain that precedent cases, such as *PNM* and *MISO,* demonstrate that changes to the underlying Schedule 2 tariff provisions effectively eliminate compensation for third-party generators without separate rate challenges.[124]

48. Reactive Service Providers and Generation Developers argue that the NOPR violates the D.C. Circuit's holding

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[107] NYISO Initial Comments at 2–5.

[108] *Id.* at 7–8.

[109] *Id.* at 7–8.

[110] *Id.* at 14.

[111] Indicated Trade Associations Initial Comments at 22–24 (citing *Smyth* v. *Ames,* 169 U.S. 466, 546 (1898)).

[112] Generation Developers Initial Comments at 26 (citing *Horne* v. *Dept. of Ag.,* 576 U.S. 350, 359, 367 (2015); *FPC* v. *Hope Nat. Gas Co.,* 320 U.S. 591, 603 (1944); *Bluefield Waterworks & Improvement Co.* v. *Pub. Serv. Comm'n,* 262 U.S. 679, 690 (1923)).

[113] PSEG Initial Comments at 18–19 (citing *Bluefield Waterworks & Improvement Co.* v. *Pub. Serv. Comm'n,* 262 U.S. at 690; *Duquesne Light Co.* v. *Barash,* 488 U.S. 299, 308 (1989) (''If the rate does not afford sufficient compensation, the State has taken the use of the utility property without paying just compensation.'')).

[114] PSEG Initial Comments at 19–20 (citing *Ameren Servs. Co.* v. *FERC,* 880 F.3d 571, 581–82 (D.C. Cir. 2018)).

[115] MISO Transmission Owners Reply Comments at 12 n.33.

[116] *Id.* (citing *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.,* Order No. 1000–A, 77 FR 32184 (May 31, 2012), 139 FERC ¶ 61,132, at P 368 (citing *Connolly* v. *Pension Guar. Corp.,* 475 U.S. 211, 224 (1986)), *order on reh'g and clarification,* Order No. 1000–B, 77 FR 64890 (Oct. 24, 2012), 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41 (D.C. Cir. 2014)).

[117] *Id.* (citing Order No. 1000–A, 139 FERC ¶ 61,132 at P 369 (citing *Connolly* v. *Pension Guar. Corp.,* 475 U.S. at 223)).

[118] *Id.* (citing *Bd. of Regents of State Coll.* v. *Roth,* 408 U.S. 564, 577 (1972) (''To have a property interest in a benefit, a person clearly must have more than an abstract need or desire for it. He must have more than a unilateral expectation of it. He must, instead, have a legitimate claim of entitlement to it.''); *Del. Riverkeeper Network* v. *FERC,* 895 F.3d 102, 108–09 (D.C. Cir. 2018) (citing *Town of Castle Rock, Colo.* v. *Gonzales,* 545 U.S. 748, 756 (2005)).

[119] Eagle Creek Initial Comments at 4; NHA Initial Comments at 8–9.

[120] Eagle Creek Initial Comments at 4; NHA Initial Comments at 8.

[121] Eagle Creek Initial Comments at 4–5; NHA Initial Comments at 8.

[122] NHA Initial Comments at 8–9; *see also* Eagle Creek Initial Comments at 4–5.

[123] Joint Customers Reply Comments at 13–14.

[124] *Id.* (''There is no validity to the argument that individual rate challenges must be pursued by the Commission or complainants, and it is well established that a change to the underlying Schedule 2 in a transmission provider's tariff, as proposed by the Commission in the NOPR, will contemporaneously end compensation to third-party generators with no further action required.''); *see also* PJM IMM Initial Comments at 9 (''The NOPR does not propose a new Commission policy. Rather, it extends and makes uniform policies that have long applied in jurisdictional markets.'').

in *Atlantic City.*[125] They assert that by using the Commission's authority under section 206 of the FPA to eliminate reactive power compensation, the NOPR essentially strips generating facilities of their ability to make filings under section 205 of the FPA to recover the costs of the reactive power service that they provide.[126]

2. Commission Determination

49. Based on our review of the record, we find that there is substantial evidence to support the conclusion that transmission rates are unjust and unreasonable to the extent they include charges associated with the provision of reactive power within the standard power factor range. We therefore adopt the preliminary findings in the NOPR concerning the need for reform[127] and, pursuant to section 206 of the FPA, conclude that certain revisions to Schedule 2 of the *pro forma* OATT, *pro forma* LGIA, and *pro forma* SGIA are necessary to ensure rates that are just, reasonable, and not unduly discriminatory or preferential.

50. We agree with commenters that the current framework allows for transmission rates that are ''neither just nor reasonable'' and ''can result in transmission customers being required to pay for a service that generators already are required to provide and that costs them little or nothing to provide.''[128] As reflected in the record, absent reform, transmission customers would be required to continue to pay charges associated with generating facilities' provision of reactive power within the standard power factor range even though such charges are without a sufficient economic basis and do not result in transmission customers receiving commensurate reliability benefits. The need for reform is particularly acute given that ''transmission rates have been rising in recent years and costs are only expected to increase in the near term to accommodate projected future transmission system needs.''[129]

51. As described below, most commenters agree or do not dispute that real and reactive power are provided as joint products,[130] with joint costs.[131] Similarly, most commenters agree or do not dispute that, under their interconnection agreements and in accordance with good utility practice, generating facilities have a long-standing obligation to provide reactive power within the standard power factor range in order to interconnect reliably to the transmission system. Most commenters agree or do not dispute that generating facilities must produce reactive power within the standard power factor range to allow the generating facilities' real power to reliably flow to load.[132] As such, we disagree with some commenters who challenge the Commission's preliminary finding that providing reactive power within the standard power factor range has no or *de minimis* costs[133] and find, as discussed in greater detail below, that there is substantial evidence to conclude that in satisfying such obligations generating facilities incur no incremental investment, or fixed costs, and at most *de minimis* variable costs over and above those needed to provide real power.[134] This is because no additional equipment is required to provide reactive power; rather the same equipment that is needed to produce, and is used to produce, real power also provides reactive power functions, at no additional capital cost. Variable costs, if any, are limited to the fuel costs (in synchronous facilities) or the cost of foregone direct current power (in non-synchronous facilities) necessary to provide the reactive power and to reliably inject real power into the transmission system.[135] For example, in *Panda Stonewall* the annual revenue requirement of $2,051,894 included just $10,018 of identified variable costs.[136] In light of this evidence, we find that charging transmission customers for the provision of reactive power within the standard power factor range results in unjust and unreasonable rates.[137]

52. ISO–NE and NYISO oppose the NOPR and seek flexibility to preserve their existing reactive power compensation regimes. We deny their requests. ISO–NE and NYISO principally argue that their flat-rate

[125] *Atl. City Elec. Co.* v. *FERC,* 295 F.3d 1 (D.C. Cir. 2002) (*Atl. City*).

[126] Generation Developers Initial Comments at 31–32 (citing *Atl. City,* 295 F.3d at 9–10); Reactive Service Providers Initial Comments at 54.

[127] NOPR, 186 FERC ¶ 61,203 at PP 24–27, 28.

[128] *See, e.g.,* MISO Transmission Owners Initial Comments at 5; Joint Customers Initial Comments at 6–16, PJM IMM Initial Comments at 1–4, 6–9; PJM IMM Reply Comments at 2–3, 6–7; Ameren Initial Comments 2–3; AEP Initial Comments at 4–5; Ohio FEA Initial Comments at 5–6; TAPs Initial Comments at 1, 3–8; PGE Initial Comments at 3–4.

[129] *See, e.g.,* New England Consumer Advocates Initial Comments at 3 & n.7 (citing, *e.g.,* Massachusetts Attorney General Maura Healey, Initial Comments, Docket No. RM21–17–000, at 28 (filed Aug. 17, 2022); *see also* New England States Committee on Electricity, New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid (2020), *https://nescoe.com/resource-center/vision-stmt-oct2020/*).

[130] *See PSC VSMPO-Avisma Corp.* v. *U.S.,* 688 F.3d 751, 756 (Fed. Cir. 2012) (''[J]oint products [are] two dissimilar end products that are produced from a single production process.'') (citing Robert A. Anthony & James S. Reece, *Accounting Principles* 442 (5th ed. 1983).

[131] A joint cost is an expenditure that benefits more than one product, and for which it is not possible to separate the contribution to each product. *Permian Basin,* 390 U.S. at 761 n.25 (citing Accounting Tools, *The Supply and Price of Natural Gas 25* (1962)) (''Joint costs 'are incurred when products cannot be separately produced.'''); *https://www.accountingtools.com/articles/joint-cost.*

[132] *See SPP,* 119 FERC ¶ 61,199, at P 28 (''[I]f a generator is to sell (and be able to deliver) its power to a customer, reactive power is essential to the transaction. Thus, it is hardly surprising that the Commission has concluded, . . . , that the provision of sufficient reactive power is an obligation of a generator interconnected to the system, and that, . . . , a generator is not entitled to separate compensation for providing reactive power within its deadband.'').

[133] *See, e.g.,* Eagle Creek Initial Comments at 3–4; Indicated Trade Associations Initial Comments at 7; ACORE Initial Comments at 2; Elevate Renewables Initial Comments at 9–12; Generation Developers Initial Comments at 13; Glenvale Initial Comments at 9–10; Indicated Reactive Power Suppliers Initial Comments at 2, 9–10; Indicated Trade Associations Initial Comments at 2, 6; Middle River Power Initial Comments at 2–3; NEI Initial Comments at 4–5, 8–9; NHA Initial Comments at 2, 4–5.

[134] Although the Commission found in the MISO Rehearing Order, and earlier, that ''Reactive Service requires *little or no* incremental investment'' *see, e.g.,* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 29 (emphasis added), we note that beyond vague assertions that incremental fixed costs are incurred, no evidence of investment or fixed costs specific to providing reactive power was provided in response to requests for such costs in the MISO Rehearing Order, the NOI, or the NOPR. As such, the Commission concludes below that there are *no* incremental or fixed costs to provide reactive power beyond those to provide real power.

[135] Under certain transmission system conditions, the generating facility may operate at a power factor of 1.0, which represents zero incremental variable costs and thus zero total costs of providing reactive power. A generating facility operating at any reactive power level (*i.e.,* a power factor other than 1.0) will incur some amount of incremental fuel cost, but the Commission generally considers these costs *de minimis* within the standard power factor range. *See, e.g., APS,* 94 FERC at 61,080 (''We note that operating a generating unit within the proposed [standard power factor range] does not affect the generation output of a unit.''); Commission Staff Report, *Principles for Efficient and Reliable Reactive Power Supply and Consumption,* Docket No. AD05–1–000, at 96 (2005 Staff Report) (2005) (''The marginal cost of providing reactive power from within a generator's capability curve (D-curve) is near zero.'').

[136] *Panda Stonewall, LLC,* 176 FERC ¶ 61,072, at P 6 n.9 (2021). We note that the heating losses component reflects the incremental fuel cost of providing reactive power. *See, e.g., Panda Stonewall, LLC,* 174 FERC ¶ 61,266, at P 155 (2021) (''The *AEP* methodology already has a means in place to provide compensation for the small amount of additional fuel used during the production of reactive power, which is a heating loss calculation based on the MW-hours of actual reactive power production and the usage charges for fuel.'').

[137] *See Belmont Mun. Light Dep't* v. *FERC,* 38 F.4th at 173, 179, 186 (2022) (finding that the Commission's approval of a portion of ISO–NE's Inventoried Energy Program ''was not reasoned decisionmaking'' and ''thwart[ed] the [Commission's] own 'longstanding policy that rate incentives must be prospective and that there must be a connection between the incentive and the conduct meant to be induced''' because it would compensate market participants for conduct they already engage in as part of standard business operations).

compensation regimes are transparent, not administratively burdensome, designed to prevent double-recovery, and able to procure significant reliability benefits at ''reasonable'' or ''low'' cost. However, these arguments ignore the preliminary findings of the NOPR, namely that generating facilities providing reactive power within the standard power factor range are only meeting their obligations under their interconnection agreements in accordance with good utility practice, and in doing so incur no or at most a *de minimis* increase in variable costs beyond the cost of providing real power. As explained in this final determination and decades of prior Commission precedent, in order to reliably interconnect to the transmission system and deliver real power to customers, generating facilities must be capable of maintaining voltage levels for injecting real power into the transmission system.[138] As relevant here, these findings apply equally to flat-rate compensation regimes like ISO–NE's and NYISO's, as well as the compensation regimes of PJM and certain non-RTO regions. Thus, the ISO–NE and NYISO regimes, while easier to implement administratively, also impose unreasonable and unsupportable costs on transmission customers.

53. ISO–NE's and NYISO's claims regarding transparency, administrative burden, and preventing double recovery all presuppose that compensation is due, and thus that a compensation method is needed. But, where compensation is found to be unjust and unreasonable, as we find here, such a compensation methodology will necessarily result in unjust and unreasonable rates and thus is not permissible.

54. Additionally, we agree with New England Consumer Advocates,[139] who argue that any payment for reactive power capability within the standard power factor range must yield some roughly commensurate incremental benefit *above and beyond* that which would accrue absent payment.[140] As discussed below,[141] ISO–NE and NYISO allude generally to reliability benefits from reactive power compensation over the full range of a resource's capability to provide reactive power—that is, both within and outside of the standard power factor range—rather than the narrower focus of this final determination. And, in both ISO–NE (except for certain circumstances as explained by ISO–NE) [142] and NYISO, as everywhere, generating facilities must provide reactive power within the standard power factor range to make sales of real power regardless of whether they receive separate compensation.[143]

55. We do not dispute that the provision of reactive power within the standard power factor range provides reliability benefits, only that there are no incremental fixed costs other than joint costs that are also associated with the production of real power and at most *de minimis* incremental variable costs that would warrant a separate compensation mechanism. We also find that there is substantial evidence to conclude that, under the current reactive power compensation framework, reactive power-related transmission charges are not tied to geographic need and result in excess reactive power capability that is not required for interconnection and does not provide transmission customers with commensurate reliability benefits.[144] Accordingly, we deny ISO–NE's and NYISO's respective requests for flexibility to include in transmission rates charges associated with the provision of reactive power within the standard power factor range.

56. We reject commenters' arguments that the final determination violates the Fifth and Fourteenth Amendments of the U.S. Constitution. The final determination's elimination of reactive power payments for the provision of reactive power within the standard power factor range is not confiscatory and would not amount to a taking of property. As noted above, generating facilities incur no or at most a *de minimis* increase in variable costs beyond the cost of providing real power and have the opportunity to seek recovery of any costs they do incur. In addition, commenters' arguments that the obligation to provide reactive power within the standard power factor range is unconstitutional are impermissible

[138] *See, e.g., BPA,* 120 FERC ¶ 61,211 at P 21 (''The purpose for which generation assets are built (including reactive power capability to maintain voltage levels for generation entering the grid) is to make sales of real power.''); *SPP,* 119 FERC ¶ 61,199 at P 28 (''[I]f a generator is to sell (and be able to deliver) its power to a customer, reactive power is essential to the transaction''). *See also PJM Interconnection, L.L.C.,* 145 FERC ¶ 61,280, at P 17 (2013) (approving tariff revisions that require interconnection customers to pay for upgraded telecommunication equipment (phasor measurement units) as the ''data is integral to improved communication and to the reliability of the system and, as such, benefits both the system and the generators'').

[139] New England Consumer Advocates Initial Comments at 5 (''To the extent . . . benefits are achieved by compliance with a generating facility's interconnection agreement and/or as 'good utility practice,' [New England Consumer Advocates] agree[] with the Commission that ratepayers should not be paying separately for the costs to produce a joint reactive power product.'').

[140] *See, e.g., Ill. Com. Comm'n.* v. *FERC,* 576 F.3d at 476 (''[The Commission] is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members.'').

[141] *See infra* II.D.2.

[142] ISO–NE notes that not all generating facilities are obligated to provide reactive power within the standard power factor range. ISO–NE Initial Comments at 9. Specifically, ISO–NE notes that several older generating facilities in New England have interconnection agreements that pre-date the obligation to provide reactive power within the standard power factor range. *Id.* ISO–NE states that these resources choose to participate in the Schedule 2 VAR compensation program, incurring an obligation to maintain and provide VAR service in New England. *Id.* Any generating facilities with individualized bilateral contracts providing for reactive power compensation within the standard power factor range may pursue claims that they have an independent contractual right to reactive power compensation within the standard power factor range, but we express no opinion here as to whether any such generator would be entitled to such compensation.

[143] *See, e.g., BPA,* 120 FERC ¶ 61,211 at P 21 (''The purpose for which generation assets are built (including reactive power capability to maintain voltage levels for generation entering the grid) is to make sales of real power.''); SPP Order on Rehearing, 121 FERC ¶ 61,196 at P 15 (''As we have previously explained, reactive power *is required for an interconnecting generator to deliver its power* and reactive power produced within the [standard power factor range] and is, therefore, generally not compensable.'' (emphasis added)).

[144] Joint Customers Initial Comments at 12 (''This incentive structure to provide payment based on reactive capability results in the building of unnecessary capabilities in locations it is not or may not be needed and does not allocate the costs associated with reactive capability in a manner that is at least roughly commensurate with the benefits received.'' (citing *Ill. Com. Comm'n.* v. *FERC,* 576 F.3d at 477)); MISO Transmission Owners Initial Comments at 8 (''Moreover, the capability-based compensation methodology currently permitted by the Commission . . . allows and even incentivizes generators to add as much reactive equipment as they desire, *i.e.,* to gold plate a facility's reactive capability, regardless of whether that reactive support is needed at that point on the grid.''); TAPS Initial Comments at 4–5 (''Nor can customers be assured they are receiving reliability benefits commensurate to the reactive power compensation paid under the current approach. The existing approach to reactive power capability compensation does not adequately consider a generator's actual contribution to reliability, or lack thereof. For example, that approach does not account for relevant factors such as location, the need for reactive power, deliverability to where reactive power may be needed, possible degradation in generator performance or other changes over time. The result is that the current approach to reactive power compensation requires consumers to pay excessive charges for reactive power that may not be needed or is in the wrong location.'' (citations omitted)). *See Belmont Mun. Light Dep't* v. *FERC,* 38 F.4th at 187–90 (finding that the Commission's acceptance of ISO–NE's Inventoried Energy Program ''was not reasoned decision making'' because record evidence indicated that certain types of generating facilities ''would not change their behavior in response to payments.'').

collateral attacks on our prior determinations and unpersuasive.[145]

57. The Commission has repeatedly held that ''the provision of sufficient reactive power is an obligation of a generator interconnected to the system, and . . . as a general matter, a generator is not entitled to separate compensation for providing reactive power within its deadband.'' [146] A generating facility must in fact produce reactive power to move real power from the generating facility to the transmission system to deliver its real power to customers, while maintaining system reliability.[147] It is only by virtue of comparability that generating facilities were previously entitled to reactive power compensation.[148]

58. Simply stated, the obligation to provide reactive power within the standard power range exists independent of, and was not altered by, the NOPR's proposal: it was stated in Order No. 2003 and applies to individual generating facilities through their interconnection service agreements. This final determination changes only the allowance for transmission providers to provide compensation at their discretion to their own and affiliated generating facilities, and then to third-party generating facilities under the comparability standard for the provision of reactive power within the standard power factor range. This change eliminates a stream of revenue under Schedule 2, but we find here that such elimination is just and reasonable given that the record demonstrates that generating facilities incur no or at most a *de minimis* increase in variable costs beyond the cost of providing real power.[149] Moreover, to the extent that generating facilities have any costs associated with providing reactive power within the standard power factor range, generating facilities may seek to recover these costs through energy or capacity sales.[150] Accordingly, and consistent with precedent, commenters have not persuaded us that they have a property interest in continued compensation under Schedule 2, or that this final determination would unconstitutionally deprive generating facilities of that putative property interest under the Takings Clause or Due Process Clause of the Fifth Amendment.

59. We disagree with Eagle Creek's and the NHA's assertions that most reactive service rate schedules on file enjoy the *Mobile-Sierra* presumption and as a result, in order for the Commission to disallow the existing reactive service rates, each rate on file must be demonstrated by the Commission to ''seriously harm the public interest.'' [151] While the *Mobile-Sierra* doctrine establishes a more rigorous application of the just and reasonable standard when the Commission proposes to change an individual contract negotiated at arms-length,[152] reactive power-related transmission rates are not individually negotiated contract rates, but rather transmission owner tariff-based rates of general applicability reflected in the transmission owner's Schedule 2.[153] The fact that the Commission has accepted generating facilities' rate filings setting forth reactive power rates covering the provision of reactive power within the standard power factor range establishes only the rate at which the generating facility is obligated to sell reactive power to a transmission provider; that rate does not establish an obligation for the transmission provider to purchase such reactive power. Those individual rates establish only the charges that transmission providers will include in transmission rates if, and only if the transmission providers' OATTs require the payment of compensation for reactive power.[154]

60. As discussed above, the final determination requires revisions to

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[145] MISO Transmission Owners Reply Comments at 12 n.33 (''Moreover, as 'legislation [that] readjust[s] rights and burdens is not unlawful solely because it upsets otherwise settled expectations,' the Commission's action implementing the changes in the NOPR would not constitute an unconstitutional taking just because the changes would 'impact the benefits and burdens' of the agreement entered into by generators interconnecting with the Transmission System. Generators have only a unilateral expectation of payment for the provision of reactive power and not a legitimate claim of entitlement to compensation.'') (citations omitted). *See also MISO,* 182 FERC ¶ 61,033 at P 62; MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 52–54 (''Vistra has not persuaded us that it has a property interest in continued Reactive Service compensation under the Tariff, nor that MISO TOs' proposal would unconstitutionally deprive generators of that putative property interest under the Takings Clause or Due Process Clause of the Fifth Amendment.'').

[146] *See, e.g., MISO,* 182 FERC ¶ 61,033 at P 62 (citing *SPP,* 119 FERC ¶ 61,199 at P 28); MISO Rehearing Order, 184 FERC ¶ 61,022 at P 52 (finding that protesters constitutional claims were impermissible collateral attacks on the Commission's prior determinations given ''[t]he obligation to provide Reactive Service exists independent of, and was not altered by, MISO TOs' proposal: it was stated in Order No. 2003 and applies to individual generators through their GIAs.'').

[147] *See, e.g.,* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 53 (''[T]he function of generators' Reactive Service is to ensure that generators' real power can enter the transmission grid while maintaining system reliability.''); *SPP,* 119 FERC ¶ 61,199 at P 28 (explaining that if a generator is to sell (and be able to deliver) its power to a customer, reactive power is essential to the transaction).

[148] NOPR, 186 FERC ¶ 61,203 at P 4 (citing Order No. 2003–A, 106 FERC ¶ 61,220 at P 416). *See also* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 26 (''On rehearing, we continue to reject, as collateral attacks on that longstanding policy, arguments that stand-alone compensation for Reactive Service is generically required—for example, to ensure that generators can recover their costs for Reactive Service capability. These arguments would negate the conclusions in Order Nos. 2003 and 2003–A that such compensation should not be provided, except as required by the comparability standard.'').

[149] *See* MISO Transmission Owners Initial Comments at 6 (''The MISO Transmission Owners' experience supports the Commission's preliminary finding that providing reactive power within the standard power factor range requires little or no cost to generators. Generators incur little or no costs beyond what is already needed to produce real power because the same equipment used to produce real power includes reactive power functions.'' (citations omitted)); PJM IMM Reply Comments at 3 (''Neither the [Indicated Trade Associations] nor any other opposing commenter, nor any of the precedent relied upon by opposing commenters, identify any additional costs or more than de minimis costs incurred by generators in order to provide reactive capability.'').

[150] MISO Rehearing Order, 184 FERC ¶ 61,022 at P 53; *BPA,* 120 FERC ¶ 61,211 at P 20; BPA Rehearing Order, 125 FERC ¶ 61,273 at P 11; *see also* NOPR, 186 FERC ¶ 61,203 at P 24; *see also* MISO Transmission Owners Initial Comments at 6; PJM IMM Reply Comments at 3.

[151] Eagle Creek Initial Comments at 4; NHA Initial Comments at 8–9.

[152] The Commission has explained that the *Mobile-Sierra* ''public interest'' presumption applies to an agreement only if the agreement has certain characteristics that justify the presumption. In ruling on whether the characteristics necessary to justify a *Mobile-Sierra* presumption are present, the Commission must determine whether the agreement at issue embodies either: (1) individualized rates, terms, or conditions that apply only to sophisticated parties who negotiated them freely at arm's length; or (2) rates, terms, or conditions that are generally applicable or that arose in circumstances that do not provide the assurance of justness and reasonableness associated with arm's-length negotiations. Unlike the latter, the former constitute contract rates, terms, or conditions that necessarily qualify for a *Mobile-Sierra* presumption. *E.g., Linden VFT, LLC* v. *Pub. Serv. Elec. & Gas Co.,* 161 FERC ¶ 61,264, at P 27 (2017); *PJM Interconnection, L.L.C.,* 161 FERC ¶ 61,262, at P 18 (2017); *Sw. Power Pool, Inc.,* 144 FERC ¶ 61,059, at P 127 (2013), *order on reh'g and compliance,* 149 FERC ¶ 61,048, at P 94 (2014) (citations omitted); *Midwest Indep. Transmission Sys. Operator, Inc.,* 142 FERC ¶ 61,215, at P 177 (2013), *order on reh'g and compliance,* 147 FERC ¶ 61,127, at P 108 (2014) (citations omitted).

[153] *See, e.g., Wabash Valley Power Ass'n, Inc.* v. *FERC,* 45 F.4th 115, 120 (D.C. Cir. 2022) (''[A] contract requiring the purchaser to pay a utility's 'going rate' on file with FERC, without more, does not eliminate review under the ordinary just-and-reasonable standard.'').

[154] *Cf. Whitetail Solar 3, LLC,* Opinion No. 583, 184 FERC ¶ 61,145, at P 45 (2023) (affirming the Presiding Judge's finding that Schedule 2, not Applicants' interconnection agreements, determines whether generating facilities are eligible for compensation, therefore, ''there is no reason for the Commission to amend the [interconnection agreements] of all existing distribution-connected generation, as Applicants suggest would be necessary in light of the Initial Decision.''); *see also MISO,* 182 FERC ¶ 61,033 at P 63 (''As described above, MISO [Transmission Owners] have the unilateral right to change Schedule 2 through an FPA section 205 filing and by doing so, they automatically change the rate payable for Reactive Service that generators contractually agreed to in section 9.6.3 of their GIAs.'' (citations omitted)).

Schedule 2 to prohibit the inclusion in transmission rates of charges associated with reactive power in the standard power factor range and, for consistency, also requires conforming revisions to the *pro forma* LGIA and *pro forma* SGIA to remove language related to the comparability standard. Since Schedule 2 is a tariff-based rate, that rate can be modified under the ordinary just and reasonable standard.[155] However, this final determination does not affect the ability of generating facilities to pursue claims that they have an independent contractual right to reactive power compensation within the standard power factor range, based on a bilateral agreement with the relevant transmission owner.[156]

61. We also find that Generation Developers' and Reactive Service Providers' [157] assertions that the final determination would violate *Atlantic City* by depriving generating facilities of their FPA section 205 filing rights lack merit. The Commission is not depriving generating facilities of their filing rights. The commenters' arguments fundamentally misunderstand generating facility compensation under the Commission's *pro forma* OATT and interconnection agreements. The final determination is not adjusting, overturning, or reducing to zero any generating facility's rate for reactive power within the standard power factor range. The final determination addresses only the justness and reasonableness of transmission rates chargeable to transmission customers under Schedule 2 and by extension, payable to the transmission providers' own generating facilities or affiliated generating facilities and third-party generating facilities under the comparability standard, consistent with their interconnection agreements, not any independent right of generating facilities to establish a rate under FPA section 205. While this does result in generating facilities, affiliated and non-affiliated, no longer being entitled to compensation for the provision of reactive power within the standard power factor range as a function of comparability, the Commission has found that such an outcome does not undermine the generating facilities' FPA section 205 filing rights.[158]

B. Cost of Producing Reactive Power

62. The NOPR preliminarily found that providing compensation for the provision of reactive power within the standard power factor range is unjust and unreasonable. The Commission relied on three key points to support this preliminary finding.

63. First, the NOPR relied on the Commission's prior findings that, for both synchronous and non-synchronous generating facilities, because all equipment used to produce reactive power is also necessary to produce and deliver real power to the transmission system, there are no incremental fixed costs associated with the provision of reactive power within the standard power factor range.[159] The NOPR also explained that the Commission has repeatedly found, that ''[v]ariable costs of generating reactive power are *de minimis*'' and ''generally limited to changes in losses within the generating facility which are part of the overall efficiency of the resource and, as such, are typically captured in the resource offers.'' [160] Thus, by providing reactive power within the standard power factor range, both synchronous and nonsynchronous facilities incur no additional fixed costs and at most *de minimis* variable costs beyond which they already incur to provide real power.[161]

64. Second, the NOPR relied on the fact that all generating facilities must provide reactive power within the standard power factor range as an obligation of good utility practice and to meet the obligations under their interconnection agreements.[162]

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[155] *See* Joint Customers Reply Comments at 14 (''There is no validity to the argument that individual rate challenges must be pursued by the Commission or complainants, and it is well established that a change to the underlying Schedule 2 in a transmission provider's tariff, as proposed by the Commission in the NOPR, will contemporaneously end compensation to third-party generators with no further action required.'').

[156] For example, ISO–NE and NEPOOL claim that certain agreements exist that do not obligate certain non-generator resources to provide reactive power either within or outside of the standard power factor range and are still entitled to compensation. *See supra* n.142; ISO–NE Initial Comments at 9; NEPOOL Reply Comments at 9. We express no opinion here as to whether any such generating facility, such as those situations noted by ISO–NE and NEPOOL, would be entitled to such compensation under such agreements.

[157] Generation Developers Initial Comments at 31–32 (citing *Atl. City,* 295 F.3d at 9–10); Reactive Service Providers Initial Comments at 54.

[158] *Cf. MISO,* 182 FERC ¶ 61,033 at P 65 (''[W]e find that MISO TOs' proposal does not restrict independent power producers' FPA section 205 rights to file a rate for reactive power; instead, the proposal addresses only the rates chargeable to transmission customers under Schedule 2 and by extension, payable to resources consistent with their GIAs, not any independent right of generators to seek compensation under FPA section 205.''); Opinion No. 583, 184 FERC ¶ 61,145 at P 45 (''Applicants' [interconnection agreements] do not establish an independent right outside the context of Schedule 2 to reactive power compensation for merely meeting the technical requirements required for interconnection.''); *see also* Joint Customers Initial Comments at 14 (''Without comparability as an issue, it is *existing* Commission policy that it is inappropriate to compensate within the standard power factor range. The Order No. 2003 determination that compensation should not be paid for reactive service meeting interconnection requirements remains well supported.'' (emphasis in original)). We also note that individual generating facility reactive power tariffs themselves do not establish a payment obligation, only the rate that a buyer will pay *if* it takes service. A tariff rate is an offer to sell service at the stated rate; it does not establish an obligation on any party to pay that rate. *See* 18 CFR 35.2(c)(1) (''The term *tariff* as used herein shall mean a statement of (1) electric service as defined in paragraph (a) of this section *offered on a generally applicable basis*) (emphasis added)); *Sw. Power Pool, Inc.,* 149 FERC ¶ 61,048 at P 106 (''The Commission's use of the term 'tariff rates' as generally applicable rates is justified by the definition of the term 'tariff' set forth in the Commission's regulations under the FPA, which state, in part, that a tariff is 'a statement of . . . electric service . . . offered on a generally applicable basis.' ''). In order to constitute an obligation, a party must sign a *pro forma* or other service agreement. *See Cal. Indep. Sys. Operator Corp.,* 100 FERC ¶ 61,234, at 61,834 (2002) (''[T]he Commission moved to a paradigm of standard agreements in which terms and conditions that are included in a public utility's OATT and bilateral contracts are replaced by *pro forma* service agreements''). Therefore, if transmission providers revise their Schedule 2's to eliminate compensation for the provision of reactive power within the standard power factor range, no party will exist to pay the generating facility's filed tariff rate. *See, e.g., PNM,* 178 FERC ¶ 61,088 (finding that the transmission owner is not required to pay for reactive power, but not instituting section 206 proceedings to cancel reactive power tariffs).

