REPORT OF THE ELECTRICITY COMMITTEE

This report covers significant legal developments pertaining to the electric power system in 2022.*

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I. FERC ADVANCED NOTICE OF PROPOSED RULEMAKING ON TRANSMISSION PLANNING, COST ALLOCATION, AND GENERATOR INTERCONNECTION

A. Introduction and Background

The Federal Energy Regulatory Commission (FERC or Commission) issued the Advanced Notice of Proposed Rulemaking (ANOPR) in response to ongoing and accelerating changes to the nation's electrical grid and transmission system.[1] These fundamental changes to the grid are driven by new sources of power generation and new demands on the nation's transmission infrastructure.[2] Because of the accumulation of changes to the grid and the inevitability of further changes, the Commission is revisiting transmission regulations to fulfill its statutory obligation to secure a reliable grid and reasonable rates for ratepayers.[3] To address these major obligations, the ANOPR focuses on three key categories: (1) "regional transmission planning;" (2) generation interconnection; and (3) strengthened transmission oversight.[4] To achieve the Commission's goals of grid reliability and reasonable rates, measures to improve planning, increased efficiencies through coordination between and within regions, better methods of accounting for benefits, and optimizing cost dispersal are common themes throughout the ANOPR.[5] The ANOPR was succeeded by the issuance of a Notice of Proposed Rulemaking (NOPR) on April 21, 2022.[6]

B. *Transmission Planning and Cost Allocation*

The ANOPR sought comment on two categories of reforms for regional transmission planning and cost allocation.[7] The first category of reforms concerns planning for forecasted transmission needs.[8] The Commission sought comment on four subcategories of reforms related to planning: (1) future scenario modeling; (2) identification of geographic zones with high renewable energy potential; (3) incentives for regional transmission facilities; and (4) enhanced inter-state and inter-regional coordination.[9] Regarding scenario modeling, the Commission sought comment on factors to consider, mandated timeframes, stochastic or probabilistic benefit assessments, and methods of accounting for future generation.[10] The ANOPR sought comment on how to best structure a requirement for transmission providers to assess geographic areas for potential renewable energy generation.[11] As part of the broader effort to create efficiencies throughout transmission plan-

1. Advanced Notice of Proposed Rulemaking, *Building for the Future Through Electrical Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 86 Fed. Reg. 40,266 (2021).
2. *Id.*
3. *Id.*
4. *Id.*
5. 86 Fed. Reg. 40,266, at 40,267.
6. Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 87 Fed. Reg. 26,504, 26,506 (to be codified at 18 C.F.R. pt. 35) (2022).
7. 86 Fed. Reg. 40,266, at 40,274, 40,277.
8. *Id.* at 40,274.
9. *Id.* at 40,274-76.
10. *Id.* at 40,274-75.
11. 86 Fed. Reg. 40,266, at 40,275.

ning, the Commission sought comment on how to incentivize the regional facilities that would be more efficient "than local alternatives."[12] Finally, the Commission sought comment on whether inter-regional coordination procedures need reform to facilitate the above transmission planning proposals.[13]

The second category of reforms upon which the Commission sought comment relate to the potential synchronization of the "regional transmission planning" and "generator interconnection processes."[14] The ANOPR also sought comment on how better forecasting of generation may reduce costs associated with interconnection.[15]

C. *Interconnection Study Process*

The ANOPR discusses two categories of potential reforms related to interconnection.[16] First, the Commission sought comment on cost allocation for transmission facilities planned through the regional transmission planning process, specifically the provisions that will facilitate a more robust planning process that better accounts for benefits (both quantifiable and unquantifiable), and changes in the resource generation mix.[17]

The second category concerning interconnection deals with potential reforms for the initial funding of interconnection-related network upgrades.[18] The Commission is concerned that the participant funding model, whereby interconnection customers bear the upfront upgrade costs, prices-out many new generation sources and does not account for the benefits of these new generation sources.[19] The ANOPR sought comment on the potential of requiring transmission providers to bear the upfront costs of interconnection upgrades by crediting the new interconnection customers.[20]

D. *Enhanced transmission oversight*

The ANOPR sought comment on three major proposals for enhanced transmission oversight.[21] First, the Commission sought comment on mandating transmission providers to establish Independent Transmission Monitors.[22] These monitors would improve transparency and oversight by reviewing planning processes and costs of facilities, and by evaluating whether decisions made by the transmission provider facilitate efficient rates.[23]

12. *Id.* at 40,276.
13. *Id.* at 40,276-77.
14. *Id.* at 40,277.
15. 86 Fed. Reg. 40,266, at 40,277.
16. *See generally* 86 Fed. Reg. 40,266.
17. *Id.* at 40,277.
18. *Id.* at 40,287.
19. *Id.* at 40,284-85.
20. 86 Fed. Reg. 40,266, at 40,286.
21. *See generally* 86 Fed. Reg. 40,266.
22. *Id.* at 40,291-93.
23. *Id.* at 40,291-92.

Second, the ANOPR sought comment on adding state oversight to enhance transmission oversight.[24] The ANOPR sought comment on the advisability of the SPP model of a state regulatory committee which provides input on regionally important matters related to the transmission grid, and any number of other regulatory constructs.[25]

Finally, the Commission sought comment on potentially limiting recovery costs for abandoned projects.[26] Under the FPA, government-funded reimbursement ranges between 50-100% of incurred costs for abandoned projects, and the Commission fears this may create an incentive to abandon projects.[27] Transmission planning accounts for many of these projects and their abandonment therefore damages the process and hurts ratepayers.[28]

II. FERC Notice of Proposed Rulemaking on Transmission Planning, Cost Allocation, and Generator Interconnection

In April 2022, the FERC published a Notice on Proposed Rulemaking with numerous reforms concerning regional transmission planning, cost allocation, and generator interconnection.[29]

A. Regional Transmission Planning

As identified in the NOPR, the Commission is concerned that current "regional transmission planning processes" result in inefficiencies because the planning time horizon is too short.[30] This short-term planning, as identified by the Commission, results in piece-meal improvements to the grid rather than comprehensive and long-term improvements that account for anticipated changes in demand and the generation resource mix.[31] The NOPR expresses concern that the current short-term approach to "regional transmission planning" also fails to capture the true benefits of planned regional transmission facilities.[32] The cumulative effect of these planning shortfalls is that ratepayers ultimately pay for inefficiencies.[33]

To remedy the inefficiencies associated with short-term planning, the Commission proposes a requirement that "public utility transmission providers" implement a long-term planning process with three key components.[34] Under this proposal, public utility transmission providers would be required to (1) "identify transmission needs" based on a series of scenarios that specifically account for

24. *Id.* at 40,293.
25. 86 Fed. Reg. 40,266, at 40,293.
26. *Id.* at 40,293-94.
27. *Id.*
28. *Id.*
29. 87 Fed. Reg. 26,504.
30. *Id.* at 26,518-19.
31. *Id.*
32. *Id.* at 26,519.
33. 87 Fed. Reg. 26,504, at 26,519.
34. *Id.*

changes in demand and generation resource mix; (2) coordinate regional transmission planning and the generator interconnection process; (3) assess "the benefits of regional transmission facilities" over a minimum 20 year time period from the date these facilities begin service; and (4) implement transparent criteria for the selection of transmission facilities.[35] Though much of the NOPR seeks to correct problems identified from previous orders, the "transmission planning principles [of] coordination; openness; transparency; information exchange; comparability; and dispute resolution" remain a requirement.[36]

The NOPR proposes a mandate for public utility transmission providers to identify transmission needs based on a series of long-term planning scenarios. The Commission defines a scenario as "a hypothetical sequence of events that includes assumptions used to forecast transmission needs."[37] To ensure comprehensive planning, the Commission proposes five requirements for the scenario planning used by public utility transmission providers.[38] Scenario planning must incorporate: (1) four scenarios; (2) a 20-year planning horizon, reassessed every three years; (3) FERC-identified factors which account for changes in demand and the generation resource mix; (4) "best available data," which is current and derived from multiple expert sources; and (5) consideration of geographic zones with high potential for power generation.[39]

To add efficiency, the NOPR proposes guidance for coordinating regional transmission planning and generator interconnection.[40] The Commission believes that too often public utility transmission providers fail to plan for network upgrades based on anticipated demand and generation resource mix, and instead enact these upgrades in response to upgrades directly related to interconnection.[41] The Commission states that part of this issue stems from the fact that public utility transmission providers often use baseline models that do not account for projects in the queue until those projects have a completed facilities study.[42] As a solution, the Commission proposes that public utility transmission providers identify and address interconnection shortfalls.[43] The Commission identifies shortfalls with the following four criteria for public utility transmission providers to prioritize: (1) the interconnection issue has come up at least twice in the last five years; (2) the upgrade is at least 200 kV or $30,000,000; (3) the network upgrade has not occurred because the interconnection request was withdrawn; and (4) the network need is not addressed in another part of the grid.[44] The Commission believes this

35. *Id.* at 26,519-20.
36. *Id.* at 26,520-21.
37. 87 Fed. Reg. 26,504, at 26,522.
38. *Id.* at 26,522-23.
39. *Id.*
40. *Id*. at 26,533.
41. 87 Fed. Reg. 26,504, at 26,533.
42. *Id.* at 26,534.
43. *Id.* at 26,535.
44. *Id.*

will remedy current issues because fixing underlying grid issues and reducing barriers to entry for new sources will ultimately lead to better rates for ratepayers.[45]

The Commission proposes that public utility transmission providers evaluate regional transmission facilities in two steps.[46] First, public utility transmission providers are to "evaluate the benefits of [these] . . . facilities" based on their assessed ability to meet needs based on demand and resource mix.[47] Public utility transmission providers are to be transparent in their methodology for identifying and calculating these benefits.[48] Second, the Commission proposes that public utility transmission providers evaluate these benefits over a 20-year period.[49] Additionally, benefits are to be evaluated as a "portfolio" of regional transmission facilities, instead of individual assessments of each facility.[50]

