DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM21–17–000]

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to reform both the *pro forma* Open Access Transmission Tariff and the *pro forma* Large Generator Interconnection Agreement to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation requirements. Specifically, the proposal would require public utility transmission providers to; conduct long-term regional transmission planning on a sufficiently forward-looking basis to meet transmission needs driven by changes in the resource mix and demand; more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning processes; seek the agreement of relevant state entities within the transmission planning region regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through long-term regional transmission planning; adopt enhanced 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; and revise their existing interregional transmission coordination procedures to reflect the long-term regional transmission planning reforms proposed in this NOPR. In addition, the proposal would not permit public utility transmission providers to take advantage of the construction-work-in-progress incentive for regional transmission facilities selected for purposes of cost allocation through long-term regional transmission planning and would permit the exercise of federal rights of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider with the federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities.

DATES: Comments are due July 18, 2022 and Reply Comments are due August 17, 2022.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways. Electronic filing through *https://www.ferc.gov,* is preferred.

- *Electronic Filing:* Documents must be filed in acceptable native applications and print-to-PDF, but not in scanned or picture format.
- For those unable to file electronically, comments may be filed by USPS mail or by hand (including courier) delivery.
  - *Mail via U.S. Postal Service Only:* Addressed to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.
  - *Hand (including courier) delivery:* Deliver to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

The Comment Procedures Section of this document contains more detailed filing procedures.

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SUPPLEMENTARY INFORMATION:

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I. Introduction

1. In this Notice of Proposed Rulemaking (NOPR), the Federal Energy Regulatory Commission (Commission) is proposing, pursuant to its authority under section 206 of the Federal Power Act (FPA),[1] to reform its electric regional transmission planning and cost allocation requirements. The proposed reforms are intended to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.

2. This NOPR builds on Order Nos. 888,[2] 890,[3] and 1000,[4] in which the Commission incrementally developed the requirements that govern regional transmission planning and cost allocation processes to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.

3. With respect to regional transmission planning, as discussed in more detail below, the reforms proposed in this NOPR would require public utility transmission providers to conduct long-term regional transmission planning on a sufficiently forward-looking basis to meet transmission needs driven by changes in the resource mix and demand.[5] As part of this long-term regional transmission planning, public utility transmission providers would be required to: (1) Identify transmission needs driven by changes in the resource mix and demand through the development of long-term scenarios that satisfy the requirements set forth in this NOPR, including accounting for low-frequency, high-impact events such as extreme weather events; (2) evaluate the benefits of regional transmission facilities to meet these needs over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities; and (3) establish transparent and not unduly discriminatory criteria to select transmission facilities in the regional transmission plan for purposes of cost allocation that more efficiently or cost-effectively address these transmission needs in collaboration with states and other stakeholders. We do not propose in this NOPR to change Order No. 1000's requirements for public utility transmission providers with respect to existing reliability and economic planning requirements. Additionally, we propose to require that public utility transmission providers more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning processes.

4. With respect to transmission cost allocation, the reforms proposed in this NOPR would require that public utility transmission providers in each transmission planning region seek the agreement of relevant state entities within the transmission planning region regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through long-term regional transmission planning[6] and revise their OATTs to include those method or methods.

5. We also propose to not permit public utility transmission providers to take advantage of the construction-work-in-progress (CWIP) incentive for regional transmission facilities selected for purposes of cost allocation through long-term regional transmission planning.

6. With respect to federal rights of first refusal, the reforms proposed in this NOPR would amend Order No. 1000's requirements, in part, to permit

[1] 16 U.S.C. 824e. Section 206 requires that Commission-jurisdictional rates, terms, and conditions, including those for transmission services, be just and reasonable and not unduly discriminatory or preferential. The phrase ''Commission-jurisdictional rates,'' as used in this NOPR, includes rates, terms, and conditions.

[2] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Pub. Utils.; Recovery of Stranded Costs by Publ. 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 Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N. Y.* v. *FERC,* 535 U.S. 1 (2002).

[3] *Preventing Undue Discrimination & Preference in Transmission Serv.,* Order No. 890, 72 FR 12266 (Mar. 15, 2007), 118 FERC ¶ 61,119, *order on reh'g,* Order No. 890–A, 73 FR 2984 (Jan. 16, 2008), 121 FERC ¶ 61,297 (2007), *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228, *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[4] *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.,* Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), *order on reh'g,* Order No. 1000–A, 77 FR 32184 (May 31, 2012), 139 FERC ¶ 61,132, *order on reh'g and 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).

[5] A public utility transmission provider means a public utility that owns, controls, or operates transmission facilities. The term public utility transmission provider should be read to include a public utility transmission owner when the transmission owner is separate from the transmission provider, as is the case in regional transmission organizations (RTO) and independent system operators (ISO). The term ''public utility'' means ''any person who owns or operates facilities subject to the jurisdiction of the Commission . . . .'' 16 U.S.C. 824(e).

[6] This NOPR refers to such facilities as ''Long-Term Regional Transmission Facilities''.

the exercise of federal rights of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider with the federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with the proposal below.

7. With respect to transparency and coordination, we propose to require public utility transmission providers to adopt enhanced 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.

8. With respect to interregional transmission coordination and cost allocation, the reforms proposed in this NOPR would require that public utility transmission providers revise their existing interregional transmission coordination procedures to reflect the long-term regional transmission planning reforms proposed in this NOPR.

9. The proposed reforms in this NOPR related to regional transmission planning and cost allocation requirements, like those of Order Nos. 890 and 1000, are focused on the transmission planning process, and not on any substantive outcomes that may result from this process. Taken together, these proposed reforms would work together to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation requirements. This, in turn, would fulfill our statutory obligation to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.

10. The Advance Notice of Proposed Rulemaking (ANOPR),[7] the Commission also sought comment on reforms related to cost allocation for interconnection-related network upgrades, interconnection queue processes, interregional transmission coordination and planning, and oversight of transmission planning and costs. While this NOPR does not propose broad or comprehensive reforms directly related to these topics, we will continue to review the record developed to date and expect to address possible inadequacies through subsequent proceedings that propose reforms, as warranted, related to these topics. In addition, concurrent with the issuance of this NOPR, we notice a technical conference on Transmission Planning and Cost Management.

11. We seek comment on the reforms proposed herein and encourage commenters to identify enhancements to those reforms that could better support development of more efficient or cost-effective transmission facilities than is the case under the Commission's existing regional transmission planning and cost allocation requirements.

II. Background

A. Historical Framework: Order Nos. 888, 890, and 1000

12. Over the last several decades, the Commission has taken multiple significant actions on transmission planning and cost allocation, including issuing Order Nos. 888, 890, and 1000. In 1996, the Commission issued Order No. 888, which implemented open access to transmission facilities owned, operated, or controlled by a public utility and included certain minimum requirements for transmission planning. In 2007, the Commission issued Order No. 890 to address deficiencies in the *pro forma* OATT that it identified after more than 10 years of experience since Order No. 888. Among other OATT reforms, the Commission required all public utility transmission providers' local transmission planning processes to satisfy nine transmission planning principles: (1) Coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.[8]

13. Then, in 2011, the Commission recognized the need for further transmission planning reforms with its issuance of Order No. 1000. The Commission based the reforms it adopted in Order No. 1000 on changes in the energy industry, its experience implementing Order No. 890, and a robust record developed through technical conferences and comments from a diverse range of stakeholders.[9] The Commission stated in Order No. 1000 that ''the electric industry is currently facing the possibility of substantial investment in future transmission facilities to meet the challenge of maintaining reliable service at a reasonable cost.''[10] In establishing the requirements of Order No. 1000, the Commission found that the existing requirements of Order No. 890 were not adequate, noting that Order No. 1000 ''expands upon the reforms begun in Order No. 890 by addressing new concerns that have become apparent in the Commission's ongoing monitoring of these matters.''[11] The Commission then enumerated multiple concerns that it had regarding existing transmission planning practices, including concerns about: (1) The lack of an affirmative obligation to develop a transmission plan evaluating if a regional transmission facility ''may be more efficient or cost-effective than solutions identified in local transmission planning processes;'' (2) the lack of a requirement to address Public Policy Requirements;[12] (3) the federal right of first refusal for incumbent transmission developers to build upgrades to their existing transmission facilities; (4) the lack of procedures to identify and evaluate the benefits of interregional transmission facilities; and (5) cost allocation for regional and interregional transmission facilities.[13]

14. Order No. 1000 included a package of reforms to ensure that the transmission planning and cost allocation requirements embodied in the *pro forma* OATT were adequate to support the development of more efficient or cost-effective transmission facilities.[14] The reforms in Order No. 1000 fell into the following categories: Regional transmission planning; transmission needs driven by Public Policy Requirements; nonincumbent transmission developer reforms; regional and interregional cost allocation, including a set of principles for each category of cost allocation; and interregional transmission coordination. The reforms focused on the process by which public utility transmission providers engage in regional transmission planning and associated cost allocation rather than on the outcomes of the process.[15]

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[7] *Building for the Future Through Electric Regional Transmission Planning & Cost Allocation & Generator Interconnection,* 86 FR 40266 (July 15, 2021), 176 FERC ¶ 61,024 (2021) (ANOPR); *see infra* P 18 (briefly summarizing the ANOPR).

