REPORT OF THE ELECTRICITY COMMITTEE

This report covers significant legal developments pertaining to the electric power system from September 2023 through June 2024.*

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I. FERC ORDER NO. 1920 – BUILDING FOR THE FUTURE THROUGH ELECTRIC REGIONAL TRANSMISSION PLANNING AND COST ALLOCATION

A. Introduction

Order No. 1920 builds on the electric transmission planning and cost allocation requirements set out in Order Nos. 888, 890 and 1000.[1] The Federal Energy Regulatory Commission (FERC) determined that the current planning requirements are deficient because they do not require transmission providers to perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs.[2] Long-Term Transmission Needs are defined as "transmission needs identified through Long-Term Regional Transmission Planning by, among other things . . . running scenarios and considering the enumerated categories of factors."[3] Currently, planning requirements do not adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs.[4] Moreover, current planning requirements do not consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs.[5]

By relying on shorter-term transmission planning and studies, current planning processes can fail to identify Long Term Needs and thereby undervalue or ignore benefits of transmission investments to meet those needs.[6] To remedy these deficiencies, the Final Rule requires Transmission Providers to undertake several requirements, discussed below.

1. Order No. 1920, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 at P 1 (2024) [hereinafter Order No. 1920].
2. *Id.*
3. *Id.* at P 39.
4. *Id*.
5. Order No. 1920, *supra* note 1, at P 39.
6. *Id.* at PP 117, 122.

B. Long-Term Regional Transmission Planning Requirements

1. Requirement to Participate in Long-Term Regional Transmission Planning (LRTP)

LTRTP means regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs.[7]

2. Development of Long-Term Scenarios

The Final Rule requires transmission planners to (1) develop and use Long-Term Scenarios as part of LTRTP, and (2) use such scenarios to identify and evaluate Long-Term Regional Transmission Facilities to meet Long-Term Transmission Needs.[8] FERC describes Long-Term Scenarios as "scenarios that incorporate various assumptions using best available data inputs about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon to identify Long-Term Transmission Needs and enable the identification and evaluation of transmission facilities to meet such transmission needs."[9]

The Final Rule requires transmission providers to make transparent the methodology, criteria, assumptions, and data used to develop each Long-Term Scenario.[10] It also requires transmission providers to offer meaningful opportunity for stakeholder input, including from state and local regulators, as well as non-jurisdictional entities, into the factors used to develop Long-Term Scenarios.[11] However, transmission providers have discretion to give different weight to different sources (ex: give more weight to a state's input).[12]

3. Long-Term Scenarios Requirements

The Final Rule requires Long-Term Scenarios as part of LTRTP to use no less than a twenty-year transmission planning horizon.[13] Transmission planners must plan for the entire duration of the twenty-year horizon.[14]

The Final Rule requires transmission providers to reassess and revise the Long-Term Scenarios used in LTRTP at least once every five years.[15] To do so, they must reassess whether the data inputs and factors need to be updated and

7. *Id.* at PP 2, 140, 224.
8. *Id.* at P 298.
9. Order No. 1920, *supra* note 1, at P 302.
10. *Id.* at P 305.
11. *Id*.
12. *Id.* at P 306.
13. Order No. 1920, *supra* note 1, at P 344.
14. *Id.* at P 347.
15. *Id.* at P 377.

revise the scenarios, as needed, to reflect the updates.[16] Transmission providers may develop entirely new Long-Term Scenarios or update previously developed scenarios.[17] Transmission providers must conclude an LTRTP planning cycle before developing Long-Term Scenarios for the next LTRTP planning cycle so that there is not overlap and confusion between planning cycles.[18]

The Final Rule requires the following minimum set of seven factors to be incorporated into the development of Long-Term Scenarios: (1) Federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand;[19] (2) Federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification;[20] (3) State-approved integrated resource plans and expected supply obligations for load-serving entities;[21] (4) Trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies;[22] (5) Resource retirements;[23] (6) Generator interconnection requests and withdrawals; and (7) Utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.[24]

Transmission providers may rely on open and transparent stakeholder processes to identify the factors in the first three categories, and they are not required to independently identify such factors.[25] Transmission providers have discretion to account for each factor in the last four categories by discounting or providing relatively different weight to the factor (ex: assuming only a fraction of a corporate renewable energy procurement will be met and including the fraction in the modeling for some or all of the scenarios).[26] However, even if factors within the last four categories are discounted the transmission provider still must incorporate them into each scenario.[27]

The Final Rule requires transmission providers to develop at least three distinct Long-Term Scenarios as part of LTRTP.[28] At least once during the five-year LTRTP cycle, transmission providers must develop at least three such scenarios that incorporate the seven categories of factors.[29] These Long-Term Scenarios are

16. *Id.*
17. Order No. 1920, *supra* note 1, at P 377.
18. *Id.* at P 381-382.
19. *Id.* at P 434.
20. *Id.* at P 440.
21. Order No. 1920, *supra* note 1, at P 448.
22. *Id.* at P 458.
23. *Id.* at P 465.
24. *Id.* at P 482.
25. *See* Order No. 1920, *supra* note 1, at P 509.
26. *Id.* at P 516.
27. *Id.* at P 518.
28. *Id.* at P 559.
29. Order No. 1920, *supra* note 1, at P 560.

to be plausible and diverse.[30] To be plausible, an individual scenario must be "reasonably probable," and the set of scenarios together must "reasonably capture probable future outcomes."[31] To be diverse, the set of scenarios should have distinct facilities or benefits.[32]

The Final Rule requires transmission providers "to develop at least one sensitivity, applied to each Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area."[33]

The Final Rule requires use of "best available data inputs" in developing Long-Term Scenarios. "Best available data inputs" means data inputs that are timely, developed using best practices and diverse and expert perspectives, satisfy the Order Nos. 890 and 1000 principles, and reflect the category of factors required to be incorporated into the Long-Term Scenarios.[34] Transmission providers are required to update, as necessary, all data inputs each time they reassess and revise the Long-Term Scenarios.[35]

FERC stated that transmission providers may propose to identify geographic zones that have the potential for large amounts of new generation within the transmission planning region as part of LTRTP, but they must demonstrate that the process for identifying such zones is consistent with or superior to LTRTP requirements.[36]

4. Evaluation of the Benefit of Regional Transmission Facilities

The Final Rule requires Transmission Providers in each planning region to measure the following set of seven "baseline" benefits to evaluate Long-Term Regional Transmission Facilities under each Long-Term Scenario as part of LTRTP: (1) "Avoided or Deferred Reliability Transmission Facilities and Aging Infrastructure Replacement";[37] (2) A benefit that can be characterized and measured as either reduced loss of load probability or reduced loss of load probability or reduced planning reserve margin;[38] (3) Production cost savings;[39] (4) Reduced transmission energy losses;[40] (5) Reduced congestion due to transmission outages;[41] (6)

30. *Id.* at P 575.
31. *Id*.
32. *Id*.
33. Order No. 1920, *supra* note 1, at P 593.
34. *Id.* at P 633.
35. *Id*.
36. *Id.* at P 665.
37. Order No. 1920, *supra* note 1, at P 745.
38. *Id*. at P 748.
39. *Id*. at P 761
40. *Id*. at P 775.
41. Order No. 1920, *supra* note 1, at P 784.