The Commission proposed that public utility transmission providers include in their OATTs transparent selection criteria for the identification of transmission facilities and a codified process for the utility transmission provider to coordinate with state entities for criteria development.[51] The Commission advances two potential approaches to regional transmission facility selection.[52] "Under a least regrets approach," facility selection is based on expected net benefits over a greater number of scenarios.[53] Under the "weighted-benefits approach," facility selection is based on expected benefits weighted by probability.[54]

In addition to long-term planning of transmission facilities, the NOPR also proposes a mandatory process whereby public utility transmission providers must consider the use of "dynamic line ratings" and "advanced power flow control devices."[55] The NOPR refers to these as Grid Enhancement Technologies (GETs).[56] The Commission considers these important because their employment may often be more efficient and cost effective than the construction of entirely new transmission facilities.[57]

B. Regional Transmission Cost Allocation

The NOPR identifies effective cost allocation as integral to the statutory imperative that rates be "just and reasonable and not unduly discriminatory or preferential."[58] To achieve this, the Commission proposes cost allocation reforms in

45. 87 Fed. Reg. 26,504, at 26,536.
46. *Id.* at 26,537.
47. *Id.*
48. *Id.*
49. 87 Fed. Reg. 26,504, at 26,537.
50. *Id.*
51. *Id.* at 26,547.
52. *Id.* at 26,549.
53. 87 Fed. Reg. 26,504, at 26,549.
54. *Id.*
55. *Id.* at 26,552.
56. *Id.*
57. 87 Fed. Reg. 26,504, at 26,552.
58. *Id.*

the following categories: (1) state involvement in the cost allocation associated with long-term regional transmission facilities; (2) a mandatory time period for cost allocation negotiations; (3) an enhanced identification of benefits to more effectively allocate costs associated with transmission facilities; and (4) procedures to coordinate regional transmission facility planning and generator interconnection.[59]

The Commission proposes three options concerning tariff revision for public utility transmission providers to incorporate state involvement in cost allocation related to regional transmission facilities.[60] State involvement must come from a relevant state entity which is responsible for "utility regulation or siting."[61] First, the OATT can codify a method for long-term regional cost allocation.[62] Second, the OATT can include a state agreement process whereby at least one state entity agrees to the cost allocation method.[63] Under a system of agreement with a state entity, the Commission specifies four options: (1) all parties agree to a cost allocation method; (2) the parties agree to an agreement process with the state; (3) the state entities agree to forgo a cost allocation role; or (4) a combination of the first three options.[64] Finally, the OATT can include a combination of the first two methods.[65]

Regardless of the method chosen for incorporation in the OATT, the public utility transmission provider must comply with the six following cost allocation principles: (1) transmission facility costs must be allocated approximately to their expected benefits; (2) areas that will not benefit cannot be allocated costs involuntarily; (3) benefit-to-cost ratios cannot exceed 1.25-to-1; (4) cost allocation must occur within a planning region (unless an outside region voluntarily assumes costs); (5) beneficiary determinations "must be transparent;" and (6) different types of transmission facilities can have different cost allocation methods in different regions.[66]

As part of the wider effort to ensure deliberate planning to facilitate efficient transmission, the Commission proposes a requirement that public utility transmission providers codify a window of time in their OATT to negotiate transmission facility cost allocation with state entities.[67] This is to be a separate cost allocation method than applies through the standard Long-Term Regional Transmission planning process.[68] This alternate cost allocation method is intended to gain buy-

59. *Id.* at 26,557-60.
60. *Id.* at 26,557.
61. 87 Fed. Reg. 26,504, at 26,557.
62. *Id.*
63. *Id.*
64. *Id.*
65. 87 Fed. Reg. 26,504, at 26,557.
66. *Id.* at 26,553.
67. *Id.* at 26,559-60
68. *Id.*

in from stakeholders and will, therefore, more likely result in higher rates of facility construction because of the increased perception of fairness.[69]

In the absence of agreement from state entities, or the Commission's rejection of the state's "cost allocation method," the transmission facility developer is entitled to proceed with cost allocation methods derived from the Long-Term Regional Transmission Planning process.[70]

Effective cost allocation must sufficiently account for the benefits associated with the transmission facility.[71] The Commission assesses that the current process for cost allocation evaluation likely results in "public utility transmission providers undervaluing [potential] benefits of Long-Term Regional Transmission Facilities."[72] The Commission therefore proposed a standardized list of benefits that public utility transmission providers are to consider when evaluating transmission facilities.[73] Simultaneously, public utility transmission providers are to publish the benefits and how those benefits are calculated in the utility's long-term regional transmission planning.[74]

The Commission proposes coordination between Regional Transmission Planning and Generator Interconnection processes because this coordination will allocate costs to a greater number of beneficiaries.[75]

C. Interregional Transmission Planning and Coordination

The Commission assesses that FERC Orders 890 and 1000 are "too narrowly focused geographically" and fall short of requiring analysis of potential benefits that could be gained through inter-regional transmission facility cooperation.[76] As a remedy, the Commission proposes a requirement for public utility transmission providers to make two major revisions to their inter-regional coordination procedures.[77] First, public utility transmission providers are to add an information-sharing requirement so that transmission providers in other regions have access to information regarding transmission needs identified in the Long-Term Regional Transmission Planning process.[78] Second, transmission providers will be required to identify and evaluate, in concert with other interregional providers, interregional transmission facilities that are potentially more efficient or cost effective to address needs identified in the Long-Term Regional Transmission Planning process.[79]

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69. 87 Fed. Reg. 26,504, at 26,559.
70. *Id.* at 26,559-60.
71. *Id.* at 26,553.
72. *Id.* at 26,560.
73. 87 Fed. Reg. 26,504, at 26,560.
74. *Id.* at 26,526-27.
75. *Id.* at 26,536.
76. *Id.* at 26,577.
77. 87 Fed. Reg. 26,504, at 26,577.
78. *Id.*
79. *Id.*

D. Other Key Provisions of the NOPR

The Commission seeks a balance between the need to incentivize infrastructure and the need to protect ratepayers.[80] The Commission, therefore, proposes a bar on the use of the Construction Work in Progress Incentive (CWIP) for Long-Term Regional Transmission Facilities to shield ratepayers from potentially funding projects that do not run to completion.[81]

To reestablish the potential benefits of the federally created right of first refusal for public utility transmission providers that was eliminated in FERC Order No. 1000, the Commission now proposes a reinstatement of the right of first refusal in certain circumstances.[82] The Commission proposes to "find presumptively just and reasonable and not unduly discriminatory or preferential the establishment of a federal right of first refusal" if joint-ownership requirements are met for incumbent transmission providers.[83]

The Commission now proposes an amendment to FERC Order No. 1000 so that incumbent transmission providers can, but will not be required to, take advantage of the federal right of first refusal if joint ownership is established.[84] If an incumbent transmission provider does not exercise this right of first refusal, the public utility transmission provider is to abide by the standard "competitive transmission development process to select a qualified transmission developer to use the regional transmission cost allocation method for the selected regional transmission facilities."[85]

The NOPR proposed public utility transmission provider tariff alterations to enhance transparency of the local transmission planning process and to identify opportunities for facility right-sizing.[86] The Commission has identified the replacement of transmission infrastructure as a systemic planning shortfall.[87] Currently, transmission facilities that are replaced with equivalent or smaller capacity are not subject to transmission planning requirements specified in FERC Orders No. 890 and 1000.[88] Often this means that analysis to evaluate whether facility replacement can be done "more efficiently or cost-effectively" does not occur.[89] The Commission proposes a requirement that public utility transmission providers revise their OATTs to increase public transparency of (1) their transmission planning inputs; (2) identified "local transmission needs;" and (3) "potential local or

80. *Id.* at 26,561.

81. 87 Fed. Reg. 26,504, at 26,560-61. CWIP was originally created under the Energy Policy Act of 2005 and refined under FERC Order No. 679 to incentivize transmission projects which have large gaps between project initiation and revenue generation by enabling transmission developers to pass costs on to rate payers during construction. *Id.*

82. *Id.* at 25,677-78.

83. *Id.* at 26,566.

84. *Id.* 26,564-65.

85. 87 Fed. Reg. 26,504, at 26,566.

86. *Id.* at 26,576.

87. *Id.* at 26,571.

88. *Id.* at 26,570-71.

