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MEMORANDUM

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TO: NEPOOL Transmission Committee

FROM: Eric K. Runge, Margaret Czepiel, Dina A. Goldman (NEPOOL Counsel)

DATE: May 22, 2024

RE: Summary of Order No. 1920 (RM21-17)

On May 13, 2024, the Federal Energy Regulatory Commission ("FERC" or "the Commission") issued Order No. 1920 ("Order No. 1920" or "Final Rule") pursuant to Section 206 of the Federal Power Act ("FPA"). The Commission's stated purpose in Order No. 1920 is to remedy deficiencies with and build upon the existing regional and local transmission planning and cost allocation requirements, incrementally established in Order Nos. 888,[1] 890,[2] and 1000,[3] to ensure that the rates, terms, and conditions for transmission service provided by transmission providers remain just and reasonable and not unduly discriminatory or preferential.[4] Transmission providers are directed to submit compliance filings within ten and twelve months[5] of the effective date of the Final Rule (60 days after its publication in the *Federal Register*, which as of the date of this memo has not yet occurred).[6]

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[1] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1 (2002).

[2] *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, 118 FERC ¶ 61,119 (2007), *order on reh'g,* Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007) (cross-referenced at 118 FERC ¶ 61,119), *order on reh'g and clarification*, Order No. 890-B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

[3] *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), Order No. 1000-A, 77 FR 32184 (May 31, 2012), 139 FERC ¶ 61,132 (2012), *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[4] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 at P 1 (2024) ("Order No. 1920"), which can be accessed here: https://www.iso-ne.com/static-assets/documents/100011/a05_order1920.docx. Order No. 1920 is approximately 1300 pages.

[5] Transmission providers are required to file compliance filings within 10 months of the effective date of the Final Rule for all compliance requirements except those related to interregional planning coordination, and within 12 months of the effective date for interregional coordination requirements. *Id.* at P 12.

[6] *Id.* at P 12.

NEPOOL counsel previously reported on this rulemaking proceeding when FERC published the Advance Notice of Proposed Rulemaking ("ANOPR") in 2021[7] and the Notice of Proposed Rulemaking ("NOPR") in 2022.[8] The Final Rule adopts several reforms from the NOPR, but also declines to adopt several reforms, as discussed herein. NEPOOL Counsel gave a presentation on the Final Rule at the May 16, 2024 Transmission Committee Meeting, and will coordinate with ISO-NE counsel on stakeholder engagement to develop a compliance filing in response to Order No. 1920.[9] This memorandum provides a high-level summary of Order No. 1920, first with some key points and then with section-by-section brief descriptions of the main determinations of the Final Rule. If you have any questions about this memo or its subject matter, please contact Eric Runge, ekrunge@daypitney.com, 617-378-1284 or Margaret Czepiel, mczepiel@daypitney.com, 202-924-8391.
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Key Points:

In Order No. 1920, FERC finds substantial evidence exists to support the conclusion that the existing regional transmission planning and cost allocation processes are unjust, unreasonable, and unduly discriminatory or preferential. FERC explains that under existing processes, transmission providers are not required to: (1) perform a sufficiently long-term assessment of transmission needs identifying Long-Term Transmission Needs; (2) adequately account for known determinants of Long-Term Transmission Needs prospectively; and (3) consider the broader benefits of regional transmission facilities planned to meet Long-Term Transmission Needs. The result is less efficient and cost-effective investment in transmission infrastructure and higher costs to customers and, therefore, unjust and unreasonable rates. Accordingly, pursuant to Section 206 of the Federal Power Act, the Commission finds it necessary to require reforms to existing transmission planning and cost allocation requirements. Specifically, the Final Rule requires transmission providers to:

- Participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning ("LTRTP") on a cycle that occurs at least once every five years.[10]
- Each LTRTP to be conducted consistent with the planning principles of Order No. 890 and 1000.[11]

[7] See NEPOOL Counsel Memorandum available here and NEPOOL Counsel presentation available here.

[8] See NEPOOL Counsel Memorandum available here and NEPOOL Counsel presentation available here.

[9] See NEPOOL Counsel presentation available here.

[10] For the purposes of the Final Rule, Long-Term Regional Transmission Planning 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. Order No. 1920 at P 38.

[11] Id. at P 228.

- Conduct LTRTP through, among other things, the use of Long-Term Scenarios ("LTS") to identify Long-Term Transmission Needs and to identify, evaluate and select Long-Term Regional Transmission Facilities ("LTRTF")[12] to meet those needs.
- Use at least three LTS in each LTRTP cycle.
- In the LTS use seven specific categories of factors driving transmission needs.
- Ensure that the LTS are plausible and diverse and use best available data.
- Use an open and transparent stakeholder process to develop the LTS.
- Include low-frequency, high-impact weather events as stress tests for each of the LTS.
- Measure and use at least the seven specified benefits to evaluate LTRTF as part of LTRTP.
- Calculate the benefits of LTRTF over at least a 20-year time horizon starting from the estimated in-service date of the transmission facilities, and use this minimum 20-year benefit horizon for the evaluation and selection of LTRTF in the regional transmission plan for cost allocation purposes.
- Include in their Open Access Transmission Tariffs ("OATTs") an evaluation process, including selection criteria, to identify and evaluate LTRTF for potential selection to address Long-Term Transmission Needs.[13]
- Use stakeholder engagement and consultation with Relevant State Entities to develop evaluation and selection criteria.
- File one or more ex ante Long-Term Regional Transmission Cost Allocation Methods[14] to allocate the costs of LTRTF (or a portfolio of such Facilities) that are selected.
- If desired, adopt a State Agreement Process,[15] wherein Relevant State Entities[16] agree to such a State Agreement Process that would provide up to six months after selection for its participants to determine, and transmission providers to file, a cost allocation method for specific LTRTF.

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[12] For the purposes of the Final Rule, a Long-Term Regional Transmission Facility is a regional transmission facility that is identified as part of Long-Term Regional Transmission Planning to address Long-Term Transmission Needs. Order No. 1920 at P 41.

[13] For the purposes of Order No. 1920, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in this Final Rule, running scenarios and considering the enumerated categories of factors. Order No. 1920 at P 39.

[14] A Long-Term Regional Transmission Cost Allocation Method is defined as an *ex ante* regional cost allocation method for one or more selected Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation. Order No. 1920 at P 43.

[15] A State Agreement Process is defined as a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) before or no later than six months after they are selected. *Id.* at P 45.

[16] A Relevant State Entity is defined as any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state. *Id.* at P 44.

- During the established six-month Engagement Period: (1) provide notice of the starting and end dates for the six-month time period; (2) post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(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 Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables robust participation by Relevant State Entities.
- Include in their OATTs a process to provide Relevant State Entities and Interconnection Customers the opportunity to voluntarily fund the cost of, or a portion of the cost of, an LTRTF that otherwise would not meet the transmission providers' selection criteria.
- Include in their OATTS provisions that require transmission providers – in certain circumstances – to reevaluate LTRTF that were previously selected.
- Under certain conditions address through the existing regional transmission planning processes interconnection-related network upgrade needs originally identified through the generator interconnection process.
- Consider more fully the alternative transmission technologies of dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching in LTRTP and existing Order No. 1000 regional transmission planning and cost allocation processes.
- Adopt transparency requirements for local transmission planning processes and improve coordination between regional and local transmission planning with the aim of identifying potential opportunities to "right size" replacement transmission facilities.
- Revise interregional transmission coordination processes to reflect the LTRTP reforms adopted in the Final Rule.
- Meet additional information sharing and transparency requirements with respect to their interregional transmission coordination process.
- Submit a compliance filing within 10 months of the Final Rule's effective date (60 days after publication in the *Federal Register*) for all requirements of the Final Rule, except for those related to interregional transmission coordination.
- Submit a compliance filing within 12 months of this Final Rule's effective date for all interregional transmission coordination requirements.[17]

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[17] *Id.* at PP 2-13. Under Section 206 of the FPA, FERC has authority to address any practice that impacts rates for interstate electricity services if such practices are unjust, unreasonable, or unduly discriminatory. Both the DC Circuit and FERC found that regional transmission planning and cost allocation processes directly affect rates, allowing FERC to establish just and reasonable replacement practices. *Id.* at P 86 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55 (quoting 16 U.S.C. 824e(a))).