[159] NOPR, 186 FERC ¶ 61,203 at PP 29–31 (''[S]ynchronous and non-synchronous resources provide real and reactive power as joint products, with joint costs.'').

[160] *Id.* P 31.

[161] *Id.* PP 8, 28.

[162] *Id.* P 33 (citing *MISO,* 182 FERC ¶ 61,033 at P 53 (''Bearing in mind that the provision of reactive power within the standard power factor range is, in the first instance, an obligation of the interconnecting generator and good utility practice, MISO [transmission owners] do not have an obligation to continue to compensate an independent generator for reactive power within the standard power factor range when its own or affiliated generators are no longer being compensated.'' (citations omitted)); *id.* P 54 (''We find unpersuasive protesters' arguments that it is not just and reasonable to eliminate compensation for Reactive Service within the standard power factor range because generators have come to rely on the compensation for Reactive Service in order for the generators to remain financially viable. The Commission has previously rejected such arguments, finding that all newly interconnecting generators are required to provide reactive power within the power factor range of 0.95 leading to 0.95 lagging as a condition of interconnection.'' (citations omitted)); *PNM,* 178 FERC ¶ 61,088 at PP 29, 33 (rejecting generating facility's arguments that it is ''just and reasonable for it to be compensated for investments made'' to provide reactive support consistent with interconnection requirements even though transmission provider elected to no longer pay its own or affiliate generators for such reactive power); *Nev. Power Co.,* 179 FERC ¶ 61,103 at P 22 (finding that the generating facility's argument, ''that it is not just and reasonable to eliminate their compensation for reactive service because they made investments in their generating facilities based on the expectation that they would receive compensation for reactive service,'' unpersuasive because all newly interconnecting generators are required to provide reactive power within the standard power factor range as a condition of

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Additionally, the NOPR emphasized that ''reactive support by generating facilities operating within the standard power factor range ensures that when these facilities inject real power—the product that their facilities exist to create and sell—onto the grid under normal conditions, they can do their part to maintain adequate voltages and to not threaten reliability.'' [163] In other words, a generating facility must produce reactive power within the standard power factor range in order to generate and safely inject real power into the transmission system and comply with reliability requirements. As such, providing reactive power within the standard power factor range can be regarded as a joint product with providing real power, with joint costs.

65. Third, the NOPR noted that in regions where generating facilities recover their costs by participating in organized competitive wholesale markets, providing separate compensation for the provision of reactive power within the standard power factor range risks overcompensation and market distortions in ways that did not exist prior to the existence of organized markets.[164] The NOPR explained that the AEP Methodology was created in an era of vertically integrated utilities, when most utilities filed FERC Form No. 1s, used the Uniform System of Accounts (USofA) to classify their costs, and recovered those costs through cost-based rates.[165] Today, however, most generating facilities recover their costs through competitive markets in both RTO/ISO and non-RTO/ISO regions, so the imprecision of the AEP Methodology, the NOPR explained, becomes more significant because it can lead to arbitrary increases in the utility's total recovery when cost-based reactive power payments are added to any market recoveries.[166] The NOPR added that this is especially true when markets fail to account for separate, cost-based reactive power revenues by using standard rate making techniques.[167]

1. Comments

66. Many commenters support the NOPR's finding that transmission charges for generating facilities' provision of reactive power within the standard power factor range are unjust and unreasonable.[168] Likewise, many commenters support the NOPR's preliminary finding that generating facilities already provide reactive power within the standard power factor range at no cost or *de minimis* cost.[169] Ameren and MISO Transmission Owners agree with the NOPR that providing reactive power within the standard power factor range requires little or no cost to generators because the same equipment used to produce real power includes reactive power functions.[170] In support, MISO Transmission Owners point to *MISO* and the MISO Rehearing Order wherein the Commission also concluded that, based on that record, reactive power service within the standard power factor range required little or no incremental investment. MISO Transmission Owners add that, as the Commission found in the MISO Rehearing Order, even newer wind turbines use inverters that allow generating facilities to produce and control reactive power without costly additional equipment.[171] MISO Transmission Owners also state that generating facility equipment typically comes with reactive power capabilities that not only meet the standard range requirements (*i.e.,* 0.95 leading and 0.95 lagging) but exceed them (*e.g.,* 0.80–0.90).[172] MISO Transmission Owners argue that since generating facilities bear no or at most *de minimis* incremental costs to provide reactive power within the standard power factor range, one must consider what the actual purpose is of compensating generating facilities for such service.[173]

67. Joint Customers state that attempts to undermine the NOPR, such as challenging the assertion that incremental costs of providing reactive service within the standard power factor range are *de minimis,* are meritless.[174] Joint Customers argue that the costs incurred by generators to meet interconnection requirements are necessary for safe and reliable grid operations and that arguments against the *de minimis* designation often misrepresent the incremental costs involved in meeting interconnection requirements versus providing additional reactive capability.[175] Joint Customers note that claims of excessive costs for non-synchronous generators to comply with power factor requirements are collateral attacks on prior Commission orders, particularly Order No. 827.[176]

68. The PJM IMM, MISO Transmission Owners, and several other commenters assert that providing reactive power within the standard power factor range is an obligation of interconnection and consistent with good utility practice.[177] The PJM IMM asserts that the Commission has a long

interconnection); Order No. 2003, 104 FERC ¶ 61,103 at P 546.

[163] NOPR, 186 FERC ¶ 61,203 at P 13 (citing MISO Rehearing Order, 184 FERC ¶ 61,022 at P 23).

[164] *Id.* at P 39.

[165] *Id.*

[166] *Id.*

[167] *Id.* at 39 & nn.100–02. The Commission noted that, in PJM for example, while the capacity market rules currently account for reactive power payments to resources by assuming average reactive power compensation of $2,546 per MW-year, reactive power revenue requirements in PJM range from roughly $1,000 per MW-year to $13,000 per MW-year. The Commission noted that this wide range of actual compensation, which is both above and below the assumed reactive power compensation in the capacity market rules, can lead to market distortions.

[168] AEP; Ameren; Joint Consumer Advocates; Joint Customers; MISO Transmission Owners; New England Consumer Advocates; Ohio FEA; PGE; PJM; the PJM IMM; the Transmission Access Policy Study Group.

[169] *See* Ameren Initial Comments at 3; Joint Customers Reply Comments at 11–13; MISO Transmission Owners Initial Comments at 5–7; New England Consumer Advocates Initial Comments at 4–6; PJM IMM Initial Comments at 4.

[170] Ameren Initial Comments at 3 (citing *BPA,* 120 FERC ¶ 61,211 at P 21 (''Evidence from numerous reactive power rate filings demonstrates newly interconnecting resources have the capability to provide reactive power, some well in excess of the required 0.95 leading to 0.95 lagging. It is also well-documented that the same equipment used to produce real power includes reactive power functions and thus there is little, if any, incremental cost associated with providing reactive power.'')); MISO Transmission Owners Initial Comments at 5–7 (citing *MISO,* 182 FERC ¶ 61,033 at P 55; MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 25 n.76, 29–30, 34, 41–42 (''[T]he record establishes, that Reactive Service requires little or no incremental investment.'')); MISO Transmission Owners Reply Comments at 9; *see also* Ohio FEA Initial Comments at 3.

[171] MISO Transmission Owners Initial Comments at 7 & n.18 (citing MISO Rehearing Order, 184 FERC ¶ 61,022 at P 30 n.98 (''[O]lder wind generators could not produce and control reactive power without the use of costly equipment [ ] 'because they did not use inverters like other non-synchronous generators' but modern turbines now use inverters and newer wind generators now can.'')).

[172] *Id.* at 7.

[173] *Id.* at 9.

[174] Joint Customers Reply Comments at 11–13.

[175] *Id.*

[176] *Id.* at 13 (citing Order No. 827, 155 FERC ¶ 61,277 at P 11 (''Prior to Order No. 827, non-synchronous generators were exempt from complying with power factor requirements. The entire point of Order No. 827 was to find that technological advancements had reduced the cost of compliance such that non-synchronous generators no longer needed the exemption. The order also explicitly maintained the compensation scheme for reactive power, with all that means for the elimination of compensation if not justified by comparability.'').

[177] PJM IMM Initial Comments at 6–9 (citing PJM, OATT, Attachment O, §§ 4.7.1.1.1., 4.7.1.2. (3.0.0)); Joint Consumer Advocates Initial Comments at 6–7; MISO Transmission Owners Reply Comments at 4; TAPS Initial Comments at 6; Ohio FEA Initial Comments at 5; Joint Customers Initial Comments at 14–16; PGE Initial Comments at 4 (citing *MISO,* 182 FERC ¶ 61,033 at P 53 (noting that in the acceptance of the MISO Transmission Owners application to end compensation within the standard power application, the Commission reiterated its policy ''that the provision of reactive power within the standard power factor range is, in the first instance, an obligation of the interconnecting generator and good utility practice.'')).

standing policy that ''treats the provision of reactive power inside the [standard power factor range] as an obligation of good utility practice rather than as a compensable service and permits compensation inside the [standard power factor range] only as a function of comparability.'' [178]

69. The PJM IMM states that reactive power is not the only design obligation the generation interconnection customers assume.[179] The PJM IMM notes, for example, that generating facilities are required to provide primary frequency response capability, but the PJM OATT does not provide an out of market payment for such service because it is treated as an obligation assumed by generation interconnection customers for receiving interconnection service.[180] MISO Transmission Owners also point out that the SEIA, the national trade association for the U.S. solar industry, has acknowledged that reactive power compensation does not affect a generator's operations and that provision of reactive power within the standard power factor range is required regardless of compensation.[181]

70. Additionally, MISO Transmission Owners agree that the Commission's line of precedent since Order No. 2003 has required interconnecting generators to be able to provide reactive power within the standard power factor range without compensation, with few exceptions.[182] MISO Transmission Owners argue that generators are incented by their own reliability requirements to install the equipment that will help keep their projects on-line and delivering real power, and that ''skimping'' on equipment that can provide reactive power across a range of operating conditions is not in generators' best operational interests or consistent with good utility practice.[183] MISO Transmission Owners state that generating facilities are also required by the North American Electric Reliability Corporation (NERC) reliability standards to operate in automatic voltage control mode and maintain a voltage set point provided by the transmission provider.[184]

71. MISO Transmission Owners and the PJM IMM agree with the NOPR's preliminary finding that the current reactive power compensation framework allows for undue compensation and potential market distortions, and they argue that the current compensation framework leads to ''black-box'' settlements that lack transparency and result in vastly disparate rates.[185] The PJM IMM argues that separately compensating resources based on a judgment-based allocation of capital costs is not appropriate in the PJM markets.[186] The PJM IMM argues that cost-of-service compensation for reactive power distorts markets and undermines competition.[187] The PJM IMM asserts that the current rules create strong incentives for generating facilities to attempt to maximize the allocation of capital costs to reactive service in order to maximize guaranteed, nonmarket revenues.[188] The PJM IMM claims that there is no reasonable basis for the disparity in the price to customers from different types of generators for the same service and that reactive power is a homogeneous product which should have the same price for all sellers. The PJM IMM notes that the most recent reactive power rate cases settled prior to issuance of the NOPR have resulted in costs well in excess of the reactive power revenue offset assumed in PJM's capacity market.[189]

72. Many other commenters, in contrast, challenge the Commission's preliminary finding that providing reactive power within the standard power factor range has no or *de minimis* costs.[190] The Indicated Trade Associations and Generation Developers emphasize that the costs of equipment and production associated with reactive power, particularly for renewable resources, are substantial and involve significant capital investments.[191] Indicated Reactive Power Suppliers, NEPGA, and Reactive Service Providers assert that eliminating compensation for reactive power within the standard power factor range is unjust and unreasonable, given the substantial capital costs incurred by generators.[192] They argue that the NOPR's proposal fails to account for these costs as well as for lost opportunities for real power generation and renewable energy credits.[193] They assert that the

[178] PJM IMM Initial Comments at 6–8 (citing NOPR, 186 FERC ¶ 61,203 at P 5 (citing BPA Rehearing Order, 125 FERC ¶ 61,273 at P 18)); *see also* MISO Transmission Owners Initial Comments at 10–12.

[179] PJM IMM Initial Comments at 8.

[180] *Id.* (citing PJM, OATT, Attachment O § 4.7.2. (3.0.0)).

[181] MISO Transmission Owners Initial Comments at 9 & n.24 (citing SEIA, *Reactive Power Compensation: How to Unlock New Revenue Opportunities for Solar and Storage Projects, Solar Energy Industries Association* 4 (July 29, 2020), *https://old.seia.org/sites/default/files/2023-01/Speaker%20Q&A%20-%20Reactive%20Power%20Compensation%20Webinar.pdf* (also attached as Exhibit I) (''Filing for and receiving reactive revenues has no impact on the generator's operating profile. The ISO/RTOs have a right to dispatch generators to provide reactive service as needed to maintain reliability.'')). The MISO Transmission Owners also add that ''[a]t the same time MISO was experiencing a dramatic increase in the amounts transmission customers paid for reactive power service prior to its elimination of compensation for reactive power service within the deadband, SEIA highlighted that MISO was one of the two 'most lucrative' regions for reactive power compensation, where generators received millions of dollars in compensation for having the capability to produce reactive power within the deadband, a capability that was already a condition of obtaining interconnection.'' *Id.* at 9–11.

[182] *Id.* at 10–11 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 546; Order No. 2003–A, 106 FERC ¶ 61,220 at PP 410, 416; Order No. 827, 155 FERC ¶ 61,277 at P 59).

[183] *Id.* at 11 & n.29 (citing MISO Rehearing Order, 184 FERC ¶ 61,022 at P 35 n.116 (''[G]enerators have incentives to install equipment to ensure that their generation remains online and delivering real power.'')).

[184] *Id.* at 11–12 (citing Reliability Standard VAR–002–3—Generator Operation for Maintaining Network Voltage Schedules), at 2 (Aug. 1, 2014), *http://www.nerc.com/pa/Stand/Reliability%20Standards/VAR-002-3.pdf* (''R2 . . . Generator Operator shall maintain the generator voltage or Reactive Power schedule (within each generating Facility's capabilities).'').

[185] *Id.* at 8; PJM IMM Initial Comments at 4–6; *see also* Joint Customers Initial Comments at 4–6.

[186] PJM IMM Initial Comments at 3–4.

[187] *Id.* at 4–6.

[188] *Id.* at 4. The PJM IMM asserts that these revenues provide a nonmarket advantage to generating facilities that receive them, resulting in an arbitrary and nonmarket-based advantage (*i.e.*, distortionary).

[189] *Id.* at 6 (explaining that in PJM's capacity market, ''the parameters that define the demand curve . . . are based on the costs of new entry of a reference generating unit, less net revenues from other PJM markets'' such as reactive power revenues). The PJM IMM explains that the level of these net revenues that are subtracted, or offset, from the costs of new entry, are based on a calculation from the PJM IMM of the average Schedule 2 payment for reactive done in 2008 and based on reactive rates from prior years. However, the PJM IMM states that ''[m]ost recent cases settled prior to issuance of the NOPR have settled for costs well in excess of the average cost and well in excess of the [] offset amount'' and that ''[t]he issue is growing in significance.'' *Id.* at 5.

[190] Eagle Creek Initial Comments at 3–4; Indicated Trade Associations Initial Comments at 7; ACORE Initial Comments at 2; Elevate Renewables Initial Comments at 9–12; Generation Developers Initial Comments at 13; Glenvale Initial Comments at 9–10; Indicated Reactive Power Suppliers Initial Comments at 2, 9–10; Indicated Trade Associations Initial Comments at 2, 6; Middle River Power Initial Comments at 2–3; NEI Initial Comments at 4–5, 8–9; NHA Initial Comments at 2, 4–5. Indicated Trade Associations also assert that prior Commission orders cited by the NOPR to support the assertion that no costs or *de minimis* costs are incurred to provide reactive power within the standard power factor range do not provide evidence to support the conclusion. Indicated Trade Associations Initial Comments at 8 (citing *BPA,* 120 FERC ¶ 61,211 at P 21; BPA Rehearing Order, 125 FERC ¶ 61,273 at P 7 n.7; *Ariz. Pub. Serv. Co.,* 94 FERC ¶ 61,027, at 61,080 (2001) (*APS*)); Onward Energy Reply Comments at 2.

[191] Indicated Trade Associations Initial Comments at 10; Generation Developers Initial Comments at 13.

[192] Indicated Trade Associations Reply Comments at 6–7; NEPGA Reply Comments at 3 (citing Indicated Trade Association Initial Comments, Affidavit of Michael Borgatti, Docket No. RM22–2–000 at 9–10 (filed May 28, 2024)); Reactive Service Providers Initial Comments at 37–40.

[193] *See* Indicated Trade Associations Initial Comments at 11–12 (''[F]or renewable resources,

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Commission's proposal is inconsistent with the FPA's purpose of ensuring just and reasonable returns on investment, particularly for inverter-based resources, which incur distinct incremental costs for reactive power provision.[194]

73. Some commenters argue that there is an insufficient legal foundation under section 206 of the FPA to demonstrate that all existing reactive power rates are unjust and unreasonable.[195] Generation Developers assert that the fact that many generators are required to provide reactive power as a condition of receiving interconnection service and consistent with good utility practice does not provide a basis for concluding that the compensation received by generating facilities is unjust and unreasonable.[196] Generation Developers assert that the Commission's reasoning improperly assumes that generating facilities investing in reactive power capability are not performing a service that benefits the transmission system, but is instead only needed to support their own deliveries.[197] Generation Developers assert that the NOPR's categorical determination that the just and reasonable reactive power rate is zero, and thus all reactive rates that are not zero are unjust and unreasonable, fails to comply with the requirements of section 206 of the FPA.[198] NEI adds that the Commission failed to meet its section 206 burden because the NOPR does not offer substantial evidence that reactive power costs are zero or minimal, cost allocation is inappropriate, or reducing reactive power compensation to zero would allow generators to recover their costs, plus a reasonable rate of return.[199]

74. Generation Developers assert that the Commission ignores well-documented evidence that certain types of generating facilities, namely inverter-based generating facilities, incur distinct, incremental costs associated with providing reactive power.[200] Generation Developers assert that, when the Commission first required that generating facilities be capable of supplying reactive power within the standard power factor range in Order No. 2003, it explicitly exempted wind generating facilities from that requirement because most wind generators could not maintain the power factor range.[201] Generation Developers state that the Commission also generally exempted wind generators from operating within the standard power factor range in Order No. 661 because ''for wind plants, reactive power capability is a significant added cost.'' [202] Generation Developers assert that while the Commission removed this exemption in Order No. 827 [203] after finding that technological advancements made it so the cost of reactive power no longer presented an obstacle to the development of wind generation, it ''notably did not find that there were no such costs or even *de minimis* costs associated with the provision of reactive power by wind resources.'' [204] Instead, Generation Developers argue that the Commission removed this exemption based on its finding that imposing an obligation on non-synchronous generating facilities to provide reactive power within the standard power factor range was necessary to support transmission service and reliability.[205] Generation Developers add that, even if costs have declined over the years, the Commission has not demonstrated that it would be just and reasonable to nullify the rate schedules of facilities that came online years before the technological advancements referenced in Order No. 827 and had to make incremental investments to its facility to produce reactive power within the standard power factor range.[206]

75. Generation Developers argue that the 2014 Staff Report is the most recent and comprehensive evidence on the costs that non-synchronous generating facilities incur in providing reactive power.[207] Generation Developers assert that the NOPR does not provide any evidence to support that the costs of providing reactive power have changed since the Commission's observations in the 2014 Staff Report, but instead relies on a rehearing order in a proceeding concerning the MISO transmission owners' proposal to eliminate reactive power compensation within the standard power factor range for the proposition that non-synchronous generating facilities have no or *de minimis* costs.[208] Generation Developers assert that the Commission's reliance on a statement from the MISO Rehearing Order, and the purported failure of parties in that proceeding to demonstrate costs of non-synchronous facilities, does not satisfy the Commission's burden in this case.[209] Generation Developers add that the Commission's reliance on cases that pre-date the emergence of non-synchronous generating facilities for the proposition that all generating facilities have no or *de minimis* costs is misplaced.[210] For example, Generation Developers contend that the Commission erred in citing Duke Energy Corporation's comments to the NOI in support of its finding that the inverter is the most critical equipment for the production of reactive power from non-synchronous resources.[211]

76. PSEG similarly notes that the Commission has long used the AEP Methodology to allocate costs associated

having to back down generation in order to produce reactive power would also result in lost renewable electricity production tax credits, renewable energy certificates, and similar benefits''); Generation Developers Initial Comments at 13.

[194] *See* Indicated Trade Associations Reply Comments at 7; Generation Developers Initial Comments at 13, 20–21.

[195] Generation Developers Initial Comments at 24–25; Middle River Power Initial Comments at 4; NEI Initial Comments at 7; PSEG Initial Comments at 2–3, 11–12; Reactive Service Providers Initial Comments at 7–54; NYISO Initial Comments at 1.

[196] Generation Developers Initial Comments at 25.

[197] *Id.*

[198] *Id.* at 31; PSEG Initial Comments at 12–13.

[199] NEI Initial Comments at 8.

[200] Generation Developers Initial Comments at 13–17.

[201] *Id.* at 13 (citing Order No. 2003, 104 FERC ¶ 61,103 (noting that the Commission exempted wind generation from the requirement because ''wind generators for the most part cannot maintain the required power factor, simply because the necessary technology does not exist for wind generators'')).

[202] *Id.* at 13–14 (citing Order No. 661, 111 FERC ¶ 61,353 at P 46; Order No. 661–A, 113 FERC ¶ 61,254). Generation Developers add that in Order No. 661, the Commission was presented with evidence that ''wind turbines cannot meet the proposed power factor standard over the full range of real power output, and that dynamic VAR control (DVAR) banks or static capacitors would have to be installed *at an additional expense to meet the proposed power factor over the entire range.*'' Generation Developers Initial Comments at 13 (citing Order No. 661–A, 113 FERC ¶ 61,254 at P 45 (emphasis added)). Generation Developers state that while Order No. 661 was limited to wind resources, the Commission extended the exemption to other non-synchronous resources on a case-by-case basis. Generation Developers Initial Comments at 14 (citing *Nev. Power Co.,* 130 FERC ¶ 61,147, at P 27 (2010)).

[203] Order No. 827, 155 FERC ¶ 61,277 at P 21.

[204] Generation Developers Initial Comments at 14.

[205] *Id.* (citing Order No. 827, 155 FERC ¶ 61,277 at P 4) (''The Commission instead made its decision to apply reactive power requirements to non-synchronous resources based on its 'balancing the *costs* to newly-interconnecting non-synchronous generators of providing reactive power with the benefits to the transmission system of having another source of reactive power.' '').

[206] *Id.* at 17.

[207] *Id.* at 14–15 (citing 2014 Staff Report (''[M]ost dynamic reactive power, which is crucial to transmission system reliability, is provided by generators.''). Specifically, Generation Developers state that the 2014 Staff Report made the following findings: ''(1) the costs of reactive power equipment for wind generators range from 3.18% to 4% of their capital costs; and (2) the costs of adding reactive power capability to solar photovoltaic generators range from 2% to 20% of a project's total costs, depending on project size.'' *Id.* at 15 (citing 2014 Staff Report app. 2 at 2–3).

[208] *Id.* at 15 (citing NOPR, 186 FERC ¶ 61,203 at P 29 n.70 (citing MISO Rehearing Order, 184 FERC ¶ 61,022 at P 30)).

[209] *Id.*

[210] *Id.* at 16 (citing *BPA,* 120 FERC ¶ 61,211; METC Rehearing Order, 97 FERC at 61,852–53; *APS,* 94 FERC at 61,080).

[211] *Id.* at 16–17 n.52 (citing Duke Energy Corporation Initial Comments to the NOI at 4).

with the provision of reactive power within the standard power factor range.[212] PSEG witness Dr. Dumais observes that the AEP Methodology identifies four categories of equipment costs that are involved in the production of reactive power from synchronous generating facilities.[213]

77. Indicated Trade Associations argue that the cases cited to in the NOPR to support the finding that there are no or *de minimis* costs associated with producing reactive power do not support the Commission's assertion.[214] For example, Indicated Trade Associations assert that in *BPA,* the Commission summarily stated without evidence that ''the incremental cost of reactive power service within the deadband is minimal.'' [215] Indicated Trade Associations assert that, on rehearing, however, when a party argued that '' 'only the short-run marginal cost of producing the next increment of reactive power 'can logically be described as minimal' because it excludes capability costs,' . . . the Commission sidestepped this issue, stating that 'the issue of whether or not the cost is minimal is not relevant to whether the independent power producers are entitled to compensation.' '' [216] Indicated Trade Associations argue that in *APS,* another order cited in the NOPR, ''the Commission simply noted that intervenors 'have not demonstrated that [the proposed reactive power] requirement will limit the real power output of a generating unit and therefore will not result in any lost opportunity costs.' '' [217]

78. Elevate and Glenvale further argue that the Commission's assumption that all resource classes, including energy storage resources, incur no or minimal costs is unsupported by evidence.[218] Elevate asserts that recurring capital investments are required to address battery degradation caused by the provision of reactive power.[219] Specifically, Elevate argues that while the level of degradation increases as the reactive power to real power ratio moves further from unity, even the provision of reactive power within the standard power factor range contributes to the degradation of the storage resource's capability.[220] Elevate states that energy storage resources must make significant and recurring capital investments to address this degradation, which, in Elevate's experience, costs approximately one percent of the resource's original capital investment annually.[221] Elevate asserts that the record is devoid of any evidence that energy storage resources incur no or *de minimis* costs to provide reactive power.[222] Glenvale argues that there are marginal, operational, and replacement costs associated with providing reactive power within the power factor range for solar generating facilities.[223] Specifically, Glenvale asserts that, at the capital investment stage, there are different inverter options that allow generating facilities to provide reactive service outside of generating hours (*e.g.,* allowing solar generating facilities to provide reactive power at night) and that this incurs additional costs which would not be required if the generating facility were not set up to provide reactive power at night.[224] Glenvale also asserts that inverters use electricity to provide reactive power, explaining that when a generating facility is synchronized, this presents as reduced generation, and when a generating facility is not synchronized, the generator must either use an alternate power source or it presents as negative generation (both of which Elevate states result in additional costs).[225] Glenvale also states that the provision of reactive power can result in a reduced inverter service life.[226] Glenvale notes that it is difficult to allocate these costs among each of the three service conditions—within the standard power factor range while synchronized, within the standard power factor range at night, and outside the standard power factor range at all times—but Glenvale asserts that at least some of the costs are attributable to providing reactive power within the standard power factor range.[227] NEI asserts that there are real costs for nuclear generating facilities to provide and maintain reactive power capability, including: properly sized generators, maintenance associated with normal operations to preserve reactive power capability, and additional repairs that may be needed to address age-related degradation to equipment that might otherwise impair reactive power capability.[228]

79. Relatedly, NEI explains that nuclear generators are most likely to be called upon to provide reactive power services and thus are the generators most likely to face accelerated degradation and damage to reactive power equipment.[229]

80. Reactive Service Providers argue that there is no evidence to support the claim that providing reactive power within the standard power factor range requires no incremental investment, and that even if the investment needed were *de minimis,* that would not be a reason to not provide compensation.[230] Reactive Service Providers further contend that there is no evidence that the costs of providing reactive service have increased since the advent of RTOs and IPPs [231] or that generating facilities are recovering their costs in regions where transmission providers do not provide compensation.[232]

81. Eagle Creek criticizes the Commission's determination that there are no or *de minimis* costs associated with the provision of reactive power in the standard power factor range as flawed based on its own tariff cases under the AEP Methodology and argues that eliminating compensation for reactive power would be arbitrary and capricious.[233] ACORE, Indicated Reactive Power Suppliers, and Middle River Power similarly argue that their facilities have demonstrated just and reasonable compensation covering actual reactive power costs during settlement negotiations.[234]

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[212] PSEG Initial Comments at 9.

[213] *Id.,* Prepared Testimony of Dr. Paul A. Dumais at 11, 1:11.

[214] Indicated Trade Association Initial Comments at 7–8.

[215] *Id.* at 8 (citing *BPA,* 120 FERC ¶ 61,211 at P 21).

[216] *Id.* (citing BPA Rehearing Order, 125 FERC ¶ 61,273 at n.7).

[217] *Id.* (quoting *APS,* 94 FERC at 61,080; citing NOPR, 186 FERC ¶ 61,203 at P 29 n.70).

[218] Elevate Initial Comments at 9–12; Elevate Reply Comments at 7–9; Glenvale Initial Comments at 9–10.

[219] Elevate Initial Comments at 9–12; Elevate Reply Comments at 7–9.

[220] Elevate Reply Comments at 8.

[221] *Id.*

[222] Elevate Initial Comments at 12.

[223] Glenvale Initial Comments at 9–10.

[224] *Id.* at 9.

[225] *Id.*

[226] *Id.* at 9–10 & n.29 (citing Ramanathan Thiagarajan, Adarsh Nagarajan, Peter Hacke, and Ingrid Repins, *Effect of Reactive Power on Photovoltaic Inverter Reliability and Lifetimes* (2019), *https://www.nrel.gov/docs/fy19osti/73648.pdf.*) (''One characterization in recent research is that providing reactive power within the standard power factor range reduces service life by one year, and that providing reactive power outside of the standard range reduces service life by a second year.'')).

[227] *Id.* at 10.

[228] NEI Initial Comments at 5.

[229] *Id.* at 14–16.

[230] Reactive Service Providers Initial Comments at 37–40.

[231] *Id.* at 31–34.

[232] *Id.* at 37–41.