89. 87 Fed. Reg. 26,504, at 26,570.

regional transmission facilities that" can be altered as remedies to transmission needs.[90] The Commission also proposes three mandated stakeholder meetings to focus on "the criteria, assumptions, and models related to each public utility transmission provider's local transmission planning;" the outputs of these meetings are to be made publicly available.[91]

The Commission's focus for right-sizing is on facilities that (1) operate at or above 230 kV; and (2) facilities that have been identified for replacement within 10 years.[92] Once identified, information concerning public utility transmission facilities selected for right-sizing will be made publicly available.[93]

Initial comments on the NOPR are due July 18, 2022.[94] Reply comments are due August 17, 2022.[95]

III. FERC DOCKET NO. RM20-16-000; ORDER NO. 881, MANAGING TRANSMISSION LINE RATINGS

On December 16, 2021, FERC issued Order No. 881 revising "the *pro forma* Open Access Transmission Tariff (OATT) and the [C]ommission's" corresponding regulations in an effort to "improve the accuracy and transparency of electric transmission line ratings."[96] Order No. 881 hinges on the Commission's proposed revisions from a NOPR issued on November 19, 2020.[97] Adopting many of the proposed reforms in the NOPR, the Commission issued Order No. 881, requiring that:

> (1) public utility transmission providers implement ambient-adjusted ratings on the transmission lines over which they provide transmission service; (2) RTOs and ISOs [must] establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; (3) public utility transmission providers must use uniquely determined emergency ratings; (4) public utility transmission owners [must] share transmission line ratings and transmission line rating methodologies with their respective transmission provider and with market monitors in RTOs and ISOs; and (5) public utility transmission providers [must] maintain a database of transmission owners' transmission line ratings and transmission line rating methodologies on the transmission provider's Open Access Same-Time Information System (OASIS) site or other password protected website.[98]

In the final order, the Commission adopts definitions for transmission line ratings, ambient adjusted ratings and dynamic line ratings, additionally the Commission also adopts requirements for the wider use of ambient adjusted ratings,[99]

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90. *Id.* at 26,573.
91. *Id.*
92. *Id.* at 26,574.
93. 87 Fed. Reg. 26,504, at 26,575.
94. *Id.* at 26,580.
95. *Id.*
96. Final Rulemaking, *Managing Transmission Line Ratings*, 87 Fed. Reg. 2,244 (2021) (to be codified at 18 C.F.R. pt. 35).
97. *Id*. at 2,246.
98. *Id.* at 2,244.
99. *Id.* at 2,245.

for emergency ratings,[100] and to improve transparency.[101] The final rule also notes that the Commission has opened a proceeding in AD22-5-000 to explore the potential for further action on dynamic line ratings.[102]

A. Transmission Line Ratings

In this final rule, Order No. 881, the Commission

> adopt[ed] the definition of transmission line rating… [to] mean the maximum transfer capability of a transmission line, computed in accordance with a written transmission line rating methodology and consistent with good utility practice, considering the technical limitations on conductors and relevant transmission equipment, such as thermal flow limits, as well as technical limitations of the transmission system, such as system voltage and stability limits.[103]

The Commission will "not require transmission line ratings that are not affected by ambient air temperatures to be rated using forecasts of ambient air temperatures."[104] However, the Commission "decline[s] to define . . . which electric system equipment ratings are (or are not) [impacted] by ambient air temperatures."[105] The Commission also "decline[s] to provide a [universal] exception from the [ambient adjusted ratings] requirement for power transformers."[106] As provided by the exceptions adopted in the ruling, "if a transmission provider, [upon] good utility practice, determines that a . . . power transformer's rating is not affected by ambient air temperature, then that transformer would fall within the scope of such exceptions to the [ambient adjusted ratings] requirement."[107]

B. Ambient Adjusted Ratings

In this final rule, Order No. 881, the Commission adopted to apply ambient adjusted ratings requirement to all transmission lines, exceptions provided, to "ensure that wholesale rates remain just and reasonable and strike an appropriate balance between benefits and challenges of [ambient adjusted ratings] implementation."[108] The Commission also "adopt[s] a requirement for transmission providers to use [ambient adjusted ratings] when evaluating the availability of and requests for near-term transmission service."[109] The Commission "defines requests for near-term transmission service to include . . . requests for near-term point-to-point transmission service, . . . network resource designations, and secondary service

100. 87 Fed. Reg. 2,244, at 2,245-46.
101. *Id.* at 2,246.
102. *Id.* at 2,285.
103. *Id.* at 2,251.
104. 87 Fed. Reg. 2,244, at 2,251.
105. *Id.*
106. *Id.*
107. *Id.* at 2,252.
108. 87 Fed. Reg. 2,244, at 2,257.
109. *Id.* at 2,258.

where the start and end date of the designation/request is within the next 10 days."[110]

The [C]ommission adopted a requirement for "transmission providers [to] use [ambient adjusted ratings] as the relevant transmission line rating when determining whether to curtail or interrupt near-term point-to-point transmission service . . . if such curtailment or interruption is . . . necessary [due] to issues related to flow limits on transmission lines and anticipated to occur within the next 10 days,"[111] and "when determining whether to curtail network or secondary service or redispatch network or secondary service, if such curtailment or redispatch is . . . necessary [due to] issues related to flow limits on transmission lines and anticipated to occur within 10 days of such determination."[112]

C. Seasonal Line Ratings

For transmission service in the longer term, the Commission requires that "transmission providers . . . use seasonal line ratings" as the basis for evaluation for requests "ending more than 10 days from the date of the request" and that transmission providers use seasonal line ratings as the basis for the determination of the necessity of curtailment, interruption or redispatch of transmission service that is anticipated to occur more than 10 days in the future. [113]

D. Exceptions and Alternate Ratings

The Commission adopts to "allow exceptions to the [ambient adjusted ratings] and seasonal line rating requirements in instances where the transmission provider determines . . . that the transmission line rating of a transmission line is not affected by ambient air temperatures."[114] "In this [case], the transmission provider[s] may use a transmission line rating for that transmission line."[115] Additionally the Commission:

> establishe[s] a 'System Reliability' section in *pro forma* OATT Attachment M [to] allow . . . transmission provider[s] to temporarily use a transmission line rating different than would otherwise be required . . . in instances [where] the . . . provider reasonably determines . . . that the use of . . . a temporary . . . rating is necessary to ensure the safety and reliability of the transmission system.[116]

E. Emergency Ratings

In this final ruling, the Commission adopts to "require . . . transmission providers [to] use emergency ratings for contingency analysis in the operations horizon and in post-contingency simulations of constraints, [and] define[s] an 'emergency rating' . . . as a transmission line rating that reflects operation for a specified,

110. *Id.*
111. *Id.*
112. 87 Fed. Reg. 2,244, at 2,258.
113. *Id.* at 2,257.
114. *Id.* 2,279.
115. *Id.*
116. 87 Fed. Reg. 2,244, at 2,279-80.

finite period, rather than reflecting continuous operation."[117] The Commission is "requiring that emergency ratings be uniquely *determined* . . . based on assumptions that reflect the specified, finite duration of emergency ratings, as distinct from the assumptions used to calculate normal ratings, which reflect a power transfer capability that can be maintained indefinitely."[118] The Commission also states that "emergency ratings must also include an adjustment for ambient air temperature and daytime/nighttime solar heating, consistent with the [ambient adjusted ratings] requirements for normal ratings."[119]

F. Transparency

In this final ruling, the Commission adopts three additional transparency requirements for transmission providers; 1) "share transmission line ratings and methodologies" with any transmission provider upon request; 2) maintain a database of its "transmission line ratings and methodologies on the transmission provider's OASIS site, or other password-protected website;" 3) "post on OASIS, or . . . other password-protected website," which transmission lines qualify for an exception to the ambient adjusted rating or seasonal line rating requirements and the reasons why such transmission lines qualify for an exception.[120]

G. FERC Docket No. RM20-16-001; Order No. 881-A, Managing Transmission Line Ratings

On December 16, 2021, FERC issued Order No. 881.[121] "On January 18, 2022, several entities filed requests for rehearing and/or clarification of Order No. 881" regarding the new ambient adjusted rating requirements, the annual recalculation of seasonal line ratings, and the new transparency requirements adopted in the final ruling.[122] On May 19, 2022, FERC issued Order No. 881-A sustaining the result of Order No. 881, and denying all requests for rehearing, but providing some clarifications.[123]

1. Ambient Adjusted Ratings - Related Requirements of Order No. 881

"[The [C]ommission] clarify[ies] two aspects of the [ambient adjusted ratings] requirements related to transmission providers' transmission protection relay settings."[124] The Commission also notes that in Order No. 881, it "stated that relay settings 'in the majority of cases should not exceed [ambient adjusted rating] values," the Commission clarifies that was an error.[125]

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117. *Id.* at 2,290.

118. *Id.*

119. *Id.* at 2,246.

120. 87 Fed. Reg. 2,244, at 2,246.

121. *Id.*

122. Order No. 881-A, *Managing Transmission Line Ratings*, 87 Fed. Reg. 31,712 (2022) (to be codified at 18 C.F.R. 35) [hereinafter Order No. 881-A].

123. *Id.* at 31,712-13.

124. *Id.* at 31,715.

125. *Id.* at 31,716 (quoting 87 Fed. Reg. 2,244).

2. Seasonal Line Ratings—Annual Recalculation Requirement

The Commission clarifies that it "did not prescribe the procedure for recalculating seasonal line ratings, including determining which inputs have changed in a year,"[126] and that "the requirement to engage in an annual recalculation does not require transmission owners to undertake unnecessary change from year to year."[127]

3. OASIS Access

The Commission clarifies that transmission providers must implement ambient adjusted ratings on all transmission lines, but have the discretion "to post transmission line ratings and methodologies-related data to a password protected section of their OASIS site *or* another password protected website."[128] "If the transmission provider chooses to post the data to its own website . . . users must be able to access the data in a manner that is comparable to if it were posted to OASIS and subject to OASIS requirements."[129]

IV. Energy and Ancillary Services Market Reforms To Address Changing System Needs

A. Staff Report

On September 8, 2021, the Commission issued a Staff paper entitled "Energy and Ancillary Services Market Reforms to Address Changing System Needs," which was prepared to guide conversations at two upcoming technical conferences.[130] The paper observes that the RTO/ISO energy and ancillary markets "will [require] more operational flexibility . . . as the resource mix evolves to include more variable energy resources and as loads change as a result of weather-dependent distributed energy resources, electrification and other factors."[131] Several RTO/ISOs have begun to make proposals to implement reforms to energy and ancillary services markets to accommodate these changes, some of which remain under FERC consideration.[132]

The paper provides background on the provision of ancillary services in RTO/ISO markets and context on issues caused by changes in the resource mix and load, which can lead to unanticipated changes in net load that create operational challenges.[133] This is exacerbated by "meteorological forecast errors,"