I. Need for Reform

The Commission found that current regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory largely due to the lack of long-term, forward-looking, and comprehensive transmission planning causing providers to overlook future system conditions.[18] This oversight is becoming increasingly critical due to changing reliability needs, demand, and supply in the transmission investment landscape, which is expected to see substantial growth.[19]

The current transmission planning and cost allocation processes fail to assess long-term transmission needs adequately, consider future determinants of these needs, and evaluate the broader benefits of planned regional transmission facilities. This deficiency leads to piecemeal development of transmission infrastructure that is less efficient and cost-effective in meeting transmission needs, resulting in unjust and unreasonable rates to customers.[20]

LTRTP would address these shortcomings by reducing reliance on inefficient solutions, leveraging economies of scale, optimizing replacement facilities, selecting facilities that address multiple needs, and providing stakeholders with better insight and transparency into transmission solutions' costs and benefits for long-term needs.[21] In light of changing demands on the transmission system, the record also affirms that regional transmission planning that identifies more efficient or cost-effective transmission solutions helps to ensure cost-effective transmission development for customers and yield better cost returns than localized or piecemeal transmission solutions.[22]

II. Long-Term Regional Transmission Planning

A. Requirement to Participate in Long-Term Regional Transmission Planning

The Final Rule requires transmission providers in each transmission planning region to participate in a regional transmission planning process that includes LTRTP, meaning regional transmission planning that is long-term, forward-looking, and comprehensive to identify Long-Term Transmission Needs, transmission facilities that meet such needs, measure 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 transmission facilities to meet Long-Term Transmission Needs.[23] As provided in the NOPR, the Final Rule requires that LTRTP comply with the following existing Order Nos. 890 and 1000 transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information

[18] *Id.* at P 85.

[19] *Id.* at PP 94-96.

[20] Id, at PP 85-89.

[21] *Id.* at P 114.

[22] *Id.* at P 100.

[23] *Id.* at P 224.

exchange; (5) comparability; and (6) dispute resolution.[24] Long-Term means a minimum 20-year planning horizon.

FERC also adopted requirements regarding how transmission providers must conduct LTRTP. Specifically, transmission providers must: (1) develop LTS to identify transmission needs and which facilities can meet those needs; (2) use and measure, at least, seven required benefits to evaluate Long-Term Regional Transmission Facilities over, at least, 20 years starting from the estimated in-service date of each transmission facility; and (3) evaluate whether LTRTF are the more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs, and use selection criteria (in collaboration with states and other stakeholders) that allow transmission providers to select such LTRTFs.[25] FERC clarified that transmission providers will be in compliance with Order No. 1000 by conducting Long-Term Regional Planning in accordance with this Final Rule.[26]

In particular, transmission providers must: (1) must develop at least three LTS using a transmission planning horizon of at least 20 years LTS; (2) reassess and revise the LTS at least once every five years; (3) incorporate in the LTS Commission-identified categories of factors that drive Long-Term Transmission Needs LTS; (4) ensure that each LTS is plausible and diverse and that the set of LTS represents a diverse range of plausible outcomes LTS;[27] (5) perform sensitivity analyses on each LTS as a stress test of uncertain operational outcomes during multiple concurrent and sustained generation and/or transmission outages due to extreme weather events across a wide area; and (6) use "best available data" in developing the LTS.[28]

B. Development of LTS

FERC adopted with modification, the NOPR proposals to require transmission providers to (1) develop and use LTS as part of LTRTP and (2) use those LTS to identify and evaluate LTRTFs needed to meet Long-Term Transmission Needs.[29] These Long Term Transmission Needs are

[24] *Id.* at P 224.

[25] *Id.* at P 225.

[26] If a transmission provider believes that it participates in a regional transmission planning process that fulfills the requirements adopted in this Final Rule, it may describe in its compliance filing how its process meets these requirements. *Id.* at P 243.

[27] PP 575-579. The set of at least 3 LTS must be plausible and diverse: (1) plausible, meaning that each scenario must itself be reasonably probable, and collectively that the set of plausible scenarios must reasonably capture probable future outcomes, and (2) diverse, in the sense that transmission providers can distinguish distinct transmission facilities or distinct benefits of similar transmission facilities in each LTS. Diverse also means that the LTS represent a reasonable range of probable future outcomes consistent with the requirement for plausibility, based on assumptions about the factors and data inputs.

[28] *Id.* at P 248.

[29] *Id.* at P 298.

similar in kind to transmission needs identified through existing regional transmission planning processes established under Order No. 1000.[30] The Final Rule requires that transmission providers use the Seven Required Benefits to help to inform their identification of Long-Term Transmission Needs.[31]

C. LTS Requirements

Transmission Planning Horizon. As provided in the NOPR, the Final Rule requires that transmission providers use no less than a 20-year transmission planning horizon to develop LTS to identify Long-Term Transmission Needs that will materialize at any point in the 20 year period or more following the commencement of the LTRTP cycle, and any solutions to those needs.[32]

Frequency of LTS Revisions. FERC modified the NOPR proposal to require that transmission providers reassess and revise the LTS used in LTRTP at least once every five years.[33] Specifically, they must reassess whether the data inputs and factors incorporated in existing LTS need to be updated and update them as needed. At the outset of a LTRTP cycle, transmission providers may craft entirely new LTS or update the data inputs and factors of previously developed ones.[34] This process, which begins with the development of LTS, must conclude no later than five years after when it began.[35] FERC further requires that each step of the LTRTP Cycle and the determination of the LTRTFs be completed no later than three years from when the cycle began.[36] An LTRTP Cycle must be completed before developing LTS starting the next cycle. [37] Transmission providers must designate a point in time or action that concludes the cycle.[38] Transmission providers need not routinely reevaluate selected LTRTFs.[39]

To the extent that transmission providers believe that a shorter LTRTP cycle is appropriate for their transmission planning region and circumstances, they may propose on compliance to conduct LTRTP more frequently.[40]

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[30] *Id.* at P 300.

[31] *Id.* at P 301.

[32] *Id.* at PP 344, 346.

[33] *Id.* at P 377.

[34] *Id.* at P 377.

[35] *Id.* at P 378.

[36] *Id.* at P 379.

[37] *Id.* at P 381.

[38] *Id.* at P 381.

[39] *Id.* at P 383.

[40] *Id.* at P 384.

Categories of Factors for LTS. Transmission providers must incorporate seven specific categories of factors in developing LTS.[41] The seven factor categories are: (1) federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand; (2) federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved integrated resource plans and expected supply obligations for load-serving entities; (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies; (5) resource retirements; (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.[42] While additional factors may be included without FERC approval, none of the seven specified factor categories may be excluded.[43]

Incorporating a category of factors into the LTS means more than merely considering each category of factors in developing LTS.[44] In coordination with stakeholders, transmission providers must account for the factors or group of factors likely to affect Long-Term Transmission Needs.[45]

In first three categories transmission providers must assume that legally binding obligations (i.e., federal, federally-recognized Tribal, state, and local laws and regulations) are followed, state-approved integrated resource plans are followed, and expected supply obligations for load-serving entities are fully met. Factors in these categories must not be discounted.[46] Transmission providers have discretion in how to treat factors in last four categories with input from stakeholders in open and transparent process.[47]

<u>Factor Categories 1-3:</u>

Factor Category One is comprised of: federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand, in the development of LTS.[48] These Factors include among other things, legally binding obligations, incentives (e.g., tax credits), and/or restrictions promulgated by policymakers that will affect new or existing generators, or

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[41] *Id.* at P 409.

[42] Id.

[43] *Id.* at PP 411, 412.

[44] *Id.* at P 413.

[45] *Id.* at P 415.

[46] Id. at P 507

[47] Id. at P 516.

[48] *Id.* at P 432.

demand.[49] Energy equity and justice laws and regulations are also potential factors within Factor Category One to the extent that they are likely to affect Long-Term Transmission Needs.[50]

Factor Category Two is comprised of: federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification, in the development of LTS.[51] These factors include legally binding obligations, incentives, and/or restrictions that affect Long-Term Transmission Needs differently than Factor Category One. For example, the carbon intensity of electricity generation or electrifying energy end uses may need to be limited, thereby significantly increasing electricity use in certain sectors of the economy, such as transportation and building heating and cooling.[52] If certain laws or regulations are passed that could fit into both categories one and two, a transmission provider must account for them in only one category.[53]

Factor Category Three is comprised of: state-approved integrated resource plans and expected supply obligations for load-serving entities, in the development of LTS.[54] These factors include resource plans that are developed and reviewed through a retail proceeding in jurisdictions where the retail regulator does not formally approve such plans.[55] The term "state-approved utility integrated resource plans" must be construed broadly to include any resource plan developed and reviewed through a retail commission proceeding and submitted to the relevant transmission provider for use in LTRTP because it would enable a more complete consideration of state-approved integrated resource plans and expected supply obligations for load-serving entities.

Furthermore, load-serving entities that are taking transmission service pursuant to an OATT are required to provide transmission providers with information on their projected loads and resources over the planning horizon, consistent with the information exchange transmission planning principle established in Order No. 890.[56]

Treatment of Specific Categories of Factors 1-3: With regard to the first three categories of factors, transmission providers must assume that laws and regulations and state-approved integrated resource plans are followed, and expected supply obligations for load-serving entities are fully met.[57] Therefore, each LTS must account for and not discount, factors in these categories

[49] *Id.* at P 433.

[50] *Id.* at P 433.

[51] *Id.* at P 440.

[52] *Id.* at P 440.

[53] *Id.* at P 440.

[54] *Id.* at P 447.

[55] *Id.* at P 448.

[56] *Id.* at P 449.