Mitigation of extreme weather and unexpected system conditions;[42] and (7) Capacity cost benefits from reduced peak energy losses.[43]

FERC expressly stated that transmission providers are not allowed to use a screen approach when measuring the seven required benefits.[44] Specifically, transmission providers may not apply an initial screen to benefit categories to determine which benefits are significant before investing staff resources and modeling work to provide a detailed quantification.[45] The Final Rule requires transmission providers to include in their Open Access Transmission Tariffs (OATTs) a general description of the method they will use to measure each of the seven benefits in the required benefits set and any additional benefits they may propose to use.[46]

The Final Rule requires transmission providers to calculate the benefits of Long-Term Regional Transmission Facilities over a minimum time horizon of twenty years starting from the estimated in-service date of the transmission facilities.[47] This minimum twenty-year benefit horizon is required to be used for both the evaluation and selection of Long-Term Regional Transmission Facilities (but not for purposes of cost allocation).[48]

The Final Rule allows, but does not require, transmission providers to use a portfolio approach to evaluating benefits of Long-Term Regional Transmission Facilities.[49]

5. Evaluation and Selection of Long-Term Regional Transmission Facilities

The Final Rule requires transmission providers to design and include in their OATTs an evaluation process, including selection criteria, to identify and evaluate Long-Term Regional Transmission Facilities for potential selection to address Long-Term Transmission Needs.[50] The evaluation process must identify facilities that address needs, measure the benefits of the facilities, and designate a point in the evaluation process where a facilities selection determination is made for purposes of cost allocation.[51]

The evaluation process and selection criteria must include the following minimum requirements: The determination of why a particular Long-Term Regional Transmission Facility was selected or not must include the measured benefits for each alternative Long-Term Regional Transmission Facilities (or portfolio of such

42. *Id*. at P 791.
43. *Id*. at P 812.
44. *Id.* at P 739.
45. Order No. 1920, *supra* note 1, at P 739.
46. *Id.* at P 837.
47. *Id*. at P 859.
48. *Id.*
49. Order No. 1920, *supra* note 1, at P 889.
50. *Id.* at PP 911, 924.
51. *Id.* at P 916.

facilities) considered in the LTRTP process;[52] Identification of one or more Long-Term Regional Transmission Facilities (or portfolio of such facilities) that address the Long-Term Transmission Needs identified through LTRTP;[53] Non-incumbent developers must be able to propose transmission facilities in the LTRTP process;[54] The evaluation process must estimate costs and measure the benefits of the Long-Term Regional Transmission Facilities that are identified or proposed for potential selection;[55] The evaluation process must include a point in the process where the facilities selection determination will be made, which must be no later than three years following the beginning of the LTRTP cycle;[56] Determinations must be sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such facilities) was selected or not selected, including estimated costs and measured benefits of each alternative facility (or portfolio of such facilities).[57]

The Final Rule clarifies that transmission providers have an affirmative obligation to identify (but not necessarily select) Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs—regardless of whether anyone proposes facilities for consideration in the LTRTP process.[58] Transmission providers are required to propose an evaluation process and selection criteria that seek to maximize benefits accounting for costs over time without over-building transmission facilities.[59]

Transmission providers are required to consult with and seek support from relevant state entities regarding the evaluation process and selection criteria and include a demonstration on compliance that they made a good faith effort in that regard, but they do not need to detail points of disagreement or whether the states support the evaluation process and selection criteria.[60] Transmission providers are not required to obtain state support and states do not have a veto over the evaluation process or selection criteria.[61]

The "[F]inal [R]ule requires transmission providers to include in their OATTs a process to provide" states and interconnection customers with the option to voluntarily fund all or part of the costs of a Long-Term Regional Transmission Facility that otherwise would not meet the selection criteria.[62] The OATT provisions must describe (1) the process whereby funding opportunities are made available, including timely notice and a meaning opportunity, (2) the period during which the option to provide voluntary funding may be exercised, (3) the method

52. *Id.* at P 954.
53. Order No. 1920, *supra* note 1, at P 955.
54. *Id*.
55. *Id*.
56. *Id*.
57. Order No. 1920, *supra* note 1, at P 955.
58. *Id.* at P 957.
59. *Id.* at P 964.
60. *Id.* at P 994.
61. Order No. 1920, *supra* note 1, at P 996.
62. *Id.* at P 6.

to determine the amount of voluntary funding required to ensure that the facility meets the selection criteria, and (4) the mechanism to memorialize the voluntary funding agreement.[63]

The Final Rule does not require transmission providers to select any particular Long-Term Regional Transmission Facility, even when a facility meets the selection criteria.[64]

The Final Rule requires transmission providers to reevaluate selected Long-Term Regional Transmission Facilities in certain circumstances, when (1) development delays would jeopardize a transmission provider's ability to meet its reliability needs or reliability-related service obligations (ex: missed milestones), (2) actual or projected costs of a selected facility significantly exceed cost estimates used in the selection (ex: exceed a threshold of cost escalation), or (3) under certain circumstances, significant changes in federal, federally recognized Tribal, state, or local laws or regulations cause reasonable concern that the facility may no longer meet the selectin criteria.[65]

6. Implementation of Long-Term Regional Transmission Planning

Transmission providers are required to explain in their compliance filings how the initial timing sequence for LTRTP interacts with existing regional transmission planning processes.[66] First, they must address possible interaction between the LTRTP process and existing Order No. 1000 process.[67] Second, they must address possible displacement of regional transmission facilities from existing regional transmission planning processes.[68]

C. Local Transmission Planning Inputs in the Regional Transmission Planning Process

The Final Rule requires transmission providers (1) enhance the transparency of the local transmission planning process, and (2) evaluate whether transmission facilities that need replacing can be "right sized" to more efficiently or cost-effectively address Long-Term Transmission Needs identified in LTRTP.[69]

1. Enhanced Transparency

Transmission providers are required to modify the regional transmission planning process in their OATTs to enhance the transparency of: (1) criteria, models, and assumptions used in the local transmission planning process, (2) the local transmission needs they identify through the local transmission planning process, and (3) the potential local or regional transmission facilities they will evaluate to address local transmission needs. This information must be publicly posted and

63. *Id*. at P 1013.
64. *Id.* at P 1019.
65. Order No. 1920, *supra* note 1, at P 1050.
66. *Id.* at P 1071.
67. *Id*.
68. *Id*.
69. Order No. 1920, *supra* note 1, at P 1577.

publicly noticed with at least three stakeholder meetings (assumptions, needs, and solutions meetings) per planning cycle that provide an opportunity for comment.[70]

2. Opportunities to Right-Size Replacement Facilities

The Final Rule defines "right-sizing" as the process of modifying a transmission provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability.[71] In each LTRTP cycle, the Final Rule requires transmission providers to evaluate whether transmission facilities (1) operating above a specified kV threshold (not to exceed 200 kV) and (2) that the transmission provider that owns the asset "anticipates replacing in-kind with a new facility during the next 10 years can be "right-sized" to more efficiently or cost-effectively address a Long-Term Transmission Need."[72]

"Right-sized" facilities must meet criteria in the Final Rule that help ensure that *replacement* facilities are being addressed and not entirely new transmission facilities.[73] Transmission providers must include a description of how the proposed cost allocation method (1) calculates incremental costs of the right-sized portion of the facility, and (2) tracks the portion of costs that are allocated in accordance with the Long-Term Regional Transmission Cost Allocation Method (LTRTCAM) (or State Agreement Process) and that would have been allocated pursuant to the method that otherwise would have applied to the in-kind replacement facility.[74]

D. Coordination or Regional Transmission Planning and Generator Interconnection Processes

The Final Rule requires transmission providers to revise the regional transmission planning processes in their OATTs to evaluate for selection regional transmission facilities that address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process.[75]

Transmission providers are required to evaluate for selection in their existing Order No. 1000 regional transmission facilities to address interconnection-related transmission needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades where: (1) The transmission provider has identified interconnection-related network upgrades in interconnection studies to address those interconnection-related transmission needs in at least two interconnection queue cycles during the preceding five years; (2) An interconnection-related network upgrade identified to meet those interconnection-related transmission needs has a voltage of at least 200 kV *and* an estimated cost of at least $30 million; (3) Such interconnection-related network upgrade(s) have

70. *Id.* at P 1626.
71. *Id*. at P 1649.
72. *Id.* at P 1677.
73. Order No. 1920, *supra* note 1, at P 1679.
74. *Id.* at P 1719.
75. *Id*. at P 104.