[233] Eagle Creek Initial Comments at 3–4. Eagle Creek argues that, for each of its tariff cases, it submitted evidence documentation of the fixed and sunk costs that it invested to increase its reactive power generation. *Id.*

[234] ACORE Initial Comments at 2; Indicated Reactive Power Suppliers Initial Comments at 9; Middle River Power Initial Comments at 2–3 (noting that Middle River Power owns 19 fossil-fired generating facilities that recover approximately $4.5 million in annual reactive power revenues through their reactive service tariffs

Continued

82. Indicated Trade Associations assert that the Commission fails to reconcile the NOPR's insistence that there are no segregable costs associated with the provision of reactive power with its longstanding precedent of the AEP Methodology, where the Commission approved isolating costs of providing reactive power.[235] NEI asserts that, rather than point to actual data that demonstrates generating facility costs for providing reactive power, the NOPR relies on the misplaced theory that ''because both synchronous and non-synchronous resources provide real and reactive power as joint products, with joint costs, . . . any allocation of joint fixed costs between real and reactive power could be viewed as inherently arbitrary.'' [236] NEI and Generation Developers argue that the AEP Methodology compensates generators based on their actual costs and reactive capabilities, providing them with a just and reasonable opportunity to recover their investments in reactive service capability, and asserts that the Commission has repeatedly confirmed this cost allocation methodology and its underlying factual predicates in numerous proceedings.[237] Generation Developers suggest that the Commission has allocated real and reactive power costs using the AEP Methodology for over two decades [238] and has rejected arguments that the AEP Methodology results in an improper allocation of costs or is used merely as a matter of administrative convenience.[239] The NHA asserts that the Commission correctly identifies real power and reactive power as jointly produced commodities, but it incorrectly attributes the cost of all generation equipment to be predominantly for the production of real power.[240]

83. Clean Energy Associations assert that reactive power is not always coupled with real power as they believe the Commission states in the NOPR.[241] Middle River Power argues that the Commission's statement that generating facilities are being asked to provide reactive power in order to offset the impact of the power they inject into the system is incorrect.[242] Similarly, Middle River Power asserts that the Commission has previously found that generators are being asked to supply reactive power to support load. Clean Energy Associations argues that the Commission conflates the cost of equipment with the cost of providing an essential transmission service and that providing reactive power—even within the standard power factor range—comes at the expense of providing real power.[243] Clean Energy Associations note that a possible solution to this problem could be that the Commission distinguish ''reactive power capability'' from the ''reactive power service.'' [244]

84. ACORE asserts that a requirement to provide a service does not negate the fact that costs are incurred to provide that service.[245] Similarly, Elevate and Indicated Trade Associations argue that, even if it were true that resources do not incur distinct costs associated with reactive power, the Commission fails to point to precedent to support its conclusion that the lack of distinct costs is an appropriate basis on which to deny resources the ability to recover those costs.[246] The Indicated Trade Associations assert that the NOPR's assumption that there are no or minimal costs associated with the provision of reactive power directly contradicts Order No. 888, which Indicated Trade Associations argue found that reactive service from generating facilities must be priced at cost, thereby acknowledging that there are distinguishable costs associated with the provision of reactive power.[247] Middle River Power argues that the Commission has historically required compensation for reactive power as a separate ancillary service.[248]

85. Reactive Service Providers assert that the Commission has not supported its claim that generating facilities (and specifically IPP) already have an obligation to provide reactive service within the standard power factor range.[249] Reactive Service Providers argue that the NOPR's finding is contrary to decades of Commission precedent,[250] and the Commission ''lost its way as it proceeded to Order No. 2003 and beyond, caught up in a myopic view that unbundling and the emergence of the IPP industry somehow transferred the 'obligation' to provide reactive service within the standard range from the Transmission Provider to the IPP generator.'' [251] Reactive Service Providers assert that transmission providers alone have the obligation to maintain a reliable and stable transmission system, and generating facilities are purely a tool that transmission providers use to fulfill this obligation.[252] Reactive Service Providers assert that in Order No. 888, the Commission determined that various ancillary services support the transmission system so that load can be served, but the Commission notably did not find that generating facilities have this obligation.[253] Instead, Reactive Service Providers argue that the Commission merely recognized that generating facilities were a critical tool that transmission providers can use to maintain the safe and reliable operation of the transmission system.[254] Reactive Service Providers assert that, for Reactive Supply and Voltage Control from Generation Sources (which

on file with Commission, which it argues were ''demonstrated in rigorous proceedings before the Commission'' to be just and reasonable compensation covering actual costs).

[235] Indicated Trade Associations Initial Comments at 9; *see also id.* (citing *Va. Elec. & Power Co.,* 114 FERC ¶ 61,318, at P 3 (2006)) (''[T]he Commission expressly instructed generators to use the AEP Methodology '*to compute the portion of plant investment attributable to reactive power production* . . . Because these production plants produce real and reactive power, *AEP* developed an allocation factor to *segregate the reactive production function from the real power production function. The allocation factor is used to determine the amount of investment allocable to reactive power.*' '') (emphasis added by Indicated Trade Associations)).

[236] NEI Initial Comments at 10 (citing NOPR, 186 FERC ¶ 61,203 at P 30)

[237] *Id.* at 10–11; Generation Developers Initial Comments at 7–9.

[238] Generation Developers Initial Comments at 8–9 (citing *Dynegy Midwest Generation, Inc.,* 125 FERC ¶ 61,280 at P 11; *Bluegrass Generation Co., L.L.C.,* 118 FERC ¶ 61,214, *order on reh'g,* 121 FERC ¶ 61,018, at P 12 (2007)).

[239] *Id.* (citing *Bluegrass Generation Co.,* 121 FERC ¶ 61,018 at P 12 (''This policy is not a matter of administrative convenience . . . but the result of the Commission's deliberate determination that the AEP methodology is a just and reasonable manner of calculating a reactive power revenue requirement'').

[240] NHA Initial Comments at 4–5 (noting that ''[t]here is no basis for this assumption, especially if the Commission believes the AEP Methodology is incapable of isolating real and reactive cost.'').

[241] Clean Energy Associations Initial Comments at 7.

[242] Middle River Power Initial Comments at 3.

[243] Clean Energy Associations Initial Comments at 6–7.

[244] *Id.*

[245] ACORE Initial Comments at 2.

[246] Elevate Initial Comments at 9–10; Indicated Trade Associations Initial Comments at 9.

[247] Indicated Trade Associations Initial Comments at 9 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,720–21).

[248] Middle River Power Initial Comments at 2–3.

[249] Reactive Service Providers Initial Comments at 7 (citing NOPR, 186 FERC ¶ 61,203 at P 5).

[250] *Id.* at 9.

[251] *Id.* at 8.

[252] *Id.* at 8–9 (citing Affidavit of Dennis W. Bethel).

[253] *Id.* at 9 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,349 (noting that the Commission adopted the following definition of ancillary services: ''Those services that are necessary to support the transmission of capacity and energy from resources to load while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice'' and that the Commission determined that ''A control area is part of an interconnected power system with a common generation control system. It may contain one or several utilities. The operator of the control area is responsible for balancing generation and load and for maintaining reliable system operation.'')).

[254] *Id.*

ultimately became Schedule 2), the Commission noted that:

NERC states that reactive supply is provided from both generation resources and transmission facilities (*e.g.,* capacitors), and lists its provision as two services, distinguished by the facilities that supply them. NERC further distinguishes reactive supply service based on the source of the need for the service: (1) reactive supply needed to support the voltage of the transmission system; and (2) reactive supply needed to correct for the reactive portion of the customer's load at the delivery point.[255]

Reactive Service Providers assert that NERC did not identify the impact of generating facilities to the transmission system as a reason or need for reactive supply, but instead only identified the transmission system and load as needing the reactive service, noting that generating facilities would serve those needs at the point of interconnection.[256] Reactive Service Providers assert that, while both before and after Order No. 888, transmission providers holistically relied on generation- and transmission-based reactive assets to fulfill their obligations to maintain the voltage of the transmission system, generating facilities never had an independent obligation to provide reactive service, as the Commission asserts in the NOPR.[257]

86. Reactive Service Providers assert that when the Commission issued Order No. 2003, it summarily stated that, as a condition to obtain interconnection service, the generating facility must provide reactive service within the standard power factor range.[258] Reactive Service Providers argue that the Commission did not amass any evidence in the Order No. 2003 proceeding to explain why generating facilities have an obligation to provide reactive service within the standard power factor range and posit that the Commission may have come to this conclusion in Order No. 2003 and the NOPR ''because the Transmission Provider has always relied on generators as one of its tools to enable the Transmission Provider to fulfill its obligation to maintain the Transmission System in a safe and reliable manner.'' [259] Reactive Service Providers assert that none of the transmission system operators, NERC, and the Commission, in nearly all precedent, have ever concluded that generation has an ''obligation'' to provide reactive service within the standard range; the Commission's statement in Order No. 2003 is an outlier.[260]

87. Similarly, Reactive Service Providers assert that ''good utility practice'' does not entail an obligation for generating facilities to provide reactive power for free, and the Commission has not explained why it believes such obligation exists.[261] Reactive Service Providers argue that the current compensation scheme for reactive power is consistent with the Commission's definition of good utility practice because it includes practices that ''could have been expected to accomplish the desired result *at a reasonable cost* consistent with good business practices, reliability, safety and expedition.'' [262] Reactive Service Providers assert that good utility practice does not address what the electric industry (*i.e.,* the transmission provider) can achieve for free, but rather a cost that the transmission provider must pay as a matter of ''good business practices'' in order to fulfill its obligation.[263] Indicated Trade Associations argue that the Commission cannot deprive public utilities from just and reasonable compensation for reactive power within the standard power factor range by simply classifying it as a condition of interconnection, particularly when the Commission established that condition.[264]

88. Generation Developers assert that the NOPR errs in concluding that separate compensation for reactive power may result in a windfall to generators. Generation Developers note that many generators across markets are in fact increasingly unable to recover their costs.[265] Indicated Trade Associations similarly refute the NOPR's preliminary conclusion that separate compensation for reactive power within the standard power factor range may result in market distortions, contending that all rates are approved by the Commission and that any distortions are a result of PJM's capacity market rules.[266]

2. Commission Determination

89. Based on our review of the record, we conclude that compensation for the provision of reactive power within the standard power factor range is unjust and unreasonable because: (1) the provision of such reactive power requires either no or at most a *de minimis* increase in variable costs beyond the cost of providing real power; (2) such compensation may result in undue compensation and other market distortions; and (3) the provision of reactive power within the standard power factor range is an obligation of the generating facility as an interconnection customer and consistent good utility practice.[267]

90. As explained in the NOPR, because real and reactive power are provided as joint products with joint costs produced from the same

[255] *Id.* at 10 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,355).

[256] *Id.*

[257] *Id.* at 11.

[258] *Id.* at 11–12.

[259] *Id.* at 12.

[260] *Id.* at 12–19 (citing Order No. 661, 111 FERC ¶ 61,353 at PP 50–51 (''this Final Rule requires the wind plant to maintain the required power factor range only if the Transmission Provider shows through the System impact Study, that such capability is required of that plant to ensure safety or reliability. . . . ''[B]ecause the Transmission Provider is responsible for the safe and reliable operation of its transmission system (pursuant to NERC and regional reliability council standards), it is in the best position to establish if reactive power is needed in individual circumstances.''); Order No. 827, 155 FERC ¶ 61,277 at P 35 (''balancing the costs to newly-interconnecting non-synchronous generators of providing reactive power *with the benefits to the transmission system of having another source of reactive power*'') (emphasis added by Reactive Service Providers)); *id.* at 18 (''[I]n Order No. 901, the [Commission] continued the clear distinction between a Transmission Provider that has the obligation to plan and operate the Transmission System and generation that is a tool that Transmission Providers must account for and uses to fulfill its obligation to plan and operate the Transmission System.'') (citing *Reliability Standards to Address Inverter-Based Res.,* Order No. 901, 88 FR 74250 (Oct. 30, 2023) 185 FERC ¶ 61,042, at P 174 (2023)).

[261] *Id.* at 19.

[262] *Id.* at 19–20 (quoting at Order No. 2003, 104 FERC ¶ 61,103 at P 56) (emphasis added by Reactive Service Providers). Reactive Service Providers assert that the Commission adopted the same definition of ''good utility practice'' in Order No. 2003 as it did in Order No. 888. *Id.* at 19.

[263] *Id.* at 20.

[264] Indicated Trade Associations Initial Comments at 23 (citing *Banton* v. *Belt Line Ry. Corp.,* 268 U.S. 413, 420 (1925) (''[t]he commission under the guise of regulation may not compel the use and operation of the company's property for public convenience without just compensation.''); *Gulf Power Co.* v. *U.S.,* 187 F.3d 1324, 1331 (11th Cir. 1999) (''[c]haracterizing the mandatory access provision as a regulatory condition . . . cannot change the fact that it effects a taking by requiring a utility to submit to a permanent, physical occupation of its property'')).

[265] Generation Developers Initial Comments at 27 (citing CAISO, 2022 Annual Report on Market Issues & Performance 15 (July 11, 2023), *http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx;* PJM, Energy Transition in PJM: Resource Retirements, Replacements and Risks 10 (Feb. 24, 2023), *https://insidelines.pjm.com/pjm-details-resource-retirements-replacements-and-risks.*).

[266] Indicated Trade Associations Reply Comments at 9.

[267] PJM IMM Initial Comments at 6–9; Joint Consumer Advocates Initial Comments at 6–7; MISO Transmission Owners Reply Comments at 4; TAPS Initial Comments at 6; Ohio FEA Initial Comments at 5; Joint Customers Initial Comments at 14–16; PGE Initial Comments at 4 (citing *MISO,* 182 FERC ¶ 61,033 at P 53 (noting that in the acceptance of the MISO Transmission Owners application to end compensation within the standard power application, the Commission reiterated its policy ''that the provision of reactive power within the standard power factor range is, in the first instance, an obligation of the interconnecting generator and good utility practice.'')).

equipment, any allocation of joint fixed costs between real and reactive power could be viewed as inherently arbitrary.[268] And while the production of reactive power within the standard power factor range can result in certain incremental variable costs such as fuel, maintenance, and potentially other costs, we continue to find, based on the record and past precedent, that variable costs of generating reactive power within the standard power factor range are at most *de minimis.*[269] With respect to fixed costs, for synchronous generating facilities, ''the same equipment is used to provide real and reactive power.'' [270] Non-synchronous generating facilities use a different physical process to produce reactive power, but ''the most critical element in VAR production, the inverter,'' [271] is also necessary for non-synchronous generating facilities to produce real power that can be reliably injected into AC systems.[272] In other words, for both synchronous and non-synchronous generating facilities, ''[t]here are few if any identifiable costs incurred by generators in order to provide reactive power'' [273] beyond the investments in equipment already necessary to generate and supply real power to the transmission system.[274]

91. While most commenters agree or do not dispute that all equipment used to produce reactive power, for both synchronous and non-synchronous generating facilities, is also necessary in order to produce and deliver to the transmission system real power, several commenters dispute the NOPR's findings that both synchronous and non-synchronous facilities incur no or at most a *de minimis* increase in costs beyond the cost of providing real power.[275] However, these commenters do not identify any specific costs beyond those incurred to ensure that real power can be reliably injected into the transmission system.[276] For example, Indicated Trade Associations, Generation Developers, and Glenvale emphasize that there are costs of equipment and production associated with reactive power, but they provide only vague references to those specific equipment costs and identify no distinct equipment (apart from equipment already needed for real power production).[277] Many of the commenters opposing the rule also conflate the cost of providing reactive power capability within and outside the standard power factor range.[278] For example, commenters suggest that there are opportunity costs to provide reactive power capability, even within the standard power factor range, because doing so requires a generating facility to forgo real power production.[279] As explained in the NOPR and in other Commission precedent, however, reactive power opportunity costs are an issue only when providing reactive power *outside* the standard power factor range. This is because, unlike operating within the standard power factor range, generating facilities operating outside the standard power factor range forgo generating more real power output and thus, forgo sales of real power.[280] Importantly, commenters do not provide any evidence to support their assertion that operating within the standard power factor range will limit the real power output of their generating facilities. To the contrary, rather than limiting real power output, real power cannot be supplied from a generating facility unless that facility is producing reactive power within the standard power factor range to generate and safely inject real power into the

[268] NOPR, 186 FERC ¶ 61,203 at P 30; (citing PJM IMM Initial Comments to the NOI at 2 (''There is no reason to include complex rules that arbitrarily segregate a portion of a resource's capital costs as related to reactive power and that require recovery of that arbitrary portion through guaranteed revenue requirement payments based on burdensome cost of service rate proceedings.''); *id.* at 3, 5, 21, 24; *Permian Basin,* 390 U.S. at 804 (''There is ample support for the Commission's judgment that the apportionment of actual costs between two jointly produced commodities, only one of which is regulated by the Commission, is intrinsically unreliable.''); Richard A. Posner, *Natural Monopoly and Its Regulation,* 21 Stan. L. Rev. 548, 595 (1969) (''[W]here services involve joint or common costs a rational allocation is impossible even in theory. How much of the cost of a telephone handset is assignable to local and how much to interstate telephone service?''); *see also A.A. Poultry Farms, Inc.* v. *Rose Acre Farms, Inc.,* 1400 (7th Cir. 1989) (''How does one allocate the cost of activities that have joint products? Agencies engaged in ratemaking struggle with these problems for years, even decades, without producing clear answers.'')).

[269] NOPR, 186 FERC ¶ 61,203 at P 31 (citing SPP Initial Comments to NOI at 2; PJM IMM Initial Comments to NOI at 4.).

[270] Ameren Initial Comments at 3; MISO Transmission Owner Reply Comments at 9. *See also* NOPR, 186 FERC ¶ 61,203 at P 29 (citing Edison Electric Institute Initial Comments to the NOI at 6).

[271] Duke Energy Corporation Initial Comments to the NOI at 4.

[272] *See, e.g.,* MISO Transmission Owners Initial Comments at 7 (''[E]ven newer wind turbines use inverters that allow for the generator to produce and control reactive power without costly additional equipment.); *see also* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 30 (''As to non-synchronous resources, the principal piece of equipment required for non-synchronous resources to produce reactive power is the inverter, which is already necessary to convert the direct current produced by non-synchronous resources to alternating current—*i.e.,* to supply real power that can be injected into alternating current power systems. On rehearing and in earlier protests, no party points to any other equipment costs incurred by non-synchronous generating facilities that are attributable to providing Reactive Service.'' (citations omitted)).

[273] PJM IMM Initial Comments to the NOI at 4; *see also* MISO Transmission Owners Reply Comments at 7–8.

[274] MISO Transmission Owners Initial Comments at 6 (''The MISO Transmission Owners' experience supports the Commission's preliminary finding that providing reactive power within the standard power factor range requires little or no cost to generators. Generators incur little or no costs beyond what is already needed to produce real power because the same equipment used to produce real power includes reactive power functions.'' (citations omitted)); PJM IMM Reply Comments at 3 (''Neither [Indicated Trade Associations] nor any other opposing commenter, nor any of the precedent relied upon by opposing commenters, identify any additional costs or more than de minimis costs incurred by generators in order to provide reactive capability.''); MISO Transmission Owners Reply Comments at 9–10 & n.29. *See also, BPA,* 120 FERC ¶ 61,211 at P 21 (finding that the incremental cost of reactive power service within the deadband is minimal); METC Rehearing Order, 97 FERC at 61,852–53 (''[R]eactive power provided, not as an ancillary service, but rather as a ''no cost'' service within reactive design limitations, may therefore, be provided without compensation.''); *APS,* 94 FERC at 61,080 (rejecting generators' arguments for reactive power compensation for operating within standard power factor range because the generators failed to demonstrate that ''such a requirement will limit the real power output of a generating unit and therefore will not result in any lost opportunity costs'' or that operating a generating unit within the proposed standard power factor range will ''affect the generation output of a unit'').

[275] NOPR, 186 FERC ¶ 61,203 at PP 8, 28.

[276] The only incremental costs identified in the NOPR were heating losses. NOPR, 186 FERC ¶ 61,203 at P 28 & n.74.

[277] Eagle Creek Initial Comments at 3–4; Generation Developers Initial Comments at 13; Glenvale Initial Comments at 9–10 Indicated Trade Associations Initial Comments at 7–12; Middle River Power Initial Comments at 2–3.

[278] *See* Clean Energy Associations Initial Comments at 6–7 (''However, during certain generating facility and grid operating conditions, when the generator provides an actual service (*i.e.,* injects reactive power to support voltage) it could come at the cost of production of real power. During that time, reactive power is prioritized and real power generated by the plant may be limited. In such a case the generation facility is prioritizing the utilization of their asset to assist or enhance grid stability at the cost of their revenue, which is primarily obtained from real power sales. The Commission should consider this opportunity cost in the context of interconnection customers that participate in regional wholesale markets.'')

[279] *See, e.g.,* Indicated Reactive Power Suppliers Initial Comments at 10 (''Stripping generators of the ability to be compensated for reactive power supply, including lost opportunity costs, within the [standard power factor range] is not just and reasonable and not supported by the record.''); Indicated Trade Associations Initial Comments at 11 (''The NOPR also completely ignores the fact that the provision of reactive power within the deadband represents a lost opportunity to produce real power, thereby resulting in lost opportunity costs.'').

[280] *See, e.g.,* NOPR, 186 FERC ¶ 61,203 at P 32 (''[I]f the transmission provider requires a generating facility to provide reactive power outside of the standard power factor range, the generating facility may have to 'reduce its MW output in order to comply with such an instruction[,]' which could limit the generating facility's opportunity to receive compensation for real power sales.'') (citing CAISO Initial Comments to NOI at 4).

transmission system and comply with reliability requirements.

92. Like in *MISO,* the commenters here fail to identify any incremental fixed costs associated with the provision of reactive power within the standard power factor range and identify only *de minimis* variable costs.[281] In *MISO,* the MISO transmission owners proposed to eliminate all charges under Schedule 2 for the provision of reactive power within the standard power factor range. Like here, protesters opposing MISO's proposal challenged the conclusion that reactive power within the standard power factor range required little or no incremental investment. The Commission rejected their protests, finding that they had failed to identify any record evidence demonstrating that there are more than minimal capital expenditures on equipment or additional operations and maintenance costs attributable to providing such reactive power. Like here, protesters alluded to alleged opportunity costs and operation and maintenance costs but failed to point to any evidence of such costs.

93. Although Generation Developers claim that the report is the most recent and comprehensive evidence on the costs of non-synchronous generating facilities to provide reactive power, Generation Developers' arguments regarding the evidence in the 2014 Staff Report ignore that the Commission found in the MISO Rehearing Order that even newer wind turbines use inverters that allow generating facilities to produce and control reactive power without costly additional equipment,[282] and has found elsewhere[283] that the provision of reactive power requires no or at most *de minimis* variable costs beyond the cost of producing real power.

94. Generation Developers also assert that the Commission's reliance on a statement from the MISO Rehearing Order, and the purported failure of parties in that proceeding to demonstrate significant incremental costs of non-synchronous facilities, does not satisfy the Commission's burden in this case.[284] Generation Developers add that the Commission's reliance on cases that pre-date the emergence of non-synchronous generating facilities for the proposition that all generating facilities have no or *de minimis* costs is misplaced.[285] Indicated Trade Associations similarly argue that Commission precedent cited in the NOPR (*i.e., BPA* and *APS*) does not support the conclusion that the incremental costs of the provision of reactive power within the standard power factor range are at most *de minimis.*[286]

95. We disagree with Indicated Trade Associations and Generation Developers. Commenters provide no support for the contention that decades of Commission precedent are irrelevant for purposes of supporting our findings here, including precedent from after the emergence of non-synchronous generating facilities.[287] As demonstrated by the decades of Commission precedent cited in the NOPR and here, many of the findings in this final determination are not new. The Commission has reached similar conclusions based on similar evidence (or lack thereof) in other proceedings, including with respect to the provision of reactive power within the standard power factor range by non-synchronous generating facilities.[288] This precedent coupled with the evidence in this record, supports this final determination, including with respect to non-synchronous generating facilities.[289]

96. Glenvale contends that certain types of non-synchronous generating facilities incur additional costs to provide reactive power when not providing real power, such as for solar generating facilities providing reactive power at night.[290] However, as these capabilities relate to the provision of reactive power when not providing real power, such costs necessarily are for the provision of reactive power outside the standard power factor range and thus are not impacted by and are beyond the scope of this proceeding.

97. Similarly, some commenters point to capital investments that expand a generating facility's reactive power capability beyond the standard power factor range,[291] but that capability, and thus that investment, does not address the relevant issue of whether transmission charges associated with the provision of reactive power within the standard range are just and reasonable.[292]

98. Eagle Creek and others argue that rates calculated using the AEP Methodology are themselves evidence of significant reactive-power-related capital investments.[293] Putting aside

[281] *See, e.g.,* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 29 (''We continue to conclude, and the record establishes, that Reactive Service requires little or no incremental investment.''); METC Rehearing Order, 97 FERC at 61,852–53 (''[R]eactive power provided, not as an ancillary service, but rather as a ''no cost'' service within reactive design limitations, may therefore, be provided without compensation.''); *APS,* 94 FERC at 61,080 (rejecting generators' arguments for reactive power compensation for operating within standard power factor range because the generators failed to demonstrate that ''such a requirement will limit the real power output of a generating unit and therefore will not result in any lost opportunity costs'' or that operating a generating unit within the proposed standard power factor range will ''affect the generation output of a unit''); *BPA,* 120 FERC ¶ 61,211 at P 21 (''[T]he incremental cost of reactive power service within the [standard power factor range] is minimal.''). *See also S. Co. Servs., Inc.,* 80 FERC at 62,091 (noting also that the primary function of a generating plants is to produce real power; thus, if costs were allocated based on the ''predominant'' function of the equipment, ''all of the costs of generation would thus be assigned to real power production and there would be no basis for any separate reactive power charge'').

[282] MISO Transmission Owners Initial Comments at 7 (citing MISO Rehearing Order, 184 FERC ¶ 61,022 at P 30 n.98 (''[O]lder wind generators could not produce and control reactive power without the use of costly equipment [ ] because they did not use inverters like other non-synchronous generators but modern turbines now use inverters and newer wind generators now can.'')).

[283] METC Rehearing Order, 97 FERC at 61,852–53.

[284] Generation Developers Initial Comments at 15.

[285] *Id.* at 16 (citing *BPA,* 120 FERC ¶ 61,211; METC Rehearing Order, 97 FERC at 61,852–53; *APS,* 94 FERC at 61,080).

[286] Indicated Trade Associations Initial Comments at 8 (citing *BPA,* 120 FERC ¶ 61,211 at P 21; BPA Rehearing Order, 125 FERC ¶ 61,273 at P 7 n.7; *APS,* 94 FERC at 61,080).

[287] *See, e.g., MISO,* 182 FERC ¶ 61,033; *PNM,* 178 FERC ¶ 61,088 at PP 29–31.

[288] *See, e.g.,* MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 29–31 (finding that providing reactive service requires ''little or no incremental investment'' by both synchronous and non-synchronous resources); *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097 at PP 7, 28 (finding that non-synchronous generating facilities are comparable to traditional synchronous generating facilities, in that there are for both types of generating facilities very little if any incremental costs incurred to provide reactive power); 2005 Staff Report at 96 (''The marginal cost of providing reactive power from within a generator's capability curve (D-curve) is near zero.'').

[289] We also note that Order No. 827, which was issued in 2016, after the 2014 Commission Staff Report, removed the exemption for wind generating facilities to provide reactive power because of ''declining costs'' resulting from ''improvements in technology.'' Order No. 827, 155 FERC ¶ 61,277 at P 24. In Order No. 827, the Commission noted that other types of non-synchronous generating facilities were not exempt from the requirement to provide reactive power and that Order No. 827's findings applied to all newly interconnecting non-synchronous generating facilities. *Id.* P 22.

[290] Glenvale Initial Comments at 9–10.

[291] *See, e.g.,* Eagle Creek Initial Comments at 3 (''Where Eagle Creek Reactive Generators made specific capital investments that enhanced reactive service—for example, by installing upgraded exciters with demonstrable power factor improvements—their related reactive compensation case was necessarily strengthened.'').

[292] We note that the additional capabilities are not required as a condition of interconnection. Furthermore, all generating facilities are allowed to seek compensation when directed to provide reactive power beyond the standard power factor range. This final determination does not change the ability of generating facilities to seek compensation associated with providing reactive power outside the standard power factor range.

[293] *See, e.g.,* ACORE Initial Comments at 2 (''A requirement to provide a service does not negate the fact that costs are incurred, as demonstrated by the multiple settlements reached for payment of this

Continued

that these commenters provide no support for their contentions, the AEP Methodology is a *cost allocation methodology* only; it is not designed to, and does not, establish ''evidence of significant reactive-power-related capital investments.'' To the contrary, were it possible to identify discrete, incremental capital investments made to provide reactive power within the standard power range, the AEP Methodology could be utilized to allocate such reactive power costs incurred by the generator; however, no such incremental capital costs exist here, and so the AEP Methodology is inapplicable. In addition, as noted in the NOPR, the AEP Methodology originated in an era of vertically integrated utilities that recovered both generation and transmission costs entirely through cost-based rates and classified those costs under USofA accounting requirements.[294] The Commission accepted the AEP Methodology as a way to assign these costs using a cost-of-service allocation method for assigning joint costs between the generation and transmission functions. As the PJM IMM explains ''The AEP Method[ology] is not about identifying incremental costs incurred to provide reactive power . . . [but rather] allocates the costs of an integrated power plant between reactive power and real power.'' [295] As noted in the Fern Initial Decision, ''The standard techniques for addressing a facility that operates in both a monopoly market and a competitive market—cost allocation and revenue credit—have no connection to the AEP [M]ethod[ology],'' and ''[a]uto-transporting a monopoly-era method into an organized-market context—which is exactly what this proceeding's witnesses do, what dozens of settlements do and what this Initial Decision does—is not regulating based on physical facts.'' [296]

99. We also disagree with those commenters that suggest that the mere existence of joint products requires allocating costs to both real and reactive power production. These assertions disregard longstanding Commission precedent.[297] PSEG, for example, relies on *Dynegy Midwest Generation, Inc.* v. *FERC* for the proposition that ''the NOPR . . . conflicts with Commission and judicial precedents that have long recognized that there are specific fixed costs associated with the production of reactive power.'' [298] But the Commission explicitly rejected this same argument when Dynegy made it in the *MISO* proceeding.[299]

100. Thus, based on the totality of the record, we agree with Ameren that, for both synchronous and non-synchronous generating facilities, ''it is [ ] well-documented that the same equipment used to produce real power includes reactive power functions,'' and thus ''there is little, if any, incremental cost associated with providing reactive power'' beyond the investments in equipment already necessary to generate and supply real power to the transmission system.[300] As discussed below, we also find that the joint costs associated with the production of real and reactive power are costs that generating facilities must incur to provide the real power for which they are compensated.[301]

101. Reactive Service Providers argue that the Commission has not supported its claim that generating facilities already have an obligation to provide reactive service within the standard power factor range. Specifically, Reactive Service Providers assert that when the Commission issued Order No. 2003, it summarily stated that a generating facility must provide reactive service within the standard power factor range as a condition to obtain interconnection service, but it did not amass any evidence to explain why generating facilities have this obligation. Reactive Service Providers claim that Order No. 2003 is an outlier among Commission precedent and that none of the transmission system operators, NERC, or the Commission, in nearly all precedent, has ever articulated such obligation. However, as discussed at length above, outlined in the NOPR, and reiterated in recent Commission decisions, the Commission has for decades stated that ''the provision of reactive power within the standard power factor range is, in the first instance, an obligation of the interconnecting generator and good utility practice.'' [302] We find Reactive

service.''); Indicated Reactive Power Suppliers Initial Comments at 9 (''[S]ubstantial cost support included with the proposed reactive service tariffs of each of the Indicated Reactive Power Suppliers . . . meticulously demonstrate the fixed and sunk costs allocable to reactive power production using the AEP [M]ethodology'').