[57] *Id.* at P 507.

once determined they are likely to affect Long-Term Transmission Needs.[58] Transmission providers are not obligated to independently identify each factor in the first three categories, but they may choose to as part of the stakeholder process.[59]

For certain factors, transmission providers may not have sufficient information to determine how the factor will affect Long-Term Transmission Needs.[60] In such instances, transmission providers have discretion over how to account for a factor as long as the assumptions in each LTS are consistent with legally binding obligations, state-approved integrated resource plans, and expected supply obligations of load-serving entities.[61] Transmission providers may model assumptions that exceed the minimum requirements of factors in the first three categories in developing LTS to the extent that each LTS remains plausible.[62] Two legally binding factors may have conflicting or opposite implications for Long-Term Transmission Needs. In such circumstances, transmission providers shall reconcile this information while giving full effect to the maximum extent possible to all legally binding factors.[63]

<u>Factor Categories 4-7:</u>

Factor Category Four is comprised of: trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies.[64] These factors may include, but are not limited to cost and technology trends for: utility-scale generation construction costs for different generating technologies; distributed energy resources; storage technologies with differing duration limitations; carbon capture and sequestration; small modular nuclear; light-, medium-, and heavy-duty electric vehicles and electric vehicle supply equipment; and ground- and air-source heat pumps.[65]

Factor Category Five is comprised of: resource.[66] FERC clarifies that, to develop plausible LTS, transmission providers must account for likely resource retirements beyond those that have been publicly announced.[67] FERC noted that it is not specifying how transmission

[58] *Id.* at P 507.

[59] *Id.* at P 508.

[60] *Id.* at P 512.

[61] *Id.* at P 512.

[62] *Id.* at P 513.

[63] *Id.* at P 513.

[64] *Id.* at P 456.

[65] *Id.* at P 458.

[66] *Id.* at P 463.

[67] *Id.* at P 464.

providers must estimate resource retirements, and clarified that transmission providers may include what they believe to be appropriate confidentiality protections in their proposals to account for resource retirements that might take place over the transmission planning horizon.[68]

Factor Category Six is comprised of generator interconnection requests and withdrawals.[69]

Factor Category Seven is comprised of: utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.[70]

Treatment of Specific Categories of Factors 4-7: Transmission providers have more discretion in how they account for each factor in the last four categories of factors than for each factor in the first three categories.[71] After transmission providers have determined that a specific factor, stakeholder-identified or otherwise, is likely to affect Long-Term Transmission Needs over the transmission planning horizon, they must assess the extent to which the factor's anticipated effects on Long-Term Transmission Needs are likely to be realized in full, in part, or exceeded, for purposes of developing a plausible and diverse set of LTS.[72]

Transmission providers may emphasize specific factors by modeling more than the projected change in some or all LTS to reflect the transmission providers' view that Long-Term Transmission Needs will be impacted by that factor.[73] Unlike Factors 1-3, Transmission providers may choose to discount the effects on Long-Term Transmission Needs due to factors in Factor Categories Four through Seven to account for uncertainty when developing plausible and diverse LTS.[74]

Stakeholder Process and Transparency. Transmission providers are required to revise the regional transmission planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including federally-recognized Tribes and states, with a meaningful opportunity to propose potential factors and to provide timely input on how to account for specific factors in the development of LTS.[75]

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[68] *Id.* at P 466.

[69] *Id.* at P 472.

[70] *Id.* at P 481.

[71] *Id.* at P 516.

[72] *Id.* at P 516.

[73] *Id.* at P 516.

[74] *Id.* at P 516.

[75] *Id.* at PP 528, 560.

Transmission providers must publish on OASIS or other public website: (1) the list of the factors in each of the seven required categories of factors that they will account for in their LTS; (2) a description of each factor that they will account for in their LTS; (3) a general statement explaining how they will account for each of those factors in their LTS; (4) a description of the extent to which they will discount any factors in Factor Categories Four through Seven in each LTS; and (5) a list of the factors that they considered but did not incorporate in their LTS.[76] A general statement explaining how each factor will be accounted for must also be published on the website.[77]

Consistent with Order No. 890's transmission planning principles, transmission providers must give stakeholders a meaningful opportunity to provide timely input on the information incorporated into LTS.[78] This includes the opportunity to propose factors, provide information and identify sources of best available data, propose how a factor may affect Long-Term Transmission Needs, and explain how that factor could be reflected in the development of LTS, including the extent to which it is appropriate to discount the effects of certain factors on Long-Term Transmission Needs.[79]

FERC reiterated that transmission providers may exclude a stakeholder-identified factor from development of LTS if the transmission provider determines that the factor is unlikely to influence Long-Term Transmission Needs over the transmission planning horizon.[80]

Number and Development of LTS. Transmission providers must develop at least once during the five-year LTRTP cycle, a minimum of three distinct LTS as part of LTRTP that incorporate the seven categories of factors.[81] They should also publicly disclose the data and inputs used to create each LTS.[82]

Types of LTS. FERC found that the individual and set of at least three LTS must be: (1) plausible, meaning that each scenario must itself be reasonably probable, and collectively that the set of plausible scenarios must reasonably capture probable future outcomes, and (2) diverse, in the sense that: (i) one can distinguish distinct transmission facilities or distinct benefits of similar transmission facilities in each LTS, and (ii) the set of at least three LTS represent a reasonable

[76] *Id.* at P 528.

[77] *Id.* at P 531.

[78] *Id.* at P 529.

[79] *Id.* at P 529.

[80] *Id.* at P 537.

[81] *Id.* at P 559.

[82] *Id.* at P 560.

range of probable future outcomes consistent with the requirement for plausibility, based on assumptions about the factors and data inputs.[83]

Sensitivities for High-Impact, Low Frequency Events. The Final Rule requires that transmission providers develop at least one extreme weather event sensitivity per LTS, designed as a "stress test" for the LTS.[84] In conducting this sensitivity, transmission providers change the data inputs of the underlying LTS—in terms of load, generation, generator outages, and transmission outages—to account for uncertainties resulting from multiple, concurrent, and sustained generation and/or transmission outages due to an extreme weather event across a wide area, while maintaining the underlying longer-term determinants of the LTS (e.g., the installed capacity of each generation resource). Transmission providers are not precluded from considering additional sensitives and can use the required sensitivity analyses to evaluate the need for, or benefits of, increased Interregional Transfer Capability provided by candidate LTRTFs.[85]

Specificity of Data Inputs. FERC adopted the NOPR proposal, with modification, to require transmission providers to use "best available data inputs" when developing LTS.[86] The "best available data inputs" are timely, developed using best practices and diverse and expert perspectives, and adopted via a process that satisfies the transmission planning principles of Order Nos. 890 and 1000.[87] The best available data inputs must also reflect the factors transmission providers account for in their LTS.[88] The Final Rule requires transmission providers to update, as necessary, all data inputs each time their LTS are reassessed and revised.[89]

FERC required that transmission providers comply with the following planning principles identified in Order Nos. 890 and 1000 in determining which data inputs to include in their LTS: the coordination transmission planning principles, stakeholder participations requirements;[90] and the right to challenge data inputs via dispute resolution.[91]

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[83] *Id.* at PP 575, 576.

[84] Id. at P 86.

[85] *Id.* at PP 597, 599.

[86] *Id.* at P 633.

[87] *Id.* at P 633.

[88] *Id.* at P 633.

[89] *Id.* at P 633.

[90] *Id.* at P 634.

[91] *Id.* at P 634.

In addition, FERC declined to adopt the suggestion of commenters to standardize data inputs used by transmission providers and establish specific accuracy standards in LTRTP.[92]

Identification of Geographic Zones. Transmission providers are encouraged, but not required, to consider geographic zones that have the potential for development of large amounts of new generation as part of their regional transmission planning process.[93] The Commission determined that imposing such a requirement was not necessary given the use of the factor categories in the LTS, which will have the effect of identifying where on the system large amounts of new generation are likely to be sited.[94]

D. Evaluation of the Benefits of Regional Transmission Facilities

Requirement to Use Set of Seven Required Benefits. The Final Rule requires transmission providers to measure a set of seven required benefits for LTRTF under each LTS.[95] FERC rejected the flexible approach in the NOPR finding it would not address deficiencies in existing regional planning and cost allocation processes. Requiring use and evaluation of the seven benefits will help ensure that transmission providers are considering a sufficiently broad range of benefits when selecting a facility and that resulting rates for such facilities are just and reasonable. Transmission providers may also propose to measure and use additional benefits in LTRTP.[96]

<u>Benefit 1:</u> Avoided or deferred reliability transmission facilities and aging infrastructure replacement

Benefit 1 is the reduced costs due to avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities.[97] This benefit requires transmission providers to measure and use the benefits associated with avoiding or delaying such transmission needs to help to ensure that, when conducting LTRTP, transmission providers identify, evaluate, and select LTRTFs that more efficiently or cost-effectively address Long-Term Transmission Needs.[98]

<u>Benefit 2:</u> Benefit that can be characterized and measured as either (a) reduced loss of load probability or (b) reduced planning reserve margin

[92] *Id.* at PP 639, 641.

[93] *Id.* at P 487.

[94] *Id.* at P 487.