126. Order No. 881-A, *supra* note 122, at 31,723.
127. *Id.* at 31,723.
128. *Id.* at 31,725.
129. *Id.*
130. FERC, Energy and Ancillary Services Market Reforms to Address Changing System Needs, 1, 3 (2021) https://cms.ferc.gov/sites/default/files/2021-09/20210907-4002_Energy%20and%20Ancillary%20Services%20Markets_2021_0.pdf.
131. *Id*. at 3.
132. *Id*.
133. *Id*. at 7-8.

which can increase the uncertainty of "net load forecasts."[134] To address the limitation of their existing market designs in managing this variability, RTOs and ISOs "have increasingly had to rely on out-of-market . . . actions," which can undermine price formation in energy and ancillary service markets.[135] Thus, each RTO/ISO within the Commission's jurisdiction "has either implemented . . . or proposed reforms to address" these issues.[136]

The paper proceeds to summarize these efforts, which include reforms to "increas[e] shortage prices [and] procur[e] higher quantities of existing ancillary services products ([*i.e.*, operating reserve demand curve revisions]), [as well as to] creat[e] new ancillary services products."[137] It also summarizes reforms under consideration in various RTO/ISO stakeholder processes.[138]

B. Order

On April 21, 2022, the Commission issued an order directing RTOs/ISOs to file reports within 180 days containing specific information regarding their changing system needs and plans for potential reforms.[139] In the order, the Commission declines to propose a "one-size-fits-all solution" to address changing system needs, but rather, finds it appropriate to conduct further information gathering to better understand system needs and potential mechanisms for addressing them.[140] The required reports must cover each of the following areas:

- Current system needs in light of the changes in resource mix and load profiles, including whether these needs vary across time horizons within the energy and ancillary service markets and whether there are resource capabilities that could address these needs.[141]
- How these needs are expected to change over time, including how system needs forecasts are developed and what time horizons are expected to present the greatest challenges.[142]
- Information on planned energy and ancillary service market reforms to meet expected system needs, including any ongoing stakeholder processes, how well these efforts will incentivize behaviors that will allow RTOs/ISOs to meet their changing needs, how RTOs/ISOs plan to improve operational practices and how future

134. ENERGY AND ANCILLARY SERVICES MARKET REFORMS TO ADDRESS CHANGING SYSTEM NEEDS, *supra* note 130, at 14.

135. *Id*. at 11.

136. *Id*. at 12.

137. *Id*. at 16.

138. ENERGY AND ANCILLARY SERVICES MARKET REFORMS TO ADDRESS CHANGING SYSTEM NEEDS, *supra* note 130, at 22-24.

139. *Modernizing Wholesale Elec. Mkt. Design*, 179 FERC ¶ 61,029 at P 1 (2022).

140. *Id*. at P 7.

141. *Id*. at P 15.

142. *Id*. at P 20.

reforms will address current mechanisms that incentivize inflexibility.[143]

- Information about other reforms, such as capacity market or resource adequacy reforms, to address changing system needs, as well as reforms needed to address challenges that arise from sources beyond the RTO/ISO markets themselves (such as coordination between balancing authorities, coordination between transmission and distribution operations and "inflexibility in the fuel supply").[144]

Commissioner Danly issued a concurrence, in which he stressed that the Commission should not attempt to "engineer a record by which [it] might later justify Commission action in pursuit of narrow, preordained policy goals."[145] Commissioner Christie also issued a concurrence, in which he suggested that the Commission "expand the scope" of its inquiry beyond energy and ancillary services market constructs.[146] He points out that the Commission has taken no action related to the record it has developed on the role of capacity markets in achieving reliability and resource adequacy and proposes additional "fundamental questions" that should be asked on ISOs/RTOs, including the "all-important question of the continued use of locational marginal pricing (LMP) in these market constructs."[147]

V. BELMONT MUN. LIGHT DEP'T, ET AL. V. FERC, 38 F.4TH 173 (D.C. CIR. 2022)

On June 17, 2022, the D.C. Circuit Court of Appeals issued an opinion in *Belmont Mun. Light Dep't, et al. v. FERC*, 38 F.4th 173 (D.C. Cir. 2022) (*Belmont*) partially vacating a portion of the FERC order in *ISO New Eng. Inc.*, 171 FERC ¶ 61,235 (2020) (June 2020 Order) that accepted for filing tariff revisions, that in part, would implement a program called the Inventoried Energy Program (IEP).[148] Under the IEP, ISO New England Inc. (ISO-NE) would provide payments to electric generating facilities "to maintain up to three days' worth of fuel on-site" for the purpose of "incent[ing] market participants to acquire more inventoried energy than they otherwise would and compensate [those] resources for improving . . . energy reliability."[149] Eligible resources would include: natural gas, oil, trash-to-energy, biomass, coal, nuclear, hydroelectric, solar paired with energy storage, and wind paired with energy storage.[150] The court's vacatur severs FERC's order insofar as it approved the portion of the IEP that would apply to nuclear, coal, biomass, and hydroelectric fuel sources, thus finding "FERC's acceptance of ISO-NE's proposal to compensate those resource owners—despite record evidence that

143. 179 FERC ¶ 61,029 at P 36.
144. *Id*. at P 41.
145. *Id.* at P 2 (Danly, Comm'r., concurring).
146. *Id.* at P 2 (Christie, Comm'r., concurring).
147. 179 FERC ¶ 61,029 at PP 3-4 (Christie, Comm'r, concurring).
148. Belmont Mun. Light Dep't v. FERC, 38 F.4th 173 (D.C. Cir. 2022).
149. *Id.* at 177.
150. *Id.* at 178, 189.

they would not change their behavior in response to [IEP] payments—was not reasoned decision making," and instead, was "arbitrary and capricious."[151] Pursuant to this vacatur, the court remanded the matter "to FERC for further proceedings consistent with its opinion."[152]

The court's rationale rested in part on the fact that the July 2016 Order is contrary to past precedent and that FERC did not make any attempt to explain why it now believes it is appropriate to move away from that precedent.[153] Ultimately, the court determined that FERC's June 2020 Order was severable because there are other categories of resources eligible to participate in the IEP program that would otherwise "meet ISO-NE's proposed conditions for selling inventoried energy."[154] The court also found there to be "strong record evidence that demonstrates that IEP, even without the excluded resources, is designed to improve the Northeast's energy reliability when there is stress on the region's grid in future winters."[155] In summary, the Court left intact FERC's "June 2020 order except for the portion of the IEP that is arbitrary and capricious."[156]

VI. WEST VIRGINIA V. EPA

On June 30, 2022, the U.S. Supreme Court issued its decision in *West Virginia v. EPA*, using the major questions doctrine to limit, but not void, EPA's authority to regulate greenhouse gas (GHG) emissions from existing stationary sources under Clean Air Act (CAA or Act) Section 111(d).[157] The Court concluded that the major questions doctrine precludes EPA from demanding "generation-shifting," which is the approach taken in the Obama Administration's Clean Power Plan (CPP) requiring power plants to transition from higher-GHG emitting (e.g., coal) to lower-GHG emitting (e.g., natural-gas, wind, and solar) production.[158] The Court did not opine on any measures other than CPP that EPA may use as the "best system of emission reduction (BSER)" under Section 111(d).[159]

A. Background

On January 19, 2021, the D.C. Circuit's decision in *American Lung Association v. EPA* vacated the Trump Administration's Affordable Clean Energy (ACE) Rule, a less stringent GHG emissions rule compared to the CPP, and invalidated

151. *Id*. at 179.

152. *Belmont*, 38 F.4th at 190.

153. *Id*. 178-79. *See ISO New Eng., Inc.*, 154 FERC ¶ 61,133, at P 13 (2016) (FERC order accepting the New England Power Pool's (NEPOOL) proposal and rejecting ISO-NE's proposal to include coal, nuclear, and hydro-electric resources in the Winter Reliability Program because substantial expert testimony supporting NEPOOL's proposal reflected that coal, nuclear, and hydroelectric resources are not likely to change their behavior in response to the particular payments outlined in the ISO-NE Proposal).

154. *Belmont*, 38 F.4th at 188-89.

155. *Id*. at 189.

156. *Id*.

157. West Virginia v. EPA, 142 S. Ct. 2587 (2022).

158. *Id.* at 2604-07.

159. *Id.* at 2602.

EPA's repeal of the CPP.[160] Following the D.C. Circuit's decision, no regulation of existing power plant GHG emissions was in place.[161] EPA also issued a memo disclaiming the intent to implement either ACE or the CPP.[162] States including West Virginia appealed.[163] On October 29, 2021, the Supreme Court granted review the D.C. Circuit's decision.[164]

B. Majority Opinion

Chief Justice Roberts wrote the majority opinion in *West Virginia v. EPA*, joined by Justices Thomas, Alito, Gorsuch, Kavanaugh, and Barrett.[165] The majority opinion began by an introduction of different programs under CAA and the history of the CPP and ACE Rules.[166] Next, the Court rejected EPA's argument that "no [party] had Article III standing to seek . . . review" of the CPP.[167] The Court found that the States were injured by the vacatur of the ACE Rule and the CPP repeal, which "purport[ed] to bring the Clean Power Plan back."[168] The Court concluded that the States had standing and thus the case was not moot.[169]

On the merits, the Court found that this was a "major questions case" because EPA's Section 111(d) interpretation authorized the agency to "forc[e] a shift throughout the power grid from one type of energy source to another," and "substantially restructure the American energy market."[170] The Court then focused on the narrow question of whether Congress authorized EPA to employ generation-shifting measures under Section 111(d) of the Act.[171] Answering in the negative, the Court looked at the text, context, and history of Section 111(d)'s implementation, finding that Section 111(d) allows EPA to set an emissions cap on sources "based on the application of particular controls," but that "there is no control a coal plant operator can deploy to attain the emissions limits established by the [CPP]."[172]

Notably, the Court affirms that "EPA itself still retains the primary regulatory role in Section 111(d), [and it is] [t]he Agency, not the States, [that] decides the

160. Am. Lung Ass'n v. EPA, 985 F.3d 914 (D.C. Cir. 2021).

161. Kevin McElfresh & Patrick Parenteau, *Beyond the Fence-line: SCOTUS Grants Petitions Challenging EPA's Authority to Regulate Coal-fired Emissions*, VT. J. OF ENVTL. L. (2022), https://vjel.vermontlaw.edu/copy-of-8-vol-23

162. Memorandum from Joseph Goffman, Acting Assistant Adm'r to the EPA Reg'l Adm'rs Regions I – X, (Feb. 12, 2021).

163. *West Virginia*, 142 S. Ct. at 2597 (Petitioners are the States of West Virginia, Alabama, Alaska, Arkansas, Georgia, Indiana, Kansas, Louisiana, Missouri, Montana, Nebraska, Ohio, Oklahoma, South Carolina, South Dakota, Texas, Utah, and Wyoming, and Mississippi Governor Tate Reeves).