[294] *See, e.g.,* Joint Customers Reply Comments at 6–7; ELCON Initial Comments at 5. As noted in the NOI, most of the filings at the Commission seeking to establish rates for reactive power compensation are made by generating facilities (both synchronous and non-synchronous) that have received waivers of the Commission's requirement to maintain their accounts under the USofA rules and to file FERC Form No. 1.

[295] PJM IMM Reply Comments at 3. *See also* PJM IMM Initial Comments at 3 (''The *AEP* Method[ology] was based on three sentences in testimony filed in 1993 that provide no logical, engineering or economic support for allocating a part of generator capital investment to reactive. That testimony was about a subjective decision to reassign costs that were already fully accounted for and not about any asserted costs to provide reactive power that were not recovered elsewhere and not for any asserted additional costs of providing reactive power.''); Joint Customers Reply Comments at 12 (''The amount of *total plant cost* that is *allocated* to the reactive function based on a power factor for ratemaking purposes under the *AEP* [M]ethodology is not at all indicative of actual incremental costs for incremental levels of additional reactive capability.'' (emphasis in original)). *See also* 2005 Staff Report at 69 (''[T]he allocation factor used in the AEP Methodology does not directly relate to the incremental investment cost in providing reactive capability or supply'').

[296] *Fern Solar LLC,* 183 FERC ¶ 63,004, at P 937 (2023).

[297] *See, e.g.,* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 26 (''[W]e continue to reject, as collateral attacks on that longstanding policy, arguments that stand-alone compensation for Reactive Service is generically required—for example, to ensure that generators can recover their costs for Reactive Service capability.''); *Entergy Servs. Inc.,* 114 FERC ¶ 61,303, at P 14 (2006) (''In Order No. 2003, the Commission emphasized that an interconnecting generator should not be compensated for reactive power when operating its Generating Facility within the established power factor range, since it is only meeting its obligation. Generators interconnected to a transmission provider's system need only be compensated where the transmission provider directs the generator to operate outside the dead band.'' (internal citations omitted)).

[298] PSEG Initial Comments at 13 & n.33 (citing *Dynegy Midwest Generation, Inc.* v. *FERC,* 633 F.3d 1122, 1126 (D.C. Cir. 2011)).

[299] MISO Rehearing Order, 184 FERC ¶ 61,022 at P 31 (''Vistra challenges the conclusion that Reactive Service requires little or no incremental investment by claiming that the D.C. Circuit in *Dynegy* rejected that conclusion. We disagree with Vistra's interpretation of *Dynegy.* Rather, in *Dynegy,* the court concluded that the Commission had not made any such finding in that case, instead providing only a 'glancing remark' to this effect, and that the record in that case did not support such a finding. Here, in addition to noting the Commission's previous conclusions that Reactive Service capability requires little or no incremental investment, we have further explained immediately above the basis for this finding.'').

[300] *See, e.g.,* Ameren Initial Comments at 3; MISO Transmission Owners Initial Comments at 6 (''Generators incur little or no costs beyond what is already needed to produce real power.''); PJM IMM Initial Comments at 4 (''There are few if any identifiable costs incurred by generators in order to provide reactive power. Separately compensating resources based on a judgment based allocation of capital costs was never and is not now appropriate in the PJM markets. Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation . . . . [T]here is no reason to include complex rules that arbitrarily segregate a portion of a resource's capital costs as related to reactive power.'').

[301] *See* PJM IMM Initial Comments at 12 (''The market approach should be used, as it is overwhelmingly more efficient than the current rate case, cost of service approach. Supporters of the cost of service approach have never explained why a nonmarket approach is required in PJM or why it is preferable to a market approach.''); *id.* at 11–12 (''There is no evidence that units are built as a result of reactive revenue. There is no evidence that sources of revenue are not fungible and that a decrease in reactive revenues could be not replaced with other sources of revenue. There is no basis for adding new resources to the already very crowded interconnection queue solely based on out of market subsidies from reactive revenues.'').

[302] *MISO,* 182 FERC ¶ 61,033 at PP 53–54 (citing Order No. 2003–A, 106 FERC ¶ 61,220 at P 416;

Service Providers' comments challenging this well-established policy to be a collateral attack on Order No. 2003.[303]

102. Further, as the Commission has explained, to interconnect reliably to the transmission system and deliver power to customers, generating facilities must be capable of maintaining voltage levels for injecting real power into the transmission system.[304] Said differently, ''if a generator is to sell (and be able to deliver) its power to a customer, reactive power is essential to the transaction.'' [305] Thus, standalone compensation for the provision of reactive power within the standard power factor range does not result in just and reasonable transmission rates.

103. Some commenters note that because Order No. 888 defined voltage support as a distinct ancillary service, it must be compensated separately.[306] The Commission's policy on reactive power compensation has evolved since issuing Order No. 888, which included provisions regarding reactive power from generating facilities as an ancillary service in Schedule 2 of the *pro forma* OATT.[307] Specifically, in Order No. 2003, when adopting the *pro forma* LGIA, the Commission initially concluded that the interconnection customer should not be compensated for reactive power when operating within the range established in the interconnection agreement because doing so ''is only meeting [the generating facility's] obligation.'' [308] And in Order No. 2003–A, the Commission clarified that ''if the Transmission Provider pays its own or its affiliated generators for reactive power within the established range, it must also pay the Interconnection Customer.'' [309] As a result, since Order No. 2003–A, the sole basis for reactive power capability compensation within the standard power factor range has been comparability (*i.e.,* to ensure comparable treatment between affiliated and unaffiliated generating facilities), not compensability (*i.e.,* an independent right to receive compensation for reactive power within the standard power factor range).[310] The Commission has reiterated these findings in subsequent orders permitting transmission providers to eliminate separate compensation for generating facilities providing reactive power within the standard power factor range.[311] Accordingly, commenters' arguments in this regard are without merit.

104. We also find Elevate's and Glenvale's arguments that some resource classes incur additional costs, including Elevate's claims about battery degradation, unpersuasive.[312] Elevate highlights battery degradation caused by the provision of reactive power, while Glenvale notes the operational and replacement costs associated with providing reactive power within the standard power factor range but neither explains how or why such costs are different and separate from the costs to provide real power. Degradation of components of a generator, including degradation of batteries, is a natural and inevitable result of power plant operation. As a result, the costs incurred by a generator to address such degradation, like other costs discussed above, are costs that generating facilities must incur to provide the real power for which they may seek compensation; nor

SPP, 119 FERC ¶ 61,199 at P 28) (''Accordingly, by designing their generating facilities to have the capability to provide reactive support, interconnecting generators are meeting the conditions of interconnection required of all generators and as a general matter are not entitled to compensation under the Commission's precedent unless the transmission provider pays its own or affiliated generators for reactive power within the standard power factor range.''); NOPR, 186 FERC ¶ 61,203 at P 16.

[303] *See e.g., ISO N. England Inc.,* 138 FERC ¶ 61,238, at P 17 (2012) (''[A] collateral attack is '[a]n attack on a judgment in a proceeding other than a direct appeal,' and is 'generally prohibited.' '' (quoting *N. England Conf. of Pub. Utils. Comm'rs* v. *Bangor Hydro-Elec. Co.,* 135 FERC ¶ 61,140, at P 27 (2011))).

[304] *See, e.g., MISO,* 182 FERC ¶ 61,033; MISO Rehearing Order, 184 FERC ¶ 61,022 at P 23 (citing METC Rehearing Order, 97 FERC at 61,852–53); *see also* MISO Transmission Owners Initial Comments at 11 (''Moreover, generators are incented by their own reliability requirements to install the equipment that is most likely to keep their projects on-line and delivering real power.'' (citations omitted)); NOPR, 186 FERC ¶ 61,203 at P 33 (''For example, CAISO states that ''[t]he rationale for the CAISO's existing approach to reactive power compensation is that the reactive power ranges called for in each interconnection agreement represent a reasonable range of what a generator is expected to provide the CAISO without additional compensation in accordance with good utility practice and as a condition of being part of the CAISO markets and CAISO grid.'') (citing CAISO Initial Comments to the NOI at 3).

[305] *SPP,* 119 FERC ¶ 61,199 at P 28. This has always been a physical reality of the transmission system, even for wind generating facilities that were exempted from providing reactive service within the standard power factor range prior to Order No. 827. Specifically, in Order No. 827, the Commission ''exempted wind generators from the uniform reactive power requirement because, historically, the costs to design and build a wind generator that could provide reactive power were high and *could have created an obstacle to the development of wind generation.*'' Order No. 827, 155 FERC ¶ 61,277 at P 4 (emphasis added). During this period of exemption, wind generating facilities would have had to rely on dynamic reactive power service supplied by other generating facilities and equipment on the transmission system capable of providing reactive support to allow their real power to reliably flow onto the transmission system. In essence, prior to Order No. 827, the Commission allowed the nascent wind industry to make up for these reactive power deficiencies by relying on transmission customers for reactive support because it determined that the costs of requiring them to provide their own reactive power could have been prohibitive. By the time of Order No. 827, that rationale for the exemption no longer existed, and the Commission, in removing this exemption for wind generating facilities in Order No. 827, noted that ''[d]ue to technological advancements, the cost of providing reactive power no longer presents an obstacle to the development of wind generation.'' *Id.* Additionally, the Commission expressed its concern ''that, as the penetration of non-synchronous generators continues to grow, exempting a class of generators from providing reactive power could create reliability concerns, especially if those generators represent a substantial amount of total generation in a particular region, or if many of the resources that currently provide reactive power are retired from operation. In addition, as noted above, maintaining the exemptions for wind generators places an undue burden on synchronous generators to supply reactive power without a reasonable technological or cost-based distinction between synchronous and non-synchronous generators.'' *Id.* P 25.

[306] *See, e.g.,* Indicated Trade Associations Initial Comments at 9 (''This assumption is at odds with Order No. 888, which expressly found that reactive service from generation facilities must be priced at cost''); NEI Initial Comments at 4 (''Unsurprisingly, in Order No. 888 the Commission found that reactive power is one of six ancillary services necessary to provide basic transmission service within every control area. Schedule 2 of the Open Access Transmission Tariff thus required that transmission providers provide—and transmission customers pay for—reactive power.''); PSEG Initial Comments at 13 (''The NOPR, if adopted, would effectively eliminate reactive power as one of ancillary services that the Commission has recognized since Order No. 888.''); Middle River Power Initial Comments at 2–3 (citing Indicated Energy Trade Associations Initial Comments at 21; Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,707 (''[T]ransmission customer actions do not eliminate entirely the need for generator-supplied reactive power.'' ''The transmission provider must provide at least some reactive power from generation sources.'')).

[307] NOPR, 186 FERC ¶ 61,203 at P 12; Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,705–07 & n.359; *see also* BPA Rehearing Order, 125 FERC ¶ 61,273 at P 18.

[308] Order No. 2003, 104 FERC ¶ 61,103 at P 546.

[309] Order No. 2003–A, 106 FERC ¶ 61,220 at P 416; *see also* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 24 (''Order No. 2003 reflects the distinction between these two different reactive power concepts. When the transmission provider asks the interconnecting generator to operate its facility outside the established power factor range, the transmission provider is required to pay the interconnecting generator for the provision of such reactive power. By contrast, compensation for reactive power when the generating facility is operating within the established power factor range is generally not required. The sole exception the Commission identified was that 'if the Transmission Provider pays its own or its affiliated generators for reactive power within the established range, it must also pay the Interconnection Customer.' '' (internal citations omitted)).

[310] BPA Rehearing Order 125 FERC ¶ 61,273 at P 18.

[311] *See, e.g., MISO,* 182 FERC ¶ 61,033 at PP 52–53; MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 23–25, 41; *PNM,* 178 FERC ¶ 61,088 at PP 29–31; *Nev. Power Co.,* 179 FERC ¶ 61,103 at PP 20–21; *BPA,* 120 FERC ¶ 61,211 at P 20; *E.ON U.S. LLC,* 119 FERC ¶ 61,340 at P 15; *Entergy Servs., Inc.,* 113 FERC ¶ 61,040 at P 38.

[312] Elevate Initial Comments at 9–12; Elevate Reply Comments at 7–9.

do transmission customers receive benefits that are commensurate with the charges for the provision of reactive power within the standard power factor range. Moreover, as discussed further below, battery storage resources, like all other generating facilities, still have the opportunity to seek to recover their costs through sales of energy and capacity, and the Commission's actions here do not undercut those opportunities.[313]

105. Similarly, regarding NEI's assertion that nuclear generating facilities incur disproportionate degradation from the provision of reactive power within the standard power factor range, we find that to the extent there are *de minimis* variable costs associated with providing reactive power within the standard power factor range, generating facilities in RTO/ISO markets could seek to recover such costs through energy and capacity markets. Transmission providers are responsible for maintaining voltage levels within their regions and have authority to direct generating facilities to operate at appropriate power factors to ensure system reliability.[314]

106. In response to Clean Energy Associations' assertion that reactive power is not always coupled with real power,[315] we reiterate that the final determination addresses only compensation for the provision of reactive power within the standard power factor range and that producing solely reactive power (*i.e.,* a power factor of zero) entails reactive power production outside of the standard power factor range. As such, we find Clean Energy Associations' concerns outside the scope of this final determination.

107. We also find that compensation for the provision of reactive power within the standard power factor range could result in undue compensation and other market distortions.[316] In response, Reactive Service Providers assert that generating facilities cannot be receiving windfalls from reactive power compensation because many generating facilities across multiple regions are retiring due to economic factors.[317] However, these statements confuse compensation for reactive power within the standard power factor range with general cost recovery for generating facilities, which involves many other revenue streams. Our findings here are that generating facilities incur no incremental fixed costs and at most *de minimis* variable costs incremental to the cost of providing real power, because no additional equipment is required to provide reactive power and variable costs are limited to the fuel costs (in synchronous facilities) or foregone direct current power (in non-synchronous facilities) necessary to provide the reactive power required to safely inject real power into the transmission system and comply with reliability requirements. Similarly, Indicated Trade Associations[318] contend that separate reactive power compensation cannot lead to market distortions because such rates have been approved by the Commission. But this argument ignores the final determination's central logic that such rates lack a sufficient economic basis, and the comments in this proceeding have not refuted that central logic.

108. As discussed further below, any purported *de minimis* variable costs associated with providing reactive within the standard power factor range can be recovered through other means.[319]

C. Cost Recovery

109. In the NOPR, the Commission preliminarily found that separate compensation for providing reactive power within the standard power factor range is not necessary for generating facilities to recover their costs.[320] The Commission noted that, although the prospect of receiving separate, fixed reactive power payments may be beneficial for developing certain generating facilities, resource developers continue to develop new generating facilities in regions without such payments.[321] Furthermore, the NOPR explained that the basis for these payments has always been comparability rather than compensability.[322]

110. Instead, in the context of RTO/ISO markets, the Commission preliminarily found it would be more efficient for generating facilities to seek to recover any identified costs to provide reactive power within the standard power factor range, to the extent they exist, through energy and capacity sales, because competition between generating facilities may incentivize efficiency and increase transparency.[323]

111. The Commission noted that it has previously and repeatedly rejected arguments that generating facilities need separate reactive power payments, because the incremental cost of reactive power within the standard power factor range is minimal.[324] Therefore, consistent with those findings, the NOPR preliminarily found that eliminating compensation for reactive power within the standard power factor range would not compromise the ability of IPPs in non-RTO/ISO regions to recover their costs associated with producing reactive power within the range because generating facilities have the opportunity to seek to recover such costs in other ways, such as through higher power sales rates or through

[313] PJM IMM Reply Comments at 4–5 (''The NOPR does not require a finding that generators recover all of their cost in markets. Markets do not include such guarantees. In competitive markets, generation owners may overrecover their costs in markets at times and generators may underrecover their costs at times. The point is that when markets provide an opportunity to recover all costs, those same costs should not be recovered in a separate cost of service rate. The same investment should not be recoverable and recovered in two parallel regulatory regimes. That result is plainly unjust and unreasonable.'').

[314] *See* MISO Transmission Owners Initial Comments at 11–12 (citing *VAR–002–3— Generator Operation for Maintaining Network Voltage Schedules,* North American Electric Reliability Corporation, at 2 (Aug. 1, 2014), *http://www.nerc.com/pa/Stand/Reliability%20Standards/VAR-002-3.pdf* (''R2 . . . Generator Operator shall maintain the generator voltage or Reactive Power schedule (within each generating Facility's capabilities).'').

[315] Clean Energy Associations Initial Comments at 7.

[316] *See, e.g.,* PJM IMM Initial Comments at 4 (''The current rules create strong incentives for generators to attempt to maximize the allocation of capital costs to reactive in order to maximize guaranteed, nonmarket revenues. Those nonmarket revenues provide a nonmarket advantage to those generators who receive them. This is a return to using the regulatory process for advantage rather than competing in the market. That advantage is arbitrary, not market based and therefore distortionary.'').

[317] Reactive Service Providers Initial Comments at 27.

[318] Indicated Trade Associations Reply Comments at 9.

[319] *See infra* II.C.2; *see also* Joint Customers Initial Comments at 16 (''Finally, there is no reason to believe incremental costs of reactive power could not be recovered in the same way other costs are recovered. This could be through capacity markets and through power sales, depending on the regional characteristics of how generators cover other costs.'').

[320] NOPR, 186 FERC ¶ 61,203 at P 45.

[321] For example, as of February 21, 2024, there were 453 total generating facilities in the CAISO interconnection queue, 440 of which were non-synchronous generating facilities. This corresponds to 122,885 MW of capacity, 120,043 MW of which comes from the non-synchronous generating facilities in the queue. *See* CAISO, *Formatted Generator Interconnection Queue Report, https://rimspub.caiso.com/rimsui/logon.do* (last visited Feb. 21, 2024). Similarly, as of February 21, 2024, there were 947 total generating facilities in the SPP interconnection queue, 770 of which were non-synchronous generating facilities. This corresponds to 175,243 MW of capacity, 141,879 MW of which comes from the non-synchronous generating facilities in the queue. *See* SPP, *Generator Interconnection Active Requests, https://opsportal.spp.org/Studies/GIActive* (last visited Feb. 21, 2024).

[322] NOPR, 186 FERC ¶ 61,203 at P 45.

[323] *Id.*

[324] *Id.* P 47 (citing *BPA,* 120 FERC ¶ 61,211 at P 21).

power purchase agreements (PPA).[325] The Commission further noted that the experiences of CAISO, SPP, MISO, and non-RTO/ISO regions where generating facilities do not receive separate compensation for the provision of reactive power within the standard power factor range and the evidence in the record demonstrate that: (1) eliminating compensation has not led to an insufficient supply of reactive power in those regions and that (2) generating facilities in these regions have been able to recover any purported costs associated with the production of reactive power.[326]

112. In the NOPR, the Commission sought comment on whether, and if so how, the elimination of separate compensation for reactive power within the standard power range would affect generating facilities' ability to recover their costs—if any.[327]

1. Comments

113. Several Commenters argue that the record supports the finding that generating facilities can recover any purported costs of providing reactive power in the standard power factor range through their sales of energy and capacity.[328] TAPS contends that the Commission is not required to guarantee that generating facilities recover their incremental costs of providing reactive power in the standard power factor range (to the extent those costs exist), but rather the ''opportunity to recover costs is all that is required.'' [329] TAPS explains that the Commission has never required payment of separate, cost-based reactive power compensation within the standard power factor range to all interconnecting generators in all circumstances, but has rather given transmission providers the option to provide for such reactive power compensation for its own generation, provided all generators on its system were treated comparably, and transmission providers could also eliminate such compensation for itself and others on a comparable basis.[330] New England Consumer Advocates states that any final determination should ensure that ratepayer costs for reactive power compensation are sufficiently justified, and that ISO–NE should articulate specific benefits and compare those benefits with the cost of compensation.[331]

114. Ohio FEA states that it supports prohibiting, as expeditiously as possible, the inclusion in transmission rates of charges related to the provision of reactive power within the standard power factor range because generators have an opportunity to recover all costs, including reactive power costs, through PJM markets.[332]

115. Several commenters argue that the NOPR's proposal would resolve cost causation issues that result from the current practice of providing separate compensation for reactive power within the standard power factor range.[333] Joint Customers, Ameren, TAPS, and MISO Transmission Owners argue that the current incentive to provide payment based on reactive power capability results in the building of unnecessary capabilities in locations it may not be needed and does not allocate costs associated with reactive power in a manner that is roughly commensurate with the benefits received.[334] They assert that the current scheme results in a proliferation of charges for reactive power that is disconnected from the actual benefits received.[335]

116. MISO Transmission Owners argue that, contrary to some commenters' claims, the NOPR's proposed changes do not violate cost causation principles because generating facilities will still be compensated for the reactive power their generating facilities supply when they are required to operate outside the standard power factor range.[336] MISO Transmission Owners state that ''cost causation involves customers paying for a cost that they cause, not suppliers receiving compensation for services provided,'' and assert that some ''commenters attempt to turn this concept on its head'' by ''plac[ing] the focus on the service provider rather than the paying customer in an attempt to require payment for a service they are already obligated to provide as a condition of interconnection.'' [337] MISO

[325] *Id.*

[326] *Id.* P 48.

[327] *Id.* P 49.

[328] *See* AEP Initial Comments at 4–6; Joint Consumer Advocates Initial Comments at 7–8 (''[Joint Consumer Advocates] assert that PJM generators will still have a more than ample opportunity to recover the costs associated with their provision of reactive power''); Joint Customers Initial Comments at 15 (''Generators have other means of covering costs incurred to meet interconnection design requirements.''); Joint Customers Reply Comments at 15; MISO Transmission Owners Initial Comments at 16–17; MISO Transmission Owners Initial Comments at 15 (''Moreover, transmission providers have mechanisms for maintaining system reliability in the face of premature retirements, including identifying resources as ''system support resources.'') (citations omitted)); Ohio FEA Initial Comments at 5 (''Ohio . . . supports competitive markets to induce efficiency and control costs'').

[329] TAPS Initial Comments at 7 & n.19 (citing *CXA La Paloma, LLC* v. *CAISO,* 165 FERC ¶ 61,148, at P 71 (2018) (''The Commission has been clear that suppliers in competitive wholesale electricity markets are not guaranteed full cost recovery, but only the opportunity to recover their costs.'')).

[330] *Id.* at 6–7 & n.18 (citing *MISO,* 182 FERC ¶ 61,033 at P 53 (''MISO [Transmission Owners] do not have an obligation to continue to compensate an independent generator for reactive power within the standard power factor range when its own or affiliated generators are no longer being compensated.''); *Id.* (citing *PNM,* 178 FERC ¶ 61,088 at P 29; *Nev. Power Co.,* 179 FERC ¶ 61,103, P 20 (2022); *BPA,* 120 FERC ¶ 61,211 at P 20; *E.ON U.S. LLC,* 119 FERC ¶ 61,340 at P 15; *Entergy Servs., Inc.,* 113 FERC ¶ 61,040 at P 38) (''Commission's precedent allows transmission providers to eliminate compensation for reactive power within the standard power factor range for all generators, regardless of whether the generator is owned by or otherwise affiliated with a transmission owner or is independent.'')).

[331] New England Consumer Advocates Initial Comments at 4–6. *See also id.* at 5 (''To the extent . . . benefits are achieved by compliance with a generating facility's interconnection agreement and/or as 'good utility practice,' [New England Consumer Advocates] agree[] with the Commission that ratepayers should not be paying separately for the costs to produce a joint reactive power product.'').

[332] Ohio FEA Initial Comments at 5.

[333] Ameren Initial Comments at 3; Joint Customers Initial Comments at 12–13; TAPS Initial Comments at 4–5; MISO Transmission Owners Reply Comments at 11–12; MISO Transmission Owners Initial Comments at 5; PGE Initial Comments at 3–4.

[334] Joint Customers Initial Comments at 12–13; Ameren Initial Comments at 3; TAPS Initial Comments at 4–5; MISO Transmission Owners Reply Comments at 11–13. *See also* Joint Customers Initial Comments at 5–6 (''The Commission's policy of looking strictly to capability for determining cost recovery for Reactive Service incentivized overbuilding of capability beyond what was required based on interconnection requirements. This policy of not considering need or requiring a demonstration of need by the transmission owner has resulted in compensation for reactive capability without an actual demonstrated benefit to transmission system customers. This disconnect between capability and any actual demonstrated benefit highlights serious concerns that charges to customers are not related to any benefits received.'' (citations omitted)).

[335] Joint Customers Initial Comments at 12–13; Ameren Initial Comments at 3; TAPS Initial Comments at 4–5; MISO Transmission Owners Reply Comments at 11–13. *See also* MISO Transmission Owners Initial Comments at 15 (''Moreover, transmission providers have mechanisms for maintaining system reliability in the face of premature retirements. When generators advise MISO of a planned retirement via Attachment Y of the MISO Tariff, MISO completes a review to determine whether any Transmission System reliability concerns are caused by the retirement. If voltage concerns arise in the Attachment Y study, options to address the voltage concerns are reviewed and ultimately a permanent solution is identified. If the permanent solution cannot be implemented before the planned retirement date, then the MISO Tariff has a designation for ''system support resources,'' under which generators are eligible to receive cost-based compensation to support their continued operation until an alternative solution to the reliability problem posed by the resources' retirement is developed.'' (citations omitted)).

[336] MISO Transmission Owners Reply Comments at 11.

[337] *Id.* at 12 (citing *K N Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992) (''[A]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them.''); *Entergy Ark., LLC* v. *FERC,* 40 F.4th 689, 692 (D.C.

Continued

Transmission Owners argue that commenters' claims that the NOPR's proposed changes violate cost causation principles is a collateral attack on principles first promulgated in Order No. 2003 and its progeny because that series of orders required generators to provide reactive power within the standard power factor range without compensation, with few exceptions.[338] MISO Transmission Owners argue that the NOPR's proposed changes do not change generating facilities' obligation to provide reactive power within the deadband, but rather they remove the unnecessary costs associated with payments to generating facilities.[339]

117. Ohio FEA and New England Consumer Advocates state that they support the Commission's efforts to mitigate escalating transmission costs for customers, particularly when those costs provide no incremental benefit to the customers who pay them.[340]

118. Joint Customers acknowledge that the Commission generally allows for flexibility to account for regional differences. However, Joint Customers argue that such regional variations do not undermine the general rule against compensation for meeting interconnection requirements related to the standard power factor range.[341] Joint Customers contend that ''[t]here is a sufficient record for a determination that compensation for meeting interconnection requirements related to the standard power factor range should be prohibited as a general matter, with the understanding that generators directed to operate outside that range will continue to be compensated.'' [342] Joint Customers witness Dr. Bresmer argues that a generating facility providing reactive power within the standard power factor range is simply meeting its interconnection obligations and not providing an ancillary service.[343]

119. Several commenters [344] argue that there is not sufficient evidence to support the conclusion that energy markets or capacity markets could or should be used to recover the costs of providing reactive power. Glenvale [345] and Indicated Reactive Power Suppliers [346] each state that reactive power and capacity are two distinct types of services and should not be combined. Glenvale argues that energy markets do not necessarily provide revenue opportunities due to competition and long-term contracts that do not allow certain generators access to these energy markets for several years. Indicated Trade Associations note that certain types of resources may not even participate in the capacity market.[347] For example, Glenvale argues that some generators that provide reactive power but choose not to participate in the capacity market will not be able to recover lost reactive revenues.

120. Some commenters argue that generating facilities will be unable to recover reactive power costs in their PPAs.[348] Indicated Trade Associations argue that generators may have relied on existing reactive power compensation policies when they structured their PPAs, bilateral arrangements, and behind the meter arrangements.[349] Indicated Trade Associations [350] and Generation Developers [351] each claim that the notion that PPA counterparties will be willing to renegotiate their contracts to allow them to charge a higher rate to recover the costs of a different service belies a basic understanding of wholesale markets.

121. Some commentators [352] point to RTO/ISO market rules as potential barriers to recouping reactive power costs. Indicated Trade Associations assert that the Commission has required RTOs and ISOs to implement energy offer caps based on generators' verifiable marginal costs.[353] Generation Developers argue that the Commission should require RTOs/ISOs to revise their tariffs to eliminate existing barriers to the recovery of reactive power costs and permit generating facilities to accurately reflect their investments in reactive power capability in their capacity offers.[354]

122. Generation Developers argue that energy markets allow resources to sell energy on a day-ahead and real-time basis, with prices generally reflecting variable costs that are insufficient to allow resources to recover their fixed costs.[355] Generation Developers state that RTO/ISO market mitigation rules generally prohibit generating facilities from reflecting fixed costs in their mitigated energy offer costs, often referred to as the ''missing money problem,'' and eliminating reactive power compensation would exacerbate this issue.[356] Generation Developers argue that relying on capacity markets for reactive power compensation would result in arbitrary differences in the ability of resources to recover their costs because they would be required to provide reactive power regardless of whether they clear the capacity market.[357] Generation Developers also

Cir. 2022) (''In assessing whether a rate is 'just and reasonable,' FERC and the courts determine, among other things, whether the rate comports with the 'cost-causation principle' which requires that the rates charged for electricity reflect the costs of providing it.'' (citing *Old Dominion Elec. Coop.* v. *FERC,* 898 F.3d 1254, 1255 (D.C. Cir. 2018))).

[338] *Id.* at 11–13. *See also* MISO Transmission Owners Initial Comments at 16 (''As the Commission explains, compensation for providing reactive power within the deadband is unnecessary, as resources are otherwise able to recover their costs. The Commission is correct in finding that there are many other mechanisms through which generators may recover the costs of reactive power service, if they need to. This is consistent with Commission precedent that has repeatedly highlighted how generators have the opportunity to recover any legitimate costs through other means. The Commission has found generators may recover such costs through power purchase agreements or capacity and energy market offers. As the Commission found when accepting the elimination of reactive power compensation in MISO, generators can still include the costs of reactive service in energy offers or capacity offers, even if subject to market power mitigation.'' (citations omitted)).

[339] MISO Transmission Owners Reply Comments at 12–13.

[340] Ohio FEA Initial Comments at 4; New England Consumer Advocates Initial Comments at 3–4.

[341] Joint Customers Reply Comments at 14–15.

[342] *Id.* at 15.

[343] *See, e.g.,* Joint Customers Initial Comments, Affidavit of Dr. Albert W. Bremser at 6:3–7 (''When a generating facility is operating within the standard power factor range, the generating facility is meeting its responsibility to maintain appropriate operational voltage levels for real power moving onto the transmission system. It is only when a generating facility is called upon to operate outside the standard power factor range that it is providing an ancillary service.'' (citations omitted)).