[95] *Id.* at P 719.

[96] *Id.* at P 729.

[97] *Id.* at P 745.

[98] *Id.* at P 745.

Benefit 2(a) is decreasing the frequency of load loss and improving reliability by providing additional pathways for connecting generation resources to load in regions constrained by weather and unplanned outages (if the planning reserve margin is not changed despite lower loss of load events), by reducing the likelihood of load shed events.[99] Benefit 2(b) is the reduction in capital costs of generation needed to meet resource adequacy requirements (i.e., planning reserve margins) while holding loss of load probability constant.[100] Transmission providers must measure reduced loss of load events by holding the planning reserve margin constant, or measure the reduction in planning reserve margins by holding loss of load events constant, but may not measure both simultaneously due to overlap between these benefits.[101]

<u>Benefit 3:</u> Production cost savings

Benefit 3 is defined as savings in fuel and other variable operating costs of power generation when transmission facilities displace higher-cost supplies by increasing the dispatch of lower cost suppliers, leading to reduced market clearing prices.[102] LTRTFs could result in these savings by allowing for displacement of higher-cost supplies. Failure to require use of Benefit 3 could result in transmission providers not identifying, evaluating, and selecting LTRTFs that more efficiently or cost-effectively address Long-Term Transmission Needs.[103]

<u>Benefit 4:</u> Reduced transmission energy losses

Benefit 4 is defined as the reduced total energy necessary to meet demand stemming from reduced energy losses incurred in transmitting power from generation to loads.[104] The Commission found that transmission providers must measure and use this benefit in LTRTP because it will help to ensure that they identify, evaluate and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs. The Final Rule does not require transmission providers to adopt any single method to measure reduced transmission energy losses.[105]

<u>Benefit 5:</u> Reduced congestion due to transmission outages

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[99] *Id.* at P 756.

[100] *Id.* at P 758.

[101] *Id.* at P 755.

[102] *Id.* at P 767

[103] *Id.*

[104] *Id.* at P 781.

[105] *Id.* at P 782.

Benefit 5 is reduced production costs resulting from avoided congestion during transmission outages.[106] FERC found that use of this benefit will help to ensure that transmission providers identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs, and replace current production cost simulations that only consider generation outages without addressing transmission outages.[107]

<u>Benefit 6:</u> Mitigation of extreme weather events and unexpected system conditions

Benefit 6 is reduced production costs and reduced loss of load (or emergency procurements necessary to support the system), including due to increased Interregional Transfer Capability, during extreme weather events and unexpected system conditions, such as unusual weather conditions or fuel shortages that result in multiple concurrent and sustained generation and/or transmission outages.[108] Transmission providers must: (a) measure benefits of reduced loss of load and not only reduced production costs; (b) account for both extreme weather events and unexpected system conditions when transmission facilities have particularly high value (examples of unexpected system conditions can include, system contingencies in the form of generator and/or transmission outages, extreme or volatile production costs, and generation and/or load forecast error); and (c) measure the benefits associated with any increase in Interregional Transfer Capability provided by an LTRTF during an extreme weather event or unexpected system condition that results in multiple and concurrent sustained generation and/or transmission outages. Benefits 5 and 6 calculate benefits of reduced congestion due to transmission outages, but Benefit 6 includes a more expansive set of transmission outages (like extreme weather).[109]

<u>Benefit 7:</u> Capacity cost benefit from reduced peak energy losses

Benefit 7 accounts for reduced generation capacity investment needed to meet peak load.[110] FERC found it necessary to include the capacity cost benefits from reduced peak energy losses in LTRTP because standard production cost modeling and the other benefits within the Final Rule will not capture this benefit.[111]

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[106] *Id.* at P 788.

[107] *Id.* at PP 788-89.

[108] *Id.* at P 800.

[109] *Id.* at P 803.

[110] *Id.* at P 817.

[111] *Id.*

Notably, FERC does not require the other five benefits that were presented in the NOPR,[112] but transmission providers have the option to measure and use additional benefits beyond those included in the Final Rule, including on a transmission facility or plan-specific basis, in a way that is consistent with Order Nos. 890 and 1000.[113]

Identification, Measurement, and Evaluation of the Benefits of Long-Term Regional Transmission Facilities. The Final Rule requires transmission providers in every region to include in their OATTs a general description of how they will measure each of the seven benefits included in the required set of benefits to be used in LTRTP.[114]

Evaluation of Transmission Benefits Over a Longer Time Horizon. The Final Rule requires transmission providers as part of LTRTP, to calculate the benefits of LTRTF over a 20-year time horizon starting from the estimated in-service date of the transmission facilities. This benefit horizon must be used to evaluate and select LTRTFs.[115] FERC also requires that to the extent that transmission providers estimate the costs of LTRTFs beyond the in-service date of the transmission facilities, they must estimate those future costs over the same time horizon.[116]

Evaluation of the Benefits of Portfolios of Transmission Facilities. FERC adopted the NOPR proposal to allow, but not require, transmission providers in each transmission planning region to use a portfolio approach when evaluating the benefits of LTRTF.[117] The Final Rule requires transmission providers that propose to use a portfolio approach when evaluating the benefits of LTRTF to include provisions in their OATTs regarding their use of the portfolio approach.[118]

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

Requirement to Adopt an Evaluation Process and Selection Criteria. The Final Rule requires transmission providers to include in their OATTs an evaluation process, including selection criteria, to identify and evaluate LTRTFs for potential selection to address Long-Term Transmission Needs.[119] Transmission providers in each transmission planning region must

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[112] The NOPR also included mitigation of weather and load uncertainty, deferred generation capacity investments, access to lower cost generation, increased competition, and increased market liquidity. Id. at PP 820-821.

[113] *Id.* at P 822.

[114] *Id.* at P 837.

[115] *Id.* at P 859.

[116] *Id.* at P 859.

[117] *Id.* P 889.

[118] *Id.*

[119] *Id.* at P 911.

establish a LTRTP evaluation process that: (1) identifies LTRTFs that address Long-Term Transmission Needs; (2) measures the benefits of the identified LTRTFs consistent with the Final Rule requirements; and (3) designates a point in the evaluation process at which transmission providers will determine whether to select or not select identified LTRTFs in the regional transmission plan for purposes of cost allocation.[120] The evaluation and selection criteria must be developed using an open and transparent stakeholder process and with input from Relevant State Entities.[121]

The Final Rule requires that the transmission developer of a LTRTF that is selected, whether incumbent or non-incumbent, be eligible to use the applicable cost allocation method for the LTRTF.[122] Also consistent with Order No. 1000, selection in the regional transmission plan does not entitle the transmission developer to site or construct LTRTFs, nor does it obviate the need for the transmission developer to obtain other state, local, and/or federal permits or authorizations.[123]

Flexibility. The Final Rule requires transmission providers in each transmission planning region to propose, after consultation with Relevant State Entities and other stakeholders, evaluation processes, including selection criteria that they believe will ensure that more efficient or cost-effective LTRTFs are selected to address the transmission planning region's Long-Term Transmission Needs.[124] In response to a comment from NEPOOL, FERC clarified that transmission providers make the selection decisions in LTRTP.[125]

Minimum Requirements. Order No. 1920 requires transmission providers to propose evaluation processes, including selection criteria that are transparent and not unduly discriminatory.[126] Transmission providers' evaluation of transmission facilities must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular LTRTF (or portfolio of such Facilities) was selected or not selected.[127] This determination must include the measured benefits for each alternative LTRTF (or portfolio of such Facilities) considered in LTRTP.[128]

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[120] *Id.* at P 916.

[121] Relevant State Entities means "any state entity responsible for utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state." *Id*. at P 1309.

[122] *Id.* at P 912.

[123] *Id.* at P 917.

[124] *Id.* at P 924.

[125] *Id.* at P 926.

[126] *Id.* at P 954.

[127] *Id.*

[128] *Id.*

Transmission providers must propose on compliance evaluation processes, including selection criteria, that aim to ensure that more efficient or cost-effective LTRTFs are selected to address Long-Term Transmission Needs.[129]

Transmission providers' evaluation processes must aim to ensure the selection of more efficient or cost-effective LTRTFs to address Long-Term Transmission Needs.[130] Order No. 1920 accordingly adopts several requirements/guidelines, including:

- Transmission providers must identify one or more LTRTFs (or portfolio of such Facilities) that address the Long-Term Transmission Needs identified through LTRTP;[131]
- Transmission providers' evaluation processes must estimate the costs and measure the benefits of the LTRTF (or portfolio of such Facilities) that are identified or proposed for potential selection, in addition to evaluating the identified LTRTFs (or portfolio of such Facilities) using any qualitative or other quantitative selection criteria that the transmission providers propose;[132]
- Transmission providers must designate a point in the evaluation process at which transmission providers will determine whether to select or not select identified LTRTFs (or portfolio of such Facilities);[133]
- The evaluation process must culminate in determinations that are sufficiently detailed for stakeholders to understand why a particular LTRTF (or portfolio of such Facilities) was selected/not selected;[134]
- Transmission providers are required to develop and use at least three LTS, and one sensitivity analysis applied to each LTS, when conducting LTRTP. Each LTS or sensitivity analysis may suggest that different Long-Term Transmission Needs exist, that different LTRTF would resolve those needs, or that such LTRTF would provide different benefits for transmission customers;[135]
- Transmission providers may not impose as a selection criterion a minimum benefit-cost ratio that is higher than 1.25-to-1.00 (consistent with Order No. 1000 and the regional cost allocation principle);[136]

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[129] *Id.* at P 955.