164. West Virginia v. EPA, 142 S. Ct. 420 (2021).

165. *West Virginia*, 142 S. Ct. at 2587.

166. *Id.* at 2599-2604.

167. *Id.* at 2606-07.

168. *Id.* at 2606.

169. *West Virginia*, 142 S. Ct. at 2607.

170. *Id*. at 2610-12.

171. *Id.* at 2614.

172. *Id*. at 2610.

amount of pollution reduction that must ultimately be achieved."[173] The Court determined that EPA cannot use Section 111(d) to cap GHGs "at a level that will force a nationwide transition away from the use of coal to generate electricity" without Congress's explicit authorization.[174] Finding that authorization lacking, the Court reversed the DC Circuit's decision in *American Lung Association v. EPA*.[175]

C. Concurrence

Justice Gorsuch authored the concurrence, joined by Justice Alito.[176] Justice Gorsuch discussed the history of the major questions doctrine and its use by the Court, and the importance of ensuring that agencies do not usurp Congress's role by going beyond "fill[ing] up the details."[177] Justice Gorsuch particularly stressed that "the Constitution does not authorize agencies to use pen-and-phone regulations as substitutes for laws passed by the people's representatives."[178]

D. Dissent

Justice Kagan, joined by Justices Breyer and Sotomayor, dissented.[179] The dissent criticized the Court for taking up the case, viewing the majority opinion as "an advisory opinion on the proper scope of the new rule EPA is considering."[180] The dissent opined that the term "best system of emission reduction" under Section 111(d) is conspicuously broad and would comfortably include generation-shifting.[181] "A key reason Congress makes major questions doctrine broad delegations like Section 111 is so an agency can respond, appropriately and commensurately, to new and big problems."[182] The dissent also criticized the majority for having "announc[ed] the arrival of the 'major questions doctrine,' which replac[ed] normal text-in-context statutory interpretation with some tougher-to-satisfy set of rules."[183] The dissent further explained that the major questions doctrine should only apply "when there is a mismatch between an agency's challenged action and its congressionally assigned mission and expertise," but the dissent found no such mismatch in this case.[184]

173. *West Virginia*, 142 S. Ct. at 2601-02.
174. *Id*. at 2616.
175. *Id*.
176. *Id.*
177. *West Virginia*, 142 S. Ct. at 2616-17.
178. *Id*. at 2626.
179. *Id.* at 2626.
180. *Id.* at 2628.
181. *West Virginia*, 142 S. Ct. at 2628.
182. *Id*.
183. *Id*. at 2633-34.
184. *Id*. at 2623-24.

E. Moving Forward

West Virginia v. EPA limits the scope of EPA's authority to reduce GHG emissions and concludes that EPA cannot regulate under the section in a way that would force the power grid to shift power generation from one source to another, but still leaves EPA options to use Section 111(d) and other CAA provisions to control GHGs emissions.[185] The decision's impact goes beyond environmental regulation ─ identifies factors of what constitutes a major question and what issues are major enough that require Congress to give agencies regulatory authority in very specific and clear ways.[186]

Immediately following the Court's ruling in *West Virginia v. EPA*, EPA Administrator Michael Regan issued a statement reassuring that EPA will continue "to us[e] the full scope of [its] authorities" to reduce GHG emissions, protect communities, and support growing a clean energy economy.[187] President Joseph Biden also responded that the Administration "will work with states and cities to pass and uphold laws that protect their citizens" and "will keep pushing for additional Congressional action."[188]

VII. PENNSYLVANIA RGGI LITIGATION

The Commonwealth of Pennsylvania's potential entry into the Regional Greenhouse Gas Initiative (RGGI) remains uncertain.[189] Following Governor Wolf's October 3, 2019 Executive Order,[190] the Pennsylvania Department of Environmental Protection (DEP) undertook a rulemaking to limit the CO2 emissions of fossil fuel-fired electric generating units located in the Commonwealth and "establish the Commonwealth's participation in the Regional Greenhouse Gas Initiative (RGGI), a regional CO_2 Budget Trading Program."[191] Following delays in publication of the DEP's final rule, litigation was initiated involving the interpretation of the Commonwealth's Regulatory Review Act and the timelines for regulatory approval, and, while that litigation was pending including a petition for preliminary injunction filed by intervenors from the Commonwealth's legislature, the final CO_2 Budget Trading Program regulation was published in the Pennsylvania Bulletin on April 23, 2022, the implementation of which would enter Pennsylvania

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185. *West Virginia*, 142 S. Ct. at 2610, 2615-16.

186. *Id.* at 2620-21 (J. Gorsuch concurring).

187. *EPA Administrator Regan Issues Statement on West Virginia v. Environmental Protection Agency*, EPA, https://www.epa.gov/newsreleases/epa-administrator-regan-issues-statement-west-virginia-v-environmental-protection (last updated June 30, 2022).

188. *Statement by President Joe Biden on Supreme Court Ruling on West Virginia v. EPA*, THE WHITE HOUSE (June 30, 2022), https://www.whitehouse.gov/briefing-room/statements-releases/2022/06/30/statement-by-president-joe-biden-on-supreme-court-ruling-on-west-virginia-v-epa/.

189. Jane Borthwick Story, *Pennsylvania Takes Next Step Toward Cap-and-Trade Amid Resistance*, JONES DAY (July 28, 2021), https://www.jdsupra.com/legalnews/pennsylvania-takes-next-step-toward-cap-8604444/.

190. Pa. Exec. Order No. 2019-07 (Oct. 3, 2019), https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/.

191. CO2 Budget Trading Program, 52 Pa. B. 2337, 2471 (Apr. 23, 2022).

into RGGI on July 1, 2022.[192] A hearing on the request for preliminary injunction was held on May 10 and 11, 2022, and post-hearing briefs were filed.[193]

On April 25, 2022, opponents of the Commonwealth's RGGI regulation filed a separate petition for review and application for preliminary injunction in the Commonwealth Court of Pennsylvania seeking declaratory and injunctive relief against DEP and the Commonwealth's Environmental Quality Board with respect to the CO_2 Budget Trading Program regulation.[194] A hearing was held on Petitioners' preliminary injunction application on May 10 and 11, 2022 and post-hearing briefs were filed.[195]

As of June 30, 2022, both preliminary injunctions applications remained pending and the future of the Commonwealth of Pennsylvania's CO_2 Budget Trading Program regulation and its potential entry into RGGI remains uncertain.[196]

VIII. IMPROVEMENTS TO GENERATOR INTERCONNECTION PROCEDURES AND AGREEMENTS

In June 2022, FERC issued a NOPR to address improvements to generator interconnection procedures and agreements.[197] Citing "interconnection queue backlogs," the need to improve certainty in the interconnection process, and the need prevent undue discrimination in new technologies, FERC is proposing reforms to its "*pro forma* Large Generator Interconnection Procedures (LGIP) . . . *pro forma* Small Generator Interconnection Procedures (SGIP) . . . *pro forma* Large Generator Interconnection Agreement (LGIA), [and] *pro forma* Small Generator Interconnection Agreement (SGIA)."[198] The proposed reforms fall into three categories: reforms to implement a first-ready, first-served customers study process; reforms to increase the speed of interconnection queue processing; and reforms to incorporate technological advancements into the interconnection process.[199]

In setting up the grounds necessitating the proposed reforms, the NOPR provides a detailed background of the existing *pro forma* procedures and agreements and identifies shortcomings in the current processes that are resulting in backlogs

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192. *Id.* at 2471, 2511.

193. Ziadeh v. Pa. Legis. Reference Bureau, Docket No. 41 MD 2022 (Pa.Commw. Ct. May 13, 2022).

194. *See generally* Bowfin KeyCon Holdings v. Pa. Dep't of Env't Prot. & Pa. Env't Quality Bd., Docket No. 247 MD 2022 (Pa. Commw. Ct. Apr. 25, 2022).

195. *Id.*

196. *Id.*

197. Notice of Proposed Rulemaking, *Improvements to Generator Interconnection Procedures and Agreements*, 87 Fed. Reg. 39,934 (2022).

198. *Id.* at 39,935. The instant NOPR is a direct result of the 2021 Advance Notice of Proposed Rulemaking (ANOPR) in Docket No. RM21-17-000. *See* 86 Fed. Reg. 40,266. The ANOPR presented potential reforms to the Commission's requirements governing the regional transmission planning and cost allocation and generator interconnection processes. *Id.* Transmission planning and cost allocation issues are currently being addressed in the NOPR in the same docket, while the outstanding concerns with the generator interconnection queue process are the subject of the instant NOPR. *Id.*; 87 Fed. Reg. 39,934.