not been developed and are not currently planned to be developed because the interconnection request(s) driving the need for the network upgrade(s) has been withdrawn; and (4) The transmission provider has not identified an interconnection-related network upgrade to address the relevant interconnection-related transmission need in an executed generator interconnection agreement or in a generator interconnection agreement that the interconnection customer requested that the transmission provider file unexecuted with FERC.[76]

Rather than requiring an "in-depth qualitative analysis of individual interconnection requests," the Final Rule's only requirement is that transmission providers evaluate regional transmission facilities to address interconnection-related transmission needs that meet these criteria for potential selection.[77]

E. Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices

The Final Rule requires transmission providers to consider, in LTRTP and existing Order No. 1000 regional transmission planning processes, "dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching" for each identified transmission need.[78] FERC requires transmission providers to measure the required benefits and any additional benefits the transmission providers elect to measure and use those measured benefits in their evaluation processes to determine if a regional transmission facility that incorporates, or solely consists of, any of the enumerated list of alternative transmission technologies would more efficiently or cost-effectively address Long-Term Transmission Needs.[79]

FERC requires that, for every competitive transmission development process in a given transmission planning region, transmission providers must identify with sufficient detail in their OATTs the points in a given process at which the transmission providers will consider the potential use of alternative transmission technologies.[80] The Final Rule requires transmission providers in non-regional transmission organization (RTO) regions to update their energy management systems, if needed to implement dynamic line ratings or any of the alternative transmission technologies.[81]

F. Regional Transmission Cost Allocation

1. Overview of Requirements

FERC finds that facilitating state regulatory involvement in the cost allocation process could minimize delays and additional costs associated with state and

76. *Id.* at P 1130.
77. Order No. 1920, *supra* note 1, at P 1146.
78. *Id*. at P 8.
79. *Id.* at P 1199.
80. *Id.* at P 1205.
81. Order No. 1920, *supra* note 1, at P 1215.

local siting proceedings.[82] FERC *requires* transmission providers in each transmission planning region to revise their OATTs to include one or more LTRTCAMs for LTRTFs that are selected.[83] The relevant LTRTCAM on file would apply as a backstop cost allocation methodology.[84] FERC also *permits* (but does not require) transmission providers to include in their OATTs a State Agreement Process if Relevant State Entities indicate that they have agreed to such a process.[85]

2. Requirement to Seek Agreement of Relevant State Entities

In the Final Rule, FERC requires a transmission provider to establish a six-month Engagement Period, during which transmission providers must: (1) Provide notice of the starting and end dates for the six-month time period (such as on website or Open Access Same-Time Information System) and provide an opportunity for any Relevant State Entity to participate; (2) Post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a LTRTCAM(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and (3) Provide a forum for negotiation of a LTRTCAM(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities.[86]

3. State Agreement Process

The Final Rule allows, but does not require, transmission providers to adopt a State Agreement Process for allocating the costs of all, or a subset of, LTRTFs.[87] FERC defines a State Agreement Process as a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for LTRTFs (or a portfolio of such Facilities) either before or no later than six months after the facilities are selected in the regional transmission plan for purposes of cost allocation.[88] If the Relevant State Entities indicate to a transmission provider that they have agreed to a State Agreement Process and the transmission provider decides to include that State Agreement Process in its Final Rule compliance filings, then the transmission providers must also detail the State Agreement Process in proposed tariff provisions to their OATTs, including: how agreement would be reached; which entities can participate; how such voluntary agreements by the Relevant State Entities may be shared with transmission providers; the event triggering the beginning of the State Agreement Process, the duration of the State Agreement Process, and a description of the LTRTFs to which the process applies; and the manner in which a transmission provider would file a section 205 filing to

82. *Id.* at P 1293.
83. *Id.* at P 1291.
84. *Id.* at P 1292.
85. Order No. 1920, *supra* note 1, at P 75.
86. *Id.* at PP 1354, 1356.
87. *Id.* at P 1412.
88. *Id.* at P 45.

seek FERC acceptance of a cost allocation method resulting from a State Agreement Process.[89]

4. Backstop Cost Allocation to Comply with Five of Six Order No. 10000 Cost Allocation Principles

Order No. 1000 adopted six cost allocation principles: (1) the costs of selected transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; (2) those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities; (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1; (4) costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs; (5) the method for determining benefits and identifying beneficiaries must be transparent; and (6) there may be different regional cost allocation methods for different types of transmission facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.[90]

In the Final Rule, FERC requires transmission providers to demonstrate in their compliance filings that any LTRTCAMs (to which Relevant State Entities have *not* indicated that they agree) comply with Order No. 1000 regional cost allocation principles (1) through (5).[91] FERC declined to require compliance with principle (6).[92]

5. Identification of Benefits in Cost Allocation

FERC requires transmission providers to demonstrate that the required LTRTCAM(s) (to which Relevant State Entities have *not* indicated they agree) comply with Order No. 1000 regional transmission cost allocation principles (1) through (5) and do not allocate costs by project type (*i.e.*, principle (6) reliability, economic, or transmission needs driven by Public Policy Requirements).[93]

G. Construction Work in Progress (CWIP) Incentive

In the Final Rule, FERC declined to act on the Notice of Proposed Rulemaking (NOPR) proposal to limit the availability of the CWIP Incentive for LTRTF.[94] Instead, FERC found "that any action on the CWIP Incentive is more appropriately considered in a separate proceeding to allow for a holistic approach to transmission incentives after FERC has finalized the [LTRTP] reforms."[95]

89. Order No. 1920, *supra* note 1, at PP 1415-16.
90. *Id.* at P 1458.
91. *Id.* at P 1505.
92. *Id.* at P 1469.
93. Order No. 1920, *supra* note 1, at P 1506.
94. *Id.* at P 1547.
95. *Id.* at P 1547.

H. Exercise of Rights of First Refusal (ROFR) for LTRTFs

Faced with competing comments on Order No. 1000's track record for competitive transmission development and the causes of the investment disincentive concerns identified in the NOPR, FERC declined to act on the NOPR proposal to permit the exercise of a federal ROFR.[96]

I. Interregional Transmission Coordination

In the Final Rule, FERC adopted the NOPR proposal to require transmission providers in neighboring transmission planning regions to revise their existing interregional transmission coordination procedures (and regional transmission planning processes as needed) to: (1) share information regarding their respective transmission needs identified in LTRTP, as well as potential transmission facilities to meet those needs; (2) identify and jointly evaluate interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address transmission needs identified through LTRTP; and (3) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to transmission needs identified through LTRTP.[97]

FERC also found that additional transparency was warranted and required transmission providers to provide additional information concerning LTRTP on their public website or through the email list used for communication of information related to interregional transmission coordination procedures, including: (1) the Long-Term Transmission Needs discussed in the interregional transmission coordination meetings; (2) any interregional transmission facilities proposed or identified in response to Long-Term Transmission Needs; (3) the voltage level, estimated cost, and estimated in-service date of the interregional transmission facilities proposed or identified as part of Long-Term Regional Transmission Planning; (4) the results of any cost-benefit evaluation of such interregional transmission facilities, with such results including both any overall benefits identified (which may occur across multiple transmission planning regions), as well as any benefits particular to each transmission planning region; and (5) the interregional transmission facilities, if any, selected to meet Long-Term Transmission Needs.[98]

J. Compliance Requirements

FERC requires each Transmission Provider to submit a compliance filing within ten months of the effective date of this final rule revising its OATT and other document(s) subject to FERC's jurisdiction to demonstrate that it meets all of the requirements adopted in the Final Rule.[99] Transmission Providers in each transmission planning region are required to propose a date, no later than one year from the date of the compliance filing, on which they will commence the first

96. *Id.* at P 1548.
97. Order No. 1920, *supra* note 1, at P 1741.
98. *Id.* at P 1753.
99. *Id.* at P 1768.