[344] *See, e.g.,* Clean Energy Associations Initial Comments at 8–9; EDPR Initial Comments at 4–5; Elevate Initial Comments at 8–9; Generation Developers Initial Comments at 18–19; Glenvale Initial Comments at 5–6, 8–9; Indicated Reactive Power Suppliers Initial Comments at 14; Indicated Trade Associations Initial Comments at 3, 15; ISO–NE Initial Comments at 1–2; NAGF Initial Comments at 1; NEI Initial Comments at 12–13; NEPGA Reply Comments at 1, 4–6; NHA Initial Comments at 6–7; PSEG Initial Comments at 2–3, 6, 14–15; Reactive Service Providers Initial Comments at 56–62, 77.

[345] Glenvale Initial Comments at 6.

[346] Indicated Reactive Power Suppliers Initial Comments at 11–12.

[347] Indicated Trade Associations Initial Comments at 15 (citing PJM OATT, Attachment DD, § 6.6A(c) (0.0.0) (providing a categorical exception from the capacity must-offer obligation for certain types of resources)).

[348] EDPR Initial Comments at 4–5; Generation Developers Initial Comments at 19; Indicated Trade Associations Initial Comments at 18; Reactive Service Providers Initial Comments at 59–62.

[349] Indicated Trade Associations Initial Comments at 17–18.

[350] *Id.*

[351] Generation Developers Initial Comments at 19.

[352] *Id.* at 18–19, 34–35; Glenvale Initial Comments at 6; Indicated Trade Associations Initial Comments at 12–15; Reactive Service Providers Initial Comments at 77.

[353] Indicated Trade Associations Initial Comments at 12–13 (citing *Offer Caps in Mkts. Operated by Reg'l Transmission Orgs. and Indep. Sys. Operators,* Order No. 831, 81 FR 87770 (Dec. 5, 2016), 157 FERC ¶ 61,115, at PP 5, 7 (2016), *on reh'g,* Order No. 831–A, 82 FR 53403 (Nov. 16, 2017), 161 FERC ¶ 61,156 (2017)).

[354] Generation Developers Initial Comments at 34–35.

[355] *Id.* at 18.

[356] *Id.*

[357] *Id.* at 19.

assert that there is no nexus between the capacity value assigned to a generating facility and its reactive power capability.[358] In addition, Generation Developers state that ''[t]he Commission has a statutory obligation to ensure that [Commission]-jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential'' and assert that this requirement ''prohibits the Commission from denying utilities the opportunity to recover their costs, plus a reasonable rate of return.'' [359]

123. Indicated Trade Associations argue that including reactive power costs in energy offers would increase a generator's risk of not clearing in the energy market. Indicated Trade Associations further contend that capacity markets do not provide for recovery of reactive power costs because capacity offers from existing resources are limited to avoidable or going forward costs and do not allow for inclusion of costs that have already been incurred to provide reactive power.[360]

124. Some commenters [361] argue that the NOPR violates the cost causation and beneficiary pays principles because customers benefit from reactive power, including reactive power provided within the standard power factor range, and thus generating facilities should be compensated for this service.[362] Generation Developers argue that while the cost causation principle does not require ''exact precision,'' it does require that Commission-approved rates ''be based on the costs of providing the service to the utility's customers, plus a just and fair return on equity.'' [363] Generation Developers and Reactive Service Providers assert that the NOPR's proposal would insulate transmission providers and customers from any responsibility to pay for costs associated with the services they are receiving, which is ''precisely the type of free ridership that the [FPA] and the cost causation principle are intended to prevent.'' [364] Generation Developers argue that the Commission is essentially directing generating facilities to recover the costs of reactive power from customers purchasing energy and capacity, rather than the transmission customers that benefit from the reactive service.[365]

125. Several commenters [366] who oppose the NOPR assert that removing compensation within the standard power factor range would result in discriminatory treatment between generating facilities and transmission owners. These commenters argue that, under the NOPR, generating facilities would be prohibited from recovering their costs to provide reactive power under Schedule 2, yet transmission owners that install reactive power equipment and assets as part of their transmission system would be able to recover the costs of those assets through transmission rates charged to transmission service customers. They contend that transmission owners would have guaranteed cost recovery for the very same service that generating facilities would be prohibited from collecting under this NOPR.[367] ACORE asserts that reactive power provides the same benefit to the system, regardless of who owns the capacitor banks.[368]

126. NEI and PSEG both argue that the 2005 Staff Report recognized this discriminatory concern and contend that the Commission therefore recommended that all providers of reactive power should be paid on a nondiscriminatory basis.[369] Reactive Service Providers add that unless and until the Commission proposes to also eliminate the opportunity for transmission providers to collect costs associated with providing reactive service, the NOPR's proposal is *per se* discriminatory and preferential, in violation of the FPA.[370] Indicated Trade Associations suggest that by disincentivizing generators from competing to provide reactive power service, the NOPR creates a preference for higher-cost transmission solutions installed by transmission owners, which will harm consumers.[371]

127. Relatedly, Reactive Service Providers and Indicated Trade Associations assert that the NOPR raises competition concerns.[372] Reactive Service Providers argue that even if the transmission provider elects to no longer pay generating facilities for reactive power service, the transmission provider will still be able to collect the costs of generation-based reactive power service through retail rates.[373] Reactive Service Providers assert that this ''is a sweet deal that allows the Transmission Provider to lean on the IPP to provide the service for free under the [Commission]'s jurisdiction, with the utility simply shifting to another forum to recover the same generation-based costs.'' [374] Reactive Service Providers argue that the NOPR undermines the competition that the Commission sought to facilitate in Order No. 2003, and while IPPs are disadvantaged by losing a revenue stream, utility-generation is able to make that revenue stream up through retail rates, thereby putting utility generation in a stronger position to compete.[375] To the extent that reactive power service costs are recoverable by transmission owners through state retail rates, NEI recognizes that such rates are outside the Commission's jurisdiction.[376] NEI asserts, however, that this does not excuse the Commission from considering transmission owners' ability to recover their reactive power costs at the state level when the Commission is setting its own jurisdictional wholesale rates.[377]

[358] *Id.*

[359] *Id.* at 6.

[360] Indicated Trade Associations Initial Comments at 14.

[361] Indicated Reactive Power Suppliers Initial Comments at 9; Generation Developers Initial Comments at 4, 9–12; Reactive Service Providers Initial Comments at 62–63.

[362] Indicated Reactive Power Suppliers Initial Comments at 9; Generation Developers Initial Comments at 4, 9–12; Reactive Service Providers Initial Comments at 62–63.

[363] Generation Developers Initial Comments at 9–10 (citing *Sithe/Indep. Power Partners, L.P.* v. *FERC,* 285 F.3d 1, 5 (D.C. Cir. 2002)).

[364] *Id.* at 10; Reactive Service Providers Initial Comments at 62–63.

[365] Generation Developers Initial Comments at 10–13.

[366] ACORE Initial Comments at 3; Generation Developers Initial Comments at 8–9; Indicated Trade Associations Initial Comments at 27; NEI Initial Comments at 2, 16; PSEG Initial Comments at 1–3, 17; Reactive Service Providers Initial Comments at 63–64.

[367] Indicated Trade Associations Initial Comments at 25–27; Reactive Service Providers Initial Comments at 64; PSEG Initial Comments at 17; ACORE Initial Comments at 3.

[368] ACORE Initial Comments at 3.

[369] NEI Initial Comments at 16 (citing 2005 Staff Report at 4); PSEG Initial Comments at 17 (citing same).

[370] Reactive Service Providers Initial Comments at 64.

[371] Indicated Trade Associations Initial Comments at 24–26; Indicated Trade Associations Reply Comments at 16; NEI Initial Comments at 17.

[372] Indicated Trade Associations Initial Comments at 14; Reactive Service Providers Initial Comments at 45–46

[373] Reactive Service Providers Initial Comments at 45–46.; Indicated Trade Associations Initial Comments at 14 (arguing that including reactive power costs in energy offers would increase a generating facility's risk of not clearing in the energy market, and that this risk is ''particularly acute in jurisdictions where independent power producers compete with vertically integrated utilities whose generators recover costs through state-jurisdictional retail rates.'' (citations omitted)).

[374] Reactive Service Providers Initial Comments at 46.

[375] *Id.*

[376] NEI Initial Comments at 16.

[377] *Id.* at 16–17 & n.47. NEI asserts that the ''Commission still has an obligation to consider whether wholesale rates (or as here, proposed rates) are unduly discriminatory when considered in relation to retail rates, even though the latter is not subject to Commission jurisdiction.'' *Id.* (citing *Fed. Power Comm'n* v. *Conway Corp.,* 426 U.S. 271 (1976); *Commonwealth Edison Co.,* 8 FERC ¶ 61,277, at 61,848 (1979); *Sunoco, Inc. (R&M)* v. *Transcontinental Gas Pipe Line Corp.,* 114 FERC ¶ 61,180 at P 28 & n.20 (2006)).

128. NEI contends that the proposed replacement rate would result in undue discrimination against nuclear generators by imposing disproportionate burdens on them without fair compensation.[378] NEI states that the Commission has an obligation to consider whether the proposed rates are unduly discriminatory, meaning that the Commission must consider transmission owners' ability to recover their reactive power costs at the state level.[379] Elevate argues that the NOPR is inconsistent with the spirit of Order No. 841, which required that energy storage resources ''be eligible to provide services that the RTOs/ISOs do not procure through an organized market mechanism (such as blackstart service, primary frequency response service, and reactive power service) if they are technically capable of providing those services.'' [380] Elevate argues that the unique physical and operational characteristics of energy storage resources correspond with the unique revenue profile of energy storage resources.

129. Indicated Trade Associations argue that the Commission must ensure that it adopts comprehensive transition plans that account for the specific market design and rules of each RTO/ISO and direct each RTO/ISO to make filings identifying modifications to be made to existing market rules to implement the NOPR.[381] Indicated Trade Associations contend that the Commission must clarify how generating facilities will be compensated for reactive power dispatch outside the standard power factor range and note that Consolidated Edison Company of New York, Inc. requires newly connecting generating facilities to be able to provide reactive power 0.85 lagging to 0.95 leading.[382] The NHA further argues that the Commission should allow individual RTOs/ISOs to retain their reactive power compensation frameworks, as they are better suited to address regional reliability needs, and to develop compensation mechanisms to reflect locational needs.[383] Reactive Service Providers contend that there is no evidence that generating facilities are being sited without respect to whether there is a geographic need for reactive power, or that costs are no longer commensurate with benefits.[384]

130. Several commenters also submitted RTO/ISO-specific comments addressing cost recovery. As discussed above, ISO–NE, NESCOE, NEPGA, and NEPOOL argue that ISO–NE's Schedule 2 VAR compensation program should not be disturbed.[385] ISO–NE notes that the Commission denied Maine Public Utilities Commission's complaint to only allow reactive power compensation *outside* the power factor range, as VAR payments were a ''negotiated value and is not equal to, nor is it intended to recover, the cost of service of any particular generating Resource.'' [386]

131. NEPOOL explains that three factors specific to Schedule 2 contribute to the reliability benefits of reactive service in New England: (1) the generator must be dispatchable and ready to respond to the ISO's instruction to produce or absorb reactive power; (2) to be designated as a Qualified Reactive Resource,[387] a generator must have automatic voltage regulation equipment and telemetry in place to enable the ISO to determine that it is providing ''measurable dynamic reactive power voltage support to the New England Transmission System''; and (3) Schedule 2 requires reactive power testing of Qualified Reactive Resources in accordance with the applicable ISO–NE Operating Procedures.[388] NEPOOL argues that these three factors show that any final determination should allow flexibility for transmission providers, such as ISO–NE, to maintain compensation mechanisms that pay for reactive power across the full power factor range when payment is contingent on the reactive power resource meeting enhanced reliability-related requirements.

132. NEPGA states that ISO–NE's wholesale energy and capacity markets do not compensate for reactive power capability or costs, but rather transmission rates compensate for reactive power capability through ISO–NE's Schedule 2 rate design.[389] NEPGA argues that the Tariff provisions governing capacity market offers in ISO–NE do not allow a generator to include the costs for providing reactive power in its offer prices nor does the capacity market value reactive power capability. Further, NEPGA states that ISO–NE's energy market offer-price rules (both day-ahead and in real-time) likewise limit costs to those necessary to produce real power versus reactive power. Therefore, NEPGA contends that ISO–NE's wholesale markets do not, as the Commission suggests, provide an opportunity to recover the costs of the capability to provide reactive power and the actual costs to deliver reactive power.

133. NYISO states that it supports the NOPR's objective to avoid administratively burdensome processes and procedures to determine individualized cost-of-service reactive power rates for generation facilities.[390] As discussed above, NYISO and IPPNY argue that NYISO's existing reactive power and VSS compensation structure, which uses a flat dollars per MVAr-year structure, is just and reasonable.[391] NYISO and IPPNY each assert that NYISO's flat rate compensation structure for VSS has been effective for over 20 years, ensuring adequate reactive power capability and system reliability in the New York Control Area at a reasonable cost to consumers.[392] NYISO explains that the structure, accepted by the Commission since 1999, was developed with stakeholder input and Commission approval, with significant revisions in 2016 to include leading and lagging reactive power capabilities.[393] NYISO maintains that this structure aligns costs directly with services provided, ensuring reliability benefits commensurate with expenses.[394]

134. NYISO states that its flat rate compensation provides market-like incentives, encouraging resources to offer reactive power cost-effectively by rewarding increased capability and maintaining necessary equipment.[395] NYISO explains that this approach reduces the need for complex, individualized cost-based payments and integrates reactive power support efficiently into the broader market framework, promoting economic efficiency and reliability.[396]

135. NYISO contends that as the current system ensures direct

[378] *Id.* at 2.

[379] *Id.* at 16–17.

[380] Elevate Initial Comments at 12–13 (citing *Elec. Storage Participation in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators,* Order No. 841, 83 FR 9580 (Mar. 6, 2018), 162 FERC ¶ 61,127, at P 79 (2018), order on reh'g, Order No. 841–A, 167 FERC ¶ 61,154 (2019)).

[381] Indicated Trade Associations Initial Comments at 30.

[382] *Id.* at 31–32.

[383] NHA Initial Comments at 5–7.

[384] Reactive Service Providers Initial Comments at 31–34.

[385] ISO–NE Initial Comments at 1–2; NESCOE Reply Comments at 2; NEPGA Reply Comments at 6–7; NEPOOL Reply Comments at 6–7.

[386] ISO–NE Initial Comments at 9–10 (citing *Me. Pub. Util. Comm'n* v. *ISO New England Inc.,* 126 FERC ¶ 61,090 (2009)).

[387] In ISO–NE, a generating facility may submit a request, including documentation, to ISO–NE to receive additional compensation based on their verified leading and lagging reactive capability. *See* ISO–NE Schedule 2, § 3.1 (10.0.0).

[388] NEPOOL Reply Comments at 9–11.

[389] NEPGA Reply Comments at 4–6.

[390] NYISO Initial Comments at 1.

[391] *Id.* at 2; IPPNY Reply Comments at 1–2.

[392] NYISO Initial Comments at 2; IPPNY Reply Comments at 1–2.

[393] NYISO Initial Comments at 2–5.

[394] *Id.*

[395] *Id.* at 7–8.

[396] *Id.*

compensation for reactive power that is critical for maintaining system reliability, altering the compensation mechanism could lead to increased costs and complicate market operations, undermining the efficiency and effectiveness of its existing framework.[397]

136. NYISO emphasizes that as the resource mix evolves with more asynchronous and renewable resources, its flexible compensation structure is crucial for maintaining and enhancing reactive power support.[398] NYISO argues that this adaptability will ensure ongoing system reliability amidst changing resource dynamics.

137. Lastly, NYISO and IPPNY each highlight the need for continued flexibility in adjusting compensation rules to incentivize maximum reactive power capability and minimize out-of-market commitments.[399] NYISO contends that a uniform implementation approach is not suitable given the varying regional needs and existing effective compensation frameworks.[400]

138. PJM states that the NOPR would largely eliminate a number of problems that PJM and its stakeholder processes have identified. PJM explains that given that PJM stakeholders have been unable to reach consensus on a new rate paradigm after two years of work, PJM supports the proposed reforms identified in the NOPR and encourages the Commission to adopt them as proposed.[401] As discussed further below, PJM also proposes that RTOs/ISOs be allowed to implement any needed conforming changes to their market rules as part of the compliance process.[402]

139. The PJM IMM states that the NOPR would extend a just and reasonable, pro competition policy to all jurisdictional markets and public utilities while protecting PJM customers from unjust and unreasonable charges for reactive capability that generation owners are already required to provide.[403] The PJM IMM also argues that power suppliers, not customers, are responsible for the regulatory risk related to their PPAs.[404]

140. The PJM IMM adds that generating facilities in PJM incur other obligations, such as primary frequency response, as a condition of interconnection without separate compensation for such obligations.[405] The PJM IMM maintains that:

> There is no evidence that units are built as a result of reactive [power] revenue. There is no evidence that sources of revenue are not fungible and that a decrease in reactive [power] revenues could be not replaced with other sources of revenue. There is no basis for adding new resources to the already very crowded interconnection queue solely based on out of market subsidies from reactive revenues.[406]

2. Commission Determination

141. Based on the record here, we adopt the NOPR's preliminary findings and conclude that separate compensation for providing reactive power within the standard power factor range is not necessary for generating facilities to have the opportunity to recover their costs. As explained above, for both synchronous and non-synchronous generating facilities, real and reactive power are joint products, with joint costs and there are no identifiable fixed costs incurred by generating facilities to provide reactive power within the standard power factor range beyond the investments in equipment already necessary to generate and supply real power to the transmission system. Further, the record demonstrates that there are at most *de minimis* variable costs, such as fuel and maintenance costs, associated with providing reactive power within the standard power factor range. Given that the primary function of a generating facility is to produce real power, and that the provision of reactive power within the standard power factor range is necessary to the provision of real power, we find that a generating facility's fixed and variable costs are appropriately recovered through payments for real power, such as energy and/or capacity sales, whether in organized or bilateral markets.[407] Accordingly, we find that this final determination does not prevent a generating facility from seeking to recover its costs because resource owners have the opportunity to recover any of their appropriate fixed and variable costs through other revenue streams, including the opportunity to make up for lost revenues, if any, from the cessation of reactive power compensation.[408] We find that such an

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[397] *Id.* at 8–11.

[398] *Id.* at 11–13.

[399] *Id.* at 13–14; IPPNY Reply Comments at 2.

[400] NYISO Initial Comments at 14.

[401] PJM Initial Comments at 3–4.

[402] *Id.* at 6–7.

[403] PJM IMM Initial Comments at 1–2. *See also id.*at 4 (''[T]here is no reason that part of those capital costs should be paid directly in a nonmarket, guaranteed, riskless revenue stream rather than in the market.''); *id.* at 6 (''Elimination of the reactive revenue requirement and the reactive revenue offset would increase prices in the capacity market. The VRR curve, or demand curve, would shift to the right, the maximum VRR price would increase and offer caps in the capacity market would increase.'').

[404] PJM IMM Reply Comments at 5 (''When buyers and sellers enter into power purchase agreements, the contracting parties define and assign regulatory risk. Customers are not responsible to manage or pay for suppliers' risks.'').

[405] PJM IMM Initial Comments at 8 (''Reactive power is not the only design obligation that generation interconnection customers assume. Generators are also obligated to provide primary frequency response capability ''by installing, maintaining, and operating a functioning governor or equivalent controls . . .'' Primary frequency response capability is required for the reliable operation of the system. The PJM OATT does not, however, provide for an out of market payment for such capability. The provision of primary frequency capability is treated as an obligation assumed by generation interconnection customers for receiving interconnection service.'') (citations omitted)); *Id.* at 9 (''The PJM OATT includes a number of other obligations on generation interconnection customers, many of which are important and impose costs, but does so without including any special provisions for out of market compensation.''); PJM IMM Reply Comments at 6 (''The fundamental logic of the obligation to provide reactive service, frequency control service and other essential elements of interconnecting to the power grid is that the grid is a network. All generators who connect to the grid benefit from that network effect. All generators who connect to the grid have corresponding obligations to the grid that permit the grid to function as an effective and reliable network. It has always been the case that there are standards for interconnecting to the network. Meeting those standards is part of being a resource on the network. The actual costs of interconnecting to the grid can be significant for resources but those costs are part of the cost of building a resource and part of the investment decision for resource owners and not a reason for a separate guaranteed payment.'').

[406] PJM IMM Initial Comments at 12–13.

[407] We emphasize that our findings in this final determination do not affect any party's filing rights under section 205 of the FPA, including the right of generating facilities to seek cost recovery for the provision of reactive power outside the standard power factor range. *See supra* II.A.2.

[408] *See, e.g.,* PJM IMM Initial Comments at 1–2, 4, 6, 9, 12–13; PJM IMM Reply Comments at 2–5; Joint Customers Initial Comments at 16; MISO Transmission Owners Initial Comments at 16–17; Ohio FEA Initial Comments at 3, 5; Joint Consumer Advocates Initial Comments at 7–8; TAPS Initial Comments at 7–8; *see also* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 42 (''On rehearing, we conclude that Vistra has still not adequately explained why generators cannot include the costs attributable to Reactive Service in energy offers or capacity offers, even if subject to market power mitigation, ... As to capacity offers, among the ''going forward'' costs that can be recovered are ''mandatory capital expenditures necessary to comply with federal . . . reliability requirements,'' which would appear to include any (hypothetical) capital investments and expenditures associated with Reactive Service capability. As to energy offers, Vistra does not explain the basis for its assertion that the Tariff bars including any incremental costs associated with Reactive Service capability (*e.g.,* fuel costs, short-term variable operations and maintenance) in such offers. Moreover, while Vistra claims that ''a generation resource that attempts to recover its fixed costs of reactive power through its energy or capacity offers runs the risk that it will trigger application of MISO's market power mitigation rules,'' even assuming this were correct, this would not preclude generators from recovering such costs in the capacity market, but rather would require that they verify the costs with the independent market monitor. The cases Vistra cites also do not establish that where Schedule 2 compensation for Reactive Service is not available, seeking compensation

Continued

outcome is not only appropriate given the nature of the costs but also more efficient because competition between generating facilities may incentivize efficiency.[409]

142. We recognize, however, the current interplay between existing reactive power revenue compensation mechanisms and energy and capacity market rules in ISO–NE, NYISO, and PJM,[410] and, as a result, the RTOs/ISOs may request, by setting forth the specific bases and reasoning therefore for the Commission's consideration an effective date for their compliance filings that allows them to develop and propose changes to their markets that are necessary in order to accommodate this final determination's elimination of compensation for the provision of reactive power within the standard power factor range. As recognized in the NOPR and affirmed in the comments, the existing capacity market rules in PJM, ISO–NE and NYISO reflect the existence of generator payments under Schedule 2 through a revenue offset and reduce capacity market revenues accordingly. For example, as PJM and the PJM IMM explain, the PJM capacity market rules currently reflect a reactive power revenue offset in both the market seller offer caps and the Net Cost of New Entry (CONE) for the reference resource, which affects the shape of PJM's capacity market demand curve. Therefore, both PJM and the PJM IMM argue that the market rules will have to be revised to reflect the impacts of this final determination.[411] Similarly, NYISO and ISO–NE may need to propose changes to market rules to reflect the elimination of reactive power revenues resulting from this final determination. Therefore, as discussed below, we recognize that ISO–NE, NYISO, and PJM may need to develop and propose changes to their markets that may be necessary to accommodate this final determination's elimination of compensation for the provision of reactive power within the standard power factor range.[412] For the reasons explained above, we also disagree with those commenters who argue that there is not sufficient evidence to support the conclusion that energy markets or capacity markets could or should be used to seek to recover the costs currently recovered through payments for reactive power, as well as those commenters that argue that because capacity and reactive power service are separate products, their costs should likewise be recovered separately under Schedule 2. Given the same equipment is used for real and reactive power and the incremental variable costs of reactive power service within the deadband are minimal, as explained in the section above, we disagree with commenters' claims that costs, if any, currently recovered through reactive power payments cannot be recovered through other markets, especially given the transition period provided in this final determination, which addresses concerns about existing market rules that may impact cost recovery from those markets.[413] Furthermore, our finding here is supported both by experience in CAISO, SPP, MISO and certain non-RTO regions where generating facilities do not receive compensation for the provision of reactive power within the standard power factor range, and the evidence in the record to date.[414] Specifically, experience and evidence demonstrate that: (1) eliminating compensation has not led to an insufficient supply of reactive power in those regions; and (2) generating facilities in these regions have been able to recover their fixed and variable costs through other means.[415] For example, CAISO ''has seen no evidence to this point that resources cannot comply with reactive power dispatch instructions because they have insufficient funds for the equipment to meet the reactive power dispatch.'' [416] Rather, ''the lack of separate reactive power compensation in CAISO or SPP means that all costs have to be recovered through the applicable PPA, which also means that those PPA prices are higher, all other variables being equal, than they would otherwise be.'' [417]

143. We also find it of no consequence that a generating facility participates in only the energy market, as no commenter has demonstrated why these joint costs could not be recovered via energy sales, as these costs are necessary for the production and delivery of real power. However, as discussed herein, to the extent that current RTO/ISO market rules require generating facilities to subtract their separate revenue streams for reactive power from the avoidable costs they are permitted to reflect in their capacity market offers, we encourage RTOs/ISOs to propose any necessary conforming changes to their market rules in section 205 filings accompanying their compliance filings to this final determination.[418]

144. The NHA asserts that capacity markets are unequipped to situate reactive power where it is most needed because capacity markets do not allow for granular clearing prices based on specific geographic locations. In turn, the NHA argues that RTOs/ISOs should instead develop reactive power compensation rules to reflect locational requirements.[419] However, we find that generating facilities are required to provide reactive power within the standard power factor range as a matter of good utility practice and to meet the obligations under their interconnection agreements under Order No. 2003,

through other mechanisms is impermissible.'' (citations omitted)).

[409] PJM IMM Initial Comments at 1–6, 9, 12–13; PJM IMM Reply Comments at 2–5.

[410] *See, e.g.,* PJM IMM Initial Comments at 6.

[411] *See* PJM IMM Initial Comments at 6 (''Elimination of the reactive revenue requirement and the reactive revenue offset would increase prices in the capacity market. The VRR curve, or demand curve, would shift to the right, the maximum VRR price would increase and offer caps in the capacity market would increase.'').

[412] *See infra* III.B.2.

[413] *See* III.B.2; *see, e.g.,* MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 40–42; *BPA,* 120 FERC ¶ 61,211 at P 21 (finding that the argument that it is not feasible for IPPs to recover their costs through higher power sales rates ''lacks plausibility'' ''since the incremental cost of reactive power service within the deadband is minimal,'' and ''[t]he purpose for which generation assets are built (including reactive power capability to maintain voltage levels for generation entering the grid) is to make sales of real power''). *See also* Joint Customers Initial Comments at 15 (''Generators have other means of covering costs incurred to meet interconnection design requirements.''); MISO Transmission Owners Initial Comments at 16 (''As the Commission explains, compensation for providing reactive power within the deadband is unnecessary, as resources are otherwise able to recover their costs. The Commission is correct in finding that there are many other mechanisms through which generators may recover the costs of reactive power service, if they need to. This is consistent with Commission precedent that has repeatedly highlighted how generators have the opportunity to recover any legitimate costs through other means. The Commission has found generators may recover such costs through power purchase agreements or capacity and energy market offers. As the Commission found when accepting the elimination of reactive power compensation in MISO, generators can still include the costs of reactive service in energy offers or capacity offers, even if subject to market power mitigation.'' (citations omitted)).

[414] *See, e.g.,* PJM IMM Initial Comments at 4 (''[T]here is no reason that part of those capital costs should be paid directly in a nonmarket, guaranteed, riskless revenue stream rather than in the market.''); Joint Customers Initial Comments at 15 (''Generators have other means of covering costs incurred to meet interconnection design requirements.'').

[415] AEP Initial Comments at 4–6; Joint Consumer Advocates Initial Comments at 7–8; Joint Customers Initial Comments at 15–18; Ohio FEA Initial Comments at 5 (''Through the PJM markets, generators have an opportunity to recover all costs, including reactive power costs.''). *See* also MISO Transmission Owners Initial Comments at 15–17 (''The Commission is correct in finding that there are many other mechanisms through which generators may recover the costs of reactive power service, if they need to.'').

[416] NOPR, 186 FERC ¶ 61,203 at P 48 (citing CAISO Initial Comments to NOI at 5–6).

[417] *Id.* (citing LRE/UCS Initial Comments to NOI at 16).

[418] *See* PJM Initial Comments at 6–7; *infra* III.B.2.

[419] NHA Initial Comments at 5–7.

regardless of location.[420] For that reason, Order No. 2003 does not contain a location-specific component for the provisions of reactive power within the standard power factor range. Any additional reactive power capability required to satisfy specific local reliability needs, as well as the compensation for costs incurred to provide that capability (*e.g.,* capacitors, synchronous condensers), are for the transmission provider to determine and are beyond the scope of this final determination.[421]

145. In response to commenters [422] who argue that generating facilities will be unable to recover through their existing PPAs costs that are currently recovered through separate reactive power payments, the record lacks any concrete evidence showing whether, and to what extent, generating facilities factored reactive power revenues into their PPAs. Even if a generator were able to demonstrate that eliminating compensation under our rule might impact some generating facility's profitability, we do not believe that potential disrupted expectations weigh in favor of a different outcome in this situation. As a general matter, the risk of regulatory change is inherent in any long-term PPA.[423] Moreover, as explained above, because no generating facility could have reasonably relied on an inherent right to separate compensation for reactive power capability within the standard power factor range since Order Nos. 2003 and 2003–A (*i.e.,* because such compensation is required only to ensure ''comparability''), there has always been some risk in relying on compensation, because market rules can change.[424] Indeed, developers and generating facilities have been on notice since at least 2003 that the Commission regards reactive power compensation within the standard power factor range as non-compensable (other than where the comparability standard applies) —a conclusion that was patent in those orders, and reinforced repeatedly in subsequent Commission orders accepting transmission owner filings under section 205 that eliminated reactive power compensation within the standard power factor range.[425] Additionally, the Commission rejected reliance arguments in the MISO Rehearing Order [426] and *PNM.*[427] We similarly find unsupported Generation Developers'[428] concerns about energy markets being insufficient to recover fixed costs and Indicated Trade Associations' [429] concerns about not clearing the energy market when including reactive power costs in energy market bids. The record demonstrates that, in regions such as MISO, where separate compensation for the provision of reactive power within the standard power factor range has been eliminated, generating facilities continue to be developed, indicating that such developers believe there to be sufficient opportunity to recover their costs, including any costs associated with the provision of reactive power within the standard power factor range.[430] In light of this evidence, Indicated Trade Associations' and Generation Developers' arguments that organized markets do not provide sufficient opportunities for generating facilities to recover their costs fall flat.

146. We agree with Generation Developers that ''[t]he Commission has a statutory obligation to ensure that [Commission]-jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential.'' [431] Indeed, our actions here do nothing to deny generating facilities their ''opportunity to recover their costs, plus a reasonable rate of return.'' [432] As noted above, generating facilities have an opportunity to recover appropriately recoverable fixed and variable costs through other markets, including the opportunity to potentially make up for lost revenue from the cessation of reactive power compensation within the standard power factor range.[433] And if market rules in RTOs/ISOs currently inhibit such recovery, as discussed herein, we are permitting the RTOs/ISOs to request additional time to update those market rules, as may be appropriate and consistent with this final determination.