[8] Order No. 890, 118 FERC ¶ 61,119 at PP 418–601.

[9] Order No. 1000, 136 FERC ¶ 61,051 at P 3. The term ''stakeholder'' means any interested party. *Id.* P 151 n.143.

[10] *Id.* P 2.

[11] *Id.* P 22.

[12] Public Policy Requirements are requirements established by local, state or federal laws or regulations (*i.e.,* enacted statutes passed by the legislature and signed by the executive and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level). *Id.* P 2. Order No. 1000–A clarified that Public Policy Requirements include local laws or regulations passed by a local governmental entity, such as a municipal or county government. Order No. 1000–A, 139 FERC ¶ 61,132 at P 319.

[13] Order No. 1000, 136 FERC ¶ 61,051 at P 3.

[14] *Id.* PP 11–12, 42–44; Order No. 1000–A, 139 FERC ¶ 61,132 at PP 3, 4–6.

[15] Order No. 1000, 136 FERC ¶ 61,051 at P 12.

15. Among other regional transmission planning reforms in Order No. 1000, the Commission required that the following Order No. 890 transmission planning principles apply to regional transmission planning processes: (1) Coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning studies.[16]

16. In addition, with respect to the Order No. 1000 reforms, there is a distinction between a transmission facility ''included'' in a regional transmission plan and a transmission facility ''selected'' in a regional transmission plan for purposes of cost allocation. A transmission facility selected in a regional transmission plan for purposes of cost allocation is a transmission facility that has been selected pursuant to a transmission planning region's [17] Commission-approved regional transmission planning process for inclusion in a regional transmission plan for purposes of cost allocation because it is a more efficient or cost-effective transmission facility needed to meet regional transmission needs. Both regional transmission facilities and interregional transmission facilities are eligible for potential ''selection'' in a regional transmission plan for purposes of cost allocation.[18] A regional transmission facility is a transmission facility located entirely in one transmission planning region.[19] An interregional transmission facility is one that is located in two or more transmission planning regions.[20]

17. Transmission facilities selected in a regional transmission plan for purposes of cost allocation often will not comprise all of the transmission facilities that are included in a regional transmission plan.[21] Some transmission facilities are merely ''rolled up'' and listed in a regional transmission plan without going through an analysis at the regional level, and therefore, are not eligible for selection and regional cost allocation.[22] For example, a local transmission facility is a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation.[23] Thus, a local transmission facility may be rolled up and ''included'' in a regional transmission plan for informational purposes, but it is not ''selected'' in a regional transmission plan for purposes of cost allocation.

B. ANOPR and Technical Conference

18. In July 2021, the Commission issued an ANOPR presenting potential reforms to improve the regional transmission planning and cost allocation and generator interconnection processes. In issuing the ANOPR, the Commission noted that, more than a decade after Order No. 1000, it was time to review its regulations governing regional transmission planning and cost allocation and generator interconnection processes to determine whether reforms are needed to ensure Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.[24] The Commission noted that the electricity sector is transforming as the generation fleet shifts from resources located close to population centers toward resources that may often be located far from load centers. The Commission also highlighted the growth of new resources seeking to interconnect to the transmission system and that the differing characteristics of those resources are creating new demands on the transmission system. The Commission explained that ensuring just and reasonable Commission-jurisdictional rates as the resource mix changes, while maintaining grid reliability, remains the Commission's priority in adopting requirements for the regional transmission planning and cost allocation and generator interconnection processes. As a result, the Commission issued the ANOPR to consider whether there should be changes in the regional transmission planning and cost allocation and generator interconnection processes and, if so, which changes are necessary to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential and that reliability is maintained.

19. On November 15, 2021, the Commission convened a staff-led technical conference (November 2021 Technical Conference or Technical Conference) to examine in detail issues and potential reforms related to regional transmission planning as described in ANOPR. Specifically, the Technical Conference included three panels covering issues related to factors to consider in long-term scenarios, consideration of longer-term scenarios in regional transmission planning processes, and identifying geographic zones with high renewable resource potential for use in regional transmission planning processes.[25] After the Technical Conference, the Commission invited all interested persons to file comments after the Technical Conference to address issues raised during the Technical Conference.

C. Joint Federal-State Task Force on Electric Transmission

20. On June 17, 2021, the Commission established a Joint Federal-State Task Force on Electric Transmission (Task Force) to formally explore broad categories of transmission-related topics.[26] The Commission explained that the development of new transmission infrastructure implicates a host of different issues, including how to plan and pay for these facilities. Given that federal and state regulators each have authority over transmission-related issues and the impact of transmission infrastructure development on numerous different priorities of federal and state regulators, the Commission determined that the area is ripe for greater federal-state coordination and cooperation.[27] The Task Force is comprised of all FERC Commissioners as well as representatives from 10 state commissions nominated by the National Association of Regulatory Utility Commissioners (NARUC), with two originating from each NARUC region.[28]

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[16] The Commission did not include the regional participation or cost allocation transmission planning principles with respect to regional transmission planning processes because those issues were addressed by other reforms in Order No. 1000. *Id.* P 151.

[17] A transmission planning region is one in which public utility transmission providers, in consultation with stakeholders and affected states, have agreed to participate for purposes of regional transmission planning and development of a single regional transmission plan. *Id.* P 160.

[18] *Id.* P 63.

[19] *Id.* n.374.

[20] *Id.*

[21] *Id.* P 63.

[22] *Id.* PP 7, 226, 318.

[23] *Id.* P 63. The Commission clarified in Order No. 1000–A that a local transmission facility is one that is located within the geographical boundaries of a public utility transmission provider's retail distribution service territory, if it has one; otherwise the area is defined by the public utility transmission provider's footprint. In the case of an RTO/ISO whose footprint covers the entire region, a local transmission facility is defined by reference to the retail distribution service territories or footprints of its underlying transmission owing members. Order No. 1000–A, 139 FERC ¶ 61,132 at P 429.

[24] ANOPR, 176 FERC ¶ 61,024 at P 3.

[25] *Building for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection,* Further Supplemental Notice of Technical Conference, Docket No. RM21–17–000 (issued Nov. 12, 2021) (attaching agenda).

[26] *Joint Fed.-State Task Force on Elec. Transmission,* 175 FERC ¶ 61,224, at PP 1, 6 (2021).

[27] *Id.* P 2.

[28] An up-to-date list of Task Force members, as well as additional information on the Task Force, is available on the Commission's website at: *https://www.ferc.gov/TFSOET.* Public materials related to the Task Force, including transcripts from public

21. The Task Force will convene for multiple formal meetings and has thus far met twice—on November 10, 2021, and on February 16, 2022. The discussion at the November meeting was focused on incorporating state perspectives into regional transmission planning. The Task Force members discussed: Whether the existing regional transmission planning processes adequately plan for future transmission needs, including those of states in meeting their energy-related goals; what methods are currently employed to provide states a role in regional transmission planning processes and whether reforms are needed to increase consideration and incorporation of state perspectives and energy-related goals in those processes; transparency in existing regional transmission planning processes; and criteria for use in selecting transmission facilities, including the proper role for states in selection of transmission facilities identified during regional transmission planning processes.[29]

22. The February meeting included discussion of specific categories and types of transmission benefits that transmission providers should consider for the purposes of transmission planning and cost allocation. The Task Force Members discussed: Whether and how the three categories and types of transmission (to address transmission needs driven by reliability, economic considerations, and Public Policy Requirements) that are considered for the purposes of transmission planning and cost allocation should be expanded or changed; whether these categories are being adequately considered or can be improved upon; if there any specific benefits being considered by public utility transmission providers today that should be more widely adopted by other public utility transmission providers and whether certain benefits are unique to specific regions; and how the certainty of benefits should be addressed, such as whether and how benefits need to be quantified. The Task Force Members also discussed at the February meeting cost allocation principles, methodologies, and decision processes, such as whether the current cost allocation methodologies used by public utility transmission providers allocate costs roughly commensurate with estimated benefits, and if not, how should this be improved; under what set of benefits—both existing and expanded—would states be amenable to bearing the costs of transmission that is expected to deliver those estimated benefits to ratepayers; and whether there is sufficient opportunity for stakeholders, including states, to collaborate in the development and approval of cost allocation methodologies to build consensus among and increase buy-in from stakeholders within a transmission planning region, and if not, how this can be improved.[30]

D. High-Level Overview of ANOPR Comments

23. The Commission received many comments from a diverse set of parties in response to the ANOPR.[31] One hundred and seventy five parties, including federal agencies, state regulatory commissions, state policy makers and other state representatives, ratepayer advocates, municipalities, RTOs/ISOs, RTO/ISO market monitors, public utility transmission providers, transmission-dependent utilities, electric cooperatives, municipal power providers, independent power producers, transmission developers, generation trade associations, transmission trade associations, industry interest groups, consumer interest groups, energy policy and law interest groups, individual businesses, landowners, and individuals, filed initial comments that totaled over 4,000 pages without attachments. A similarly diverse set of 95 parties filed reply comments that totaled nearly 2,000 pages.