Long-Term Regional Transmission Planning cycle. Consequently, transmission providers must propose an effective date for their OATT revisions necessary to comply with this final rule that is no later than the date on which they will commence the first Long-Term Regional Transmission Planning cycle.[100]

II. FERC ORDER NO. 2023-A, ORDER ON REHEARING AND CLARIFICATION, IMPROVEMENTS TO GENERATOR INTERCONNECTION PROCEDURES AND AGREEMENTS

A. Introduction

On March 21, 2024, FERC issued Order No. 2023-A, its order on rehearing and clarification of its July 28, 2023, landmark order on generator interconnection known as Order No. 2023.[101] Order No. 2023-A sustained Order No. 2023's conclusion that existing interconnection procedures were no longer just and reasonable and required reform.[102] Order No. 2023-A did, however, grant rehearing or clarification on several issues.

Order No. 2023, as modified and clarified by Order No. 2023-A, requires that transmission providers revise their Large Generator Interconnection Procedures (LGIP) and standard Large Generator Interconnection Agreement (LGIA) contained in their open access transmission tariffs to: (1) implement a first-ready, first-served cluster study process that includes new public posting commitments related to availability of generator interconnection on the transmission system, study and commercial readiness deposits, site control requirements, allocation of study costs using a hybrid method that incorporates both pro rata and per capita allocation components, and allocation of network upgrade costs based on proportional impact; (2) adopt a 150-day interconnection study timeline and other standardized timelines aimed at increasing the speed of interconnection queue processing; (3) implement penalties for interconnection customers withdrawing projects from the interconnection queue at times other than defined decision points; and (4) respond to technological advancements by allowing more than one generating facility to co-locate behind a single point of interconnection, evaluating proposals to add a generating facility at an interconnection point without automatically labeling it a material modification, allowing customers to apply for surplus interconnection service as soon as the original interconnection customer executes an LGIA, using operating assumptions in interconnection studies that reflect the proposed charging behavior of energy storage resources (ESRs), and evaluating the use of alternative transmission technologies during the interconnection study process.[103] Order No. 2023, as affirmed by Order No. 2023-A, also eliminates the reasonable

100. *Id.* at P 1072.

101. Order No. 2023, *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,051 (2023), *order on reh'g,* Order No. 2023-A, 186 F.E.R.C. ¶ 61,199 (2024) [hereinafter Order No. 2023-A].

102. Order No. 2023-A, *supra* note 101, at P 35.

103. Order No. 2023, *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,051 at PP 4-5, 7 (2023).

efforts standard for conducting interconnection studies, implements penalties for transmission providers failing to timely complete their interconnection studies, and formally establishes an affected system study process and *pro forma* affected system study agreement.[104] Order No. 2023 also requires revisions to small generator interconnection procedures to incorporate consideration of the alternative transmission technologies into the interconnection process and provide modeling and ride-through requirements for non-synchronous generating facilities, but it does not impose the many other revisions required for large generators.[105]

Although Order No. 2023-A upheld the fundamental requirements of Order No. 2023, it granted rehearing or clarification on several discrete issues, including the following. First, Order No. 2023-A clarified that transmission providers with existing cluster study processes must modify their current processes and standard agreements as needed to comport with Order No. 2023, but that use of an Order No. 2023-compliant transmission cluster study process by such transmission providers is optional.[106] Second, Order No. 2020-A revised the standard LGIA option-to-build language to permit interconnection customers to exercise their option to build network upgrades when a network upgrade is shared by multiple customers, not only when a network upgrade is attributed to a single customer.[107] Third, the Order clarified that transmission providers need not re-justify existing tariff mechanisms addressing cost sharing of network upgrades between clusters but that transmission providers must secure FERC approval to retain previously-approved variations if Order No. 2023 implicates the prior variations.[108] Fourth, Order No. 2023-A expanded the allowed types of security associated with making commercial readiness and applicable study deposits to include cash, irrevocable letters of credit, surety bonds, and other types of security the transmission provider finds reasonably acceptable.[109] Fifth, the Order clarified that withdrawal penalties will not accrue if withdrawal does not materially affect interconnection requests within the same cluster.[110] Sixth, the Order provided that withdrawal penalties paid to transmission providers will not reduce the cost a transmission provider places in rate base for network upgrades if the transmission provider uses the penalties to offset security that would be paid to the transmission provider by interconnection customers remaining in the study.[111] Seventh, Order No. 2023-A required transmission providers to distribute study delay penalties to interconnection customers pro rata based on final study costs.[112] Eighth, the Order clarified that FERC will evaluate requests for waiver of study delay penalties by assessing whether there is good cause for relief from the penalty, not under FERC's more involved four-

104. *Id.* at P 6.
105. *See id.* at P 8.
106. Order No. 2023-A, *supra* note 101, at PP 73-74.
107. *Id.* at PP 141, 143.
108. *Id.* at P 181.
109. *Id.* at P 185.
110. Order No. 2023-A, *supra* note 101, at P 233.
111. *Id.* at P 234.
112. *Id.* at P 439.

prong waiver paradigm.[113] Ninth, the Order clarified that study penalty amounts will not accrue interest.[114] Tenth, Order No. 2023-A allows an affected system provider to pause its affected system study while the host transmission provider is conducting a cluster restudy.[115] Eleventh, while the Commission declined to require transmission providers such as regional transmission operators to revise their joint operating agreements (JOAs) as part of the rulemaking, it articulated the expectation that transmission providers will seek to revise their JOAs to ensure there is no conflict between the JOAs, Order No. 2023, and the relevant transmission providers' interconnection processes.[116] Twelfth, the Order underscored that transmission providers must, upon request, study whether an ESR will charge during peak load but need not create new study base cases in the process.[117] Finally, Order no. 2023-A clarified that the final rule does not require transmission providers to begin studying ESR charging as part of the interconnection process if they do not already do so.[118]

Several parties have sought judicial review of Orders Nos. 2023 and 2023-A, review which remains pending as of the publication date of this report.[119]

III. WINTER STORM ELLIOT SETTLEMENT

In an Order Approving Uncontested Settlement, issued December 19, 2023, FERC took two major steps: (1) it denied Chief Companies' motion to intervene in the Winter Storm Elliot Settlement negotiation; and (2) it approved the Settling Parties Offer of Settlement (Settlement) related to Winter Storm Elliot, which reduced penalties assessed on non-performing generators by 31.7%.[120]

On December 23-24, 2022, Winter Storm Elliott caused extreme weather in the PJM region, which increased electricity demand and caused many generation outages.[121] Throughout the storm, PJM implemented several Emergency Actions to help maintain system reliability, thereby sparking many Performance Assessment Intervals (PAIs).[122] Because many capacity resources failed to deliver energy and reserves during the PAIs, they incurred penalties that totaled approximately $1.8 billion.[123]

Following the storm, fifteen complaints were filed with FERC challenging PJM's assessment of penalties.[124] In April 2023, PJM filed a motion requesting

113. *Id.* at P 463.

114. Order No. 2023-A, *supra* note 101, at P 452.

115. *Id.* at P 497.

116. *Id.* at P 537.

117. *Id.* at PP 577, 581.

118. Order No. 2023-A, *supra* note 101, at P 585.

119. Filers submitted petitions for review in the FERC's rulemaking docket. *See* FERC Docket No. RM22-14-000 (May 8, 2024).

120. *PJM Interconnection, LLC et al.*, 185 FERC ¶ 61,204 at PP 11, 30, 37 (2023).

121. *Id.* at P 4.

122. *Id.*

123. *Id.*

124. 185 FERC ¶ 61,204, at P 5.