[130] *Id.*

[131] *Id.*

[132] *Id.*

[133] *Id.*

[134] *Id.*

[135] *Id.* at P 956.

[136] *Id.* at P 958.

- Transmission providers must consult with and seek the support of Relevant State Entities regarding the evaluation process and selection criteria that transmission providers propose to use to evaluate LTRTF for selection;[137]
- There are no environmental justice or equity considerations required;[138]
- Transmission providers may (but do not need to) propose to use qualitative factors in their evaluation processes and/or qualitative selection criteria, provided that they demonstrate on compliance that their proposals comply with the evaluation process and selection criteria requirements of this Final Rule;[139]
- Transmission providers may not include in their evaluation process or selection criteria any prohibition on the selection of a LTRTF based on the transmission providers' anticipated response of a state public utility commission or consumer advocates to particular LTRTF;[140]
- Transmission providers must propose on compliance an evaluation process and selection criteria that comply with the requirements of this Final Rule after consulting with and seeking the support of Relevant State Entities;[141] and
- There is no requirement for the transmission provider to select any particular LTRTF, but transmission providers may propose such a requirement.[142]

Finally, FERC requires that transmission providers propose evaluation processes, including selection criteria, that seek to maximize benefits accounting for costs over time without over-building transmission facilities.[143]

Role of Relevant State Entities. FERC requires transmission providers to consult with and seek (but not necessarily obtain) support from Relevant State Entities regarding the evaluation process, including selection criteria, that transmission providers propose to use to identify and evaluate LTRTFs for selection.[144]

Voluntary Funding Opportunities. Transmission providers must include in their OATTs a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a LTRTF that otherwise would not meet the

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137 *Id.* at P 959.

138 *Id.* at P 960.

139 *Id.* at P 961.

140 *Id.* at P 962.

141 *Id.* at P 963.

142 Id. at PP 1026-1028.

143 *Id.* at P 964.

144 *Id.* at P 994.

transmission providers' selection criteria.[145] Transmission providers have flexibility to propose certain features of such a voluntary funding process in their compliance filings but must seek support and consultation from Relevant State Entities. On compliance, transmission providers must propose OATT revisions that describe:

- The process by which transmission providers will make voluntary funding opportunities available to Relevant State Entities and interconnection customers, which must ensure that they receive meaningful and timely notice of such opportunities.
- The period during which Relevant State Entities and interconnection customers may exercise the option to provide voluntary funding.
- The method that transmission providers will use to determine the amount of voluntary funding required to ensure that the LTRTF meets the transmission providers' selection criteria; and
- The mechanism through which transmission providers and Relevant State Entities or interconnection customers will memorialize any voluntary funding agreement, e.g., a pro forma agreement in the OATT.[146]

No Selection Requirement. FERC clarified that transmission providers are not required to select any particular LTRTF—even where a particular transmission facility meets the transmission providers' selection criteria in their OATTs.[147]

Reevaluation. Transmission providers must include in their OATTs provisions that require them—in certain circumstances—to reevaluate LTRTFs that previously were selected.[148] Reevaluation must occur when there are:

- Delays in the development of a previously selected LTRTF, which would jeopardize a transmission provider's ability to meet its reliability needs or reliability-related service obligations;
- The actual or projected costs of a previously selected LTRTF later significantly exceed cost estimates used in the selection of a LTRTF; or
- Significant changes in federal, federally-recognized Tribal, state, or local laws or regulations cause reasonable concern that a previously selected LTRTF may no longer meet the transmission providers' selection criteria.[149]

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[145] *Id.* at P 1012.

[146] *Id.* at P 1013.

[147] *Id.* at P 1026.

[148] *Id.* at P 1048.

[149] *Id.* at P 1049.

However, reevaluation on the basis of cost increases or laws or regulations must be part of a subsequent LTRTP cycle following selection, and must account for updated costs and updated benefits of the LRTF. Additionally, processes and procedures must include mechanisms for tracking costs so that transmission providers have an accurate way to determine if the actual or projected costs of the previously selected LTRTF exceed cost estimates by the relevant threshold, therefore requiring reevaluation. Finally, these procedures must seek to maximize cost benefits over time without over-building transmission facilities. Transmission providers must designate a point after which all selected LTRTF will no longer be subject to reevaluation, such that the transmission developer of the selected LTRTF has adequate certainty to make investment decisions.[150]

F. Implementation of Long-Term Regional Transmission Planning

Initial Timing Sequence Implementation. Transmission providers must explain on compliance how the initial timing sequence for LTRTP interacts with existing regional transmission planning processes.[151] Explanations must enough information to ensure that stakeholders understand this interaction, including at least (1) the possible interaction between the LTRTP cycle and existing Order No. 1000 regional transmission planning processes, and (2) the possible displacement of LTRTF from the existing regional transmission planning processes.[152]

Transmission providers are required to propose on compliance a date, no later than one year from the date on which initial filings to comply with this Final Rule are due, on which they will commence the first LTRTP cycle.[153]

Periodic Forums. FERC will organize forums to share best practices in implementing LTRTP and provide notice and relevant details in advance of the forums.[154]

III. Coordination of Regional Transmission Planning and Generator Interconnection Process

FERC requires transmission providers to revise the existing regional transmission planning process in their OATTs, to evaluate for selection regional transmission facilities that address certain interconnection-related transmission needs associated with network upgrades originally identified through the generator interconnection process.[155] The Commission found that reforms

[150] *Id.* at P 1050.

[151] *Id.* at P 1071.

[152] *Id.*

[153] *Id.* at P 1072.

[154] *Id.* at P 1075.

[155] *Id.* at P 1106.

are necessary to require evaluation through the regional transmission planning and cost allocation processes those interconnection-related transmission needs associated with interconnection-related network upgrades that are repeatedly identified though the generator interconnection process.[156] First, transmission providers must evaluate regional transmission facilities to address interconnection-related transmission needs in existing Order No. 1000 regional transmission planning and cost allocation processes, rather than in LTRTP. Second, an interconnection-related network upgrade associated with identified interconnection-related transmission needs must satisfy both the minimum cost and voltage criteria ($30 million in cost and minimum voltage of 200kV) to qualify for evaluation for selection.[157] FERC allows some degree of flexibility - transmission providers may adopt the evaluation method and selection criteria from any of their existing Order No. 1000 regional transmission planning and cost allocation processes (e.g., economic or reliability processes) to evaluate and potentially select these types of transmission facilities.[158]

Transmission Planning Process Evaluation. Certain regional transmission facilities that address current interconnection-related needs must be evaluated in existing Order No. 1000 regional transmission planning and cost allocation processes instead of in LTRTP, while future interconnection-related needs will be addressed in the LTRTP through use of certain of the factor categories (specifically 1, 2, 6 and 7) in the LTS development.[159]

Qualifying Criteria. To qualify for evaluation under the regional transmission planning process an interconnection-related transmission need must meet certain qualifying criteria, including:

- The transmission provider 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 (looking back from the effective date of FERC-accepted tariff provisions proposed to comply with this reform, and the later-in-time withdrawn interconnection request occurring after the effective date of FERC-accepted tariff provisions);

- 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;

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[156] PP 1106-1121

[157] *Id.* at P 1107.

[158] *Id.* at 1111. Transmission providers will still have to evaluate and select any regional transmission facilities that address the interconnection-related transmission needs as the more efficient or cost-effective regional transmission solution as part of the regional transmission planning process in order for any regional cost allocation method to apply, and this Final Rule does not alter the existing cost allocation methods in either the generator interconnection or existing Order No. 1000 regional transmission planning process. *Id.* at P 1117.

[159] *Id.* at P 1127.

- Such interconnection-related network upgrade(s) have 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

- 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.[160]

The Commission found the above criteria to be necessary to limit the scope of the requirement for transmission providers to evaluate transmission facilities to address interconnection-related transmission needs in the regional transmission planning process to those interconnection-related transmission needs that are likely to persist, are not unique to a single interconnection request and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers. These criteria simply determine whether a transmission provider must evaluate regional transmission facilities to address any given interconnection-related transmission need for potential selection—transmission providers may still separately assess whether any particular transmission facility qualifies for selection in the relevant existing regional transmission planning processes.[161]

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

The Final Rule requires that transmission providers 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, as well as upgrades to existing transmission facilities.[162] Thus, for each identified transmission need, transmission providers must consider whether regional transmission facilities that incorporate, or consist of, any of the enumerated list of alternative transmission technologies would be more efficient or cost-effective than selecting new regional transmission facilities or upgrades to existing transmission facilities without these technologies.[163] While FERC provided the above enumerated list, it noted that transmission providers are not prohibited from suggesting other technologies on compliance.