III. Need for Reform

24. Over the last 25 years, the Commission has undertaken a series of significant reforms to ensure that transmission planning and cost allocation processes result in Commission-jurisdictional rates that are just and reasonable and not unduly discriminatory or preferential.[32] It has now been more than a decade since Order No. 1000—the Commission's last significant regional transmission planning and cost allocation rule—and there is mounting evidence that the Commission's regional transmission planning and cost allocation requirements may be inadequate to ensure Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential. In particular, although public utility transmission providers are required to participate in regional transmission planning and cost allocation processes under Order No. 1000, we are concerned that those processes may not be planning transmission on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand.

25. As a result, the regional transmission planning and cost allocation processes that public utility transmission providers adopted to comply with Order No. 1000 may not be identifying the more efficient or cost-effective transmission facilities. We are concerned that the absence of sufficiently long-term, comprehensive transmission planning processes appears to be resulting in piecemeal transmission expansion to address relatively near-term transmission needs. We are concerned that continuing with the status quo approach may cause public utility transmission providers to undertake relatively inefficient investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates.[33] That dynamic may result in transmission customers paying more than necessary to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof—either or both of which could potentially render Commission-jurisdictional rates unjust and unreasonable or unduly discriminatory or preferential. As the Commission has an obligation under the FPA to ensure that those rates are just and reasonable and not unduly discriminatory or preferential, we are proposing reforms to remedy these potential deficiencies in the Commission's existing regional transmission planning and cost allocation requirements.

26. As explained in the next section, we believe that there are substantial potential benefits of long-term regional transmission planning and cost allocation to identify and plan for transmission needs driven by changes in the resource mix and demand. But, as explained below, expansion of the high voltage transmission system is apparently increasingly occurring outside of the regional transmission planning process, and in a piecemeal fashion through other avenues, such as the generator interconnection process primarily in response to individual (or a small cluster of) interconnection requests rather than through regional

meetings, are available in the Commission's eLibrary in Docket No. AD21–15–000.

[29] *Joint Fed.-State Task Force on Elec. Transmission,* Notice of Meeting, Docket No. AD21–15–000 (issued Oct. 27, 2021) (attaching agenda).

[30] *Joint Fed.-State Task Force on Elec. Transmission,* Notice of Meeting, Docket No. AD21–15–000 (issued Feb. 2, 2022) (attaching agenda).

[31] *See* Appendix A for a list of commenters and the abbreviated names of commenters that are used in this NOPR.

[32] *See supra* PP 12–14.

[33] *S.C. Pub. Serv. Auth.,* 762 F.3d at 56–59.

transmission planning and cost allocation processes.

27. In light of those concerns, we propose reforms to require public utility transmission providers to conduct long-term regional transmission planning on a sufficiently long-term, forward-looking basis to identify and plan for transmission needs driven by changes in the resource mix and demand. Absent such reforms, we are concerned that meeting transmission needs driven by changes in the resource mix and demand through short-term, piecemeal transmission expansion will result in unjust and unreasonable and unduly discriminatory and preferential Commission-jurisdictional rates for customers. Specifically, without these reforms, we believe that regional transmission planning processes are unlikely to identify the more efficient or cost-effective solutions to transmission needs driven by changes in the resource mix and demand. Thus, we preliminarily find that these reforms are necessary to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.

A. Potential Benefits of Long-Term Regional Transmission Planning and Cost Allocation To Identify and Plan for Transmission Needs Driven by Changes in the Resource Mix and Demand

28. A robust, well-planned transmission system is foundational to ensuring an affordable, reliable supply of electricity.[34] Due to continuing changes in both supply and demand, ongoing investment in transmission facilities is necessary to ensure the transmission system continues to serve load in a reliable [35] and economically efficient fashion. Such investments also support enhanced reliability, as larger, more integrated transmission systems result in a diversity of supply and demand conditions and a certain degree of redundancy that allows the system to better withstand failures during unexpected events.[36] Proactive, forward-looking transmission planning that considers evolving supply and demand conditions more comprehensively can enable potential reliability problems and economic constraints to be identified and resolved before they affect the transmission system,[37] which can facilitate the selection of more efficient or cost-effective transmission facilities to meet transmission needs.

29. In addition, transmission can unlock the forces of competition, changing who can sell to whom, eliminating barriers to entry, and mitigating market power.[38] That, in turn, can provide a host of benefits for customers, including cost-savings from greater access to low-cost power and a wider range of resources.[39] Transmission infrastructure can also serve as a form of insurance for the uncertainties of the future, because a more robust, integrated transmission system has the potential to afford consumers the benefits of competition and enhanced reliability even if supply and demand fundamentals change over time.[40]

30. Given these potential benefits, it should be no surprise that investments in more efficient or cost-effective transmission infrastructure can yield substantial benefits to consumers.[41] For example, MISO's MVP transmission planning process resulted in transmission facilities that are estimated to generate $2.20 to $3.40 of benefit per dollar invested.[42]

31. MISO achieved these benefits by proactively planning over a 20-year period for two key drivers of transmission needs: The impacts of changing state laws on the resource mix, and a large increase in the number of generator interconnection requests.[43] To mitigate the uncertainties of such projections of need, MISO relied on scenarios to consider a range of potential future conditions [44] and

[34] 16 U.S.C. 824, 824d, 824e; *see also* U.S. DOE Comments at 2 (stating that ''strengthening and expanding existing transmission infrastructure, particularly the development of regional and inter-regional transmission projects, is key to continued access to reliable, resilient, lower-cost, and clean electricity for all'').

[35] *See, e.g.,* Testimony of James B. Robb Before the U.S. Senate Energy and Natural Resources Committee, *Reliability, Resiliency, and Affordability of Electric Service in the United States Amid the Changing Energy Mix and Extreme Weather Events,* at 9 (Mar. 11, 2021), *https://www.nerc.com/news/Headlines%20DL/NERC%20Reliability%20Hearing%20Testimony%203-11-21%20-%20Final.pdf* (testifying that more transmission infrastructure is required to ensure reliability and resilience of the bulk power system in light of changing conditions); MISO Comments at 40.

[36] U.S. DOE Comments at 18; NERC Comments at 16–17; ACORE Comments, Ex. 4, *Transmission Makes the Power System Resilient to Extreme Weather;* Mark Chupka & Pearl Donohoo-Vallett, *Recognizing the Role of Transmission in Electric System Resilience* (May 2018).

[37] MISO's Multi-Value Project (MVP) regional transmission planning process, for example, eliminated the need for approximately $300 million in reliability transmission facilities, resolving reliability violations and mitigating system instability conditions, through a forward-looking approach. Midcontinent Independent System Operator, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio,* at 11, 33 (Sept. 2017) (MTEP17 Review).

[38] Johannes Pfeifenberger et al., The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs,* at 48–49 (Oct. 2021), *https://gridprogress.files.wordpress.com/2021/10/transmission-planning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs-7.pdf* (Brattle-Grid Strategies Oct. 2021 Report); Policy Integrity Comments at 13 (citing Mohamed Awad et al., *The California ISO Transmission Economic Assessment Methodology (TEAM): Principles and Applications to Path 26,* at 3 (''A new transmission project can enhance competition by both increasing the total supply that can be delivered to consumers and the number of suppliers that are available to serve load.'')); PIOs Comments at 48 (quoting F.A. Wolak, World Bank, *Managing Unilateral Market Power in Electricity,* Policy Research Working Paper; No. 3691, at 8 (2005) (''Expansion of the transmission network typically increases the number of independent wholesale electricity suppliers that are able to compete to supply electricity at locations in the transmission network served by the upgrade . . . .'')).

[39] *See, e.g.,* PJM Interconnection, L.L.C., *PJM Value Proposition* (2019), *https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ashx* (PJM's planning of resource adequacy over a large region is estimated to result in savings of $1.2–1.8 billion.); Midcontinent Independent System Operator, *Value Proposition* (2020), *https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/* (MISO estimates $517–572 million in savings from more efficient use of existing assets and $2.5–3.2 billion from reduced need for additional assets.); Southwest Power Pool, *SPP's Value of Transmission: 2021 Report and Update* (Jan. 5, 2022) (SPP estimates $382.7 million in adjusted product costs savings in 2020 due to transmission investment.).