FERC appoint a settlement judge to resolve these complaints.[125] Citing the complexity of the underlying settlement and the risk of years of disruptive litigation, FERC appointed ALJ Matthew Vlissides Jr. to oversee the settlement.[126]

Over the course of eight in-person, publicly noticed settlement conferences, the parties negotiated a resolution to the dispute over the $1.8 billion in fines.[127] On September 8, 2023, the seventy settling parties filed a request to defer collection of unbilled penalties, pursuant to their agreement.[128] FERC noticed the filing with a comment and intervention deadline of September 15, 2023. On September 22—a week after the intervention deadline—Chief Companies filed a motion to intervene. FERC granted Chief Companies' motion to intervene with respect to the waiver dockets.[129]

On September 29, 2023, settling parties filed the Settlement with FERC, which triggered the creation of Docket No. ER23-2975-000.[130] Chief Companies filed a motion to intervene in this new docket as well. PJM filed an answer opposing Chief Companies' motion to intervene, arguing that a Settlement filing should not create a new avenue for intervention after the deadline in the underlying proceeding passed.[131] PJM also argued that permitting Chief Companies to intervene on the basis of the FERC's docket management system (which automatically created a new docket when the Settlement was filed) unfairly treated Chief Companies as equal participants in the extensive negotiations that created the Settlement, despite Chief Companies contributing nothing to the effort put forth to resolve the Winter Storm Elliott complaints.[132]

Chief Companies responded that PJM's argument that a Settlement Docket does not provide an independent basis to intervene was unsupported by regulation or precedent.[133] Chief Companies also argued that they had good cause to intervene because the Settlement protected PJM from liability for its alleged Tariff violations and reduced penalty payments to Chief Companies.[134]

Constellation filed an answer supporting PJM. Constellation asserted that Chief Companies' filing of its protest so late in the proceeding, after ample opportunity to intervene, demonstrated that it was not acting in good faith.[135]

FERC denied Chief Companies' motion to intervene in the docket created by PJM filing its settlement.[136] FERC reasoned that allowing entities to intervene in

125. *Id.* at P 6.
126. *Id.* at P 7.
127. *Id.*
128. 185 FERC ¶ 61,204, at P 8.
129. *Id.* at P 9.
130. *Id.* at P 9.
131. *Id.* at P 18.
132. 185 FERC ¶ 61,204, at P 20.
133. *Id.* at P 24
134. *Id.* at P 25.
135. *Id.* at P 27.
136. 185 FERC ¶ 61,204, at P 30.

a new docket generated by the filing of a settlement, when the entity did not participate in the underlying dockets and settlement discussions, would run contrary to cases where FERC disallowed parties intervening after a settlement agreement.[137] FERC emphasized that Chief Companies had ample opportunity to intervene and remained silent throughout the fifteen settlement proceedings.[138]

Following its denial of Chief Companies' attempt to intervene, FERC found the Settlement was "fair and reasonable and in the public interest" and approved the Settlement.[139] The Settlement reduced the penalties assessed by PJM on non-performing generators during Winter Storm Elliot by 31.7%.[140]

IV. Notice of Proposed Rulemaking, Compensation for Reactive Power Within the Standard Power Factor Range FERC

On March 21, 2024, FERC issued a Notice of Proposed Rulemaking (NOPR) proposing to revise FERC's reactive power compensation rules to limit compensation to interconnection customers.[141] If adopted, transmission providers would only be required to pay for reactive power when the transmission provider asks interconnection customers to operate their facilities outside the standard power factor range established in the interconnection agreement.[142]

To accomplish this goal, FERC is proposing to revise Schedule 2 of its *pro forma* OATT to "prohibit 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."[143] The proposal also seeks to remove section 9.6.3 of FERC's *pro forma* LGIA and section 1.8.2 of its *pro forma* small generator interconnection agreement (SGIA).[144] The LGIA and SGIA sections to be removed currently require transmission providers to "pay an interconnection customer for reactive power within the standard power factor range if the transmission provider pays its own or affiliated generators for the same service."[145]

The NOPR follows a Notice of Inquiry (NOI) issued on November 18, 2021, in which FERC "sought to 'examine whether the current regime for reactive power capability compensation requires revisions to ensure that payments for reactive

137. *Id.* at P 31.

138. *Id.* at P 33.

139. *Id.* at P 37.

140. 185 FERC ¶ 61,204, at P 39.

141. *See* Notice of Proposed Rulemaking, *Compensation for Reactive Power Within the Standard Power Factor Range*, 186 FERC ¶ 61,203 at PP 48-50 (2024) [hereinafter Compensation for Reactive Power NOPR].

142. *Id.* at P 1.

143. *Id.* at P 52.

144. *Id.*

145. Compensation for Reactive Power NOPR, *supra* note 141, at P 1.

power capability accurately reflect the costs associated with reactive power capability.'"[146] The comments and reply comments to the 2021 NOI varied.[147] Transmission customers argued that the AEP Methodology should be abandoned in favor of a new rate methodology while power generation industry groups, resource developers, and other commenters supporting renewable energy argued that the AEP Methodology should instead be modified to reflect costs more accurately.[148]

FERC's preliminary finding was 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."[149] Multiple RTOs and independent system operators (ISOs) have already elected not to compensate the provision of reactive power within the standard power factor range.[150] This group includes California Independent System Operator Corporation (CAISO), Southwest Power Pool, Inc. (SPP) and Midcontinent Independent System Operator, Inc. (MISO).[151] PJM Interconnection, L.L.C. (PJM) compensates generating facilities within the standard power factor using the *AEP Methodology*, ISO New England, Inc. (ISO-NE) and New York Independent System Operator, Inc. (NYISO) use a flat rate design, and transmission providers outside of RTOs/ISOs that pay compensation generally use the AEP Methodology.[152] Many Transmission providers outside of RTOs/ISOs do not provide separate compensation for reactive power within the standard power factor range.[153]

According to FERC, "providing reactive power within the standard power factor range is a 'no cost' or *de minimis* cost service in addition to being a resource's obligation under its interconnection agreement and good utility practice."[154] FERC also stated that to the extent that generators incur any costs associated with providing reactive power within the standard power factor range, those costs can be recovered through energy or capacity sales, thus negating the need for separate compensation.[155]

Within the RTO/ISO regions that do not currently compensate for reactive power outside the standard power factor range, FERC found no evidence of an insufficient supply of reactive power or that generating facilities in these regions have had any issues with cost recovery for reactive power.[156] FERC also found that investors in facilities in those regions can develop generating facilities that

146. *Id.* at P 20 (quoting Notice of Inquiry, *Reactive Power Capability Compensation*, 177 FERC ¶ 61, 118 (2021)).

147. *See id.* at PP 21-22.

148. *Id.* at P 21.

149. Compensation for Reactive Power NOPR, *supra* note 141, at P 25.

150. *Id.* at P 7.

151. *Id.* at P 18.

152. *Id.* at PP 17-18.

153. Compensation for Reactive Power NOPR, *supra* note 141, at P 19.

154. *Id.* at P 24.

155. *Id.*

156. *Id.* at P 7.

satisfy interconnection agreement obligations without relying on separate reactive power compensation.[157]

Despite the proposed changes, transmission providers would still be required to provide compensation for any production of reactive power outside of the standard power factor range to account for increased costs to the generator.[158] For example, if a transmission provider required a generator to provide reactive power outside the standard power factor range, the generator would need to reduce its megawatt output to satisfy the request, which could then limit the generator's opportunity to receive revenues for real power sales.[159] However, FERC emphasized that compensation for any reactive power production outside of the standard power factor range was beyond the scope of the rulemaking.[160]

Entities are requested to submit comments within sixty days after the NOPR is published in the Federal Register.[161] Reply comments are due ninety days after the publication of the NOPR in the Federal Register.[162] Once a final rule is created, the current proposed compliance procedures would give transmission providers sixty days to submit a compliance filing and then ninety days from the date of the compliance filing for the reforms to take effect.[163] The compliance schedule is subject to changes based on comments about whether the ninety-day period is sufficient for transmission providers to adapt their rates to the new scheme.[164]

FERC also seeks comment on a variety of questions raised by the proposed changes.[165] These questions include whether prohibiting compensation will affect reliability in regions where generating facilities are currently compensated,[166] whether costs can be recovered by generating facilities who are currently compensated for reactive power within the standard power factor range,[167] what impact the rule would have on business decisions within the industry,[168] and whether the compliance date should be varied for regions with an established capacity market.[169]

157. Compensation for Reactive Power NOPR, *supra* note 141, at P 7.

158. *Id.* at P 32.