147. Regarding ISO–NE's [434] reliance on the Commission's denial of the Maine Public Utilities Commission's complaint to support its assertion that ISO–NE's reactive power scheme was, and continues to be, just and reasonable, we acknowledge that our findings in this final determination represent a change in policy from prior Commission findings on compensation for the provision of reactive power within the standard power factor range. However, as discussed above, we find that the record in this proceeding demonstrates that such a change is appropriate.

[420] *See supra* II.A.2; MISO Transmission Owners Reply Comments at 12–13 (''That series of orders required, among other things, that interconnecting generators be able to provide reactive power within the deadband without compensation.'').

[421] *See* MISO Transmission Owners Initial Comments at 15 (''Moreover, transmission providers have mechanisms for maintaining system reliability in the face of premature retirements. When generators advise MISO of a planned retirement via Attachment Y of the MISO Tariff, MISO completes a review to determine whether any Transmission System reliability concerns are caused by the retirement. If voltage concerns arise in the Attachment Y study, options to address the voltage concerns are reviewed and ultimately a permanent solution is identified. If the permanent solution cannot be implemented before the planned retirement date, then the MISO Tariff has a designation for 'system support resources,' under which generators are eligible to receive cost-based compensation to support their continued operation until an alternative solution to the reliability problem posed by the resources' retirement is developed.'' (citations omitted)).

[422] EDPR Initial Comments at 4–5; Generation Developers Initial Comments at 19; Indicated Trade Associations Initial Comments at 18; Reactive Service Providers Initial Comments at 59–62.

[423] *See, e.g.,* PJM IMM Reply Comments at 5 (''When buyers and sellers enter into power purchase agreements, the contracting parties define and assign regulatory risk. Customers are not responsible to manage or pay for suppliers' risks.'').

[424] *See* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 33 (''Sophisticated parties, like independent power producers, have the ability to manage risks of this sort in entering long-term arrangements rather than assuming that this compensation will be available in perpetuity.'').

[425] *See, e.g., Nev Power Co.,* 179 FERC ¶ 61,103; *PNM,* 178 FERC ¶ 61,088 at PP 26–36; *SPP,* 119 FERC ¶ 61,199 at PP 20, 30–33.

[426] *See* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 33 (''[W]e find that generators' assumption that such compensation will continue to be available does not give rise to reliance interests that justify requiring that such compensation continue to be provided.'').

[427] *PNM,* 178 FERC ¶ 61,088 at P 33 (''[B]y designing its generating facility to have the capability to provide reactive support, Aragonne Wind is only meeting the conditions of interconnection required of all generators and is not entitled to compensation unless the transmission provider pays its own or affiliated generators for reactive power within the established range.'').

[428] Generation Developers Initial Comments at 18.

[429] Indicated Trade Associations Initial Comments at 14.

[430] *See* MISO Transmission Owners Initial Comments at 14 (''Moreover, all charges under Schedule 2 of the MISO Tariff for the provision of reactive power within the standard power factor range were eliminated in the MISO region effective December 1, 2022. MISO has since experienced no reliability issues as a result and generator interconnection applications, the first step of a process that ends with execution of an interconnection agreement that obligates the generator to provide reactive power within the deadband, remain high.'' (citations omitted)).

[431] Generation Developers Initial Comments at 6.

[432] *Id.*

[433] *See, e.g., N. Am. Elec. Reliability Corp.,* 183 FERC ¶ 61,222 (2023) (explaining that the FPA requires only that Commission-jurisdictional rates provide an opportunity for the recovery of prudently incurred costs necessary to comply with reliability standards—not that all entities have identical outcomes) (citing *ISO New England Inc.,* 132 FERC ¶ 61,044, at P 28 (2010) (''[R]esources are provided only an opportunity to recover their costs, not a guarantee that they will recover those costs.''); *Bridgeport Energy, LLC,* 113 FERC ¶ 61,311, at P 29 (2005) (''[T]he Commission has no obligation in a competitive marketplace to guarantee Bridgeport its full traditional cost-of-service. Rather, in a competitive market, the Commission is responsible only for assuring that Bridgeport is provided the *opportunity* to recover its costs.'') (emphasis in original).

[434] ISO–NE Initial Comments at 10.

148. We disagree with commenters' [435] contention that eliminating compensation for reactive power within the standard power factor range would violate the cost causation principle. As discussed above, real and reactive power are provided as joint products, with joint costs, and are produced using the same equipment; therefore, a separate cost compensation mechanism for the provision of reactive power within the standard power factor range is not necessary.[436] We are not persuaded that eliminating compensation for reactive power within the standard power factor range violates cost causation.

149. Additionally, we disagree with claims that transmission customers are the sole beneficiaries and cost-causers, as well as assertions [437] that eliminating compensation for reactive power within the standard power factor range would insulate transmission providers and customers from paying for any costs associated with the services they are receiving—essentially requiring generating facilities to recover the costs of reactive power from energy and capacity market customers, rather than the transmission customers that benefit from the reactive power service. These arguments fail because they are inconsistent with Commission precedent that explains that providing reactive power within the standard power factor range enables generating facilities to reliably deliver real power to the transmission system (*i.e.,* make real power sales).[438] In effect, these costs are ''caused'' by the operating requirements of the generating facilities to deliver real power, not by the separate needs of the transmission customers.

150. We similarly disagree with commenters'[439] assertions that eliminating compensation for reactive power within the standard power factor range would result in undue discrimination between generating facilities and transmission assets, where owners of the latter would still have guaranteed recovery of their costs of reactive power assets through transmission rates. The Commission has long held that reactive power supply from transmission facilities is distinct from reactive power supply from generating facilities, with the former constituting a basic part of transmission service.[440] This is because generating facilities must produce reactive power within the standard power factor range to allow the generating facilities' real power to reliably flow onto the transmission system, while transmission provider investment in capacitor banks is to control transmission system voltage levels to provide reliable transmission service.[441] These findings also address similar arguments raised by NEI and PSEG.[442]

151. Similarly, we find without merit Reactive Service Providers' and Indicated Trade Associations' argument that transmission owners that own generation will have a competitive advantage over IPPs by virtue of their ability to recover their costs through retail rates. Putting aside that commenters provide no support for their contention that transmission owners that own generation will be able to recover their reactive power costs through retail rates,[443] the Commission has rejected similar arguments on multiple occasions. In *SPP* and *BPA,* the Commission explained ''that merchant generators are free to negotiate rates that they charge their customers for real power that are sufficient to compensate them for any costs that they may incur in producing reactive power within their deadbands, just as affiliated generators may seek to negotiate rates that they charge their customers that are sufficient to compensate them for the costs of any reactive power that they provide within their deadbands.'' [444] The Commission also observed that ''[i]n this regard, all that the protestors have done is to note that an incumbent utility's generators may be able to make up the revenue that they previously might have earned through a separate charge for reactive power within the deadband in other ways—such as through higher power sales rates. But merchant generators are no differently situated and their ability to recover such costs has not been compromised. They, equally, may be able to recover the costs for reactive power within the deadband in other ways—such as through higher power sales rates of their own.'' [445] As in those other cases, we believe that our action here ''maintains a level playing field for all generators subject to Commission jurisdiction, such that compensation for reactive power support is separately paid when reactive power outside the deadband is dispatched to the point on the transmission system where it is needed, and in the magnitude required to ensure a stable grid.'' [446]

152. Regarding Elevate's assertion that Commission precedent, including Order No. 841, requires compensation for any service that a generating facility is technically capable of providing, we note that many regions do not provide separate compensation for each obligation of interconnection. For example, as the PJM IMM notes, generating facilities in PJM are required to provide primary frequency response and other essential transmission system services as a condition of interconnection without a separate, dedicated revenue stream.[447] Furthermore, as explained above,

[435] ACORE Initial Comments at 3; Generation Developers Initial Comments at 4, 9–12; Indicated Trade Associations Initial Comments at 27; NEI Initial Comments at 2, 16; PSEG Initial Comments at 1–3, 17; Reactive Service Providers Initial Comments at 62–64; Indicated Reactive Power Suppliers Initial Comments at 9.

[436] *See* II.B.2.

[437] Indicated Trade Associations Initial Comments at 24–26; Indicated Trade Associations Reply Comments at 16; NEI Initial Comments at 17.

[438] *See* SPP Rehearing Order, 121 FERC ¶ 61,196 at P 15 (''As we have previously explained, reactive power is *required for an interconnecting generator to deliver its power* and reactive power produced within the [standard power factor range] and is, therefore, generally not compensable.'' (emphasis added)); BPA Rehearing Order, 120 FERC ¶ 61,211 at P 21 (''The purpose for which generation assets are built (including reactive power capability to maintain voltage levels for generation entering the grid) is to make sales of real power.''); *see supra* II.A.2.

[439] Indicated Trade Associations Initial Comments at 24–27; Reactive Service Providers Initial Comments at 64; PSEG Initial Comments at 17; ACORE Initial Comments at 3; NEI Initial Comments at 2, 16.

[440] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,706 (''We accept NERC's identification of two ways of supplying reactive power and controlling voltage. One is to install facilities, usually capacitors, as part of the transmission system. We will consider the cost of these facilities as part of the cost of basic transmission service. Providing reactive power and voltage control in this way is not a separate ancillary service. The second is to use generating facilities to supply reactive power and voltage control. This use is the service named here, which must be unbundled from basic transmission service.'').

[441] *Id.* (''NERC further distinguishes reactive supply services based on the source of the need for the service: (1) reactive supply needed to support the voltage of the transmission system; and (2) reactive supply needed to correct for the reactive portion of the customer's load at the delivery point.''); *see also supra* n.439.

[442] NEI Initial Comments at 16 (citing 2005 Staff Report at 4); PSEG Initial Comments at 17 (citing same).

[443] *SPP Order on Rehearing,* 121 FERC ¶ 61,196 at P18 (''[T]ransmission owners' generators are not entitled to charge retail customers retail rates that guarantee full recovery of their costs; rather, they must first justify their rates to state authorities'').

[444] *BPA,* 120 FERC ¶ 61,211 at P 21 (citing *SPP,* 119 FERC ¶ 61,199 at P 39).

[445] *Id.*

[446] *SPP,* 119 FERC ¶ 61,199 at P 38. *See N. Am. Elec. Reliability Corp.,* 183 FERC ¶ 61,222 (rejecting claims that reliability standard gives vertically integrated utilities a competitive advantage; explaining that, while the approval of the new standard may have different implications for different entities depending on their existing compensation mechanisms, the FPA requires only that Commission-jurisdictional rates provide an opportunity for the recovery of prudently incurred costs necessary to comply with reliability standards—not that all entities have identical outcomes).

[447] *Supra* n.415.

generating facilities have an opportunity to recover their appropriate fixed and variable costs through other markets, including the opportunity to make up for lost revenue from the cessation of reactive power compensation within the standard power factor range.

153. Although ISO–NE and NYISO argue to maintain their existing reactive power compensation schemes, as discussed above, these arguments ignore the findings in this final determination, which apply equally to flat-rate compensation regimes like ISO–NE's and NYISO's, as to the compensation regimes of PJM and certain non-RTO regions. That is, generating facilities incur no incremental fixed costs and at most *de minimis* variable costs incremental to the cost of providing real power, because no additional equipment is required to provide reactive power and variable costs are limited to the fuel costs (in synchronous facilities) or foregone direct current power (in non-synchronous facilities) necessary to provide the reactive power required to safely inject real power into the transmission system and comply with reliability requirements.[448]

154. These commenters argue that transparency, administrative burden, and preventing double recovery problems are reduced or eliminated in either ISO–NE, NYISO, or both. However, all those arguments suppose that compensation is due, and thus that a compensation method is needed. But, if no separate compensation is due, all compensation methodologies will necessarily result in unjust and unreasonable rates.[449] Furthermore, we agree with New England Consumer Advocates,[450] who argue that any payment for reactive power capability within the standard power factor range must yield some roughly commensurate incremental benefit *above and beyond* that which would accrue absent payment.[451] Given those arguments, transmission customers in ISO–NE and NYISO, just like transmission customers in PJM and non-RTO regions, do not receive benefits that are commensurate with the costs of reactive power charges, even if the compensation methods used in these regions are less administratively burdensome than the methods used in other regions.[452]

D. Reliability

155. The NOPR preliminarily found that ''compensation for providing reactive power within the standard power factor range is unnecessary to maintain reliability'' and that ''requiring transmission providers to continue paying for reactive power already required by a generating facility's interconnection agreement is not necessary to ensure that generating facilities provide reactive power when required.'' [453] In addition to noting that multiple RTOs, ISOs, and non-RTO/ISO transmission providers have elected not to compensate generating facilities for the provision of reactive power within the standard power factor range under Schedule 2 of the OATT,[454] the NOPR observed that CAISO has not seen major issues of concern with the level of reactive power in its region despite not providing separate compensation for reactive power within the standard power factor range. The Commission also preliminarily found in the NOPR that requiring transmission providers to continue paying for reactive power already required by a generating facility's interconnection agreement is not necessary to ensure that generating facilities provide reactive power within the standard power factor range.[455]

156. The NOPR sought comment on the reliability impact of prohibiting transmission providers from including in their transmission rates any charges associated with the provision of reactive power within the standard power factor range from a generating facility in regions where generating facilities currently receive such compensation.[456]

1. Comments

157. Many commenters do not expect to see an impact on reliability under the NOPR proposal.[457] For example, ''MISO has not experienced reliability concerns since December 1, 2022 due to the elimination of compensation for reactive power within the standard power factor range.'' [458] Furthermore, several commenters observe that regions like MISO, which implemented similar reforms, and CAISO, which does not compensate for reactive power service, have not experienced related reliability concerns.[459] The PJM IMM argues that ''there is no evidence that expanding the just and reasonable approach to compensation already in place in CAISO, SPP, and MISO to PJM will have any adverse impact on reliability in PJM'' and that ''[t]he salient difference between PJM and CAISO, SPP, and MISO is that PJM customers paid $388,044,837.00 in out of market payments for reactive capability in 2023, and customers in CAISO, SPP and MISO, paid $0.00'' [460] for the same service. Joint Customers agree with the NOPR that the Commission's ''precedent is crystal clear that compensation is not required'' [461] for

[448] *See,* II.B.2.

[449] *See,* II.A.2.

[450] New England Consumer Advocates Initial Comments at 5 (''To the extent . . . benefits are achieved by compliance with a generating facility's interconnection agreement and/or as 'good utility practice,' [New England Consumer Advocates] agree[] with the Commission that ratepayers should not be paying separately for the costs to produce a joint reactive power product.'').

[451] *See, e.g., supra* n.140.

[452] Joint Customers Initial Comments at 5–6 (''The Commission's policy of looking strictly to capability for determining cost recovery for Reactive Service incentivized overbuilding of capability beyond what was required based on interconnection requirements. This policy of not considering need or requiring a demonstration of need by the transmission owner has resulted in compensation for reactive capability without an actual demonstrated benefit to transmission system customers. This disconnect between capability and any actual demonstrated benefit highlights serious concerns that charges to customers are not related to any benefits received.'' (citations omitted)).

[453] NOPR, 186 FERC ¶ 61,203 at P 43 (citing *Essential Reliability Servs. & the Evolving Bulk-Power Sys. Frequency Response,* Order No. 842, 83 FR 9639 (Mar. 6, 2018), 162 FERC ¶ 61,128, at P 121, *order on reh'g and clarification,* 164 FERC ¶ 61,135 (2018) (''While the Commission has approved specific compensation for discrete services that require substantial identifiable costs, such as for frequency regulation and operating reserves, the Commission has not required specific compensation for all reliability-related costs. We agree with those commenters who observe that minimal reliability-related costs such as those incurred to provide primary frequency response, are reasonably considered to be part of the general cost of doing business, and are not specifically compensated.'')).

[454] *Id.* P 15 (citing *MISO,* 182 FERC ¶ 61,033 at PP 52–53; MISO Rehearing Order, 184 FERC ¶ 61,022 at P 26; *PNM,* 178 FERC ¶ 61,088, at PP 29–31; *Nev. Power Co.,* 179 FERC ¶ 61,103 at PP 20–21; *BPA,* 120 FERC ¶ 61,211 at P 20; *E.ON U.S. LLC,* 119 FERC ¶ 61,340 at P 15; *Entergy Servs., Inc.,* 113 FERC ¶ 61,040 at P 38); *see also id.* P 18 (noting that CAISO, SPP, and MISO do not pay separately for reactive power within the standard power factor range).

[455] *Id.*

[456] *Id.* P 44.

[457] *See, e.g.,* Joint Consumer Advocates Initial Comments at 6–8; Joint Customers Reply Comments at 1–2; MISO Initial Comments at 2; MISO Transmission Owners Initial Comments at 12–16; New England Consumer Advocates Initial Comments at 4–5; Ohio FEA Initial Comments at 4; PGE Initial Comments at 2–3; PJM IMM Initial Comments at 11–12.

[458] MISO Initial Comments at 2.

[459] Joint Customers Reply Comments at 2–6; MISO Initial Comments at 2; MISO Transmission Owners Initial Comments at 14–15; TAPS Initial Comments at 5.

[460] PJM IMM Initial Comments at 11–12.

[461] Joint Customers Reply Comments at 2; *see also id.* at 3 (''The Commission is, in fact, in an enviable position where the *pro forma* revisions contemplated in the NOPR have recently been implemented on a large regional scale. For the purposes of establishing record support for the NOPR and addressing transition, discussed below, the *MISO* proceeding essentially point by point addresses the arguments recycled to oppose the NOPR. The same is true with respect to the arguments concerning reliability, which were extensively addressed in the *MISO* order and order on rehearing. But with respect to reliability, *MISO*

Continued

generators meeting interconnection requirements of providing reactive service within the standard power factor range. In addition, MISO Transmission Owners assert that eliminating reactive power compensation will not adversely affect reliability because generators are required to provide reactive power pursuant to their interconnection agreements,[462] NERC requirements,[463] and Order No. 2003.[464] Joint Customers argue that there is a ''lack of concrete evidence of adverse reliability impacts (including in regions where this exact change has been implemented)'' in the record and the commenters' concern that ''if there is not an unjustifiable free revenue stream ostensibly related to reactive service and capability, there will not be sufficient generation for real power and capacity at some unspecified point in the future'' is ''speculative to the point of incoherence.''[465]

158. MISO Transmission Owners refute the claim that the transmission system will face increased retirements due to the loss of reactive power revenue by arguing that transmission providers have mechanisms for maintaining system reliability in the face of premature retirements.[466] Relatedly, Joint Consumer Advocates, MISO Transmission Owners, and TAPS each point to ample backlogs in generator interconnection queues nationwide as protection against any threat to reliability from eliminating reactive power compensation.[467]

159. MISO Transmission Owners also counter fears[468] of inadequate incentives to make the necessary capital investments to provide reactive power by explaining that generators are incented by their own operating and reliability requirements to install the equipment that is most likely to keep their projects online and delivering real power.[469]

160. Other commenters express general reliability concerns under the NOPR proposal.[470] Commenters also argue that specific types of resources especially benefit from reactive power revenue, including energy storage,[471] hydro,[472] and nuclear.[473] Elevate explains that ''[b]ecause energy storage resources 'have the capability to operate at any power factor, they are exceptionally valuable as reactive power resources.''' [474]

161. Generation Developers argue that, without the reactive power capability of generating facilities, transmission providers will need to further invest in transmission equipment capable of providing reactive support.[475] Indicated Trade Associations assert that eliminating a source of stable, expected reactive power compensation could lead to more retirements.[476] Relatedly, Indicated Trade Associations also state that, while CAISO does not currently compensate reactive power service, it has had to rely on reliability must-run (RMR) agreements to maintain the needed reactive power.[477] NEI emphasizes the importance of reactive power, noting Chairman Wood's statement that proper reactive power management would have ''delayed'' or possibly prevented the 2003 August blackout,[478] and NERC's finding that ''reactive power is critical to the reliable and efficient operation of the power system.''[479] NEPOOL argues that payment for reactive power broadens the base of resources willing to seek to become Qualified Reactive Resources and support reliability in ISO–NE.[480]

162. Indicated Trade Associations also argue that eliminating compensation for reactive power service within the standard power factor range will hamper generators' ability to provide reactive power service outside the standard power factor range because such events do not happen with enough regularity to warrant the capital costs associated with such capability.[481] Similarly, Indicated Trade Associations argue that the increasing reliance on non-synchronous resources makes it even more important to ensure that generators have incentives to go beyond the bare minimum requirements outlined in their interconnection agreements.[482]

163. NYISO and IPPNY warn that transitioning away from NYISO's current reactive power compensation structure could introduce reliability risks and operational complexities.[483] NYISO asserts that its reactive power compensation supports electric system reliability because it requires resources to undergo annual capability tests and maintain automatic voltage control equipment to ensure consistent reactive power support.[484] NYISO explains that these resources dynamically produce or absorb reactive power, supporting the electric system within and beyond standard power factor ranges without operator intervention. NYISO emphasizes that this automatic and

is dispositive not only for its precedential value, but also in setting up a real-world test of the countervailing predictions regarding the impact of eliminating compensation for reactive service within the standard power factor range.'' (citations omitted)); *id.* at 4 (''MISO's experience validates the Commission's conclusions in approving the MISO Transmission Owners' proposed tariff revisions, as well as the Commission's skepticism regarding speculative warnings of reliability impacts. It similarly validates PJM's support for the NOPR and the conclusions of the PJM Independent Market Monitor that amending Schedule 2 of the PJM Tariff will not lead to reliability concerns.'' (internal citations omitted)).

[462] Joint Customers Reply Comments at 4–6; MISO Transmission Owners Initial Comments at 12–16; MISO Transmission Owners Reply Comments at 3–4; Ohio FEA Initial Comments at 4; PGE Initial Comments at 2–4.

[463] MISO Transmission Owners Initial Comments at 12.

[464] MISO Transmission Owners Reply Comments at 6 (citing Order No. 2003, 104 FERC ¶ 61,103 at P 546; Order No. 2003–A, 106 FERC ¶ 61,220 at PP 410, 416).

[465] Joint Customers Reply Comments at 4–6.

[466] *Supra* n.448.

[467] Joint Consumer Advocates Initial Comments at 7–8; MISO Transmission Owners Initial Comments at 12–16; TAPS Initial Comments at 5.

[468] *See, e.g.,* Indicated Trade Associations Initial Comments at 21.

[469] MISO Transmission Owners Initial Comments at 11 (citing MISO Rehearing Order, 184 FERC ¶ 61,022 at P 35 n.116 (''[G]enerators have incentives to install equipment to ensure that their generation remains online and delivering real power.'')).

[470] *See, e.g.,* Clean Energy Associations Initial Comments at 5; Elevate Initial Comments at 4–9; Elevate Reply Comments at 4–6; Generation Developers Initial Comments at 2–6; Indicated Trade Associations Initial Comments at 18–19; NAGF Initial Comments at 2; NEI Initial Comments at 2; NEPGA Reply Comments at 2–3 (citing ISO–NE Initial Comments at 6–7); NESCOE Reply Comments at 2–3 (citing ISO–NE Initial Comments at 5–8); NHA Initial Comments at 1–2, 4; NYISO Initial Comments at 8–11; PSEG Initial Comments at 4–5, 8, 16–20, 22–24; Reactive Service Providers Initial Comments at 22.

[471] Elevate Initial Comments at 4–9; Elevate Reply Comments at 4–6.

[472] NHA Initial Comments at 2.

[473] *Id.* at 6.

[474] Elevate Initial Comments at 5 (citing Meyersdale Storage, LLC Proposed Revenue Requirement under PJM Interconnection, L.L.C. Open Access Transmission Tariff, Schedule 2, Reactive Supply and Voltage Control From Generation Sources Service, Docket No. ER21–864–000, Exh. No. MEY–0001 at 11:19–22 (filed Jan. 11, 2021)).

[475] Generation Developers Initial Comments at 2–3.

[476] Indicated Trade Associations Initial Comments at 18–19; Indicated Trade Associations Reply Comments at 12.

[477] Indicated Trade Associations Initial Comments at 19–20.

[478] NEI Initial Comments at 3 (citing Letter from FERC Chairman Pat Wood, III, 1 (Feb. 4, 2005), *https://www.ferc.gov/sites/default/files/2020-05/20050310144430-02-04-05-rp-letter-wood.pdf;* 2005 Staff Report at 3 (''Inadequate reactive power has led to voltage collapses and has been a major cause of several recent major power outages worldwide.'')).

[479] NEI Initial Comments at 3–4 citing NERC, *Essential Reliability Services Task Force Measures Framework Report* 16 (Nov. 2015), *https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.*

[480] NEPOOL Reply Comments at 12.

[481] Indicated Trade Associations Initial Comments at 21.

[482] Indicated Trade Associations Reply Comments at 12.

[483] NYISO Initial Comments at 8–11; IPPNY Reply Comments at 1–2.

[484] NYISO Initial Comments at 5–7.

dynamic support is essential for maintaining system reliability.[485] Reactive Service Providers explains that inverter-based generation can and does provide VAR support even when no MW are sold.[486] Generation Developers and Reactive Service Providers highlight the pivotal role in maintaining reliability that transmission providers with a dynamic source of reactive power supply provide.[487] NYISO is concerned that eliminating compensation for reactive power within the standard power factor range will introduce confusion among existing generators and new generators, and, in the longer term, introduce reliability issues onto the electric system.[488] NYISO also believes that the final determination will result in eliminating the price signals and incentives for the reactive power necessary to maintain system reliability, instead blending those costs and payments into payments made to all capacity suppliers without a direct link to provision of the reactive power necessary to support a reliable electric system.[489]

164. Elevate adds that international electric markets recognize the importance of energy storage resources to maintaining long-term transmission system reliability.[490] For example, Elevate states that in the United Kingdom, the National Grid Electricity System Operator (ESO) has entered into a contract with the largest transmission system connected battery project in Europe to provide reactive power support services to maintain system voltages in the face of growing system variability and the retirement of thermal generation resources. Elevate states that the ESO entered this contract despite already providing compensation to resources for providing or absorbing reactive power as a condition of interconnecting and through regular solicitations to secure resources to provide more reactive power than what is required to interconnect to the transmission system.[491]

2. Commission Determination

165. Based on our review of the record, and consistent with the preliminary finding in the NOPR,[492] we conclude that prohibiting transmission providers from including in their transmission rates any charges associated with the provision of reactive power from a generating facility within the standard power factor range and thereby eliminating compensation to generating facilities for reactive power within the standard power factor range, would not negatively impact reliability. The record in this proceeding affirms our preliminary finding in the NOPR that requiring transmission customers to continue paying for reactive power already required by a generating facility's interconnection agreement is not necessary to ensure that generating facilities provide reactive power when required, as new and existing generating facilities are, and will continue to be, required to provide reactive power within the standard power factor range as a condition of obtaining and maintaining interconnection.[493] As commenters note, these findings are supported by the fact that generating facilities in CAISO, SPP, MISO, and certain non-RTO regions (*e.g.,* BPA, Arizona Public Service Company, Southern Companies) do not receive compensation for reactive power capability within the standard power factor range,[494] and there is no evidence in the record that the lack of reactive power compensation anywhere has led to an insufficient supply of reactive power in those regions.

166. For these same reasons, we also find speculative and without merit claims that elimination of compensation for reactive power within the standard power factor range will mute investment in real and reactive power capability, hasten generating facility retirements and/or RMR agreements and as a result, negatively impact reliability and require increased transmission provider investment in transmission equipment capable of providing reactive support.[495] We see no record evidence supporting these concerns, and substantial record evidence to the contrary. For example, CAISO stated that its current approach to not compensate for reactive power provided within the standard power factor range has not resulted in major issues of concern with respect to the level of reactive power,[496] and TAPS points out that reliability has not suffered in regions in which reactive power in the standard power factor range is not compensated, as confirmed by years of experience in regions in which the absence of such compensation is a long-standing practice.[497] Reliability has not been weakened in those regions because the Commission's 20 year old requirement that interconnection customers have equipment to provide such reactive power ensures that generating facilities can interconnect reliably.[498]

[485] *Id.*

[486] Reactive Service Providers Initial Comments at 21–23.

[487] Generation Developers Initial Comments at 25; Reactive Service Providers Initial Comments at 21–23.

[488] NYISO Initial Comments at 7.

[489] *Id.* at 9.

[490] Elevate Reply Comments at 6–7 (citing Energy Storage News, *Europe's largest transmission-connected BESS begins 'world first' reactive power services contract,* (Feb. 13, 2023), https://www.energy-storage.news/europes-largest-transmission-connected-bess-begins-world-first-reactive-power-services-contract/).

[491] *Id.* at 7 (citing ESO, *Obligatory Reactive Power Service, https://www.nationalgrideso.com/industry-information/balancing-services/reactive-power-services/obligatory-reactive-power-service#Document-Library* (last visited June 26, 2024); ESO, *Enhanced Reactive Power Service, https://www.nationalgrideso.com/industry-information/balancing-services/reactive-power-services/enhanced-reactive-power-service-erps#Document-library* (last visited June 26, 2024)).

[492] NOPR, 186 FERC ¶ 61,203 at P 43.

[493] Joint Consumer Advocates Initial Comments at 6–8; Joint Customers Reply Comments at 1–2; MISO Initial Comments at 2; MISO Transmission Owners Initial Comments at 12–16; New England Consumer Advocates Initial Comments at 4–5; Ohio FEA Initial Comments at 4; PGE Initial Comments at 2–3; PJM IMM Initial Comments at 11–12. *See also* Order No. 842, 162 FERC ¶ 61,128 (''[T]here are interconnection requirements for generating facilities in which the recovery of capital costs and operating expenses are not necessarily ensured.'').

[494] *See, e.g, MISO,* 182 FERC ¶ 61,033 (accepting MISO transmission owners' proposal to eliminate compensation for the provision of reactive power within the standard power factor range); *Cal. Indep. Sys. Operator Corp.,* 160 FERC ¶ 61,035 at P 19 (''[A] separate payment for the provision of reactive power capability inside the standard power factor range is not required, and we see no reason to require a separate cost recovery mechanism for reactive power capability based on the record here.''); *PNM,* 178 FERC ¶ 61,088 at P 29 (''Consistent with Commission precedent, a transmission provider may decide to eliminate compensation for having the capability of providing reactive service within the standard power factor range.'').

[495] Clean Energy Associations Initial Comments at 5; Indicated Trade Associations Initial Comments at 18–19; Indicated Trade Associations Reply Comments at 12; NEPOOL Reply Comments at 12; Elevate Initial Comments at 4–9; Elevate Reply Comments at 4–6; NEI Initial Comments at 6, 15; NHA Initial Comments at 2, 4.

[496] CAISO Initial Comments to the NOI at 5–6 (explaining that despite the fact that it does not compensate for reactive power within the standard power factor range, CAISO ''has seen no evidence to this point that resources cannot comply with reactive power dispatch instructions because they have insufficient funds for the equipment to meet the reactive power dispatch''); MISO Transmission Owners Initial Comments at 15 (''The claim that generators may have to retire units in the absence of compensation for reactive power service within the deadband is pure speculation. Prior to the elimination of compensation for reactive power within the deadband in MISO, a number of generators in MISO operated without compensation for reactive power within the deadband as they did not file their revenue requirements for reactive power when their projects came on-line.'').