[40] U.S. Dep't of Energy, *National Electric Transmission Congestion Study,* at 11 (Sept. 2015) (stating transmission expansion can strengthen and increase the flexibility of the overall network and ''create real options to use the transmission system in ways that were not originally envisioned''); Vikram S. Budhraja et al., *Improving Electricity Resource Planning Processes by Considering the Strategic Benefits of Transmission,* 22 ELEC. J. 54 (Mar. 2009), (high voltage transmission affords ''mitigation of risks as a form of insurance against extreme events'').

[41] *See, e.g.,* Southwest Power Pool, *The Value of Transmission* (Jan. 2016), *https://www.spp.org/value-of-transmission/* (A 2016 study of 348 transmission projects in SPP constructed between 2012 and 2014 found the overall ratio of benefits to costs to be at least 3.5 to 1.); NextEra Comments at 95 (citing ACEG, *Texas as a National Model for Bringing Clean Energy to the Grid* (Oct. 2017), *https://cleanenergygrid.org/texas-national-model-bringing-clean-energy-grid/*) (Transmission developed due to Texas's Competitive Renewable Energy Zone planning process estimated to save $1.7 billion each year in production costs alone, far surpassing its $6.9 billion cost.); Brattle-Grid Strategies Oct. 2021 Report at 4–8 & app. A (describing evidence showing that well-planned transmission expansion resulted in lower total cost to construct the needed transmission facilities).

[42] MTEP17 Review at 4.

[43] Midcontinent Independent System Operator, *RGOS: Regional Generation Outlet Study* at 2 (Nov. 19, 2010) (RGOS Study). MISO staff and stakeholders determined that allowing the transmission expansion needed to accommodate these requests to occur through the generator interconnection process ''would not be an efficient means for building a cost-effective transmission system either immediately, over the next 5–10 year period or in the foreseeable future beyond that time-frame.'' *Id.*

[44] MISO relied on stakeholder surveys of likely renewable energy needs over the next 20 years, and calculations of the new generation that would be needed in order to achieve state renewable portfolio

disclosed the assumptions and inputs underlying each.[45] The MVP process then identified a portfolio of ''no regrets'' transmission projects that were projected to provide multiple kinds of reliability and economic benefits under all the alternate future scenarios studied.[46] At each stage of the MVP process, MISO invested in significant stakeholder engagement and collaboration, from developing the technical parameters underlying its scenarios and the weights to give to each, to the metrics and methodology used to evaluate the portfolio of transmission projects.[47]

32. Although, as illustrated by the MVP example, transmission infrastructure can provide significant benefits to consumers, there are often substantial barriers to developing more efficient or cost-effective transmission facilities. For example, as the Commission has long recognized, ''vertically-integrated utilities do not have an incentive to expand the grid to accommodate new entries or to facilitate the dispatch of more efficient competitors.'' [48] Further, because large-scale transmission investments that geographically extend or strengthen the integration of the transmission system are both costly and tend to produce widespread benefits, there is significant risk that free ridership problems inhibit their development.[49] In any event, the logistics alone of coordinating among multiple public utility transmission providers within a region, seeking support across what is often multiple state jurisdictions, and attaining sufficient certainty over who will pay the costs of the needed transmission facilities can thwart investments in more efficient or cost-effective transmission expansion.[50]

33. We are concerned that these barriers continue to stymie investment in more efficient or cost-effective transmission facilities. In particular, we are concerned that public utility transmission providers are not engaging in the type of long-term, more comprehensive regional transmission planning and cost allocation processes—like the process used to plan the MISO MVPs—that is necessary to increase the likelihood that such highly beneficial transmission infrastructure is developed. Without this kind of transmission planning and cost allocation process, opportunities to meet transmission needs more efficiently or cost-effectively may be lost. Customers may be forced to pay for less efficient or cost-effective investment in transmission facilities that, for example, achieve lower cost-benefit ratios than would otherwise be achieved with long-term, more comprehensive regional transmission planning and cost allocation. In short, absent reforms, we are concerned customers may be paying more for less.

B. Unjust and Unreasonable and Unduly Discriminatory and Preferential Commission-Jurisdictional Rates

34. The evidence suggests that sufficiently long-term, forward-looking regional transmission planning and cost allocation to meet transmission needs driven by changes in the resource mix and demand is not occurring in most transmission planning regions on a regular or consistent basis. As such, consumers may not be seeing the benefits such as enhanced reliability, improved resource adequacy, access to lower cost and diverse resources, and other benefits that result from regional transmission planning and cost allocation processes that identify, select, and allocate the costs of the more efficient or cost-effective transmission solutions to transmission needs driven by changes in the resource mix and demand. We preliminarily find that the failure of existing regional transmission planning and cost allocation processes to perform this type of transmission planning and cost allocation is resulting in unjust, unreasonable, unduly discriminatory, and preferential Commission-jurisdictional rates.

35. More specifically, we preliminarily find that reforms are needed to the Commission's existing regional transmission planning and cost allocation requirements because they fail to require public utility transmission providers to: (1) Perform a sufficiently long-term assessment of transmission needs; (2) adequately account on a forward-looking basis for known determinants of transmission needs driven by changes in the resource mix and demand; and (3) consider the broader set of benefits and beneficiaries of transmission facilities planned to meet those transmission needs. We believe that these deficiencies may be resulting in unjust and unreasonable and unduly discriminatory and preferential Commission-jurisdictional rates to the extent that they lead to public utility transmission providers failing to identify transmission needs driven by changes in the resource mix and demand, failing to select more efficient or cost-effective transmission facilities to meet those transmission needs, and failing to allocate the costs of transmission facilities selected in the regional transmission plan for purposes of cost allocation to meet those transmission needs in a manner that is at least roughly commensurate with the estimated benefits.

1. The Transmission Investment Landscape Today

36. We begin with the facts on the ground: The evidence suggests that long-term regional transmission planning and cost allocation to identify and plan for transmission needs driven by changes in the resource mix and demand is not occurring in most transmission planning regions on a regular or consistent basis. Rather, the status quo appears to be resulting in a disproportionate share of transmission facilities to meet transmission needs driven by changes in the resource mix and demand being developed outside regional transmission planning and cost allocation processes, resulting in less efficient and cost-effective transmission development. Significant expansion of the transmission system instead appears to occur through interconnection-related network upgrades [51] constructed as a result of generator interconnection requests. Because the generator interconnection process is not designed to consider how to more efficiently or cost-effectively address transmission needs beyond the interconnection request(s) being studied, it cannot achieve the economies of scale in transmission investment needed to

standards by 2027. MISO also identified the location of expected ''renewable energy zones'' with potential to achieve high capacity factors for use in its analysis. *Id.* at 26–29.

[45] *See, e.g.,* MTEP17 Review at 16.

[46] *Id.* at 13.

[47] MISO Comments at 9.

[48] Order No. 890, 118 FERC ¶ 61,119 at P 57.

[49] Order No. 1000, 136 FERC ¶ 61,051 at P 486.

[50] *Id.* PP 498–501.

[51] The Commission's *pro forma* large generator interconnection agreement (LGIA) defines Network Upgrades as: ''the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.'' *Pro forma* LGIA Art. 1 (Definitions); *see also Standardization of Generator Interconnection Agreements & Proc.,* Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103, at P 21 (2003) (describing network upgrades developed through the generator interconnection process as those interconnection facilities located at or beyond the point where the interconnection customer's generating facility interconnects to the transmission provider's transmission system), *order on reh'g,* Order No. 2003–A, 106 FERC ¶ 61,220, *order on reh'g,* Order No. 2003–B, 109 FERC ¶ 61,287 (2004), *order on reh'g,* Order No. 2003–C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008). We refer to network upgrades developed through the generator interconnection process as interconnection-related network upgrades.

integrate significant quantities of new generation resources while maintaining Commission-jurisdictional rates that are just and reasonable and not unduly discriminatory or preferential. Transmission expansion in this incremental manner may miss the potential for more efficient or cost-effective transmission facilities to solve transmission needs driven by changes in the resource mix and demand, as well as to afford system-wide benefits that may not be achieved through piecemeal, one-off transmission upgrades. Robust long-term regional transmission planning, on the other hand, may enable the same needs to be met more efficiently or cost-effectively, or identify transmission facilities that meet those same needs while generating additional benefits. Today's incremental transmission planning may also fail to consider opportunities to "right size" certain replacement transmission facilities and thereby fail to identify the potential for more efficient or cost-effective regional transmission facilities.