159. *Id.*

160. *Id.*

161. Compensation for Reactive Power NOPR, *supra* note 141, at P 76.

162. *Id.*

163. *Id.* at P 54.

164. *Id.*

165. Compensation for Reactive Power NOPR, *supra* note 141, at P 56.

166. *Id.* at P 44.

167. *Id.* at P 49.

168. *Id.* at P 56.

169. Compensation for Reactive Power NOPR, *supra* note 141, at P 44.

V. FERC ORDER NO. 893, INCENTIVES FOR ADVANCED CYBERSECURITY INVESTMENT

Order No. 893 provides incentive-based rates for public and non-public utilities to encourage voluntary investments in Advanced Cybersecurity Technology[170] and participation in cybersecurity threat information sharing programs (CRISP).[171]

Section 40,123 of the *Infrastructure Investment and Jobs Act* (IIJA) directed FERC to promulgate a rule to establish incentive-based rates for utilities.[172] FERC promulgated Order No. 893 pursuant to that directive.

Both public and non-public utilities that have, or will have, a rate on file with FERC may apply for incentive-based rate treatment for eligible cybersecurity investments. However, utilities *may not* receive incentive-based rates on cybersecurity investments related to market-based sales of energy, capacity, or ancillary services. Instead, they must make a separate cost-of-service rate filing with FERC under FPA 205.[173]

Investments may be eligible for incentive-based rates if they are in Advanced Cybersecurity Technology or expenses related to participating in CRISP. Advanced Cybersecurity Technology includes both (a) products and (b) services. Cybersecurity products include hardware, software, or other types of IT systems.[174] Cybersecurity services include system installation and maintenance, network administration, and asset management.[175]

There is a two-step process to determine whether the Advanced Cybersecurity Technology or CRISP investments are eligible for incentive-based treatment. Investments must make (1) material improvement to cybersecurity and (2) be voluntary.

An investment will be presumed to materially improve cybersecurity if it is for either Advanced Cybersecurity Technology or participation in a CRISP.[176] In order for an investment to be voluntary, the investment cannot be mandated by

170. Order No. 893, *Incentives for Advanced Cybersecurity Investment*, 183 FERC ¶ 61,033 at P 27 (2023) (defined as any "[t]echnology, operational capability, or service, including computer hardware, software, or a related asset, that enhances the security posture of public utilities through improvements in the ability to protect against, detect, respond to, or recover from a cybersecurity threat (as defined in section 102 of the Cybersecurity Act of 2015 (6 U.S.C. 1501)") [hereinafter Order No. 893].

171. *Id.*

172. 16 U.S.C. 824s–1(c) (2024).

173. Order No. 893, *supra* note 170, at P 26.

174. *Id.* at P 4.

175. *Id.* at P 5.

176. *Id.* at P 85; *see id.* at P 40 ("[I]n determining which cybersecurity investments will materially improve a utility's security posture, [FERC] will consider the following sources: (1) security controls enumerated in the NIST SP 800-53 'Security and Privacy Controls for Information Systems and Organizations' catalog; (2) security controls satisfying an objective found in the NIST Cybersecurity Framework technical subcategory; (3) a specific cybersecurity recommendation from a relevant federal authority, such as DHS's CISA, the FBI, NSA, or DOE; (4) participation in a relevant cybersecurity threat information sharing program; and/or (5) achieving and sustaining one or more of the C2M2 Domains at the highest Maturity Indicator Level.").

Reliability Standards maintained by an Electric Reliability Organization; mandated by local, state, or federal law; an action taken in response to a federal or state agency merger condition, or consent decree from federal or state agency; or an action taken in response to a settlement agreement that resolves a dispute between a utility and a public or private party.[177]

FERC has two approaches to determine if a voluntary cybersecurity investment satisfies the eligibility criteria. First, the prequalified (PQ) list. Any cybersecurity investment that is on the PQ List is entitled to a rebuttable presumption of eligibility for incentive-based rate treatment. This presumption may be rebutted by a protestor demonstrating that, given the unique circumstances of the utility, the investment on the PQ list does not materially improve the utility's cybersecurity.[178] In the rule, FERC included two types of investments on the PQ list: (1) cybersecurity investments associated with participation in CRISP; and (2) cybersecurity investments associated with internal network security monitoring within the utility's cyber systems.

The second approach to determine if a voluntary cybersecurity benefit is eligible is through a case-by-case review. If a cybersecurity investment is not on the PQ List, FERC will conduct a case-by-case review to see if the investment materially improves cybersecurity and is voluntary. In a case-by-case review, the burden is on the utility to prove the investment materially improves cybersecurity and therefore is eligible to receive incentive-based rate treatment.[179] Rates will only be approved under the PQ or case-by-case pathway if the final rate is just and reasonable.

Incremental improvements are eligible for incentive-based rates. Where a cybersecurity investment results in a utility not only meeting a mandatory Reliability Standard but also provides cybersecurity benefits exceeding those standards, the incremental investment that resulted in the utility exceeding Reliability Standards is eligible for incentive-based rate treatment.[180]

Investments resulting in early adherence to forthcoming Reliability Standards are also eligible for incentive-based rates. If a utility makes a cybersecurity investment in preparation for a forthcoming Reliability Standard, that investment is eligible for incentive-based rate treatment until the Reliability Standard becomes mandatory.[181] For example, if a utility makes an upgrade in January to comply with a Reliability Standard that will become mandatory in July, they are eligible for inventive-based rates for six months.

FERC allows utilities to treat eligible cybersecurity investments as regulatory assets and include those assets in the transmission rate base.[182] Utilities may seek this enhanced recovery for a range of expenses, including operation and mainte-

177. Order No. 893, *supra* note 170, at P 45.

178. *Id.* at P 64.

179. *Id.* at P 107.

180. *Id.* at P 47.

181. Order No. 893, *supra* note 170, at P 117.

182. *Id.* at P 135.

nance expenses, labor costs, implementation costs, network monitoring, and training costs.[183] Utilities may use incentive-based rate recovery for up to five years and must submit annual informational reports to FERC for the duration of the cybersecurity incentive.[184]

VI. FERC ORDER NO. 897, ONE-TIME INFORMATIONAL REPORTS ON EXTREME WEATHER VULNERABILITY ASSESSMENTS CLIMATE CHANGE, EXTREME WEATHER, AND ELECTRIC SYSTEM RELIABILITY

FERC Order No. 897 (Docket No. RM22-16-000; issued June 15, 2023) directs transmission providers to file one-time reports with FERC describing current or planned policies and procedures for analyzing the threats extreme weather pose to FERC-jurisdictional transmission projects.[185]

In its discussion of the need for Order No. 897, FERC noted that extreme weather caused by climate change poses a serious threat to Bulk-Power System (BPS) reliability.[186] FERC conducted this rulemaking, in part, because of NERC's recommendation that policymakers include extreme weather scenarios as part of resource and system planning.[187] FERC was also motivated by the cost of weather-related system failures.[188] FERC emphasized that the goal of ordering these reports was to understand how transmission providers asses their extreme weather vulnerabilities, not establish new requirements.[189]

FERC promulgated this rule under section 304 of the Federal Power Act (FPA). Section 304 directs utilities to provide FERC reports that FERC deems necessary to carry out its responsibilities under the FPA. FERC noted that section 215 of the FPA empowers FERC to ensure the reliability of the BPS.[190]

In the Order, FERC directed transmission providers to file one-time reports describing current or planned policies and procedures for conducting extreme weather vulnerability assessments of their FERC-jurisdictional transmission assets and operations. FERC instructed transmission providers to review five procedures, discussed below in turn.

First, transmission providers must review how they scope extreme weather assessments. Specifically, FERC wanted transmission providers to discuss how

183. Id. at P 147.

184. *Id.* at PP 172, 193.