[497] TAPS Initial Comments at 5.

[498] *See, e.g.,* Joint Customers Reply Comments at 6 (arguing that there is a ''lack of concrete evidence of adverse reliability impacts (including in regions where this exact change has been implemented)'' in the record and that commenters' concern that ''if there is not an unjustifiable free revenue stream ostensibly related to reactive service and capability, there will not be sufficient generation for real power and capacity at some unspecified point in the

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167. In response to the reliability concerns raised by ISO–NE and NYISO, we find that their stated concerns are not specific to the proposal being adopted in this final determination—that is, their arguments are not limited to the provision of reactive power within the standard power factor range—and as a result, we find their concerns unpersuasive. ISO–NE and NYISO allude generally to reliability benefits from reactive power compensation over the full range of a generating facility's capability to provide reactive power. As such, ISO–NE's and NYISO's comments appear to address the reliability implications of eliminating reactive power compensation entirely—that is, eliminating compensation both within and outside of the standard power factor range—rather than the narrower focus of this final determination, which addresses only the provision of reactive power within the standard power factor range. However, as explained herein, the long-existing obligation of generating facilities to provide reactive power within the standard power range in order to reliably interconnect to the transmission system remains unchanged, as do the rules regarding the provision of reactive power outside the standard power factor range, which is considered a compensable ancillary service for transmitting power across the transmission system to serve load.[499] We also reject arguments about the provision of reactive power service beyond the requirements of generating facilities' interconnection agreements,[500] outside of the standard power factor range,[501] and Elevate's claims about the ESO's decision to double-compensate reactive power service in the United Kingdom for similar reasons.

168. We agree with NYISO's [502] and others' [503] statements about the importance of reactive power to reliability, including statements of dynamic reactive power sources,[504] but we note that such statements are equally true with or without reactive power compensation within the standard power factor range. Once again, requiring transmission customers to continue paying for reactive power within the standard power factor range already required by a generating facility's interconnection agreement is not necessary to ensure that generating facilities provide reactive power when required, as new and existing generating facilities are, and will continue to be, required to provide reactive power within the standard power factor range as a condition of obtaining and maintaining interconnection.[505]

169. In response to NEI's statements about the importance of reactive power in the 2005 Staff Report,[506] and NERC's Essential Reliability Services Task Force Measures Framework report,[507] we note that the 2005 Staff Report also explains that ''[i]nvestment that results in reactive power capability by generation facilities is driven by interconnection requirements, historical inertia and potential cost recovery for capacity. There is little interaction between the actual system need or value of reactive power capability and its supply by independent generation resources.'' [508] Additionally, to support our finding here, we are relying on more recent evidence, which indicates that RTOs/ISOs and non-RTO regions that have eliminated compensation for reactive power capability within the standard power factor range are not experiencing any adverse reliability impacts due to absence of reactive power compensation within the standard power factor range.[509]

E. Investment

170. The NOPR sought comment on whether, and if so how, eliminating separate reactive power compensation within the standard power factor range may affect investment decisions to build, or finish building, generating facilities, and whether, and if so, how the elimination could otherwise affect generating facilities' business decisions in those markets.[510] The NOPR also noted that in *MISO,* the Commission rejected any reliance arguments, reasoning in part that the provision of reactive power within the standard power factor range required little or no incremental investment.[511]

1. Comments

171. PGE argues that the NOPR proposal would not have a measurable impact on investment decisions.[512] MISO Transmission Owners also reject the claim that the proposed rule will disincentivize investment in new generating and storage resources.[513]

172. However, several commenters claim that ending compensation for reactive power service in the standard power factor range would have a negative impact on investment. Many commenters claim that such an action would be disruptive to generators and/or their investors, who include forecasts of such compensation as the basis for financing arrangements.[514]

future'' is ''speculative to the point of incoherence''); TAPS Initial Comments at 5; MISO Initial Comments at 2 (explaining that it would not expect to see any effect on reliability through eliminating compensation for reactive power within the standard power factor range and in fact, MISO has not experienced reliability concerns since December 1, 2022 due to the elimination of compensation for reactive power within the standard power factor range). *See also* Order No. 842, 162 FERC ¶ 61,128 at P 121 (''While the Commission has approved specific compensation for discrete services that require substantial identifiable costs, such as for frequency regulation and operating reserves, the Commission has not required specific compensation for all reliability-related costs. We agree with those commenters who observe that minimal reliability-related costs such as those incurred to provide primary frequency response, are reasonably considered to be part of the general cost of doing business, and are not specifically compensated.'').

[499] *See, e.g.,* MISO Rehearing Order, 184 FERC ¶ 61,022 at P 23 (citing METC Rehearing Order, 97 FERC at 61,852–53).

[500] Indicated Trade Associations Reply Comments at 12.

[501] Indicated Trade Associations Initial Comments at 21.

[502] NYISO Initial Comments at 5–7.

[503] *See, e.g.,* Joint Consumer Advocates Initial Comments at 6–8; Joint Customers Reply Comments at 1–2; MISO Transmission Owners Initial Comments at 12–16.

[504] Generation Developers Initial Comments at 25; Reactive Service Providers Initial Comments at 21–23.

[505] *See supra* II.B.2.

[506] *Supra* n.508.

[507] *Supra* n.509.

[508] *See* 2005 Staff Report at 69; *see also APS,* 94 FERC at 61,080 (''We note that operating a generating unit within the proposed [standard power factor range] does not affect the generation output of a unit.'').

[509] MISO Transmission Owners Initial Comments at 13–14 (''When the MISO Transmission Owners proposed to eliminate compensation for producing reactive power within the deadband, the most common protest from generators was that it would impact the reliability of the grid. However, such claims are not supported by evidence and distract from the underlying fact that generators are obligated to provide reactive power within the deadband whether or not they are compensated for it . . . MISO has since experienced no reliability issues as a result and generator interconnection applications, the first step of a process that ends with execution of an interconnection agreement that obligates the generator to provide reactive power within the deadband, remain high.'' (citations omitted)); PJM IMM Reply Comments at 5 (''There is no evidence from any of the markets where this policy already exists that it has created a reliability issue.'').

[510] NOPR, 186 FERC ¶ 61,203 at P 49.

[511] *Id.* P 16 (citing MISO Rehearing Order, 184 FERC ¶ 61,022 at P 29); MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 29–31 (finding that providing reactive service requires ''little or no incremental investment'' by both synchronous and non-synchronous resources); *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097 at PP 7, 28 (finding that non-synchronous generating facilities are comparable to traditional synchronous generating facilities, in that there are for both types of generating facilities very little if any incremental costs incurred to provide reactive power).

[512] PGE Initial Comments at 5.

[513] MISO Transmission Owners Reply Comments at 3–7.

[514] ACORE Initial Comments at 3–4; Calpine Initial Comments at 2; Clean Energy Associations Initial Comments at 4–5; Generation Developers Initial Comments at 33; EDPR Initial Comments at 1, 3–4; Elevate Initial Comments at 6; Indicated Reactive Power Suppliers Initial Comments at 13–

173. The PJM IMM maintains that:

> There is no evidence that units are built as a result of reactive [power] revenue. There is no evidence that sources of revenue are not fungible and that a decrease in reactive [power] revenues could be not replaced with other sources of revenue. There is no basis for adding new resources to the already very crowded interconnection queue solely based on out of market subsidies from reactive revenues.[515]

174. Similarly, PGE notes that transmission providers that have eliminated reactive power compensation have not observed a decrease in proposed investment.[516] MISO Transmission Owners assert that Indicated Trade Associations' claim that reactive power revenue streams can make the difference in overall profitability is unsupported by evidence.[517] Moreover, MISO Transmission Owners argue that investors could not reasonably have relied on reactive power compensation within the standard power factor range in perpetuity and should have considered the risk of its elimination when making investment decisions.[518] Similarly, Joint Customers explain that to the extent that generators voluntarily and unilaterally installed greater reactive capability than that required by their respective interconnection agreements, they did so at their own risk and for their own strategies, none of which mean that they should continue to be compensated for costs that they did not have to incur and which do not benefit transmission customers.[519]

175. NEI, Calpine, Indicated Reactive Power Suppliers, and Generation Developers argue that they relied on the Commission's longstanding precedent and policy of allowing compensation for reactive power within the standard power factor range in making their investment decisions and suggest that the final determination would be highly disruptive to market participants.[520] PSEG asserts that the final determination represents a significant departure from existing Commission policy without an adequate explanation.[521]

176. ACORE and Indicated Reactive Power Suppliers highlight the costs and potential challenges of generators with PPAs who may be unable to renegotiate those agreements to include costs related to reactive power service.[522] ACORE and Calpine argue that the NOPR proposal would impede project development during a period of greater need for generation resources.[523] Indicated Reactive Power Suppliers states that the loss of reactive power compensation could lead to generators not developing other projects because the revenue loss impacts these projects' ability to leverage finite capital based on this cash flow reduction.[524] Middle River Power also claims that the NOPR proposal may prompt investors to question the reliability and stability of other Commission-approved rates and markets.[525] Indicated Trade Associations argue that, given the narrow margins for competitive generators, small reactive power revenue streams can make the difference between whether a generator will be profitable over its life or not.[526]

177. Clean Energy Associations argue that the proposal is also disruptive to a host of interconnection customers with operating or near-completed projects and extant PPAs.[527] Clean Energy Associations also argues that the NOPR fails to consider IPP projects located in PJM with reactive power rates that are the result of Commission-approved settlements. Clean Energy Associations also argues that the Commission has not adequately considered the fundamental differences between IPP projects and projects that are utility-owned.

2. Commission Determination

178. Based on the record, we find that there is substantial evidence to support the conclusion that prohibiting the inclusion in transmission rates of reactive power rates within the standard power factor range will not have a significant impact on investment in new generating facilities.[528]

179. First, as stated above, generating facilities in CAISO, SPP, MISO, and certain non-RTO regions do not receive compensation for the provision of reactive power within the standard power factor range,[529] and, as MISO Transmission Owners explain,[530] there is no evidence in the record that: (1) these policies have led to an insufficient supply of reactive power in those regions, or (2) generating facilities in these regions have been unable to recover any costs associated with the provision of such reactive power. Because new and existing generating facilities are required to provide reactive service within the standard power factor range as a condition of interconnection, eliminating compensation for providing that service would not negatively impact investment.[531]

180. Second, we also agree with the MISO Transmission Owners, who note that because compensation for the provision of reactive power within the standard power factor range has always been based on comparability rather than compensability, ''[r]eactive power compensation is not a given'' and that ''[t]he Commission has consistently followed these principles, allowing transmission providers across the nation to eliminate compensation for reactive power service within the deadband.'' [532]

14; Indicated Trade Associations Initial Comments at 16; Middle River Power Initial Comments at 6; NEI Initial Comments at 2, 5–6, 8; NHA Initial Comments at 4–5.

[515] PJM IMM Initial Comments at 12–13.

[516] MISO Transmission Owners Reply Comments at 4–6.

[517] *Id.* at 3.

[518] *Id.* at 7.

[519] Joint Customers Initial Comments at 20.

[520] NEI Initial Comments at 8; Calpine Initial Comments at 2; Indicated Reactive Power Suppliers Initial Comments at 13; Generation Developers Initial Comments at 33–34.

[521] PSEG Initial Comments at 4, 20–22 (citing *PJM Providers Grp.* v. *FERC,* 88 F.4th at 271–72 (quoting *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. at 515); *Ass'n of Oil Pipe Lines* v. *FERC,* 876 F.3d 336, 342 (D.C. Cir. 2017)).

[522] ACORE Initial Comments at 3–4; Indicated Reactive Power Suppliers Initial Comments at 14.

[523] ACORE Initial Comments at 3–4; Calpine Initial Comments at 2.

[524] Indicated Reactive Power Suppliers Initial Comments at 13–14.

[525] Middle River Power Initial Comments at 6.

[526] Indicated Trade Associations Initial Comments at 16.

[527] Clean Energy Associations Initial Comments at 4–5.

[528] *See, e.g.,* MISO Transmission Owners Reply Comments at 3–4, 5–7; PGE Initial Comments at 5; PJM IMM Initial Comments at 12–13.

[529] *See Cal. Indep. Sys. Operator Corp.,* 160 FERC ¶ 61,035 at P 19 (''[A] separate payment for the provision of reactive power capability inside the standard power factor range is not required, and we see no reason to require a separate cost recovery mechanism for reactive power capability based on the record here.''). *See also PNM,* 178 FERC ¶ 61,088 at P 29 (''Consistent with Commission precedent, a transmission provider may decide to eliminate compensation for having the capability of providing reactive service within the standard power factor range.''); Order No. 842, 162 FERC ¶ 61,128 (''[T]here are interconnection requirements for generating facilities in which the recovery of capital costs and operating expenses are not necessarily ensured.'').

[530] MISO Transmission Owners Reply Comments at 3–4.

[531] *See, e.g., MISO,* 182 FERC ¶ 61,033 at P 55; MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 35–36; *see also* MISO Transmission Owners Initial Comments at 9–10 (''At the same time MISO was experiencing a dramatic increase in the amounts transmission customers paid for reactive power service prior to its elimination of compensation for reactive power service within the deadband, SEIA highlighted that MISO was one of the two 'most lucrative' regions for reactive power compensation, where generators received millions of dollars in compensation for having the capability to produce reactive power within the deadband, a capability that was already a condition of obtaining interconnection.'' (citations omitted)).

[532] MISO Transmission Owners Initial Comments at 19. *See also* Joint Customers Reply Comments at

Continued

As previously noted, developers have been on notice since at least Order No. 2003 and Order No. 2003–A that reactive power is not compensable within the standard power factor range (other than for comparability reasons), and so could not have relied, reasonably or otherwise, on the permanence of such compensation for investment purposes.[533]

181. Third, to the extent that generating facilities may have incurred costs by increasing their generating facilities' reactive power capabilities beyond the requirements of their interconnection agreements, we find that it is unreasonable to charge transmission customers for these costs as they were not required for interconnection and do not fit within the least justifiable cost to customers.[534] Further, as noted herein, this final determination does not address compensation for reactive power provided outside of the standard power factor range, which will continue to be compensable.

182. Fourth and finally, as discussed herein and further below, generating facilities have other opportunities to recover any *de minimis* variable costs of providing reactive power within the standard power factor range, and this final determination establishes a transition mechanism to give RTOs/ISOs time to adjust their market rules to ensure that generating facilities continue to have such other opportunities after this final determination.

183. Some commenters expressed general concerns about generating facilities and investors relying on reactive power revenues for planning purposes,[535] including concerns of interconnection customers with near-completed or operating projects, and extant PPAs,[536] as well as with IPP projects located in PJM with reactive power rates that are the result of Commission-approved settlements.[537] However, we reiterate that in this final determination[538] we have rejected any reliance arguments, reasoning in part that the provision of reactive power within the standard power factor range requires no incremental investment or fixed costs and at most *de minimis* incremental variable costs.

184. Relatedly, Indicated Trade Associations[539] argue that narrow profit margins mean that the loss of reactive power revenues could tip generating facilities out of profitability. We reiterate our finding above that the variable and incremental costs of providing reactive power within the standard power factor range requires no or at most a *de minimis* increase in variable costs beyond the cost of providing real power[540] and that generating facilities can recover any *de minimis* variable costs through other means. Additionally, no commenter provided any evidence that the loss of reactive power compensation would make a project that was otherwise profitable, unprofitable.

185. Further, we disagree with PSEG's assertions that the NOPR represents a significant departure from existing Commission policy without an adequate explanation and refer PSEG to the evidence and reasoning presented herein that we are relying upon in this final determination.[541] Consequently, we are revising the *pro forma* Schedule 2, *pro forma* LGIA, and *pro forma* SGIA to prohibit the inclusion in transmission rates of unjust and unreasonable charges related to the provision of reactive power within the standard power factor range by generating facilities. As courts of appeals have articulated on several occasions, ''[t]he APA does not require 'regulatory agencies [to] establish rules of conduct to last forever,' '' but rather, ''agencies may 'adapt their rules and policies to the demands of changing circumstances.' ''[542]

186. Similarly, in response to Middle River Power's[543] claims about the reliability and stability of other Commission-approved rates and markets, we note when the Commission finds that a rate is unjust and unreasonable, as we do here, the Commission has not only the right but the obligation under section 206 of the FPA to modify that rate in order to ensure it is just and reasonable.[544] As the PJM IMM,[545] Joint Consumer Advocates,[546] and Dr. Bremser,[547] note the Commission has previously changed compensation policies when it has determined that existing practices were resulting in unjust and unreasonable rates.[548]

F. Additional Comments

1. Comments

187. Ameren asserts that it was the right decision to eliminate compensation for reactive power

6–7 (''Additionally, claims that investors made decisions relying on the revenue stream associated with the capability to provide reactive power within the deadband fail to contend with the many instances in which the Commission accepted transmission providers' elimination of compensation for reactive power within the deadband. Sophisticated investors could not reasonably have relied on compensation for providing reactive power within the deadband in perpetuity, but rather should have considered the risk of elimination of this revenue stream when making investment decisions.'' (citations omitted)).

[533] *See* BPA Rehearing Order, 125 FERC ¶ 61,273, at P 15 & n.24 (''[N]either affiliated nor non-affiliated generators have an inherent right to any compensation for reactive power inside the deadband.'').

[534] *See* Joint Customers Initial Comments at 20 (''To the extent that generators voluntarily and unilaterally installed greater reactive capability than that required by their respective interconnection agreements, they did so at their own risk and for their own strategies, none of which mean that they should continue to be compensated for costs that they did not have to incur and which do not benefit transmission customers.'').

[535] *See, e.g.,* ACORE Initial Comments at 3–4; Calpine Initial Comments at 2; Clean Energy Associations Initial Comments at 4–5; EDPR Initial Comments at 1, 3–4; Elevate Initial Comments at 6; Generation Developers Initial Comments at 33; Indicated Reactive Power Suppliers Initial Comments at 14; Indicated Trade Associations Initial Comments at 16; Middle River Power Initial Comments at 6; NHA Initial Comments at 4–5.

[536] *See* Clean Energy Associations Initial Comments at 5.

[537] *Id.*

[538] *See supra* II.C.2.

[539] Indicated Trade Associations Initial Comments at 16.

[540] *See supra* II.B.2.

[541] *See supra* II.A.2, II.B.2, II.C.2.

[542] *Solar Energy Indus. Ass'n* v. *FERC,* 80 F.4th 956, 979 (9th Cir. 2023) (citing *Motor Vehicle Mfrs. Ass'n of U.S., Inc.* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. at 43).

[543] Middle River Power Initial Comments at 6.

[544] 16 U.S.C. 824e(a) (''Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.'').

[545] PJM IMM Reply Comments at 6 (''Such attacks on the rules and standards can be disregarded because they are collateral attacks on final rules and standards that are not within the scope of this proceeding. Reactive Service Providers arguments challenging longstanding Commission policy and multiple Commission orders are also beside the point.'').

[546] Joint Consumer Advocates Initial Comments at 8 (''[S]ection 206 of the FPA requires that the Commission act to eliminate unjust and unreasonable rates where and when it finds them. There is no statutory authorization to allow an unjust and unreasonable rate to continue.'')

[547] Joint Customers Reply Comments, Reply Affidavit of Dr. Albert W. Bremser at 4:1–3 (''My second conclusion is that permanent reliance on [Commission]-jurisdictional practices as never changing is not consistent with the typical experience of [Commission]-jurisdictional entities and ratepayers.''; *id.* at 10:2–6 (''In terms of reliance on Commission past practices or what the Commission has allowed, it is my experience that the Commission can and does change its practices and what it allows. This can impact the rates charged to ratepayers and the rates collected by companies.'').

[548] *See, e.g., Indep. Mkt. Monitor for PJM* v. *PJM Interconnection, L.L.C.,* 176 FERC ¶ 61,137 (2021); *order on reh'g,* 178 FERC ¶ 61,121 (2022).

capability in MISO, as evident by the numerous reactive power cases in which Ameren intervened from 2018–2022 that were set for hearing and settlement judge procedures, with resulting revenue requirements reduced substantially from what the filing generator proposed, and in some cases by over 50%.[549]

188. The NHA asserts that individual RTOs/ISOs should develop and/or improve upon reactive power capability compensation market rules to reflect locational requirements.[550]

189. Indicated Trade Associations request that the Commission clarify that the NOPR will not be applied in determining refunds in cases where the Commission has established settlement and hearing judge proceedings for reactive rates.[551]

190. Indicated Trade Associations argue that the Commission should not implement the NOPR proposal.[552] Indicated Trade Associations assert that the NOPR is not supported by the NOI record, which they argue was focused on *changes* and *improvements* to the methodology used to determine appropriate reactive power compensation, rather than the NOPR's proposal to *eliminate* reactive power compensation within the standard power factor range altogether.[553]

191. Glenvale avows that some generators provide reactive power within the power factor range but outside of the requirements of their interconnection agreements, such as solar generators that are not synchronized to the transmission system but still provide reactive power service.[554]

192. Clean Energy Associations also proposes their own reactive power compensation format in which the Commission would develop a new, objective, cost-based, technology-neutral rate for reactive power to encourage the proliferation of reactive power resources in a non-discriminatory way.[555]

193. Reactive Service Providers also argue that a ± 0.95 standard power factor range is arbitrary. As support, they claim that it is not NERC-mandated, that many generating facilities are not actually satisfying it, and that ''it is in essence a mandate to create headroom if and when it is needed by the Transmission Provider.'' [556] Reactive Service Providers argue that there is no difference operationally between operating within and outside the standard power factor range because that distinction does not reflect the operational realities of an integrated transmission system, where the transmission provider is ''balancing all resources instantaneously such that all load everywhere benefits.'' [557]

194. Clean Energy Associations asks that, should the Commission proceed with its proposal, that the Commission should clarify that interconnection agreements cannot adopt a standard power factor range other than 0.95 leading and lagging and specify that compensation must be provided for reactive power provided outside of the range.[558]

195. ACORE recommends that instead of removing all compensation within the standard power factor range, a cost-based, technology-neutral rate be established for reactive power, with a focus on reducing the administrative burdens of the AEP Methodology.[559]

196. Joint Customers highlight the burdens associated with the individualized review of reactive rate filings arguing that it leads to higher costs for customers without corresponding benefits and that the case-by-case approach using the AEP Methodology is resource-intensive and results in inconsistent outcomes.[560]

197. Liberty states that it believes the current methodology has resulted in ambiguity on cost formation and could lead to unjust rates for customers.[561] Liberty explains that it would generally support a cost recovery methodology change that results in reasonable rates for customers that are not duplicative in nature, in line with industry standards, and sufficiently compensates reactive power capability services.

198. Middle River Power argues that the AEP Methodology has consistently produced just and reasonable rates for Middle River Power-affiliated generation and others and that if administrative burden were a problem that must be remedied, the solution would be to reform the administrative process by which just and reasonable rates are determined.[562]

199. NEI suggests that the Commission should continue to support the AEP Methodology.[563] NEI notes that while there are implementation challenges to the AEP Methodology, as highlighted by NEI previously, such process-related concerns do not render it unjust and unreasonable.[564]

200. TAPS argues that the AEP Methodology that many generators use in their reactive power compensation filings, and which was derived many years ago for synchronous generators, is not well-suited for non-synchronous generators to which the methodology is now being applied.[565] For example, TAPS explains that TAPS members have found it very difficult to verify the inputs to the AEP Methodology for a specific generator based on publicly available data, because many generators seeking compensation do not submit a FERC Form No. 1.

2. Commission Determination

201. We appreciate the concerns raised by numerous commenters requesting that we undertake various initiatives, as set forth above. However, we find that the requested initiatives go beyond the scope of this rulemaking, which addresses only compensation for reactive power service within the standard power factor range. Accordingly, we will not address those concerns here.

III. Compliance Procedures

A. Revisions To Eliminate Compensation for Reactive Power Supply Within the Standard Power Factor Range

202. To effectuate the changes discussed herein, we are taking the following four actions.

1. Revise Schedule 2 of the Commission's Pro Forma OATT

203. We revise Schedule 2 of the Commission's *pro forma* OATT to include the following sentence at the end of Schedule 2: ''However, such rates shall not include any charges associated with the compensation to a generating facility for the supply of reactive power within the power factor range specified in its interconnection agreement.'' This revision prohibits separate compensation for the provision of reactive power within the standard power factor range specified in an interconnection agreement.

[549] Ameren Initial Comments at 5 (citing Docket Nos. ER21–1046, ER21–2329, ER21–2695, ER21–2892, ER22–526, ER22–616, ER22–615, ER22–1554, ER22–1610, ER22–1815).

[550] NHA Initial Comments at 6–7.

[551] Indicated Trade Associations Initial Comments at 32.

[552] *Id.* at 1, 7.

[553] *Id.* at 5–6.

[554] Glenvale Initial Comments at 8.

[555] Clean Energy Associations Initial Comments at 9–10.

[556] Reactive Service Providers Initial Comments at 24–29.

[557] *Id.* at 35–36.

[558] Clean Energy Associations Initial Comments at 2–3.

[559] ACORE Initial Comments at 4.

[560] Joint Customers Initial Comments at 7–11.

[561] Liberty Initial Comments at 1.

[562] Middle River Power Initial Comments at 5.

[563] NEI Initial Comments at 5.

[564] *Id.* at 11.

[565] TAPS Initial Comments at 4.

2. Revise Section 9.6.3 of the Pro Forma Large Generator Interconnection Agreement

204. We revise section 9.6.3 of the *pro forma* LGIA to remove the proviso: ''provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer.'' Accordingly, under our proposal here, section 9.6.3 of the *pro forma* LGIA would read as follows: ''Payment for Reactive Power. Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.'' Along with the other proposed revisions, this proposed revision prohibits a transmission provider from including in its transmission rates any charges associated with the supply of reactive power within the specified power factor range from a generating facility. Accordingly, transmission providers would be required to pay an interconnection customer for reactive power only when the transmission provider requests the interconnection customer to operate its facility outside the power factor range set forth in its interconnection agreement.

3. Revise Section 1.8.2 of the Pro Forma Small Generator Interconnection Agreement

205. We similarly are revising section 1.8.2 of the *pro forma* SGIA to remove the following sentence: ''In addition, if the Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.'' Accordingly, under our proposal here, section 1.8.2 of the *pro forma* SGIA would read as follows: ''The Transmission Provider is required to pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs from the Small Generating Facility when the Transmission Provider requests the Interconnection Customer to operate its Small Generating Facility outside the range specified in article 1.8.1.''

4. Compliance Procedures

206. To effectuate these changes, we require each transmission provider to submit a compliance filing as discussed below to make changes to their Schedule 2s or other OATT provisions relating to charges and payments for reactive power, as well as to their *pro forma* LGIAs and *pro forma* SGIAs in their OATTs. To the extent that any transmission provider believes that it already complies with the reforms adopted in this final determination, the transmission provider is required to demonstrate how it complies in the compliance filing required 60 days after the effective date of the final determination. In reviewing compliance filings proposed by non-RTO/ISO transmission providers, the Commission will apply the ''consistent with or superior to'' standard to deviations from the adopted *pro forma* Schedule 2 [566] and to deviations from the *pro forma* LGIA and *pro forma* SGIA.[567] In evaluating compliance filings made by RTOs/ISOs, the Commission will apply the ''consistent with or superior to'' standard to deviations from the adopted *pro forma* Schedule 2 and the ''independent entity variation standard'' to deviations from the *pro forma* LGIA and *pro forma* SGIA.[568]

B. Transition Period

207. In the NOPR, the Commission proposed to require each transmission provider to submit a compliance filing within 60 days of the effective date of the final determination. The Commission further proposed to allow 90 days from the date of the compliance filing for implementation of the proposed reforms to become effective.[569] The NOPR sought comment on whether a transition period beyond the 90-day implementation period proposed was necessary and for what duration any transition period should last.[570] Specifically, the NOPR asked if any factors, such as potential business or investment impacts, should be considered in determining whether any transition period is appropriate and what transition mechanisms other than delaying the implementation date of the final determination would minimize such disruptions.

208. The NOPR also sought comment on whether existing generating facilities that have previously received compensation for reactive power capability should be allowed to continue to receive compensation for a limited period, as an interim rate during a transition period, while prohibiting new generating facilities from receiving reactive power capability compensation.[571] The NOPR asks how it should determine eligibility for continued compensation.

209. In addition, for regions that have an established capacity market, the NOPR sought comment on whether transmission providers should be allowed to make the implementation of their compliance filing align with the region's capacity market timelines to allow costs associated with reactive power production, if any, to be incorporated into capacity market bids.[572] For regions without a capacity market, the NOPR sought comment on whether a different transition mechanism, if any, would be necessary and whether it would be unduly discriminatory or preferential to set different implementation dates for the final determination in different markets and regions.

1. Comments

210. Several commenters who support the NOPR assert that no transition beyond the 90-day transition period in the NOPR is necessary.[573] MISO Transmission Owners urge the Commission to neither provide a transition period nor compensate generators that previously received reactive power compensation for a limited period.[574] MISO Transmission Owners urge the Commission to adopt the NOPR's proposed rule to be effective immediately.[575] While Joint Customers oppose a transition period, citing Commission policy and precedent,[576] they state that only a brief transition period, if any, is necessary for the implementation of the NOPR reforms.[577]

211. PGE states that it does not believe the decision to implement these provisions in the 90-day implementation period will have a measurable impact on business or investment decisions.[578]

212. Joint Customers and MISO Transmission Owners suggest that

[566] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63.

[567] *See* Order No. 2003, 104 FERC ¶ 61,103 at PP 822–27; Order No. 2006, 111 FERC ¶ 61,220 at PP 546–50).

[568] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63; Order No. 2003, 104 FERC ¶ 61,103 at PP 822–27; Order No. 2006, 111 FERC ¶ 61,220 at PP 546–50).

[569] NOPR, 186 FERC ¶ 61,203 at P 54.

[570] *Id.* P 56.

[571] *Id.*

[572] *Id.*

[573] *See* PGE Initial Comments at 5; TAPS Initial Comments at 8; PGE Initial Comments at 5.

[574] MISO Transmission Owners Initial Comments at 17–19.

[575] *Id.* at 2.

[576] Joint Customers Reply Comments at 7–8 (citing *PNM,* 178 FERC ¶ 61,088 at P 32; *MISO,* 182 FERC ¶ 61,033 at P 67; MISO Rehearing Order, 184 FERC ¶ 61,022 at PP 32–33.)

[577] Joint Customers Initial Comments at 18–21.