37. The problems with the status quo are evident in the dramatic increase in recent years (and continuing upward trend) in investment in transmission facilities through the generator interconnection process in the form of interconnection-related network upgrades. The evidence demonstrates a sharp growth in both the total cost of interconnection-related network upgrades and in the cost of such upgrades relative to generation project costs. It appears that the average cost of interconnection-related network upgrades is increasing over time as the transmission system is fully subscribed and demand for interconnection service outpaces transmission investment. Recent studies of the total cost of network upgrades needed to interconnect new generation resources reflect this trend. In the generator interconnection study MISO published in July 2020, MISO identified the need for nearly $2.5 billion in interconnection-related network upgrades to interconnect 9.2 GW of generation in MISO South.[52] In MISO's 2020 interconnection queue outlook, MISO reported that it expects new generation resources in MISO West will need over $3 billion in interconnection-related network upgrades and noted a similar trend in other MISO sub-regions.[53] In its most recent system impact study for generator interconnection, published in April 2021, SPP identified the need for over $4.6 billion in network upgrades to interconnect 10.4 GW of generation.[54]

38. The dramatic increase in the cost of interconnection-related network upgrades per kilowatt (kW) of an interconnection customer's generating capacity may also be problematic. For example, interconnection-related network upgrade costs in MISO West went from approximately $300/kW in 2016 to nearly $1,000/kW in 2017.[55] The trend is evident in other parts of the country as well.[56] The costs of interconnection-related network upgrades seem to have become an ever-growing percentage of the total capital costs of new generation projects. According to one report, interconnection costs for new renewable resources were less than 10% of total generation project costs until a few years ago, but recently these costs have risen to as much as 50–100% of the total generation project costs.[57] At the same time, interconnection-related network upgrades appear to have transitioned from primarily small transmission facilities that serve the needs of a limited number of interconnection customers to the size and scope of what has traditionally been considered high voltage transmission facilities. For example, interconnection-related network upgrades have recently included demolishing and rebuilding multiple 500 kV transmission lines[58] and constructing long, double-circuit, 765 kV transmission lines,[59] all at significant cost to the interconnection customer—and ultimately to consumers.

39. In contrast to the significant investment in transmission facilities through the generator interconnection process, the regional transmission planning and cost allocation processes have yielded limited investment in regional transmission facilities. Transmission developers in the United States invested $20 to $25 billion annually in transmission facilities from 2013 to 2020.[60] Yet only a limited portion of these investments have gone toward regional transmission facilities since Order No. 1000. In fact, investment in regional transmission facilities in some regions has declined compared to prior Order No. 1000.[61] Moreover, across all the non-RTO/ISO regions, there has not yet been a single transmission facility selected in a regional transmission plan for purposes

[52] ICF Resources, LLC, *Just and Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits,* at 2 (Sept. 9, 2021), *https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf* (ICF Sept. 2021 Report) (attached to ACORE Comments as Exhibit 5).

[53] Americans For A Clean Energy Grid, *Disconnected: The Need for a New Generator Interconnection Policy,* at 14 (Jan. 2021), *https://acore.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf* (ACEG Jan. 2021 Interconnection Report) (attached to ACORE Comments as Exhibit 2); NextEra Comments at 16 (citing Midcontinent Independent System Operator, *2020 Interconnection Queue Outlook,* at 9 (2020), *https://cdn.misoenergy.org/MISO2020InterconnectionQueueOutlook445829.pdf* (MISO 2020 Queue Outlook)).

[54] ICF Sept. 2021 Report at 2.

[55] ACEG Jan. 2021 Interconnection Report at 14; NextEra Comments at 16 (citing MISO 2020 Queue Outlook at fig. 7).

[56] *E.g.,* ACEG Jan. 2021 Interconnection Report at 14 & tbl. 2 (showing that, as of 2019, interconnection costs in PJM for constructed wind and solar projects were $19.07/kW and 61.83/kW, respectively, as compared to a greater than 100% increase to $54/kW and $131.90/kW, respectively, for projects newly proposed today); NextEra Comments at 16–17 (stating that interconnection-related network upgrade cost estimates have nearly tripled for newly proposed wind projects, and more than doubled for solar projects in PJM); *see also* ACEG Jan. 2021 Interconnection Report at 16 (illustrating an increase in average interconnection-related network upgrade costs in NYISO from $67/kW in 2013 to $124/kW in 2019). *Compare* ACEG Jan. 2021 Interconnection Report at 15 (identifying interconnection-related network upgrade costs in 2013 in SPP as $89/kW) *with* ICF Sept. 2021 Report at 2 (citing interconnection-related network upgrade costs of $448/kW for interconnection customers studied in SPP's system impact study published in April 2021).

[57] ACEG Jan. 2021 Interconnection Report at 6; *see also id.* at 13 (stating that the rising interconnection costs of wind projects in MISO recently reached approximately 23% of the capital cost of the project); *id.* at 15 (identifying the increase in interconnection-related network upgrade costs in SPP between 2013 and 2017 as representing an increase from around 8% to over 43% of the capital cost of wind generation); NextEra Comments at 17 (similar).

[58] *See* ACEG Jan. 2021 Interconnection Report at 15 (describing interconnection-related network upgrades for a 120 MW solar plus storage project in southern Virginia to interconnect to PJM that cost as much as $12,086/kW).

[59] *See id.* (describing one interconnection-related network upgrade in SPP identified in the system impact study published in April 2021); ICF Sept. 2021 Report at 3 (same); NextEra Comments at 17 (same).

[60] Brattle-Grid Strategies Oct. 2021 Report at 2 (citing Johannes Pfeifenberger & John Tsoukalis, The Brattle Group, *Transmission Investment Needs and Challenges,* at slide 2 (June 1, 2021), *https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Investment-Needs-and-Challenges.pdf*); Johannes Pfeifenberger et al., The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value,* at 2–3 & fig.1 (Apr. 2019), *https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf* (Brattle Apr. 2019 Competition Report).

[61] *See, e.g.,* Rob Gramlich & Jay Caspary, Americans for a Clean Energy Grid, *Planning for the Future,* at 25 & fig. 8 (Jan. 2021) (included as Ex. 1 to ACORE Comments) (ACEG Jan. 2021 Planning Report) (charting the annual investment in regional transmission facilities in RTOs/ISOs from 2010 to 2018); ACORE Comments at 4 (citing Ex. 1, ACEG Jan. 2021 Planning Report at 25).

of cost allocation since implementation of Order No. 1000.[62]

40. The vast majority of investment in transmission facilities since the issuance of Order No. 1000 has been in local transmission facilities.[63] For example, transmission investment to resolve local needs accounted for almost 80% of total transmission investment in MISO from 2018 to 2020.[64] Similarly, in PJM, about two-thirds of the total transmission investment in the region went to resolving local needs.[65]

41. This evidence runs counter to the Commission's expectation that, in light of growing demand for transmission, the regional transmission planning and cost allocation reforms adopted in Order No. 1000 should have resulted in investment in more efficient or cost-effective transmission facilities over time. In Order No. 1000, the Commission recognized a growing need for transmission investment to ensure reliability and integrate new resources in light of industry trends changing the demands placed on the transmission system.[66] The Commission concluded that increasing transmission needs amplified the need for and importance of effective transmission planning and cost allocation processes to identify transmission needs and select regional transmission facilities where they are more efficient or cost-effective than the alternatives.[67]

42. In sum, the evidence suggests that improvements to the Commission's regional transmission planning and cost allocation requirements may be needed to realize the full potential of the benefits to be achieved through the planning and development of regional transmission facilities. Today, transmission needs driven by changes in the resource mix and demand appear to be largely addressed outside the regional transmission process—*e.g.,* through generator interconnection processes—through mechanisms that are not designed to consider regional transmission needs and identify and select the more efficient or cost-effective transmission facility to meet those needs. We believe that this may result in an inefficient expansion of the transmission system to meet transmission needs driven by changes in the resource mix and demand.

43. To the extent public utility transmission providers may not be identifying the more efficient or cost-effective transmission facilities needed to meet underlying transmission needs, including needs driven by changes in the resource mix and demand, over time, consumers may ultimately bear the costs of inefficient piecemeal transmission expansion. Moreover, this concern may be exacerbated when wholesale electricity rates reflect the costs of the interconnection-related network upgrades that address needs that could have been more efficiently or cost-effectively addressed through effective regional transmission planning and cost allocation. Additionally, relying on generator interconnection processes to identify transmission facilities to address transmission needs driven by changes in the resource mix and demand leaves other benefits on the table as well, as described earlier,[68] some of which are almost always (if not exclusively) achieved through the development of regional transmission facilities (*e.g.,* avoiding emergency operations and lost load, especially during extreme weather events, and increased wholesale market competition). We preliminarily find that this paradigm results in Commission-jurisdictional rates that are unjust and unreasonable and unduly discriminatory and preferential.