185. Order No. 897, *One-Time Informational Reports on Extreme Weather Vulnerability Assessments Climate Change, Extreme Weather, and Electric System Reliability*, 183 FERC ¶ 61,192 at P 1 (2023) [hereinafter Order No. 897].

186. *Id.* at P 6.

187. *Id*.

188. *Id*. at P 24.

189. Order No. 897, *supra* note 185, at P 51.

190. *Id*. at P 20.

frequently they conduct assessments;[191] what type of weather events they consider;[192] and the extent that they consider gas-electric interdependence in extreme weather vulnerability assessments.[193]

Second, FERC directed transmission providers to review how they develop inputs, including the meteorological data transmission providers rely on.[194]

Third, FERC asked transmission providers to identify vulnerabilities and exposure to extreme weather hazards, including a description of how transmission providers identify assets or operations vulnerable to extreme weather events.[195]

Fourth, transmission providers must evaluate how they estimate the costs of extreme weather vulnerability assessments.[196] Specifically, FERC asked transmission providers to discuss whether, and if so how, they estimate, or plan to estimate, the costs associated with extreme weather impacts in their extreme weather vulnerability assessments.[197] If they do estimate cost, how they evaluate:

> (a) direct costs, such as replacements or repair costs, restoration costs, associated labor costs, or opportunity costs of lost sales; and (b) indirect costs, such as costs associated with loss of service to electric customers and other utilities that purchase power from the transmission provider, including equipment damage, spoilage, and health and safety effects, in calculating the costs of extreme weather impacts.[198]

Fifth, the reports must address how transmission providers use assessments to develop extreme weather mitigation measures, "inform relevant stakeholders and government agencies of vulnerabilities and mitigation plans," and "measure the success of risk mitigation measures."[199]

FERC noted that transmission owners that are members of an RTO/ISO may file their own report or file jointly with the RTO/ISO. FERC made clear that an RTO/ISO could work with all its interested transmission owner members to complete and submit a joint one-time report.[200] FERC directed transmission providers to file their reports pursuant to Order No 897 by October 25, 2023, within 120 days of the Order's publication date in the Federal Register.[201] The public had the opportunity to comment on reports until December 26, 2023, sixty days after the report filing deadline.[202]

191. *Id*. at P 69.
192. *Id*. at app. A, Q2.
193. Order No. 897, *supra* note 185, at app. A, Q6.
194. *Id*. at P 71.
195. *Id.* at PP 82-84.
196. *Id.* at P 89.
197. Order No. 897, *supra* note 185, at P 86.
198. *Id.*
199. *Id*. at P 91.
200. *Id*. at P 48.
201. Order No. 897, *supra* note 185, at P 100.
202. *Id*. at P 104.

VII. FERC ORDER NO. 896

In Order No. 896 (Docket No. RM22-10-000, issued June 15, 2023), FERC directed the North American Electric Reliability Organization (NERC) to submit a new Reliability Standard to evaluate and address the threats extreme heat and cold weather events pose to the Reliable Operation of the Bulk-Power System.[203]

Section 215(d)(5) of the Federal Power Act empowers FERC to direct NERC to submit new Reliability Standards to FERC for its approval.[204] Order No. 896 was a response to recent extreme heat and cold weather events.[205] FERC noted that from 2011 to 2023 seven extreme weather events put stress on the Bulk-Power System, causing various degrees of load shed and threating the system's collapse.[206] While FERC recognized that existing Reliability Standards, such as TPL-001-5.1, include provisions that require transmission planners to evaluate performance during extreme weather events, FERC thought a gap remained because there was no obligation to specifically evaluate extreme heat and cold weather events.[207]

To address the reliability gap described above, FERC directed NERC to develop new or modified Reliability Standards that require ISOs/RTOs to take three new steps, discussed in turn below.[208]

First, NERC must develop benchmark planning cases, based in part on major prior extreme heat and cold weather events and/or future meteorological projections. FERC made clear that NERC should ensure these benchmarks reflect regional differences in climate and weather patterns.[209]

Second, NERC must plan for extreme heat and cold weather events using steady state and transient stability analyses that cover a range of extreme weather scenarios, including expected availability of the resource mix during extreme heat and cold weather conditions, and how extreme heat and cold weather could impact broad areas. FERC explicitly called out the need to for RTOs/ISOs to evaluate the correlation between cold weather events and increased generator outages.[210]

Third, when performance requirements during extreme heat and cold weather events are not met, NERC must develop corrective action plans that mitigate shortcomings. FERC gave NERC the flexibility to specify what circumstance require a corrective action plan. FERC noted that developing new interregional transfer capacity may be an acceptable corrective action plan but declined to set minimum transfer requirements.[211] As part of a new Reliability Standard, FERC made clear

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203. Order No. 896, *Transmission System Planning Performance Requirements for Extreme Weather*, 183 FERC ¶ 61,191 at P 1 (2023) [hereinafter Order No. 896].

204. 16 U.S.C. § 824o(d)(5) (2024).

205. Order No. 896, *supra* note 203, at P 2.

206. *Id.* at P 4.

207. *Id.* at PP 5, 23.

208. *Id.* at P 6.

209. Order No. 896, *supra* note 203, at P 38.

210. *Id.* at P 88.

211. *Id.* at P 162.

NERC should ensure RTOs/ISOs share their corrective action plans with, and solicit feedback from, relevant state regulatory agencies.[212]

The rule was published in the Federal Register on June 21, 2023. FERC directed NERC to submit new Reliability Standards to FERC by December 21, 2024, eighteen months after the rule's publication.[213] The new or modified Reliability Standard will take effect no later than 12 months after FERC approves it.[214]

VIII. MANKATO ENERGY CENTER, LLC, ET AL.

In Order on Notice of Change in Status and Terminating section 206 Proceeding (ER20-2705-001, issued September 21, 2023), FERC found that J.P. Morgan Investments was an affiliate of IIF Holding 2 LP, and their subsidiary, Mankato Companies (Mankato), because there was the absence of arm's-length bargaining power between the companies.[215] As a result, FERC ordered Mankato and IIF US Holding 2 to update their asset appendix serial numbers to reflect their affiliations with J.P. Morgan and its affiliates and to update their horizontal and vertical market power analysis with their affiliates' generation and transmission assets within sixty days.[216]

FERC initiated a section 206 proceeding in response to a Notice of Change Status filed by Mankato companies to evaluate whether J.P. Morgan Investments and Mankato, through its upstream owner IIF US Holding 2 LP, were affiliates.[217] 18 CFR § 35.36(a)(9)(iii) defines affiliates as companies where "there is liable to be an absence of arm's length bargaining in transactions."[218] When FERC is evaluating whether to allow a company to sell electricity via market-based rates, FERC closely analyzes the relationship between affiliates to ensure there is arm's length bargaining power, which will help prevent against a company exercising market power.[219]

In the present case, IFF US Holding 2 owns 96% of Onward Energy, which is the upstream owner of Mankato Companies.[220] IIF US Holding 2 is in turn owned by IIF 2 GP, a partnership of three people that have ultimate control over IIF US Holding 2.[221]

J.P. Morgan Investments was the investment advisor for IIF US Holding 2, subject to a vast Investment Advisory Agreement.[222] IIF US Holding 2 did not

212. *Id.* at P 157.

213. Order No. 896, *supra* note 203, at P 28.

214. *Id*.

215. Order on Notice of Change in Status and Terminating Section 206 Proceeding, *Mankato Energy Ctr., LLC et al.*, 184 FERC ¶ 61,170 at P 2 (2023).

216. *Id.*

217. *Id*. at P 1.

218. 18 C.F.R. § 35.36(a)(9)(iii) (2023).

219. 184 FERC ¶ 61,170, at P 64.

220. *Id.* at P 6 (IIF Holding 2 is also the indirect upstream owner of El Paso Electric Company).

221. *Id.* at P 5.