However, a transmission provider's evaluation of the enumerated alternative transmission technologies must be consistent with the other transmission solutions requirements in their OATTs.[164] The Final Rule does not require transmission providers to select any particular LTRTFs to address Long-Term Transmission Needs (i.e., in this case it does not require the selection and

[160] *Id*. at PP 1145.

[161] *Id*. at PP 1146-1148.

[162] *Id.* at P 1198. PP 1240-1247 contains an analysis of each of the enumerated technologies and why FERC found it appropriate to include such technology and not others (such as storage as transmission).

[163] *Id.* at P 1198.

[164] *Id.* at P 1199.

deployment of any particular alternative transmission technology with regard to any particular Long-Term Transmission Need).[165] Further, nothing in the Final Rule changes transmission providers' obligations to conduct transmission planning in a manner that ensures the long-term reliability of the bulk electric system.[166]

FERC clarified that the selection and use of the enumerated alternative transmission technologies incorporated into an existing transmission facility should be treated as an upgrade to that facility. Order No. 1000's elimination of any federal right of right of first refusal ("ROFR") for selected transmission facilities does not apply to upgrades to an existing transmission facility.[167] With respect to alternative transmission technologies added or deployed on a new selected regional transmission facility, both incumbent and non-incumbent transmission providers or developers designated to develop the underlying selected regional transmission facility are eligible to use the applicable regional cost allocation method for development of these upgrades.[168]

FERC further clarified that a sponsoring developer would be eligible to use the regional cost allocation method for the selected new regional transmission facility.[169] For every competitive transmission development process in a given transmission planning region, transmission providers must identify with sufficient detail in their OATTs the point or points in a given process at which the transmission providers in the transmission planning region will consider the potential use of alternative transmission technologies, including the point at which qualified transmission developers must submit any proposal to incorporate alternative transmission technologies.[170]

FERC believes that the particular benefit measurement methods that transmission providers must develop to evaluate proposed LTRTFs can be used to measure the economic benefits of incorporating the enumerated alternative transmission technologies into transmission facilities. These benefits include, but are not limited to, methods to measure production cost savings, reduced congestion due to fewer transmission outages, and capacity cost benefits from reduced peak energy losses.[171] The Commission provided some guidance on how transmission provider should evaluate dynamic line ratings but otherwise declined to mandate further details on how transmission providers should evaluate alternative transmission technologies as more efficient or cost-effective solutions.[172]

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[165] *Id.* at P 1200.

[166] *Id.* at P 1241.

[167] *Id.* at P 1202.

[168] *Id.* at P 1203.

[169] *Id.* at P 1203.

[170] *Id.* at P 1205.

[171] *Id.* at P 1208.

[172] *Id.* at P 1210. For the calculation of the economic benefits associated with dynamic lines ratings, it is appropriate for such calculations to use historical average wind speed and direction data to calculate average increases to transmission line transfer limits for use in benefit calculations. Average predicted wind speeds and direction should be sufficient to inform the transmission provider as to whether the

FERC confirmed that compliance with this Final Rule will not impact a transmission developer's compliance with Order No. 881, reasoning that Order No. 881 requires more accurate transmission line ratings, while this Final Rule requires that transmission developers consider the benefits associated with transmission line ratings, specifically wind speed, direction, and solar hearing intensity.[173]

In response to requests for additional transparency, FERC adopted the NOPR proposal to expand the requirement in Order No. 1000 that transmission providers' evaluations be sufficiently detailed for stakeholders to understand the selection or rejection of a transmission facility. Specifically, FERC adopted the NOPR proposal to require that the determination include an explanation for stakeholders to understand why dynamic line ratings, advanced power flow control devices, advanced conductors, and/or transmission switching were or were not incorporated into selected regional transmission facilities.[174]

The Final Rule further requires that transmission providers update their energy management systems, if needed to implement dynamic line ratings or any of the alternative transmission technologies. FERC noted that some transmission providers in non-RTO/ISO transmission planning regions may not need further updates because they already implemented alternative transmission technologies, and updated their energy management systems, per the requirements in Order No. 881.[175] Energy management system upgrade costs should be considered in the analysis to consider if transmission facilities that incorporating alternative transmission technologies are more efficient or cost-effective regional transmission solutions.[176]

V. Regional Transmission Cost Allocation

A. Cost Allocation for Long-Term Regional Transmission Facilities

Overall. Transmission providers are required to file one or more ex ante cost allocation methods that apply to selected LTRTF.[177] The cost allocation reforms in the Final Rule apply only to new LTRTF, not to regional reliability and economic transmission facilities that are selected pursuant to the existing Order No. 1000 regional transmission planning processes.[178]

State Agreement Approach and Relevant State Entities. Transmission providers are also permitted to revise their OATTs to include a State Agreement Process, if Relevant State Entities have agreed. However, the State Agreement Approach cannot be the sole method filed for cost

implementation of dynamic line ratings on a specific transmission line may render that line a more efficient or cost-effective regional transmission solution, and such data are widely available.

[173] *Id.* at PP 1211-12.

[174] *Id.* at P 1214.

[175] *Id.* at P 1215.

[176] *Id.* at P 1215.

[177] *Id.* at 1291.

[178] *Id.* at 1300.

allocation.[179] FERC established a six-month Engagement Period during which transmission providers must:

- provide notice of the starting and end dates for the six-month time period;
- post contact information that Relevant State Entities may use to communicate with TPs about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and
- provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process that enables meaningful participation by Relevant State Entities.[180]

If the Relevant State Entities agree on a Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process and provide that process within the required timeframe, the transmission provider may (but is not required to) file the agreed-to cost allocation method on compliance. However, the ultimate decision lies with the transmission provider.[181]

B. Long-Term Regional Transmission Facility Cost Allocation Compliance with the Existing Six Order No. 1000 Regional Cost Allocation Principles

Order No. 1920 requires Long-Term Regional Cost Allocation Methods to comply with five of the six existing Order No. 1000 regional cost allocation principles. These include:

- The allocation of the costs of selected transmission facilities to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits;
- 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;
- a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1 for purposes of screening potential solutions;
- costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs;

[179] *Id.* If a State Agreement Process fails to result in a cost allocation method agreed to by Relevant State Entities and any other authorized entities, or if FERC ultimately finds that the cost allocation method that results from a State Agreement Process is unjust, unreasonable, or unduly discriminatory or preferential, then the relevant Long-Term Regional Transmission Cost Allocation Method on file would apply as a backstop. *Id.* at P 1292

[180] *Id.* at P 1354.

[181] *Id.* at PP P 1355, 1402.

- the method for determining benefits and identifying beneficiaries must be transparent.[182]

Cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and have asked transmission providers to file, qualify as voluntary alternative cost sharing arrangements and are exempt from the requirement to adhere to the regional cost allocation principles.[183]

C. Identification of Benefits Considered in Cost Allocation for Long-Term Regional Transmission Facilities

FERC declined to adopt the NOPR proposal requiring transmission providers to identify on compliance the benefits used in Long-Term Regional Transmission Cost Allocation Methods, how they will calculate these benefits, and how these benefits reflect the benefits of regional transmission facilities that meet transmission needs driven by changes in the resource mix and demand.[184] Instead, FERC requires that transmission providers demonstrate on compliance that the required Long-Term Regional Transmission Cost Allocation Method(s) (that Relevant State Entities have not agreed to) comply with Order No. 1000 regional transmission cost allocation principles (1) through (5) and do not allocate costs by project type (i.e., reliability, economic, or transmission needs driven by Public Policy Requirements). While the cost allocation methods resulting from the State Agreement Approach or a Long-Term Regional Transmission Cost Allocation Methods that Relevant States Entities indicate they agreed to, need not comply with the Order No. 1000 regional cost allocation principles, if filed with FERC, transmission providers must nonetheless demonstrate that either of these types of cost allocation methods will allocate costs in a manner at least roughly commensurate with estimated benefits.[185]

VI. Construction Work in Progress (CWIP) Incentive

FERC declined to limit the availability of the CWIP Incentive for LTRTF at this time finding that the CWIP Incentive is more appropriately considered in a separate proceeding after FERC has finalized its LTRTP reforms.[186] In Particular, FERC concluded that whether

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[182] *Id.* at P 1471. Order No. 1000 regional cost allocation principle (6) provides that that there may be different regional cost allocation methods for different types of transmission facilities in the regional transmission plan but that there can be only one cost allocation method for each type of facility, and that method must be determined in advance. FERC declined to include this principle declined to include this because “transmission providers may not establish reliability, economic, or public policy transmission facility types as part of Long-Term Regional Transmission Planning and, therefore, may not establish Long-Term Regional Transmission Cost Allocation Methods based on reliability, economic, or public policy transmission facility types. Permitting such project-type-limited Long-Term Regional Transmission Cost Allocation Methods would be inconsistent with the long-term, forward-looking, more comprehensive regional transmission planning that we require in this Final Rule.” P 1474.

[183] *Id.* at P 1477.