44. While the reforms adopted in Order No. 1000 were an important first step towards improved regional transmission planning and cost allocation, we preliminarily find that further reforms are necessary to ensure that public utility transmission providers engage in regional transmission planning and cost allocation on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand. In Order No. 1000, the Commission was focused in particular on: The lack of an affirmative obligation for public utility transmission providers "to develop a regional transmission plan that reflects the evaluation of whether alternative regional solutions may be more efficient or cost-effective than solutions identified in local transmission planning processes;" the absence of a "requirement that public utility transmission providers consider transmission needs at the local or regional level driven by Public Policy Requirements;" the potential for federal rights of first refusal to discourage investment by nonincumbent transmission developers; the limited procedures in place for interregional transmission coordination and cost allocation; and the failure of many cost allocation methods "to account for the beneficiaries of new transmission facilities." [69] Order No. 1000 was aimed at ensuring two things: (1) That regional transmission planning processes "consider and evaluate, on a non-discriminatory basis, possible transmission alternatives and produce a transmission plan that can meet transmission needs more efficiently and cost-effectively;" and (2) "that the costs of transmission solutions chosen to meet regional transmission needs are allocated fairly to those who receive benefits from them." [70] To that end, the Commission adopted reforms that set forth the minimum requirements to achieve these goals, requirements that were noteworthy at the time and required public utility transmission providers to expend substantial time and effort to comply.

45. We believe that it is time to take the next step. The generation fleet is changing rapidly. In many cases, this is taking the form of a shift from large, centralized resources located close to population centers toward renewable resources (sometimes in combination with electric storage resources) that are often, but not always, located far from load centers where access to their fuel source, such as the wind or the sun, is greatest.[71] The growth in these resource

[62] LS Power Oct. 12 Comments, app. I, at 18 & n.57; FERC, Staff Report, *2017 Transmission Metrics,* at 19 (Oct. 6, 2017), *https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf.*

[63] *See generally* ACEG Jan. 2021 Planning Report at 25–26, 71 (describing investment in local transmission facilities nationwide since implementation of Order No. 1000). In MISO, investment in local transmission facilities went from $1.1 billion per year from 2010 to 2013, to $2.7 billion per year from 2014 to 2019. Harvard ELI Comments at 20 & n.89; *see also* ACEG Jan. 2021 Planning Report at 104 (charting MISO transmission investment by project type from 2010 to 2019); ACPA and ESA Comments at 22 (showing $247 million invested in nine regional transmission projects versus $16.6 billion in 2,165 local transmission projects in MISO between 2016 and 2020). In PJM, investment in local transmission facilities went from $1.25 billion per year from 2005 to 2013, to $3.79 billion per year from 2014 to 2020. During the same time periods, investment in regional transmission facilities decreased from $2.76 billion per year to $1.65 billion per year. Harvard ELI Comments at 21 n.92; PIOs Comments at 33 n.98 (citing PJM Transmission Expansion Advisory Committee, *Project Statistics* (May 12, 2020)); Ari Peskoe, *Is the Utility Transmission Syndicate Forever?,* 42 Energy L.J. 1, 51 n.324 (2021), *https://www.eba-net.org/assets/1/6/5_-_%5BPeskoe%5D%5B1-66%5D.pdf.*

[64] Brattle-Grid Strategies Oct. 2021 Report at 2–3.

[65] LS Power October 12 Comments, Ex. 9, at 7.

[66] *See* Order No. 1000–A, 139 FERC ¶ 61,132 at P 5.

[67] *See id.*

[68] *See supra* PP 28–32.

[69] Order No. 1000, 136 FERC ¶ 61,051 at P 3.

[70] *Id.* P 4. The interregional transmission coordination and cost allocation requirements were aimed at the same objectives with respect to possible transmission solutions located in neighboring transmission planning regions. *Id.*

[71] In its 2021 Long-Term Reliability Assessment, NERC reports over 504 GW of nameplate capacity from new solar and wind in development through 2031. In contrast, confirmed coal-fired, nuclear, and natural-gas-fired retirements through the year 2026

Continued

types is driven by many factors, including: (1) The improved economics of certain renewable resources; [72] (2) increased customer demand for such resources, including among major corporations; [73] (3) utility commitments to procure most or all of their electricity from renewable and/or non-emitting resources; [74] and (4) federal, state, and local policies incentivizing various forms of generation resources and other technologies.[75] Similarly, changes in electric demand and associated load profiles are occurring as load-serving entities shift to meet increasing needs due to the electrification of our power system as well as new large loads associated with evolving industrial and commercial needs such as the growth in data centers.[76] Moreover, transmission system operators are also increasing their reliance on regional and interregional transmission facilities to ensure operational stability in light of the rising share of variable resources in the resource mix and increasingly frequent extreme weather events.[77] Lastly, in recognition of the benefits of regional power markets, regional integration efforts have expanded since Order No. 1000, as illustrated by the creation of the Western Energy Imbalance Market (EIM) and SPP Integrated Marketplace in 2014.[78] These changes in the resource mix and demand, operational challenges, and increasing regional integration increase the importance of engaging in regional transmission planning and cost allocation to meet long-term transmission needs more efficiently or cost-effectively.

46. A diverse range of stakeholders, including state and regulatory entities,[79] consumer interest groups,[80] transmission owners,[81] independent power producers,[82] and various trade [83] and non-government organizations,[84] identify the need to build on existing regional transmission planning and cost allocation processes. A still broader range of stakeholders acknowledge, at a minimum, that there is scope for improvements in existing regional transmission planning and cost allocation processes.[85] While RTOs/ISOs defend the sufficiency of their regional transmission planning and cost allocation processes, all recognize the potential for reforms to respond to ongoing developments in the electric industry [86] and, in some instances, they have initiated analysis and other early steps toward proposing reforms.[87]

total approximately 48.4 GW. NERC, *2021 Long-Term Reliability Assessment,* at 30, 35 (Dec. 2021).

[72] *See* Lawrence Berkeley National Laboratory, *Wind Energy Technology Data Update: 2020 Edition,* at 66 (Aug. 2020) (noting the average levelized cost of wind energy for commercial wind generation has decreased from $90 per MWh in 2009, to $35 per MWh in 2019); Lawrence Berkeley National Laboratory, *Utility-Scale Solar Data Update: 2020 Edition,* at 32 (Nov. 2020) (noting the average levelized power purchase agreement price for utility-scale solar generation has decreased from approximately $160 per MWh in 2009, to approximately $40 per MWh in 2020).

[73] *See* National Renewable Energy Laboratory (NREL), *H2 2020 Solar Industry Update,* at 31 (2021) (stating that U.S. corporate solar contracts were up 34% annually in 2020, and 7.4 times higher over 5 years).

[74] *See* Deloitte, *Insights, Utility Decarbonization Strategies, Renew, Reshape, and Refuel to Zero,* at 4 (2020) (indicating 43 of 55 utilities surveyed have emissions reductions targets and 22 have net-zero or carbon-free electricity goals); Esther Whieldon, S&P Global Market Intelligence, *Path to net zero: 70% of biggest US utilities have deep decarbonization targets,* at 3–6 (2020) (indicating based on a review of utilities' climate goals and decarbonization plans that, as of December 2020, 70% of the 30 largest utilities have net-zero carbon targets, or are moving to comply with similarly aggressive state mandates).

[75] *See* Lawrence Berkeley National Laboratory, *U.S. Renewables Portfolio Standards 2021 Status Update: Early Release,* at 9 (Feb. 2021) (stating renewable portfolio standards exist in 30 states and the District of Columbia, and apply to 58% of total U.S. retail electricity sales).

[76] For example, the electrification of end uses that currently rely on other energy sources is expected, under a moderate scenario that does not factor in public policy drivers, to increase electricity demand by 2050 to about 25% above today's level. ACEG Jan. 2021 Planning Report at 35 (discussing National Renewable Energy Laboratory's "medium electrification" case); *see also* AEE Comments at 14–18 (describing local, state, and federal policies, technical and economic trends that are leading to increased electrification).

[77] For example, during Winter Storm Uri in February 2021, SPP and MISO were able to avoid major power shortfalls during the extreme cold by importing electricity from the east. During the event, MISO imported nearly 9,000 MW from PJM and several thousand MW from the Tennessee Valley Authority. ACORE Comments, Ex. 4, *Transmission Makes the Power System Resilient to Extreme Weather,* at 7.

[78] Moreover, we note that efforts for further regional integration of power markets continue today. *See, e.g.,* Kassia Micek, Megawatt Daily, *Three Colorado utilities to join SPP's Western Energy Imbalance Service Market* (Jan. 26, 2022) ("Three Colorado utilities announced plans to join [SPP's] Western Energy Imbalance Service market and continue studying long-term solutions to join or develop an organized wholesale market.").