[578] PGE Initial Comments at 5.

generators should have made business or investment decisions in anticipation of the potential elimination of reactive power within the standard power factor range.[579] Joint Customers explain that the move towards these reforms has been ongoing for years, providing ample time for market participants to adjust their investment strategies.[580] Similarly, MISO Transmission Owners assert that generators have been on notice of the prospect of the elimination of reactive power since Order No. 2003 and reminded of it routinely since then.[581]

213. MISO Transmission Owners and TAPS both oppose a transition period so that reduced rate relief can be provided to customers.[582] MISO Transmission Owners emphasize that the Commission found that by eliminating compensation for reactive power within the standard power factor range MISO would ''reduce charges to MISO's transmission customers.'' [583] MISO Transmission Owners further state that the Commission should not compensate generators that previously received reactive power compensation for a limited period for such reasons.[584] MISO Transmission Owners add that, under the current compensation scheme, generating facilities are able to ''gold-plate their reactive capabilities to the detriment of ratepayers,'' so the Commission ''should refrain from imposing any transition period or vintaging carve-outs that allow capability-based compensation to continue.'' [585] TAPS claims that customers, including TAPS members, have been harmed by excessive reactive power compensation thus far and accompanying inefficient, administratively burdensome, case-by-case determinations.[586] Therefore, TAPS argues against a transition period because generators should no longer benefit from currently unjust and unreasonable rates.[587] Likewise, Joint Customers noted the Commission has previously rejected the continuation of compensation beyond the tariff effective date.[588]

214. Calpine and Indicated Trade Associations oppose the NOPR proposal and request that if the Commission were to move forward, the Commission exempt existing resources, applying the proposed reforms only to new resources. Calpine reasons that the Commission exempted existing resources from new requirements in Order Nos. 827 and 842 and that exemptions would support market stability and investments needed for reliability.[589] Indicated Trade Associations further assert that in addition to existing resources, the exemption should also be allowed for resources in advanced stages of development.[590] Indicated Reactive Power Suppliers state that Commission-approved cost-based tariffs should last the remaining life, transfer of ownership, or expiration of PPAs for existing resources.[591] Middle River Power requests that the Commission consider implementing a legacy rate provision for generators that have existing reactive rate tariffs to mitigate adverse impacts on its current investments and contends that the Commission has a history of adopting similar measures under similar circumstances.[592] Reactive Service Providers state that the Commission should consider grandfathering the agreements of existing or near-completion generating facilities.[593] Generation Developers argue that the Commission should not eliminate reactive power compensation for resources receiving compensation pursuant to a rate schedule or tariff in effect prior to the effective date of any final determination in this proceeding.[594] EDPR also proposes that facilities which have already concluded long-term PPAs but do not yet have an established rate be allowed to prove that the long-term PPA for a facility seeking reactive power compensation was executed prior to the issuance of the NOPR.[595]

215. In absence of an exemption for existing resources, or grandfathering of existing rates and generator agreements, commenters who oppose the proposal advocate for a transition period to comply with the final determination. Eagle Creek [596] recommends a transition period of at least three to five years, Reactive Service Providers [597] a period of five years, and Indicated Reactive Power Suppliers [598] a period of seven to ten years respectively. Other commenters who ask for a transition period include AEP, requesting at least 120 days,[599] and ACORE, requesting a five to ten-year transition period.[600] Calpine [601] and AEP [602] both expressed concerns of affected generators' ability to recover their costs as justification for a transition period and cite times that the Commission has approved of a transition period in the past.

216. EDPR proposes a 10-year transition period for existing rates and PPAs. EDPR explains that it will under collect its revenues under PPAs that include an offset for reactive power compensation.[603] Therefore, EDPR proposes that facilities with an established reactive rate schedule should be allowed to keep that established rate on file during a 10-year transition period. Similarly, Reactive Service Providers argue that the

[579] Joint Customers Reply Comments at 9–10; MISO Transmission Owners Initial Comments at 18–19 (noting that generating facilities have been on notice of the prospect of the elimination of reactive power compensation since Order No. 2003 and reminded of it routinely since then).

[580] Joint Customers Initial Comments at 21.

[581] MISO Transmission Owners Initial Comments at 18–19.

[582] *Id.;* TAPS Initial Comments at 8.

[583] MISO Transmission Owners Initial Comments at 18 (citing *MISO,* 182 FERC ¶ 61,033 at P 67; MISO Rehearing Order, 184 FERC ¶ 61,022 at P 55 n.186 (rejecting an argument that the Commission should have declined to waive the 60-day notice requirement)).

[584] *Id.*at 17–18.

[585] *Id.* at 19.

[586] TAPS Initial Comments at 8.

[587] *Id.*

[588] Joint Customers Reply Comments at 8.

[589] Calpine Initial Comments at 2–3.

[590] Indicated Trade Associations Initial Comments at 29–30.

[591] Indicated Reactive Power Suppliers Initial Comments at 2; Glenvale Initial Comments at 6–7.

[592] Middle River Power Initial Comments at 6–7 (citing Indicated Energy Trade Associations Initial Comments at 24; *PJM Interconnection, L.L.C.,* 110 FERC ¶ 61,053, at P 61, *order on reh'g,* 112 FERC ¶ 61,031 (2005) (finding it appropriate to grandfather units for which construction commenced in reliance on a prior rule), *order on reh'g,* 114 FERC ¶ 61,302 (2006); *Tenn. Gas Pipeline Co.,* 62 FERC ¶ 61,062 (1993) (explaining that, the Commission had decided to ''grandfather'' prior storage arrangements ''in light of the fact that . . . historical customers have already made their conversion elections in reliance on access to this storage'')).

[593] Reactive Service Providers Initial Comments at 67–76.

[594] Generation Developers Initial Comments at 33–34.

[595] EDPR Initial Comments at 5.

[596] Eagle Creek Initial Comments at 5.

[597] Reactive Service Providers Initial Comments at 75–76.

[598] Indicated Reactive Power Suppliers Initial Comments at 2–3.

[599] AEP Initial Comments at 7–8.

[600] ACORE Initial Comments at 4.

[601] Calpine Initial Comments at 4.

[602] AEP Initial Comments at 7–8 (citing *PJM Interconnection, L.L.C.,* 117 FERC ¶ 61,331, at P 73 (2006) (''The adoption of a transition period must strike a reasonable balance between the need to implement RPM to generate relevant prices, and the provision of some period to enable parties to understand and make adjustments to the new market.''), *order on reh'g,* 119 FERC ¶ 61,318 (2007); *Midcontinent Independent System Operator,* 180 FERC ¶ 61,141, at PP 248–249 (2022) (''The transition period appropriately balances the need to implement the SAC methodology with the recognition that resource owners and LSEs may need to adjust their operations—including outage timing—and their contractual arrangements to maximize their potential SAC values.''); *PJM Interconnection, L.L.C.,* 155 FERC ¶ 61,157, at PP 150–151 (2016) (accepting a phase-in of PJM's capacity performance requirements as just and reasonable because the benefits of providing relevant entities adequate time to adjust Fixed Resource Requirement plans based on the new rules were weighed in conjunction with the interest in applying the requirements in an even-handed manner)).

[603] EDPR Initial Comments at 3–4.

Commission should allow PPAs to be reevaluated.[604]

217. Glenvale requests that if cost recovery is not possible for certain projects, the run-off for legacy projects be extended to 10 years. Glenvale explains that eligible projects would be those which are unable to access revenue in the substitute market designated by the Commission, and reasonably rely on the current tariff.[605] Glenvale claims that an extension would motivate these generators to build technologies that both support the transmission system and are a low cost to consumers.[606]

218. Several commenters argue that a transition period is necessary for RTOs/ISOs to implement the NOPR. The NHA explains that a transition period would allow RTOs/ISOs to adjust their tariffs and market designs accordingly.[607] Generation Developers assert that the Commission should direct RTOs/ISOs to propose a transition period that accounts for discrepancies between implementation of any market rule changes and when resources will be able to benefit from these changes.[608] Similarly, NAGF states that a transition period specific to each market based on their design and rules allows generators to evaluate lost revenue, cost recovery options, and the possibility of retiring, all while also providing time for planners to contemplate other generation options.[609] Clean Energy Associations ask that the Commission, should it proceed with its proposal, implement a transition period that takes into consideration regional and market differences.[610] Additionally, Indicated Trade Associations state that PJM, ISO–NE, and NYISO each currently subtract expected energy and ancillary services revenues, including reactive power revenues, from the Net CONE value used to develop demand curves for capacity market auctions.[611] Relatedly, Reactive Service Providers explain that PJM, ISO–NE, and NYISO have completed capacity auctions and assigned capacity obligations for years from now and that the Commission cannot reopen those auctions to make up for lost revenue.[612]

219. NYISO notes that shifting to event-specific reactive power compensation only when a resource is instructed to operate outside its standard power factor range would require complex market design rules—including developing market rules, incorporating reactive power into the NYISO's co-optimization of real power (*i.e.,* energy to meet load), operating reserves, and regulation service which would require extensive software changes that would take years to develop and implement based on current obligations and initiatives.[613] PJM requests that as part of their compliance filings implementing the new rate paradigm, RTOs/ISOs be permitted to propose rules around testing, monitoring, and penalties. PJM argues that this is to ensure that generators provide the reactive power capability that they are required to provide under their Commission-jurisdictional interconnection agreements when called upon, as correctly identified in the NOPR.[614]

220. NAGF [615] and PJM [616] both propose allowing transmission providers the flexibility to propose effective dates on compliance that will align with regional capacity market timelines. PJM further notes that compliance dates should align with billing and settlements timelines as well.[617] In a similar manner, Calpine suggests that in PJM, any new reactive service compensation policy should take effect no sooner than the first delivery year of the first PJM capacity auction administered under comprehensively updated new rules.[618] NAGF explains that alignment with capacity market timelines would allow costs associated with reactive power production to be incorporated into capacity market bids if the capacity market reforms permit recovery and to allow generators to better evaluate their cost recovery process and probability.[619] Likewise, PJM argues that such timeline alignments will permit generators currently receiving reactive power revenues to continue to do so until the related offsets are removed from the capacity market auction parameters.[620]

221. The PJM IMM recommends a transition period as short as possible, emphasizing that a faster transition will speed up benefits to customers and reduced revenues to generation owners.[621] The PJM IMM recommends reducing current approved rates under Schedule 2 that exceed the E&AS Offset to the level of the E&AS Offset that was applicable to the auctions for each RPM Delivery Year. The PJM IMM also suggests that pending reactive filings submitted prior to the NOPR proposal should not be approved exceeding the same aforementioned level of the E&AS Offset. The PJM IMM proposes that the E&AS Offset be reduced to zero dollars and removed from the rules immediately. As for Schedule 2 to the PJM OATT, the PJM IMM believes it should be revised to immediately remove the ability to file for new reactive capability rates and then eliminated in its entirety effective at the start of the first Delivery Year where the E&AS Offset included in the capacity market base residual auctions for such Delivery Year is zero dollars.[622]

222. The PJM IMM makes similar recommendations if PJM eliminates the E&AS Offset as a component of the market seller offer caps in the capacity market prior to the end of the proposed transition period: (1) that the E&AS Offset be reduced to zero dollars and removed from the rules immediately; (2) that Schedule 2 be eliminated from the OATT.[623]

[604] Indicated Reactive Power Suppliers Initial Comments at 2.

[605] Glenvale Initial Comments at 5.

[606] *Id.*

[607] NHA Initial Comments at 9–10.

[608] Generation Developers Initial Comments at 35.

[609] NAGF Initial Comments at 2.

[610] Clean Energy Associations Initial Comments at 2–3, 9–10.

[611] Indicated Trade Associations Initial Comments at 14–15.

[612] Reactive Service Providers Initial Comments at 57.

[613] NYISO Initial Comments at 9–10.

[614] PJM Initial Comments at 6.

[615] NAGF Initial Comments at 3.

[616] PJM Initial Comments at 4–6.

[617] *Id.* (requesting that ''transmission providers in regions with centralized capacity markets such as PJM be permitted flexibility to propose effective dates on compliance that will align with applicable capacity market and billing and settlements timelines'' to ''allow costs associated with reactive power production to be incorporated into capacity market bids, and also ensure alignment with applicable billing and settlements dates.'')

[618] Calpine Initial Comments at 4 & n.7 (noting that the Commission has recently approved a transition period associated with PJM's implementation of generator interconnection reforms (citing *PJM Interconnection, L.L.C.,* 181 FERC ¶ 61,162, at PP 8, 60 (2022))); PJM Initial Comments at 4–6 (explaining that a transition period could be ''to permit generators who are currently receiving reactive power revenues under Tariff, Schedule 2 to continue to do so until the Delivery Year of the first Base Residual Auction (''BRA'') where the removal of these reactive revenues from the Energy and Ancillary Services (''E&AS'') offset can be reflected in the auction parameters. This concept would be based on the idea that these generators submitted their bids in prior auctions without the knowledge that Tariff, Schedule 2 revenues would no longer exist, which may have impacted the bids they ultimately submitted.'').

[619] NAGF Initial Comments at 3.

[620] PJM Initial Comments at 4–6.

[621] PJM IMM Initial Comments at 14.

[622] PJM IMM Initial Comments at 15 (''Given the schedule for upcoming capacity market auctions in PJM, the timing for the transition will be a direct result of the effective date of a final determination. Given this schedule, there will be a significant lag before the Offset can be removed for an identified delivery year. For example, if the effective date of the final determination were March 1, 2025, the Offset could be eliminated and payments under Schedule 2 eliminated effective June 1, 2027, the start of the delivery year for the base residual auction scheduled to be run in June 2025.'').

[623] *Id.*

223. PJM states that it would like flexibility to implement an interim rate during the transition period.[624] PJM notes that it contemplates a number of different scenarios, including disallowing any units without existing reactive power rate schedules to collect reactive power revenue or an interim flat rate per MVAr of capability.

2. Commission Determination

224. For all transmission providers in an RTO/ISO or non-RTO/ISO region, we direct a compliance filing within 60 days of the effective date of the final determination, including a proposed effective date within 90 days from the date of the compliance filing, as proposed by the NOPR.[625] We find that the NOPR's proposal to only allow 90 days from the date of the compliance filing for implementation of the proposed reforms to become effective is appropriate. However, in recognition of the concerns raised by commenters with respect to the interplay between existing reactive power revenue compensation mechanisms and energy and capacity market rules in ISO–NE, NYISO, and PJM, we will permit those RTOs/ISOs to each request a later effective date,[626] for the Commission's consideration, in order to allow them to develop and propose any changes to their market rules that may be necessary in order to accommodate this final determination's elimination of compensation for the provision of reactive power within the standard power factor range. With any such request, the RTO/ISO must affirmatively demonstrate why such a requested effective date is necessary, given, for example, its existing market rules, and what market rule changes the RTO/ISO believes may be needed to accommodate this final determination. We find that this approach reasonably balances concerns about expediently addressing unjust and unreasonable transmission rates for reactive power with concerns raised by commenters about existing cost recovery rules in the organized markets and will ensure that the ability of generating facilities to seek any appropriate cost recovery will not be impeded.

225. This flexibility would accommodate the potential section 205 filings that some RTOs/ISOs mentioned may accompany any final determination compliance filings, such as PJM's adjustments to market rules to remove the offset in auction parameters as well as ''propose rules around testing, monitoring, and penalties, to ensure that generators actually provide the reactive power capability that they are required to provide under their Commission-jurisdictional interconnection agreements when called upon.'' [627] The Commission welcomes these and similar section 205 filings to adapt markets to accommodate the final determination as well as to clarify each RTO's/ISO's compensation scheme for reactive power service *outside* of the standard power factor range, if necessary.[628]

226. We decline to adopt a transition period in non-RTO/ISO regions beyond the 90-day implementation period proposed in the NOPR. Some generating facilities in non-RTO/ISO regions contend that the compliance period should extend until the termination of existing PPAs or request that we require all PPAs to be reevaluated to cover the foregone revenue. As explained above, the record lacks any concrete evidence showing whether, and to what extent, generating facilities factored reactive power revenues into their PPAs. And even if a generating facility were able to demonstrate that eliminating compensation under our rule might impact some generating facility's profitability, which they have not, we do not believe that potential disrupted expectations weigh in favor of a different outcome in this situation. As a general matter, the risk of regulatory change is inherent in any long-term PPA.[629] Moreover, as explained above, we are skeptical of any purported reliance interests given that generating facilities have not had an inherent right to separate compensation for reactive power capability within the standard power factor range since Order Nos. 2003 and 2003–A (*i.e.,* because such compensation is required only to ensure ''comparability''). Finally, developers and generating facilities have been on notice since at least 2003 that the Commission regards reactive power compensation within the standard power factor range as non-compensable (other than where the comparability standard applies)—a conclusion that was patent in those orders, and reinforced repeatedly in subsequent Commission orders accepting transmission owner filings under section 205 that eliminated reactive power compensation within the standard power factor range.[630]

227. We disagree with commenters who request that generating facilities with reactive rates on file prior to the effective date of the final determination be provided legacy treatment.[631] Given that the Commission finds above that allowing transmission providers to compensate generating facilities, affiliated and unaffiliated, for providing reactive power within the standard power factor range has resulted in unjust and unreasonable transmission rates, it would raise undue discrimination concerns to continue to provide payment through Schedule 2 for reactive power supply within the standard power factor range to generating facilities with rates already on file when those rates have been found to be unjust and unreasonable.[632] Although commenters point to other situations where the Commission has provided legacy treatment for existing rates, in those situations the existing rate had not been found to be unjust and unreasonable.[633]

[624] PJM Initial Comments at 4–6.

[625] NOPR, 186 FERC ¶ 61,203 at P 54.

[626] Any RTO/ISO that proposes an effective date longer than 90 days from the date of the compliance filing must include an indeterminate 12/31/9998 effective date in eTariff with their compliance filing and must provide the Commission with an estimate of when the changes will become effective and must make a filing with the Commission if they are unable to meet their estimated effective date. Further, the RTO/ISO must also notify the Commission at least 7 days prior to the effective date of their proposed changes so that Commission staff may make the required changes in eTariff.

[627] PJM Initial Comments at 7.

[628] Generation Developers Initial Comments at 34–35 (''Additionally, as part of any compliance filings submitted in response to a final rule in this proceeding, the Commission should require RTOs and [ISOs] to make revisions to their tariffs eliminating existing barriers to the recovery of reactive power costs through sales of other products. This would include, for instance, requiring RTOs/ISOs with organized capacity markets to revise their tariffs to permit resources to accurately reflect their investment in reactive power in their capacity offers. The Commission also should require RTOs/ISOs to revise their market power mitigation frameworks to permit generation resources to reflect reactive power costs in their cost-based energy curves.'').

[629] *See, e.g.,* PJM IMM Reply Comments at 5 (''When buyers and sellers enter into power purchase agreements, the contracting parties define and assign regulatory risk. Customers are not responsible to manage or pay for suppliers' risks.'').

[630] *See, e.g., Nev Power Co.,* 179 FERC ¶ 61,103; *PNM,* 178 FERC ¶ 61,088 at PP 26–36; *SPP,* 119 FERC ¶ 61,199 at PP 20, 30–33.

[631] Calpine Initial Comments at 2–3; EDPR Initial Comments at 5; Generation Developers Initial Comments at 33–34; Glenvale Initial Comments at 6–7; Indicated Trade Associations Initial Comments at 29–30; Middle River Power Initial Comments at 6–7; Reactive Service Providers Initial Comments at 67–76.

[632] *See Dynegy Midwest Generation, Inc.* v. *FERC,* 633 F.3d 1122.

[633] *See, e.g.,* Reactive Service Providers Initial Comments at 67–76 (citing Order No. 2003, 104 FERC ¶ 61,103; Order No. 661, 111 FERC ¶ 61,353; Order No. 827, 155 FERC ¶ 61,277; Order No. 2023, 184 FERC ¶ 61,054; *Cal. Indep. Sys. Op.,* 124 FERC ¶ 61,031, at PP 12, 13, 20 (2008); *Midcontinent Independent System Operator, Inc.,* 158 FERC ¶ 61,003, at PP 44, 45, 59 (2017); *Sw. Power Pool, Inc.,* 167 FERC ¶ 61,275, at P 19 (2019)) (noting that ''[i]t is common for the Commission to allow grandfathering of existing agreements and rate

Continued

IV. Information Collection Statement

228. The Office of Management and Budget's (OMB) regulations require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

229. This final determination will amend the Commission's regulations pursuant to section 206 of the FPA, to eliminate compensation to generating facilities for the provision of reactive power within the standard power factor range set forth in each generating facility's individual interconnection agreement. To accomplish this, the Commission proposes to require each transmission provider to amend the *pro forma* LGIA, the *pro forma* SGIA, and Schedule 2 in its OATT to implement the reforms proposed in this final determination. Such filings should be made under Part 35 of the Commission's regulations. Subsequently, the final determination would revise the following currently approved information collections: *FERC 516H (OMB control. No. 1902–0303): Pro Forma Open Access Transmission Tariff, FERC 516 (OMB control No. 1902–0096): Electric Tariff Filings, and FERC 516A (OMB control No. 1902–0203): Standardization of Small Generator Interconnection Agreements and Procedures [SGIA and SGIP].*

230. The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act. Comments are accepted on whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

231. Please send comments concerning the collection of information and the associated burden estimates to: Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW, Washington, DC 20503, Attention: Desk Officer for the Federal Energy Regulatory Commission. Due to security concerns, comments should be sent electronically to the following email address: *oira_submission@omb.eop.gov.* Comments submitted to OMB should refer to OMB Control No. 1902–0303, 1902–0096, or 1902–0203.

232. Please submit a copy of your comments on the information collection to the Commission via the eFiling link on the Commission's website at *https://www.ferc.gov.* If you are not able to file comments electronically, please send a copy of your comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426. Comments on the information collection that are sent to FERC should refer to Docket No. RM22–2–000.

233. *Title:* FERC 516H: *Pro Forma Open Access Transmission Tariff,* FERC 516: *Electric Tariff Filings,* and FERC 516A: *Standardization of Small Generator Interconnection Agreements and Procedures [SGIA and SGIP].*

234. *Action:* Revision of the information collection in accordance with Docket No. RM22–2–000.

235. *OMB Control No.:* 1902–0303, 1902–0096, 1902–0203

236. *Respondents for this Rulemaking:* Public utility transmission providers, including RTOs/ISOs.

237. *Frequency of Information Collection:* One-time compliance filing.

238. *Necessity of Information:* The final determination will require that transmission providers submit to the Commission a one-time compliance filing proposing tariff revisions.

239. *Internal Review:* The Commission has reviewed the changes and has determined that such changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry in support of the Commission's ensuring just and reasonable rates. The Commission has specific, objective support for the burden estimates associated with the information collection requirements.

240. *Public Reporting Burden:* The Commission's estimate consists of our estimated effort related to updating the proposed revisions to the *pro forma* OATT, and subsequent revisions to the *pro forma* LGIA and *pro forma* SGIA, and the effort related to submitting a one-time compliance filing.

241. The Commission estimates burden [634] and cost [635] as follows:

A. Collection	B. Number of respondents	C. Annual number of responses per respondent	D. Total number of responses (Column B × Column C)	E. Average burden Hrs. & cost per response	F. Total annual Hr. burdens & total annual cost (Column D × Column E)	G. Cost per respondent (Column F ÷ Column B)
FERC 516H: Pro Forma Open Access Transmission Tariff						
Transmission Providers (Schedule 2 one-time compliance filing).	40	1	40	4 hrs.; $400	160 hrs.; $16,000	$400
FERC 516: Electric Tariff Filings						
Transmission Providers (pro forma LGIA one-time compliance filing).	43	1	43	4 hrs.; $400	172 hrs.; $17,200	400

schedules when making sweeping industry changes,'' that the Commission ''has long implemented new Tariff rules in view of the economic impact to late-stage projects,'' and ''woven throughout each transition period ordered by the [Commission] is a need to carefully balance interests and preserve the expectations of the parties'')); Indicated Trade Associations Initial Comments at 29–30 (citing *PJM Interconnection, L.L.C.,* 110 FERC ¶ 61,053 at P 61; *Tenn. Gas Pipeline Co.,* 62 FERC at 61,306) (noting that when the Commission eliminated an exemption from market power mitigation, the Commission provided legacy treatment for units that commenced construction in reliance of the rule)).

[634] ''Burden'' is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the estimated burden, refer to 5 CFR 1320.3.

[635] Commission staff estimates that the respondents' skill set (and wages and benefits) for Docket No. RM22–2–000 are comparable to those of Commission employees. Based on the Commission's Fiscal Year 2024 average cost of $207,786/year (for wages plus benefits, for one full-time employee), $100/hour is used.

A. Collection	B. Number of respondents	C. Annual number of responses per respondent	D. Total number of responses (Column B × Column C)	E. Average burden Hrs. & cost per response	F. Total annual Hr. burdens & total annual cost (Column D × Column E)	G. Cost per respondent (Column F ÷ Column B)
FERC 516A: Standardization of Small Generator Interconnection Agreements and Procedures						
Transmission Providers (pro forma SGIA one-time compliance filing).	43	1	43	4 hrs.; $400	172 hrs.; $17,200	400
Totals					504 hrs.; $50,400	

V. Environmental Analysis

242. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[636] We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this final determination under § 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classification, and services.[637]

VI. Regulatory Flexibility Act

243. The Regulatory Flexibility Act of 1980 (RFA)[638] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The Small Business Administration (SBA) sets the threshold for what constitutes a small business. Under SBA's size standards,[639] transmission providers under the category of Electric Bulk Power Transmission and Control (NAICS code 221121), have a size threshold of 950 employees (including the entity and its associates).[640]

244. We estimate that there are 43 transmission providers that are affected by the reforms proposed in this final determination, based on the NERC Active Compliance Registry Matrix as of January 11, 2024.[641] The Commission used a combination of sources to determine the number of employees within each entity using open-source data and information provided by Dunn & Bradstreet. We estimate that 6 of the 43 transmission providers, approximately 14% (rounded), are small entities.

245. We estimate that one-time costs (in Year 1) associated with the reforms proposed in this final determination for one transmission provider (as shown in the table above) would be $1,200 to submit the compliance filing. Following Year 1, the Commission estimates no ongoing costs associated with this final determination.

246. According to SBA guidance, the determination of significance of impact ''should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors.''[642] We do not consider the estimated cost of $1,200 to be a significant economic impact for any of the entities that would be impacted by this final determination. As a result, we certify that the reforms proposed in this final determination would not have a significant economic impact on a substantial number of small entities.

VII. Document Availability

247. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://www.ferc.gov*).

248. From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

249. User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202)502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov*.

VIII. Effective Date and Congressional Notification

250. These regulations are effective January 27, 2025. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

By the Commission. Commissioner Chang is not participating.

Issued: October 17, 2024

Debbie-Anne A. Reese,

Secretary.

Note: The following appendices will not appear in the Code of Federal Regulations.

Appendix A: Abbreviated Names of Commenters

[636] *Reguls. Implementing the Nat'l Env't Pol'y Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[637] 18 CFR 380.4(a)(15).

[638] 5 U.S.C. 601–612.

[639] 13 CFR 121.201.

[640] The RFA definition of ''small entity'' refers to the definition provided in the Small Business Act, which defines a ''small business concern'' as a business that is independently owned and operated and that is not dominant in its field of operation. The Small Business Administrations' regulations at 13 CFR 121.201 define the threshold for a small Electric Bulk Power Transmission and Control entity (NAICS code 221121) to be 500 employees. *See* 5 U.S.C. 601(3) (citing to Section 3 of the Small Business Act, 15 U.S.C. 632).

[641] NERC, *NCR Active Entities List,* (Jan. 12, 2024), NERC_Compliance_Registry_Matrix_Excel.xlsx.

[642] U.S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act,* 18 (Aug. 2017), *https://cdn.advocacy.sba.gov/wp-content/uploads/2019/06/21110349/How-to-Comply-with-the-RFA.pdf.*

Abbreviation	Commenter(s)
ACORE	American Council on Renewable Energy.
AEP	American Electric Power Service Corporation.
Ameren	Ameren Service Company.
Calpine	Calpine Corporation.
Clean Energy Associations	Solar Energy Industries Association (SEIA) and American Clean Power Association.
C T Gaunt	Dr. Charles Trevor Gaunt.
Eagle Creek	Eagle Creek Reactive Generators.
EDPR	EDP Renewables North America LLC.
Elevate	Elevate Renewables F7, LLC.
Generation Developers	Vistra Corp. and Dynegy Marketing and Trade, LLC.
Glenvale	Glenvale LLC.
IPPNY	Independent Power Producers of New York, Inc.
Indicated Reactive Power Suppliers	KMC Thermo, LLC, Bitter Ridge Wind Farm, LLC, Guernsey Power Station LLC, Moxie Freedom LLC, Safe Harbor Water Power Corporation, BIF III Holtwood LLC, Brookfield Power Piney & Deep Creek LLC, Erie Boulevard Hydropower, L.P., Carr Street Generating Station, L.P., Bear Swamp Power Company LLC, Brookfield White Pine Hydro LLC, Brookfield Renewable Trading and Marketing LP, and Reworld Waste, LLC f/k/a Covanta.
Indicated Trade Associations	Electric Power Supply Association, The PJM Power Providers Group the New England Power Generators Association, Inc., Independent Power Producers of New York, Inc., the Coalition of Midwest Power Producers.
ISO–NE	ISO New England Inc.
Joint Consumer Advocates	Illinois Attorney General, Illinois Citizens Utility Board, Maryland Office of People's Counsel, the New Jersey Division of Rate Counsel, the North Carolina Utilities Commission Public Staff, the Office of the People's Counsel for the District of Columbia, and the West Virginia Consumer Advocate Division of the Public Service Commission.
Joint Customers	Old Dominion Electric Cooperative, Northern Virginia Electric Cooperative, Inc., and Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company d/b/a Dominion Energy Virginia.
Liberty	Liberty Utilities.
Middle River Power	Middle River Power LLC.
MISO	Midcontinent Independent System Operator, Inc.
MISO Transmission Owners	Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois; Arkansas Electric Cooperative Corporation; City Water, Light & Power; Cooperative Energy; Dairyland Power Cooperative; East Texas Electric Cooperative; Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC; Entergy Texas, Inc.; Great River Energy; Indianapolis Power & Light Company; Lafayette Utilities System; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Services; Montana-Dakota Utilities Co.; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power, Inc.; Southern Indiana Gas & Electric Company (d/b/a CenterPoint Energy Indiana South); and Southern Minnesota Municipal Power Agency.
NAGF	North American Generator Forum.
NEPGA	New England Power Generators Association, Inc.
NEPOOL	New England Power Pool.
NESCOE	New England States Committee on Electricity.
New England Consumer Advocates	Office of Massachusetts Attorney General Andrea Joy Campbell, the Connecticut Office of Consumer Counsel, the Maine Office of Public Advocate, the New Hampshire Office of Consumer Advocate, and the Rhode Island Division of Public Utilities and Carriers
NEI	Nuclear Energy Institute.
NYISO	New York Independent System Operator, Inc.
NHA	National Hydropower Association.
Ohio FEA	Ohio Office of the Federal Energy Advocate of the Public Utilities Commission of Ohio.
Onward Energy	Onward Energy Holdings, LLC.
PGE	Portland General Electric Company.
PJM	PJM Interconnection, L.L.C.
PJM IMM	Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM.
PSEG	Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC, and each wholly-owned, direct or indirect subsidiaries of Public Service Enterprise Group Incorporated.
Reactive Service Providers	CIP, D. E. Shaw Renewable Investments, L.L.C., Invenergy Renewables LLC, Leeward Renewable Energy, LLC, Lightsource Renewable Energy Operations, LLC, NextEra Energy Resources, LLC,1 Ørsted Wind Power North America, LLC, and RWE Clean Energy, LLC.
TAPS	Transmission Access Policy Study Group.

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