199. 86 Fed. Reg. 40,266, at 40,277, 40,289-90.

in the interconnection queue.[200] The existing *pro forma* generator interconnection procedures and agreements stem from FERC Order No. 2003 and Order No. 2006[201] and were adopted with the expectation that *pro forma* procedures and agreements "would prevent undue discrimination, preserve reliability, increase energy supply, and lower wholesale prices for customers."[202] The NOPR notes that in the nearly two decades since the issuance of Order Nos. 2003 and 2006, there have significant transformations in the electricity sector, resulting in challenges that "are creating large interconnection queue backlogs and uncertainty regarding the cost and timing of interconnecting to the transmission system, potentially increasing costs for consumers," which in turn can create reliability issues.[203]

Even with these developments, delays persisted, and in 2008, the Commission held a technical conference in response to concerns about the interconnection queue management.[204] The Technical Conference resulted in an order addressing interconnection queue issues in RTOs/ISOs,[205] which in turn resulted in the submission of queue reform proposals that moved to a "first-ready, first-served" approach (whereby interconnection requests are processed based on when interconnection customers meet certain project development milestones).[206] The next major change to the processes came in 2018, when the Commission issued Order 845[207] to address reforms "needed to mitigate concerns regarding systemic inefficiencies, remedy discriminatory practices, and address recent developments, including changes in the resource mix and emergence of new technologies."[208]

Despite all of these efforts, interconnection queue backlogs and study delays continue.[209] The Commission attributes the increasing backlogs to several factors, including a rapidly changing resource mix, market forces, and emerging technologies, coupled with the fact that "available transmission capacity appears to have been exhausted in many regions," and there is "a nationwide shortage of qualified engineers" to complete the interconnections and associated studies.[210] Noting that "many, if not all, of these drivers are either ongoing or increasing," the NOPR makes the preliminary finding that the "*pro forma* LGIP, *pro forma* LGIA, *pro forma* SGIP, and *pro forma* SGIA result in rates, terms, and conditions pursuant

200. 87 Fed. Reg. 39,934, at 39,935.

201. Final Rule, *Standardization of Generator Interconnection Agreements and Procedures*, 68 Fed. Reg. 49,845 (2003) (to be codified at 18 C.F.R. pt. 35); Final Rule, *Standardization of Small Generator Interconnection Agreements and Procedures*, 70 Fed. Reg. 34,189 (2006) (to be codified at 18 C.F.R. pt. 35).

202. 87 Fed. Reg. 39,934, at 39,935.

203. *Id.*

204. *Interconnection Queuing Practices*, 122 FERC ¶ 61,252 at P 3 (2008).

205. *Id.* at P 1.

206. *See, e.g.*, *Sw. Power Pool, Inc.*, 128 FERC ¶ 61,114 (2009); *Midwest Ind. Sys. Operator, Inc.*, 124 FERC ¶ 61,183 (2008); *Cal. Ind. Sys. Operator Corp.*, 124 FERC ¶ 61,292 (2008).

207. Final Rule, *Reform of Generator Interconnection Procedures and Agreements*, 83 Fed. Reg. 21,342 (208) (to be codified at 18 C.F.R. pt. 37).

208. 87 Fed. Reg. 39,934, at 39,937.

209. *Id.* at 39,938.

210. 83 Fed. Reg. 21,342, at 21,343; *see* 87 Fed. Reg. 39,934, at 39,939.

to which transmission providers provide generator interconnection service are unjust and unreasonable and unduly discriminatory or preferential."[211] To address this, the Commission finds that "reforms are needed to allow interconnection customers to interconnect in a reliable, efficient, timely manner, thereby ensuring that rates, terms, and conditions for Commission-jurisdictional services remain just and reasonable and not unduly discriminatory or preferential."[212] Each of the three categories of reforms is briefly addressed below.

A. Reforms to Implement a First-Ready, First-Served Cluster Study Process.

The first proposed reforms are intended to *implement a first-ready, first-served cluster study process*, with the objective of enabling interconnection in an "efficient and timely manner."[213] The Commission proposes changes in a number of categories and sections of the *pro forma* LGIP that would:

> (1) require transmission providers to offer an optional informational interconnection study and set minimum requirements for transmission providers to . . . publicly post available information pertaining to generator interconnection; (2) require transmission providers to implement a first-ready, first-served cluster study process that allocates costs associated with cluster studies and identified network upgrades consistent with the discussion below; and (3) impose more stringent financial commitments and readiness requirements on interconnection customers, including increased study deposits, more stringent site control requirements, a commercial readiness framework, and higher withdrawal penalties.[214]

1. Interconnection Information Access

"Transmission providers will be required to offer an . . . informational interconnection study to serve as additional information for prospective interconnection customers in deciding whether to submit an interconnection request."[215] The study, which would have to be completed within 45-days, would provide cost estimates for the transmission provider's and network upgrade costs specific to the interconnection scenario detailed in the study agreement; the study would be paid for by the interconnection customer, who would be required to submit a $10,000, deposit, "subject to a true-up based on actual study costs."[216] The Commission seeks specific comments on:

> (1) whether transmission providers should be required to establish a request window of a limited number of days each year in which potential interconnection customers can request an optional informational interconnection study and (2) the burdens on transmission providers of conducting informational studies and whether other options, such as the proposal below for public interconnection information, might strike a better balance of providing interconnection customers with useful information while making efficient use of transmission provider resources.[217]

211. 87 Fed. Reg. 39,934, at 39,939.
212. *Id.* at 39,942.
213. *Id.*
214. *Id.*
215. 87 Fed. Reg. 39,934, at 39,942.
216. *Id.* at 39,939.
217. *Id.* at 39,944.

As part of these reforms, the Commission "also proposes to set minimum requirements for transmission providers to publicly post available information pertaining to generator interconnection," and "seek[s] comment[s] on whether there are any security concerns with this proposed requirement" and "whether the assumptions specified for the analysis are the right set of assumptions."[218]

2. Cluster Study

The Commission finds that the serial first-come, first-served interconnection study process is a major cause of the backlogs resulting in the delays, resulting in inefficiencies and delays, and allocates costs to customers for upgrades that create interconnection capacity beyond what they need, the Commission notes that "clustering is the preferred method for conducting interconnection studies and . . . strongly" encourages it.[219] Therefore, the NOPR suggested reforms to the *pro forma* LGIP and LGIA to eliminate the serial interconnection study process and replace it with a first-ready, first-served cluster study process,[220] making it clear that "cluster studies are the required interconnection study method under the *pro forma* LGIP and that transmission providers may not have a first-come, first-served interconnection study method under their respective LGIPs."[221] The Commission also seeks comments related to these proposal on:

> (1) whether the Commission should require transmission providers to conduct cluster studies on subgroups of interconnection customers based on areas of geographic and electric relevance, and, if so, whether the Commission should adopt provisions governing how cluster areas should be formed to ensure that cluster areas are formed in a transparent and not unduly discriminatory manner; (2) whether the *pro forma* LGIP should specify how cluster studies must be rerun after re-study is triggered or whether there are provisions the Commission could adopt to improve the efficacy of the re-study process; and (3) whether the Commission should maintain an option in the *pro forma* LGIP for some interconnection requests to be processed outside of the annual cluster study process, and if so, in what circumstances and on what timeframe (for completion of the study), and on what priority compared to any active clusters.[222]

3. Costs

Also included are proposals for allocation of cluster study costs:

> 90% of the applicable study costs to interconnection customers on a pro rata basis based on requested MWs included in the applicable cluster, and 10% of the applicable study costs to interconnection customers on a per capita basis based on the number of interconnection requests included in the applicable cluster.[223]

Cluster network upgrade costs would be allocated based on a new "Proportional Impact Method," which "shall mean a technical analysis conducted by the transmission provider to determine the degree to which each generating facility in

218. *Id.*

219. 87 Fed. Reg. 39,934, at 39,944-46.

220. *Id.* at 39,947

221. *Id*. at 39,948.

222. *Id*. at 39,949. The specific proposed revisions to the *pro forma* LGIP *and pro forma* LGIA are set forth in paragraphs 65 to 76 of the NOPR. *Id.* at 39,947-49.

223. 87 Fed. Reg. 39,934, at 39,949.

the cluster contributes to the need for a specific network upgrade."[224] To address concerns with the current cost allocation practices, reforms would "require transmission providers to allocate the costs for network upgrade costs between interconnection customers in an earlier cluster study and interconnection customers in a subsequent cluster study that benefit from the same network upgrade in a manner that is roughly commensurate with the benefits received."[225]

4. Financial Commitments

The Commission also proposes reforms to adopt stringent financial commitments and readiness requirements, "to discourage speculative interconnection requests and allow transmission providers to focus on processing viable interconnection requests and to better approximate the cost of the interconnection study process."[226] These reforms include "(1) increased study deposits, (2) demonstration of site control, (3) commercial readiness, and (4) withdrawal penalties."[227]

a. Study Deposits

Study deposits will be required on sliding scale, ranging from $35,000 + $1,000/MW for projects greater than 20 MW and less than 80 MW and going up to $250,000 for projects equal to or greater than 200 MW.[228] These study deposits would be collected before each new phase of the "cluster . . . process (i.e., cluster study, cluster re-study and facilities study)."[229] At the time of execution of an Interconnection Agreement or the filing of an unexecuted Interconnection Agreement, the customer would be required to pay a deposit of "nine times . . . its study deposit" amount.[230] This deposit would be refunded upon "achiev[ing] commercial operation," or if the project withdraws, "would be refunded subject to [a] withdrawal penalty."[231]

b. Site Control

In order to discourage speculative and non-viable projects, the Commission proposes reforms to the site control requirements, and "preliminarily find[s] that an interconnection customer securing the exclusive land right necessary to construct its proposed generating facility (or for co-located resources, demonstration

224. *Id.* at 39,950 n.150.

225. *Id.* at 39,951-52. The specific proposed revisions to the *pro forma* LGIP *and pro forma* LGIA are set forth in paragraphs 98 to 101 of the NOPR. *Id.*

226. *Id.* at 39,952.