[79] *See, e.g.,* NARUC Comments at 5 ("NARUC identifies opportunities for reforms that may result in more efficient transmission planning and investment to the benefit of consumers, all while preserving jurisdictional authorities."); NASEO Comments at 1 ("NASEO shares the Commission's concern that the current approach to planning and allocating the costs of transmission facilities may lead to an inefficient, piecemeal expansion of the transmission grid."); NESCOE Comments at 35 ("NESCOE appreciates the Commission's leadership in recognizing a need for longer-term and comprehensive regional transmission analysis to account for this changing resource mix."); Kansas Commission Comments at 5 (stating "the KCC believes that improvements can be made to optimize regional transmission planning policies and proceedings").

[80] Iowa Consumer Advocate Comments at 1 (recognizing "an urgent need to review existing processes and identify opportunities for reform" and that failure to do so could "negatively impact reliability, and result in rates that are unjust and unreasonable"); Consumers Council Comments at 3–4 (stating reforms are "crucial" and that "since Order No. 1000 was implemented, several inefficiencies and unintended consequences have emerged in transmission planning"); District of Columbia's Office of the People's Counsel Comments at 2 (arguing there are "significant flaws" in the regional transmission planning process in PJM).

[81] *See, e.g.,* NY TOs Comments at 14 ("In conclusion, the NY TOs support the ANOPR's goals of proactive, multi-value scenario modeling and recognize that further refinements to New York's transmission planning processes and modeling will likely be needed to integrate renewables and to maintain reliability."); SoCal Edison Comments at 3 (asserting that "enhancements are necessary" to CAISO's regional transmission planning structure); AEP Comments at 2 (encouraging the Commission "to consider broad reforms for both transmission planning and generator interconnections").

[82] *See, e.g.,* Enel Comments, attach. (*Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning*) at 4 (arguing certain deficiencies result in inadequate building of transmission and result in cost-inefficient solutions for load); Northwest and Intermountain Comments at 3–4 (pointing to limitations in existing Order No. 1000 processes and advocating additional reforms are needed to ensure just and reasonable transmission rates).

[83] *See, e.g.,* Joint Statement in Support of Large Scale Transmission at 1 (ACORE, ACPA, ACEG, AEE, National Electrical Manufacturers Association, and SEIA, among other signatories, support reforms to transmission planning and cost allocation policies); WIRES Comments at 7–18 (advocating for several reforms to regional transmission planning and cost allocation processes, and against others).

[84] *See, e.g.,* R Street Comments at 1 (stating "planning processes require an overhaul"); Policy Integrity Comments at 1 (arguing "current approaches to transmission planning and cost allocation are failing to capture [ ] large potential benefits").

[85] *See, e.g.,* EPSA Comments at 2, 4 (asserting reforms will be necessary to accommodate the evolving transmission system and longer-term regional transmission planning is warranted); Industrial Customers Comments at 13 (stating "[t]o be sure, there is room for improvement"); Northern VA Coop Comments at 2 (noting "improvement is possible").

[86] MISO Comments at 7 (arguing its transmission planning process is serving its intended purpose but acknowledging "improvements may be made"); SPP Comments at 9 (stating "SPP realized there was a need to more strategically consider broader changes to SPP's transmission planning process"); PJM Reply Comments at 6 (stating "it is appropriate to enhance the long-term planning process to consider scenario planning and the interaction of many system enhancement drivers"); ISO–NE Comments at 26 (noting "improvements may be needed to optimize transmission solutions for reliability, economic, and public policy based needs"); NYISO Comments at 2 ("NYISO sees an opportunity to build on the existing successes of its processes and to evolve them to address current conditions."); CAISO Comments at 2 (supporting the goal of enhancing regional transmission planning and generator interconnection processes to account for the transmission needs of a changing resource mix).

[87] *See, e.g.,* SPP Comments at 10 (SPP Board of Directors-appointed team identified critical issues with existing transmission planning process including sub-optimal transmission plans; deficiency in collective quantification of cost-causers and beneficiaries which create free rider situations; and failure to consider congestion costs and other economic impacts in processes used to

identify needed upgrades.); ISO–NE Comments at 14–16 (initiating a 2050 Transmission Study at the request of ISO–NE states and efforts to incorporate a new forward-looking, scenario-based transmission planning tool).

2. Deficiencies in the Commission's Existing Regional Transmission Planning and Cost Allocation Requirements

47. We preliminarily find deficiencies in the Commission's existing regional transmission planning and cost allocation requirements are resulting in Commission-jurisdictional rates that are unjust and unreasonable and unduly discriminatory and preferential. In particular, we preliminarily find that the Commission's regional transmission planning and cost allocation requirements fail to require public utility transmission providers to: (1) Perform a sufficiently long-term assessment of transmission needs; (2) adequately account on a forward-looking basis for known determinants of transmission needs driven by changes in the resource mix and demand; and (3) consider the broader set of benefits and beneficiaries of regional transmission facilities planned to meet those transmission needs. We believe that these deficiencies may be resulting in unjust and unreasonable and unduly discriminatory and preferential Commission-jurisdictional rates to the extent that they lead public utility transmission providers to fail to identify transmission needs driven by changes in the resource mix and demand, select more efficient or cost-effective transmission facilities to meet those transmission needs, and allocate the costs of transmission facilities selected in the regional transmission plan for purposes of cost allocation to meet those transmission needs in a manner that is at least roughly commensurate with the estimated benefits. We address each deficiency in turn.

48. The first deficiency—that the Commission's existing regional transmission planning and cost allocation requirements do not require public utility transmission providers to perform a sufficiently long-term assessment of transmission needs—is reflected across multiple components of existing regional transmission planning processes, from the degree to which studies that inform assessment of transmission needs are forward looking, to whether forward-looking assessments actually inform selection and cost allocation of regional transmission facilities. Existing regional transmission planning and cost allocation processes typically look out and plan for transmission needs based on a relatively near-term horizon. While some existing regional transmission planning and cost allocation processes may incorporate studies or assessments that have a longer forward-looking period, these are typically for informational purposes and do not result in identification of long-term regional transmission needs, assessment of transmission alternatives to meet those needs, or selection of transmission facilities in the regional transmission plan for purposes of cost allocation.[88] Such studies or assessments may be one-off, available only upon request, or conducted at irregular intervals.[89] Additionally, many forward-looking studies treat key variables that affect transmission needs, such as generation additions and retirements, as fixed over the full time horizon of the study, even though these variables are likely to change.[90] Such studies are therefore unlikely to adequately assess transmission needs over the longer-term horizon, as they do not attempt to assess the likelihood that conditions contributing to transmission needs change.[91]

49. While it is reasonable for regional transmission planning and cost allocation processes to include near-term study of the transmission system, the absence of any longer-term assessment of transmission needs that may form the basis for selection and cost allocation may prevent public utility transmission providers from considering regional transmission facilities that may be more efficient or cost-effective in light of changing transmission needs.[92] The failure to assess longer-term transmission needs is particularly problematic given the long-lead times necessary to construct large (*e.g.,* high voltage or long distance) transmission facilities, the potential for economies of scale in transmission investment, and the long life of transmission assets, which will continue to serve transmission needs well beyond a 5- or 10-year planning horizon—all of which suggest that relying solely on shorter-term studies may fail to identify transmission needs and undervalue the benefits of transmission investments to meet those needs. Moreover, the likelihood that near-term assessments will fail to identify more efficient or cost-effective regional transmission facilities is higher during periods, as the sector is now experiencing, in which the need for transmission is expected to grow considerably.[93]

50. The second deficiency is that existing requirements fail to ensure that public utility transmission providers adequately account on a forward-looking basis for known determinants of transmission needs driven by changes in the resource mix and demand. This is closely related to the first deficiency in the sense that both relate to the failure of the existing requirements to result in processes that adequately plan for the foreseeable future. Orders Nos. 890 and 1000 afforded flexibility to public utility transmission providers to determine the inputs, assumptions, and methodologies that are used in analyses of the transmission system to identify transmission needs and produce a regional transmission plan. In the absence of clear standards, public utility transmission providers have adopted widely divergent approaches to

[88] For example, SPP is required under its tariff to conduct a 20-year study of transmission at least every five years but is prohibited from using that study as the basis for authorizing construction of a transmission solution. SPP Market Monitor Comments at 4 (citing SPP, OATT, attach. O, § IV.2 (8.0.0), § IV.2.a)

[89] For example, in response to state requests, ISO–NE recently initiated a stakeholder process to respond to the problem that ''[t]he current processes do not support the performance of state-requested transmission analysis based on state-developed scenarios, inputs and assumptions, nor do they support transmission analysis beyond the ten-year horizon.'' ISO–NE, *Attachment K Revisions: Extended-Term Planning, Transmission Committee,* at slide 3 (Sept. 28, 2021), *https://www.iso-ne.com/static-assets/documents/2021/09/a07_tc_2021_09_28_attk_ext_trans_presentation.pdf; see also* Indicated PJM TOs Comments at 25 (stating ''the PJM Tariff does not provide concrete time windows for scenario planning'').

[90] Policy Integrity Comments at 29.