[184] *Id.* at P 1505.

[185] *Id.*

[186] *Id.* at P 1546.

transmission incentives are appropriately "benefitting consumers by ensuring reliability and reducing the cost of delivered power" is a question better evaluated during a comprehensive review of transmission incentives for all regional transmission facilities.[187]

VII. Exercise of a Federal Right of First Refusal in Commission-Jurisdictional Tariffs and Agreements

FERC also declined to adopt the NOPR proposal to allow for a federal ROFR for incumbent transmission providers, conditioned on the incumbent transmission provider establishing joint ownership of the transmission facilities.[188] FERC stated that it would continue to consider the NOPR proposal and potential federal ROFR issues in other proceedings. FERC does not adopt any changes to Order No. 1000's nonincumbent transmission developer reforms.[189]

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

A. Need for Reform

FERC adopted the preliminary findings in the NOPR concerning the need for reform of the local transmission planning process and coordination between the local and regional transmission planning processes, including the evaluation of whether replacement transmission facilities could be modified (i.e., right-sized) to more efficiently or cost-effectively address transmission needs.[190]

To ensure that rates are just and reasonable, FERC identified the following deficiencies in the local transmission planning process:[191] (1) local transmission planning processes lack adequate provisions for transparency and meaningful input from stakeholders;[192] (2) additional coordination between the local and regional transmission planning processes regarding replacement of aging infrastructure is needed to evaluate whether replacement facilities can be modified (i.e. right-sized).[193] FERC found that that transmission providers' OATTs are unjust and unreasonable due to the lack of right-sizing requirements that may lead to the identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities.[194]

For these reasons, FERC adopted with certain modifications, the two reforms that FERC identified in the NOPR: (1) enhance the transparency of local transmission planning processes; and (2) require transmission providers to evaluate whether transmission facilities that need

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187 *Id.* at P 1547.

188 *Id.* at P 1550.

189 *Id.* at P 1553.

190 *Id.* at P 1569.

191 *Id.* at P 1570.

192 *Id.* at P 1571.

193 *Id.* at P 1573-74.

194 *Id.* at P 1576.

replacing can be "right-sized" to more efficiently or cost-effectively address Long-Term Transmission Needs identified in Long-Term Regional Transmission Planning.[195]

B. Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process

FERC adopted the NOPR proposal, with modification, to require transmission providers in each transmission planning region to revise the regional transmission planning process in their OATTs to enhance the transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through the local transmission planning process; and (3) the evaluation of potential local or regional transmission facilities to address those local transmission needs. For each of these three categories of local transmission planning information, transmission providers must identify and publicly post the information identified, then conduct publicly-noticed stakeholder meetings to provide an opportunity for comment on the information both before and after the stakeholder meetings. FERC clarified that this requirement applies only to local transmission planning that is within the scope of Order No. 890 and its transparency requirements. As such, this requirement does not apply to asset management projects.[196]

To provide the needed transparency and opportunities for stakeholder participation, FERC required that the regional transmission planning process include at least three publicly-noticed stakeholder meetings per regional transmission planning cycle.[197]

Specifically, FERC adopted the NOPR proposal to require that prior to the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process, transmission providers convene a stakeholder meeting to review the criteria, assumptions, and models related to each transmission provider's local transmission planning (Assumptions Meeting).[198] Next, no fewer than 25 calendar days after the Assumptions Meeting, transmission providers convene, a stakeholder meeting to review identified reliability criteria violations and other transmission needs that drive the need for local transmission facilities (Needs Meeting).[199] Finally, no fewer than 25 calendar days after the Needs Meeting, transmission providers convene, collectively, a stakeholder meeting to review potential solutions to those reliability criteria violations and other transmission needs (Solutions Meeting).[200]

Additionally, FERC required that all materials for stakeholder review during these three meetings be publicly posted no fewer than five calendar days prior to each of the meetings and

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[195] *Id.* at P 1577.

[196] *Id.* at P 1625.

[197] *Id.* at P 1626.

[198] *Id.* at P 1627.

[199] *Id.* at P 1627.

[200] *Id.* at P 1627.

that stakeholders have opportunities before and after each meeting to submit comments.[201] FERC also required that transmission providers allow for a period of no fewer than 25 calendar days following the Solutions Meeting to review and consider stakeholder feedback on the local transmission solutions.[202]

Specific Stakeholder Meeting Requirements. FERC explained that the 25 calendar-days between stakeholder meetings is just a minimum and can be modified to best meet the needs of each transmission planning region.[203]

FERC believes that providing information to stakeholders at least five calendar days prior to each of the three meetings, strikes a balance between giving stakeholders meaningful opportunity to review the meeting materials ahead of each meeting and limiting the burden to transmission providers in posting the materials ahead of time.[204]

The requirement to hold three publicly-noticed stakeholder meetings is triggered by the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process and is not tied to a particular transmission planning cycle.[205] FERC reiterated that transmission providers must post transmission planning criteria, models, and assumptions (which is already a requirement of Order No. 890) as part of the Assumptions Meeting.[206] This information must enable customers, other stakeholders, or an independent third party to replicate the results of planning studies and thereby reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion.[207]

FERC declined to set a bright-line rule that transmission providers must respond to each and every question or comment received through the stakeholder process. Nevertheless, FERC required transmission providers to respond to questions or comments in a manner that allows stakeholders to meaningfully participate in these stakeholder meetings.[208] FERC clarified that all disputes regarding transparency should be handled using the transmission provider's existing dispute resolution process.[209]

Additional Issues. FERC clarified that transmission providers must continue to apply the same safeguards to protect sensitive or critical information, such as confidentiality agreements and

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[201] *Id.* at P 1628.

[202] *Id.* at P 1628.

[203] *Id.* at P 1639.

[204] *Id.* at P 1640.

[205] *Id.* at P 1642.

[206] *Id.* at P 1643.

[207] *Id.* at P 1643.

[208] *Id.* at P 1656.

[209] *Id.* at P 1646.

password protected access to information, as required in Order No. 890 and currently apply to the sharing of transmission planning information to protect against inappropriate disclosure of confidential information.[210]

C. Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

FERC adopted the NOPR proposal, with modification to require that transmission providers evaluate whether transmission facilities are (1) operating above a specified kV threshold and (2) that an individual transmission provider anticipate replacing an existing transmission facility with one that can be "right-sized" to more efficiently or cost-effectively address a Long-Term Transmission Need as part of each LTRTP Cycle.[211] To effectuate this reform, transmission providers are required to submit in-kind replacement estimates early in each LTRTP cycle (i.e., estimates of the transmission facilities operating at and above the specified kV threshold that a transmission provider will replace within the next 10 years).[212] With respect to the specified kV threshold, transmission providers must propose on compliance a threshold that does not exceed 200 kV (e.g., 115 kV and above). FERC also adopted the NOPR proposals regarding a ROFR and cost allocation method for right-sized replacement transmission facilities.[213]

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.[214] An "in-kind replacement transmission facility" is a new transmission facility that: (1) would replace an existing transmission facility that needs to be replaced; (2) would result in no more than an incidental increase in capacity over the existing transmission facility identified as needing to be replaced; and (3) is located in the same general route as, and/or uses the existing rights-of-way of, the existing transmission facility identified as needing to be replaced.[215]

FERC clarified that a "right-sized replacement transmission facility" is a new transmission facility that: (1) would meet the need to replace an existing transmission facility as identified in the in-kind replacement estimate to address Long Term Transmission Need; (2) results in more than an incidental increase in the capacity of an existing transmission facility as identified for replacement in its in-kind replacement estimate; and (3) is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility as identified for replacement in its in-kind replacement estimate.[216]

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[210] *Id.* at P 1647.

[211] *Id.* at P 1677.

[212] *Id.* at P 1677.

[213] *Id.* at P 1677.

[214] *Id.* at P 1678.

[215] *Id.* at P 1678.

[216] *Id.* at P 1679.

Consistent with the NOPR proposal transmission providers must describe steps for right-sizing reform in their OATTs.[217] They must propose a point sufficiently early in each LTRTP cycle at which each individual transmission provider in the transmission planning region will submit its in-kind replacement estimates.[218] If transmission providers identify a right-sized replacement transmission facility as a potential solution to a Long-Term Transmission Need as part of LTRTP, that right-sized replacement transmission facility must be evaluated in the same manner as any other proposed LTRTF to determine whether it is the more efficient or cost-effective transmission facility to address the transmission need.[219] It is at this stage of the right-sizing reform where transmission providers must use the in-kind replacement estimates to determine if those facilities could be right-sized to more efficiently or cost-effectively address a Long-Term Transmission Need(s).[220] If a right-sized replacement transmission facility addresses the transmission provider's need to replace an existing transmission facility, meets the applicable selection criteria included in LTRTP, and is found to be the more efficient or cost-effective solution to a Long-Term Transmission Need, then the right-sized replacement transmission facility must be considered for selection.[221]

With regard to the timeframe for in-kind replacement estimates, FERC found that 10 years is appropriate to evaluate potential in-kind replacement transmission facilities for right-sizing because it balances the long lead times associated with developing certain transmission facilities with the uncertainty associated with the exact timing of when aging transmission facilities may need to be replaced. FERC clarified that clarify that transmission providers may update the lists of transmission facilities that they anticipate replacing in subsequent transmission planning cycles if they believe that an anticipated in-kind replacement transmission facility is more urgently needed than previously thought or if existing transmission facilities do not deteriorate as quickly as previously expected.[222]

FERC clarified that storm hardening transmission projects that do not encompass the replacement of existing transmission facilities with an in-kind transmission facility need not be included on a transmission provider's list of in-kind replacement estimates.[223]

Right of First Refusal. FERC accepted the NOPR proposal to require the establishment of a federal ROFR for a right-sized replacement transmission facility that is selected to meet Long-Term Transmission Needs.[224] This ROFR will apply to the transmission provider with the in kind replacement estimate and extends to any portion of the right-sized replacement facility located within that transmission provider's retail distribution service territory or footprint, which must

[217] *Id.* at P 1681.