227. 87 Fed. Reg. 39,934, at 39,952-53.

228. *Id.* at 39,953.

229. *Id.*

230. *Id.*

231. 87 Fed. Reg. 39,934, at 39,953.

of shared land use) is sufficient evidence of the interconnection customer's commitment to construct the generating facility."[232] Except under limited circumstances when regulatory limitations prohibit the interconnection customer from obtaining site control, the Commission "propose[s] to revise the *pro forma* LGIP to require an interconnection customer to demonstrate 100% site control at the time of submitting an interconnection request."[233] While the Commission believes that this rule will help prevent speculative interconnection requests, FERC recognizes that:

> Requiring site control effectively bars entry into the queue until land is acquired, and that this may prevent early-stage projects from entering the queue. We nevertheless believe this proposed reform to be just and reasonable because it will address the concerns with interconnection queue backlogs and study delays explained in the Need for Reform by reducing the number of interconnection requests being submitted and ensure that interconnection customers in the queue are ready to proceed.[234]

The NOPR also seeks comments on whether there are other specific situations in which the Commission should accept a deposit in lieu of site control; whether the definition of "site control" should be refined, including for specific regulatory requirements or co-ownership; whether the Commission should allow transmission providers to accept "less than 100% site control in the initial phase of the interconnection study process"; and whether a deposit in lieu of site control should be adopted to enter into the generator interconnection process.[235]

c. Commercial Readiness Framework

Noting interconnection queue backlogs and study delays "are caused in part by the minimal requirements for submitting interconnection requests and the tendency for non-viable projects to linger in interconnection queues,"[236] the Commission "proposes to revise" the commercial readiness framework in the *pro forma* LGIP.[237] The Commission proposes "that the financial requirement in lieu of readiness increases throughout the study process."[238] New terms to define "commercial readiness demonstration" and "commercial readiness deposit," and new provisions would include requirements and milestones for demonstrating commercial readiness or deposits that could be made in lieu of such demonstration.[239]

d. Withdrawal Penalties

There are currently no requirements in the *pro forma* LGIP for the "transmission providers to assess withdrawal penalties when an interconnection customer

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232. *Id*. at 39,954. The specific proposed revisions to the *pro forma* LGIP *and pro forma* LGIA are set forth in paragraphs 116 to 119 of the NOPR. *Id.* at 39,954-55.

233. *Id.* at 39,954

234. 87 Fed. Reg. 39,934, at 39,955.

235. *Id.*

236. *Id.* at 39,956.

237. *Id.*

238. 87 Fed. Reg. 39,934, at 39,956.

239. *Id*. The specific proposed revisions to the *pro forma* LGIP *and pro forma* LGIA are set forth in paragraphs 129 to 135 of the NOPR. *Id.* at 39,956-57.

withdraws from the interconnection queue," only actual study costs incurred.[240] The Commission proposes to revise the *pro forma* LGIP to require transmission providers to assess withdrawal penalties to interconnection customers in certain circumstances, preliminarily finding "that withdrawal penalties are needed to account for the harms that can occur when interconnection customers withdraw from the interconnection queue."[241] Transmission providers would be required to assess withdrawal penalties to interconnection customers that choose to withdraw at any point in the interconnection study process or do not otherwise reach commercial operation would be subject to a withdrawal penalty unless four specific conditions are met, including the:

> (1) the withdrawal does not delay the timing of other proposed generating facilities in the same cluster; (2) the withdrawal does not increase the cost of network upgrades for other proposed generating facilities in the same cluster; (3) . . . the most recent cluster study report and the costs assigned to the interconnection customer have increased 25% compared to the previous cluster study report; or (4) the interconnection customer withdraws after receiving the individual facilities study report and the costs assigned to the interconnection customer have increased by more than 100% compared to costs identified in the cluster study report.[242]

Withdrawal penalties would increase as the customer moves through the interconnection process, and the withdrawal penalty revenues be used to fund studies conducted under the cluster study process.[243]

5. Transition

The Commission proposes "that transmission providers be required to implement a transition process whereby most existing interconnection customers will be subject to the new study process, financial commitments, and readiness requirements, while certain late-stage customers will be allowed to finish the interconnection process under the existing rules."[244] The Commission would "propose to require transmission providers to offer existing eligible, interconnection customers the options, for each project in the queue, to either enter a transitional serial interconnection facilities study or a transitional cluster study, with commercial readiness requirements, or to permit them to withdraw from the interconnection queue without penalty."[245]

B. Reforms to Increase the Speed of Interconnection Queue Processing

The Commission proposes reforms in the interconnection queue processing to increase the speed of the process.[246] These reforms include (1) elimination of

240. *Id.* at 39,957.
241. *Id.* at 39,958.
242. 87 Fed. Reg. 39,934, at 39,958.
243. *Id*.
244. *Id.* at 39,959.
245. *Id.* at 39,960.
246. 87 Fed. Reg. 39,934, at 39,961.

the reasonable efforts standard, (2) addressing affected systems study process, and (3) establishing an optional resource solicitation study.[247]

1. Elimination of the Reasonable Efforts Standards

Currently, "the *pro forma* LGIP requires transmission providers to use reasonable efforts to process interconnections requests."[248] However, the Commission finds that nearly all transmission providers "regularly fail to meet interconnection study deadlines," and that such failure contributes to the delays and backlogs in the interconnection queue.[249] The Commission "propose[s] to revise the *pro forma* LGIP to eliminate the reasonable efforts standard for transmission providers completing interconnection studies, and instead impose firm study deadlines and establish penalties that would apply when transmission providers fail to meet these deadlines."[250]

2. Affected Systems

The Commission finds that the existing affected systems study processes lack consistency between transmission providers, and the lack of an affected system study process results in rates that are unjust and unreasonable.[251] To address this, the Commission "proposes to revise the *pro forma* LGIP to specify an affected system study process" that would include "initial notification, affected system scoping meeting, study process, cost allocation, study results and assessment, and financial penalties assessment."[252] The proposal includes several new definitions, and requirements for the study process with the intent to "streamline the affected systems study process" by addressing concerns about the lack of transparency and certainty in the affected systems study process.[253] The Commission seeks comments on the affected system study process.[254] Citing concerns that:

> The lack of *pro forma* agreements related to affected system studies and the construction of network upgrades on affected systems is both hindering the efficiency of the generator interconnection process through increased litigation over such agreements and leaving the door open to potential unduly discriminatory behavior against interconnection customers whose interconnection requests necessitate affected system network upgrades,

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247. *Id.* at 39,961-62, 39,969.

248. *Id.* at 39,961.

249. *Id.*

250. 87 Fed. Reg. 39,934, at 39,962. The specific proposed revisions to the *pro forma* LGIP *and pro forma* LGIA are set forth in paragraphs 168 to 170 of the NOPR. *Id.*

251. *Id.* at 39,964.

252. *Id.*

253. *Id.* The specific proposed revisions to the *pro forma* LGIP *and pro forma* LGIA are set forth in paragraphs 183 to 192 of the NOPR. *Id.* at 39,964-65.

254. 87 Fed. Reg. 39,934, at 39,964.

the Commission proposes reforms to the *pro forma* LGIP. [255] The reforms would include *pro forma* affected system study and construction agreements, with provisions that would address funding of network upgrades.[256] The Commission seeks information on whether the information required for the study report provides adequate information to the affected system interconnection customer to understand the results of the affected system study.[257] Similarly, to provide consistency in modeling across affected system studies, the Commission proposes, the Energy Resource Interconnection Service (ERIS) in the LGIP as the default modeling, regardless of the requested level of service.[258] Transmission providers could request use of a Network Resource Interconnection Service for affected system studies through a Section 205 filing on a case-by-case basis.[259]

3. Optional Resource Solicitation Study

"Although several transmission providers offer versions of the resource solicitation study concept to resource planning entities, transmission providers in general are not required to offer this option in their tariffs, and many do not"[260] and the Commission "preliminarily find that the failure to provide a study process for entities required to conduct a resource plan or resource solicitation process may result in rates for Commission-jurisdictional service that are unjust and unreasonable." [261] The Commission proposes "to revise the *pro forma* LGIP to require transmission providers to allow a resource planning entity to initiate an optional resource solicitation study," which the Commission believes "will benefit interconnection customers and transmission providers through efficiencies in studying resources vying for selection in qualifying solicitation process by grouping these resources together for purposes of informational interconnection studies."[262] The resource planning entity does not receive a queue position,[263] but the Commission does believe that the "proposal may also help resource planning entities procure resources more efficiently and effectively."[264]

C. Reforms to Incorporate Technological Advancements into the Interconnection Process

The last set of proposed reforms are intended to ensure that technological advances are incorporated into the interconnection process.[265] This group of proposed reforms include "(1) increasing flexibility in the generator interconnection

255. *Id.* at 39,966.
256. *Id.* at 39,966-67.
257. *Id.* at 39,965.
258. 87 Fed. Reg. 39,934, at 39,967.
259. *Id.* at 39,968.
260. *Id.* at 39,970.
261. *Id*.
262. 87 Fed. Reg. 39,934, at 39,971
263. *Id.* at 39,971.
264. *Id.* at 39,971-72.
265. *Id.* at 39,973.

process; (2) incorporating alternative transmission technologies into the generator interconnection process; and (3) including modeling and performance requirements for non-synchronous generating facilities."[266]

1. Increasing Flexibility in the Generator Interconnection Process

The NORP includes several proposed changes to the *pro forma* LGIP designed to increase flexibility in the generator interconnection process.[267]

a. Co-Located Generation Sites Behind One Point of Interconnection with Shared Interconnection Requests

Since "the current *pro forma* LGIP does not address interconnection requests made up of multiple generating facilities seeking to co-locate and to share a single point of interconnection," the Commission made a preliminary finding that the lack of a definitive co-location process in the *pro forma* LGIP may hinder competition and render the LGIP unjust and unreasonable or unduly discriminatory or preferential.[268] The Commission proposes to reform the *pro forma* LGIP and LGIA:

> To require transmission providers to allow more than one resource to co-locate on a shared site behind a single point of interconnection and share a single interconnection request. This proposed reform would create a minimum standard that would remove barriers for co-located resources by creating a standardized procedure for these types of configurations to enable them to access the transmission system.[269]

b. Revisions to the Material Modification Process to Require Consideration of Generating Facility Additions

The Commission is concerned that the current process for determining whether a requested modification is deemed material may result in unjust and unreasonable or unduly discriminatory or preferential outcomes.[270] To address concerns with this, the Commission proposes to revise the *pro forma* LGIP to include several new provisions, including: (1) a 60 day timeframe for reviewing the requests; (2) "the change cannot be considered an automatic material modification and the evaluation must" be completed before this determination can be made; and (3) "if the proposed change does not have a material impact on the cost or timing of any interconnection request that is lower or equally queued, and does not cause any other reliability concerns, the addition will not be considered a material modification."[271]

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266. 87 Fed. Reg. 39,934, at 39,973, 39,981, 39,983.