222. *Id.* at P 9.

have any employees, so under the agreement it delegated day-to-day responsibilities for management and operations to J.P. Morgan Investments.[223] A J.P. Morgan Investments employee served on Onward Energy's (Mankato's parent company's) Board of Directors on behalf of IIF Holding 2.[224]

J.P. Morgan Investment is affiliated with J.P. Morgan, which owns passive, non-managing interests in various public utilities. Another affiliate of J.P. Morgan Investments is J.P. Morgan Ventures Energy Corporation, which is authorized by FERC to "sell electric energy, capacity, and ancillary services at market-based rates."[225]

Mankato made the following arguments to support its position that an arm's-length relationship existed between the company and J.P. Morgan Investments. First, it argued that while J.P. Morgan made recommendations for investment and material shareholder matters, IIF US Holding 2 was the ultimate decision-maker.[226] Second, Mankato argued that it did not delegate decisions about selling electricity or operating facilities.[227] Third, Mankato argued that in performing investment advisory services for IIF US Holding 2, J.P. Morgan Investment was subject to the ultimate authority and oversight of IIF 2 GP.[228] J.P. Morgan echoed this argument.[229] Finally, Mankato contended that the SEC's rules create a "federal fiduciary relationship" between J.P. Morgan investment advisors and IIF US Holding 2 that obligated J.P. Morgan to provide the advice in the "best interest of its client, based on its client's objectives."[230] Mankato argued this fiduciary relationship provided the protections associated with an arm's-length relationship.[231] J.P. Morgan echoed this argument.[232]

FERC held that J.P. Morgan Investment was an affiliate of Mankato through IIF US Holding 2, as described in section 35.36(a)(9)(iii) of FERC's regulations. FERC reached this decision based on three primary factors: (1) "the close relationship between IIF US Holding 2 and J.P. Morgan Investments"; (2) the broad duties IIF US Holding 2 delegated to J.P. Morgan Investments; and (3) J.P. Morgan Investment's role on Mankato's Board.[233]

First, reviewing the close relationship between IIF US Holding 2 and J.P Morgan investment, FERC emphasized that J.P. Morgan Investments was empowered to execute and bind IIF US Holding 2, and that IIF US Holding 2 has no

223. 184 FERC ¶ 61,170, at PP 39-41.
224. *Id.* at P 7.
225. *Id.* at P 9.
226. *Id.* at P 28.
227. 184 FERC ¶ 61,170, at P 28.
228. *Id.*
229. *Id.* at P 51.
230. *Id.* at P 35.
231. 184 FERC ¶ 61,170, at PP 34-35.
232. *Id*. at P 51.
233. *Id.* at P 62.

employees, which made it reliant on J.P. Morgan Investments. This close relationship supported the conclusion J.P. Morgan Investments, IIF US Holding 2 (and its subsidiary Mankato Companies) were affiliates.[234]

Second, analyzing the broad duties IIF US Holding 2 delegated to J.P. Morgan Investments, FERC concluded the Investment Advisory Agreement between the two companies gave JP Morgan Investments broad authority to act on behalf of IFF US Holding 2. JP Morgan Investments was empowered to "make virtually every major decision on behalf of IIF US Holding 2."[235] The broad duties delegated to J.P. Morgan supported the conclusion the companies were affiliates.

Third, reviewing the role of a JP Morgan Investments employee on Onward Energy's Board of Directors, FERC worried that IIF US Holding 2 needed to use a JP Morgan employee to fulfill their duties on the Onward Energy Board of Directors. FERC believed this demonstrated IIF US Holding 2 could not function without JP Morgan Investments. Due to the arrangement, JP Morgan Investment employees, along with other Onward Energy board members, played a role in all aspects of Mankato's operations, including the operation of its generation facilities.[236]

Based on these findings, FERC directed Mankato to file a change in status and update their asset appendixes to reflect their affiliation with JP Morgan Investment. FERC also ordered Mankato to "update their horizontal and vertical market power analysis with their affiliates' generation and transmission assets."[237] FERC directed IIF US Holding 2 and its other subsidiaries to take a similar action.[238]

IX. Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems, FERC Order No. 887

In Order No. 887, issued January 19, 2023, FERC provided two main directives to NERC, which are discussed in turn below.[239]

In the first directive, FERC instructed NERC to ensure that any new or modified CIP Reliability Standards incorporate the following three security objectives. First, NERC must "address the need for responsible entities to develop baselines of their network traffic inside their CIP-networked environment."[240] Second, NERC must "address the need for responsible entities to monitor for and detect unauthorized activity, connections, devices, and software inside the CIP-networked environment."[241] Third, Order No. 887 requires "responsible entities to identify anomalous activity to a high level of confidence by logging network

234. *Id.* at P 66.

235. 184 FERC ¶ 61,170, at P 72.

236. *Id*. at P 76.

237. *Id.* at P 83.

238. *Id.* at P 88.

239. Order No. 887, *Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems*, 182 FERC ¶ 61,021 at P 5 (2023) [hereinafter Order No. 887].

240. *Id.*

241. *Id.*

traffic, maintaining logs and other data collected regarding network traffic, and implementing measures to minimize the likelihood of an attacker removing evidence of their tactics, techniques, and procedures from compromised devices."[242]

Notably, FERC narrowed the applicability of the final rule in response to comments on the NOPR. In the NOPR, FERC proposed to apply the INSM requirement to all medium impact BES Cyber Systems.[243] Commenters suggested narrowing this proposal so the final rule would apply to medium impact BES Cyber Systems at control centers or to medium impact BES Cyber Systems with external routable connectivity.[244] Commenters worried that applying the requirement to all medium impact BES Cyber Systems would be costly, stretch cyber security staff, and be ineffective given that many medium impact BES Cyber Systems do not have the external routable connectivity necessary to effectively implement INSM.[245]

Recognizing these concerns, FERC directed NERC to limit the INSM requirement to medium impact BES Cyber Systems with external routable connectivity. FERC noted that facilities without external routable connectivity are less vulnerable to attack, and external routable connectivity is necessary to achieve the full, real-time benefits of INSM.[246]

FERC directed NERC to submit the new CIP Reliability Standards by July 10, 2024, which is fifteen months from the effective date of the final rule.[247] FERC did not provide a specific implementation timeframe for these standards, instead allowing NERC to propose an implementation period that appropriately balances the concerns expressed in the record against the security benefit of timely implementing INSM.[248]

In the second directive, FERC ordered NERC to study the feasibility of implementing INSM for medium impact BES Systems without external routable connectivity and low impact BES Cyber Systems. In the NOPR, FERC sought comments on the benefits of extending an INSM requirement to low impact BES Cyber Systems.[249] Cybersecurity vendors supported extending the INSM requirement to these systems because they believe the low impact BES Cyber System could be used to attack the broader BES.[250] But NERC and a coalition of utilities and power generators opposed the requirement because they did not believe the marginal security benefits outweighed the large costs.[251]

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242. *Id.*

243. Notice of Proposed Rulemaking, *Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems*, 178 FERC ¶ 61,038 at P 1 (2022) [hereinafter INSM NOPR].

244. Order No. 887, *supra* note 239, at P 43.

245. *Id.* at P 47.

246. *Id.* at P 58.

247. *Id.* at P 6.

248. Order No. 887, *supra* note 239, at P 87.

249. INSM NOPR, *supra* note 243, at P 33.

250. Order No. 887, *supra* note 239, at PP 62-63.

251. *Id.* at P 65.

FERC decided not to extend the INSM requirement to low impact BES Cyber Systems or to medium impact BES Cyber Systems without external routable connectivity.[252] Recognizing that it may be necessary to do so in the future, FERC directed NERC to study: (1) the risks created by the absence of such a requirement; and (2) the challenges and solutions for extending an INSM requirement to such medium and low impact BES Cyber Systems.[253]

FERC directed NERC to complete this study by January 19, 2024, or twelve months of issuance of the final rule.[254]

252. *Id.* at P 68.

253. *Id.* at PP 88-90.

254. Order No. 887, *supra* note 239, at P 1.