[218] *Id.* at P 1681.

[219] *Id.* at P 1681.

[220] *Id.* at P 1681.

[221] *Id.* at P 1681.

[222] *Id.* at P 1685.

[223] *Id.* at P 1690.

[224] *Id.* at P 1702.

satisfy the definition of a right-sized replacement facility, including that the right-sized replacement transmission facility is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility.[225] FERC found that that permitting a federal ROFR for right-sized replacement transmission facilities will encourage transmission providers to provide their best in-kind replacement estimates, because they will not lose the opportunity to invest in a right-sized replacement transmission facility. As such, we find that a federal ROFR will remove a disincentive for transmission providers to consider right-sizing in LTRTP.[226]

Cost Allocation. FERC declined to adopt the NOPR proposal requiring that only the incremental costs of right-sizing the transmission facility be eligible for the applicable Long-Term Regional Transmission Cost Allocation Method, while the costs for the in-kind replacement transmission facility be allocated as they would have been for the original facility.[227] FERC found persuasive comments identifying the complexities and challenges associated with tracking portions of costs of two different transmission projects through time, as well as allocating the costs of a right-sized replacement transmission facility pursuant to two separate cost allocation methods.[228]

Further, FERC also required that transmission providers amend their regional transmission planning processes to provide transparency with respect to which right-sized replacement transmission facilities have been selected, as well as which transmission facilities are simply included in the regional transmission plan for informational (and not cost allocation) purposes.[229]

To the extent that transmission providers propose to allocate the costs of right-sized replacement transmission facilities pursuant to the cost allocation method described in the NOPR, FERC required that the transmission providers to explain on compliance (1) the method to determine the portion of the costs of a right-sized replacement transmission facility that is incremental to the costs that would have been incurred for the underlying in-kind replacement transmission facility, and (2) the method by which they will track the portion of costs over time that are allocated in accordance with the Long-Term Regional Transmission Cost Allocation Method (or, if adopted, subject to a State Agreement Process), as well as the portion of costs that would have been allocated pursuant to the cost allocation method that otherwise would have applied to the in-kind replacement transmission facility.[230]

FERC clarified that it is not requiring any changes pursuant to this right-sizing requirement that would affect the existing cost allocation method(s) for in-kind replacement transmission

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[225] *Id.* at P 1702.

[226] *Id.* at P 1703.

[227] *Id.* at P 1716.

[228] *Id.* at P 1716.

[229] *Id.* at P 1717.

[230] *Id.* at P 1719.

facilities that are not identified for right-sizing, or for the costs of the underlying in-kind replacement transmission facilities that would have been incurred absent right-sizing.[231]

IX. Interregional Transmission Coordination

FERC requires transmission providers to revise their existing interregional transmission coordination procedures to reflect the LTRTP reforms adopted in this Final Rule.[232] Specifically, transmission providers in neighboring transmission planning regions must revise their existing interregional transmission coordination procedures (and regional transmission planning processes, as needed) to provide for: (1) the sharing of information regarding their respective Long-Term Transmission Needs, as well as LTRTFs to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address Long-Term Transmission Needs.[233]

Transmission providers in neighboring transmission planning regions must also revise their interregional transmission coordination procedures (and regional transmission planning processes, as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to Long-Term Transmission Needs.[234]

Transmission providers must provide the following additional information concerning Long-Term Regional Transmission Planning on their public website or through the email list used for communication of information related to interregional transmission coordination procedures: (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.[235]

Compliance with this portion of the Final Rule is 12 months from the effective date, instead of 10 months.[236]

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[231] *Id.* at 1720.

[232] *Id.* at P 1751.

[233] *Id.*

[234] *Id.* at P 1752.

[235] *Id.* at P 1753.

[236] *Id.* at P 1770.

X. Compliance Procedures

FERC adopted the NOPR proposal, with modification, and requires each transmission provider to submit a compliance filing revising its OATT and other jurisdictional documents within ten months of the effective date of this Final Rule.[237]

FERC also modifies the NOPR proposal and requires each transmission provider to submit a separate compliance filing within 12 months of the effective date of this Final Rule revising its OATT and jurisdictional documents to demonstrate that it meets the interregional transmission coordination requirements adopted in this Final Rule.[238]

FERC declined to apply the independent entity variation standard, rather than the "consistent with or superior to" standard, for proposed deviations from the requirements in this Final Rule on compliance.[239]

XI. Concurrence and Dissent

Order No. 1920 was issued along party lines - a joint concurring statement was issued by Chairman Phillips and Commissioner Clements and a dissenting statement was issued by Commissioner Christie. In their concurrence, Chairman Phillips and Commissioner Clements emphasize that the Final Rule is a reliability and affordability imperative, rather than an effort to impose any policy agenda or favor any resource type.[240] Further, the concurring statement highlights that the Final Rule provides transmission planners "maximum flexibility" to develop solutions and cost allocation frameworks that provide opportunity for state involvement.[241] The concurring statement also emphasizes that, although the Final Rule did not ultimately revise Commission policy on the federal ROFR, nothing in the Final Rule should be construed as a lack of support for the concept of joint ownership or the potential federal ROFR to effectively encourage the use of join ownership of transmission facilities.[242] Finally, the concurring statement aims to rebut some of the points made in Commissioner Christie's dissent particularly with respect to state involvement in cost allocation, the public policy implications of the Final Rule and the Constitutional foundation for the Final Rule.

Commissioner Christie issued a strong, 77-page dissenting statement to the Final Rule. In Commissioner Christie's view there are several core elements at issue with the Final Rule. First, Commissioner Christie argues that the Final Rule is simply a pretext for enacting a policy agenda

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237 *Id.* at P 1768.

238 *Id.* at P 1770.

239 *Id.* at P 1772.

240 Phillips, Comm'r and Clements, Comm'r concurring at P 1.

241 *Id.* at P 8.

242 *Id.* at PP 30, 33.

to favor certain resource types that was never passed by Congress.[243] Second, the dissent argues that the Final Rule fails to fulfill the Commission's consumer protection duty required by statute and instead imposes an "absurdly complex bureaucratic blizzard of mandates and micromanagement to be imposed on every transmission provider in the United States for the transparent goal of spending trillions of consumers' dollars on transmission not to serve consumers in accordance with the FPA, but instead to serve political, corporate and other special-interest agendas that were never enacted into law."[244] Further, the dissent argues that the Final Rule's cost allocation requirements would impose costs of transmission facilities on non-consenting states and consumers while also denying states the opportunity to agree to selection criteria or involvement in selection.[245]

With respect to consumer protection, Commissioner Christie notes that the NOPR's proposal to deny transmission developers the CWIP incentive would have benefitted consumers more than "holistic or efficient planning."[246] Further, he argues that the Final Rule's proposal to review interconnection-related network upgrades as part of the transmission planning process improperly shifts costs caused by generation developers' interconnection requests from those developers to consumers.[247] It is clear from the dissent that Commissioner Christie is extremely disappointed in the lack of compromise from the NOPR to this Final Rule. While he voted for the NOPR and found it to be an overall fair compromise, in his view, the Final Rule subverts and violates the compromise that was struck in the NOPR.[248] Lastly, Commissioner Christie makes a large number of arguments regarding FERC's statutory and Constitutional authority to issue Order No. 1920. In the dissent's view, the Final Rule largely exceeds the Commission's legal authority under Section 206 of the FPA, infringes on states' authority over electric generation reserved to them by Section 201 of the FPA and violates the "major questions" doctrine and is, accordingly, an improper policy overstep by an administrative agency that should have been left to Congress.

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[243] Christie, Comm'r, dissenting at P 1 & n.3.

[244] *Id.* at P 1 & n.4, n.5.

[245] "Let's get real: Telling states to negotiate for an alternative cost allocation when the transmission provider's ex ante formula has already been designated as the default is no real negotiation at all. The final rule points a regulatory gun at states' heads redolent of The Godfather: "Here's an offer you can't refuse."" *Id*. at P 12.

[246] *Id.* at P 16.

[247] Id. at PP 103-108.

[248] *Id*. at P 11.