267. *Id.* at 39,973, 39,990.

268. *Id.* at 39,973-74.

269. 87 Fed. Reg. 39,934, at 39,974. The specific proposed revisions to the *pro forma* LGIP *and pro forma* LGIA are set forth in paragraphs 243 to 245 of the NOPR. *Id.*

270. *Id.* at 39,975.

271. *Id.* at 39,976.

c. Availability of Surplus Interconnection Service

The Commission is concerned that limiting "surplus interconnection service to only those interconnection customers that have achieved commercial operation may unduly restrict access," and that "this restriction may therefore be unjust and unreasonable or unduly discriminatory or preferential" because of that restriction.[272] The Commission proposes to revise the *pro forma* LGIP to allow interconnection customers to "access the surplus interconnection service process once the original interconnection customer has an executed LGIA or requests the filing of an unexecuted LGIA."[273]

d. Operating Assumptions for Interconnection Studies

"Because the *pro forma* LGIP [contain] only general requirements regarding operation assumptions," the Commission makes a preliminary finding that a lack of realistic operating assumptions used "in interconnection studies [for] . . . electric storage resources and co-located resources containing electric storage resources (including hybrid resources)" can result in excessive and "unnecessary network upgrades" and may hinder the timely development of new generation, thereby stifling competition in the wholesale markets, and resulting in rates, terms, and conditions that are unjust and unreasonable, and that the lack of appropriate operating assumptions used in interconnection studies may present an unduly discriminatory or preferential barrier to the interconnection of these resources.[274] To address this, the Commission proposes revisions to the *pro forma* LGIP.[275] The NOPR proposes to:

> Require transmission providers, at the request of the interconnection customer, to use operating assumptions for interconnection studies that reflect the proposed operation of an electric storage resource or co-located resource containing an electric storage resource (including hybrid resources) – i.e., whether the interconnecting resource will or will not charge during peak load conditions, unless good utility practice, including applicable reliability standards, otherwise require the use of different operating assumptions.[276]

2. Incorporating Alternative Transmission Technologies into the Generator Interconnection Process

The Commission preliminarily finds that failure to consider alternative transmission technologies, including "advanced power flow control, transmission switching, dynamic line ratings, static synchronous compensators, and/or static VAR compensators," when assessing the need for network upgrades, may render Commission-jurisdictional rates unjust and unreasonable.[277] The Commission

272. *Id.* at 39,977.

273. 87 Fed. Reg. 39,934, at 39,977.

274. *Id.* at 39,979.

275. *Id.*

276. *Id*. The specific proposed revisions to the *pro forma* LGIP *and pro forma* LGIA are set forth in paragraphs 280 to 286 of the NOPR. *Id.* at 39,979, 39,980.

277. 87 Fed. Reg. 39,934, at 39,982.

therefore proposes to revise the *pro forma* LGIP and SGIP to "require transmission providers, upon request of the interconnection customer, to evaluate the requested alternative transmission solution(s) during the LGIP cluster study and the SGIP system impact study and facilities study within the generator interconnection process."[278] Transmission providers would be required "to submit an annual . . . report" on consideration of use of alternative transmission technologies in the interconnection process.[279]

3. Modeling and Performance Requirements for Non-Synchronous Generating Facilities

The Commission preliminarily finds that the *pro forma* LGIP and *pro forma* SGIP may be unduly discriminatory or preferential to the extent that they do not require "non-synchronous generating facilities" to provide accurate and validated models to transmission providers during the generator interconnection process.[280] The Commission is concerned that:

> without a reform to require interconnection customers developing non-synchronous generating facilities to provide sufficiently accurate and validated models, interconnection studies may not identify the appropriate interconnection facilities and network upgrades needed for that interconnection request. If the interconnection studies are not able to identify the appropriate interconnection facilities and network upgrades, then the interconnection costs assigned to that interconnection customer may be skewed, resulting in unjust and unreasonable rates for interconnection service.[281]

The NOPR therefore proposes revisions to "the *pro forma* LGIP and *pro forma* SGIP to ensure that all interconnection customers requesting to interconnect a non-synchronous generating facility must provide the transmission provider with the models needed for accurate interconnection studies."[282]

The Commission also proposes revisions to the ride-through requirements.[283] Preliminarily finding that current "ride-through" provisions in the pro forma LGIA and SGIA may by unjust and unreasonable or unduly discriminatory the Commission proposes to "require newly interconnecting non-synchronous generating facilities to continue current injection inside the 'no trip zone' of the frequency and voltage ride-through curves of Reliability Standard PRC-024-3 or its successor standards, in accordance with NERC's recommendation in the NERC IBR Guideline,"[284] and expand the ride-through definition to include the ability of the large generating facility to stay connected to and synchronized with the transmission

278. *Id*. at 39,982.

279. *Id*. at 39,983. The specific proposed revisions to the *pro forma* LGIP *and pro forma* LGIA are set forth in paragraphs 298 to 229 of the NOPR. *Id.* at 39,981-82.

280. *Id.* at 39,983.

281. *Id.*

282. *Id.* at 39,987. The specific proposed revisions to the *pro forma* LGIP *and pro forma* LGIA are set forth in paragraphs 329 to 335 of the NOPR. *Id.* at 39,988.

283. *Id.* at 39,988.

284. 87 Fed. Reg. 39,934, at 39,988. The specific proposed revisions to the *pro forma* LGIP *and pro forma* LGIA are set forth in paragraphs 336 to 338 of the NOPR. *Id.*

system during system disturbances within under-voltage and over-voltage conditions as well."[285] The Commission also proposes that "all newly interconnecting large generating facilities must provide ride-through capability consistent with any standards and guidelines that are applied to other generating facilities in the balancing authority area on a comparable basis."[286]

D. Compliance

The NOPR also includes proposed compliance procedures, requiring each transmission provider to submit compliance filings revising its LGIP, LGIA, SGIP, and SGIA within 180 days of the effective date of the final rule.[287] The Commission proposes to allow appropriate entities to seek "regional reliability variations" or "independent entity variations" from the revisions to the *pro forma* interconnection procedures and agreements.[288]

FERC Chairman Glick lauded the "sweeping bipartisan agreement to advance this proposal" and stated that the NOPR "tackles what I believe to be two of the most significant challenges in developing new transmission infrastructure: Planning and cost allocation."[289] Glick went on to state that planning transmission facilities "intelligently and allocating their costs fairly is absolutely critical to ensuring that customers' rates are just and reasonable."[290] While, Commissioner Danly supported the NOPR, he also stated that he "would prefer RTOs and transmission providers come up with their own reforms through section 205 filings, rather than have the Commission issue omnibus proposals covering lists of every little thing commissioners would like to see done differently. Proposals have a propensity to turn into rules."[291] Danly stated that he suspects that FERC may be able to require first-ready, first-served clustering, more robust milestone deposits and showings, more binding RTO and transmission provider deadlines, and elimination of granting waivers, however, he went on to state that "[i]n other areas, I think the NOPR goes too far. Like the transmission expansion planning NOPR, many of the ideas floated in this NOPR seem intended to further prop up renewable resources and may be unduly discriminatory."[292] Commissioner Christie expressed support for many elements of the NOPR, but noted that there are a few proposals in the NOPR "that are not yet ready for prime time, either because they are potentially good ideas that have simply not been fully developed, or may not be a good ideas at all."[293] Similar to Danly, Christie referenced the RTOs/ISOs

285. *Id*.

286. 87 Fed. Reg. 39,934, at 39,989.

287. *Id.*

288. *Id*.

289. *Chairman Glick's Press Conference Remarks*, FERC (2022), https://www.ferc.gov/news-events/news/chairman-glicks-press-conference-remarks.

290. *Id*.

291. *Item E-1: Commissioner James Danly Concurrence Regarding Improvements to Generator Interconnection Procedures and Agreements*, FERC (2022), https://www.ferc.gov/news-events/news/item-e-1-commissioner-james-danly-concurrence-regarding-improvements-generator.

292. *Id.*

293. *Id.*

reforms, and "caution strongly that we should avoid undermining through this NOPR what the RTOs/ISOs, working through their stakeholder processes, are already doing to fix their own queue problems."[294]

Comments are due October 13, 2022 and reply comments are due November 14, 2022.[295]

294. *E-1: Commissioner Christie's Concurrence in Improvements to Generator Interconnection Procedures and Agreements*, FERC (2022), https://www.ferc.gov/news-events/news/e-1-commissioner-christies-concurrence-improvements-generator-interconnection.

295. 87 Fed. Reg. 39,934, at 39,992.