[91] PJM's long-term assessment of the transmission system ostensibly considers a 15-year horizon, for example, but does not account for changes to the generation mix beyond a 5-year period. *See* PSEG Comments at 11 (stating that ''in practice only new resources that are near the end of the interconnection queue process and have signed an Interconnection Service Agreement are considered in the RTEP base case''); Union of Concerned Scientists Comments at 10 & n.11 (''Generation additions are unchanged in the 15-year study period, as the input assumption has no additional information that would expand the set of generators included in the forecast.'').

[92] U.S. DOE Comments at 10 (stating failure to plan transmission far enough ahead results in ''adverse implications for system reliability, resilience, consumers' electricity rates, and the achievement of clean energy goals''); MISO Reply Comments at 5 (''[G]iven long-term needs of an evolving system, additional transmission is necessary to reliably serve customers now and into the future. These challenges require immediate action and further delay only increases the risk that system enhancements may not be in place in the timeframe needed.'').

[93] U.S. DOE Comments at 10 (''Relying on successive small transmission expansion projects to meet foreseeable long-term needs may lead to the need for expensive retrofits (at customers' expense) at a later date. Economies of scale and network economies suggest that an initial larger-scale buildout will often represent a lower-cost solution.''); *see also* Policy Integrity Comments at 29 (citing Álvaro García-Cerzo et al., *Robust Transmission Network Expansion Planning Considering Non-Convex Operational Constraints,* 98 Energy Econ. (June 2021)).

determining the factors that are relevant to regional transmission planning and addressing uncertainty in these variables. The result is that public utility transmission providers in some transmission planning regions do a better job than others in accounting for changes in the resource mix and demand when performing transmission planning studies. We are concerned that the reality is that none do so in a manner that ensures the consideration of more efficient or cost-effective transmission facilities to meet transmission needs driven by changes in the resource mix and demand.

51. While we recognize the inevitable uncertainty in forecasting, a number of factors that increasingly shape the resource mix and demand are known in advance and have reasonably predictable effects, especially in the aggregate. For example, the economics of new and existing generating facilities has predictable effects on the resource mix, including which existing generating facilities are likely to retire and which type of new generating facility is likely to be built to replace them. Similarly, state laws, utility integrated resource plans and resource procurements, and other regulatory actions necessarily implicate the resource mix and demand for Commission-jurisdictional services.[94] There are other known determinants of transmission needs as well, including factors affecting electricity demand (*e.g.,* electrification trends, energy efficiency improvements, and demand response deployments), the risk of extreme weather, information derived from the generator interconnection process about needed transmission expansion, and the locations where transmission needs are likely to be particularly acute or concentrated because of desirable siting conditions for new generating facilities. Yet it appears that existing regional transmission planning processes may undervalue or entirely omit consideration of some or all of these factors.[95]

52. We believe that engaging in regional transmission planning without adequate consideration of such factors may be leading to transmission investment that is not more efficient or cost-effective and, in turn, Commission-jurisdictional rates that are unjust and unreasonable and unduly discriminatory and preferential.[96] We believe that this deficiency may delay planning for the transmission system's changing operational needs until shortly before those needs manifest, despite the fact that the continued shift in the resource mix and changes in demand can be reasonably forecast based on known factors. As explained above, the lack of sufficient long-term transmission planning appears to be resulting in significant transmission investment in recent years occurring through generator interconnection processes to satisfy near-term transmission needs, resulting in piecemeal development of transmission facilities that may not more efficiently or cost-effectively meet transmission needs driven by changes in the resource mix and demand. We expect the problems created by this deficiency to only grow more acute as the factors that impact the resource mix and demand are poised to continue increasing in their impact on transmission needs.

53. The third potential deficiency is that public utility transmission providers may not identify a sufficiently broad set of benefits—and beneficiaries—associated with regional transmission facilities planned to meet transmission needs driven by changes in the resource mix and demand. Failing to adequately identify and consider the benefits of such transmission facilities may lead to sub-optimal or inefficient investment therein. In particular, the cost-benefit analyses that are used as part of the selection process may fail to identify more efficient or cost-effective transmission facilities for selection in the regional transmission plan for purposes of cost allocation because they provide an inaccurate portrayal of the comparative benefits of different transmission facilities. In addition, by not considering an expanded set of benefits and beneficiaries, cost allocation methods may fail to assign the costs of such facilities to beneficiaries in a manner that is at least roughly commensurate with the benefits they derive from them.[97]

54. We recognize that, in addressing these deficiencies, the Commission would be requiring public utility transmission providers to plan on a longer-term and more comprehensive basis. As discussed below, we acknowledge that such transmission planning may entail a more complex set of considerations compared to existing regional transmission planning requirements, which, in turn, may increase the importance of ensuring that the cost allocations method for projects identified and developed through these processes are perceived as fair.[98] As discussed below, we are proposing to address these concerns in part through greater state involvement, particularly in the development of cost allocation methods.

55. In sum, we preliminarily find that the deficiencies in the Commission's existing regional transmission planning and cost allocation requirements that we identify in this NOPR are resulting in Commission-jurisdictional rates that are unjust and unreasonable and unduly discriminatory and preferential. To address the enumerated deficiencies and ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential, we propose reforms to these requirements, as described in detail in the sections that follow.

IV. Regional Transmission Planning

56. We preliminarily find that reforms to public utility transmission providers' regional transmission planning processes are necessary to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential. As discussed below, the regional transmission planning reforms proposed in this NOPR would require that public utility transmission providers conduct regional transmission planning on a

[94] *See* AEE Comments at 10 (explaining that the majority of U.S. electricity customers take service from a load-serving entity subject to legally binding requirements that affect the resource mix).

[95] *See* SPP Market Monitor Comments at 3 & n.5 (describing that even SPP's more forward-looking scenario analysis of an emerging technology case in its Integrated Transmission Plan presently underestimates the actual growth of renewables so much that ''[w]ind capacity in service today (29.8 GW) already exceeds wind levels projected in both 2019 ITP futures that go out to 2029''); AEE Comments at 18 (MISO projects electrification effect on load in its long-term regional transmission planning, but how other transmission providers account for electrification trends is not consistent or transparent.); Brattle-Grid Strategies Oct. 2021 Report at 36 (stating that production cost simulations that are typically used to estimate the economic benefit of regional transmission facilities assumes no extreme weather events); U.S. DOE Comments, app. B (*National Laboratories 's Supplemental Information to Comments of Department of Energy to Advance Notice of Proposed Rulemaking (ANOPR)*) at 79 (stating an array of tools exist to identify and analyze high-value zones).

[96] NERC Comments at 17–18 (''Coordination and better certainty around anticipated future resource mix during transmission planning and interconnection studies could improve reliability assessments associated with the changing resource mix[.]''); ACPA and ESA Comments at 29 (claiming the current approach ''delays overall investment in the transmission system''); AEE Comments at 8 (arguing existing transmission planning processes' failure to capture ''documented and predictable trends in electricity demand and threats to the reliability, resilience, and sufficiency of the bulk electricity system'' warrant reforms).

[97] *Ill. Commerce Comm'n* v. *FERC,* 576 F.3d 470, 477 (7th Cir. 2009). Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 639 (requiring costs of regional transmission facilities to be allocated in a manner that is at least roughly commensurate with estimated benefits).

[98] *See infra* P–235– .

sufficiently long-term, forward-looking basis to identify and plan for transmission needs driven by changes in the resource mix and demand. As part of this long-term regional transmission planning, public utility transmission providers would be required, in coordination with states, to: (1) Identify transmission needs driven by changes in the resource mix and demand through the development of long-term scenarios that satisfy the requirements set forth in this NOPR; (2) evaluate the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities; and (3) establish transparent and not unduly discriminatory criteria to select regional transmission facilities in the regional transmission plan for purposes of cost allocation that more efficiently or cost-effectively address these transmission needs driven by changes in the resource mix and demand. Additionally, we propose to require that public utility transmission providers more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning processes.

A. Overview of Existing Regional Transmission Planning Processes

57. Public utility transmission providers currently plan their transmission systems to meet reliability, economic, and Public Policy Requirements needs identified through their regional transmission planning process, consistent with Order Nos. 890 and 1000.[99] The next few paragraphs provide a brief overview of how public utility transmission providers currently conduct regional transmission planning.

1. Reliability Needs

58. Public utility transmission providers within transmission planning regions conduct planning studies to help ensure the ability of the transmission system to meet minimum performance requirements under a variety of contingencies to provide reliable service to customers. These studies cover the near-term, which is years 1 through 5, and the long-term, which covers years 6 through year 10 and beyond.[100] Long-term transmission planning varies by public utility transmission provider; for example, studies conducted by RTOs/ISOs may range 10, 15, to 20 years [101] into the future depending on the transmission planning region's regional transmission planning process and test for violations of established North American Electric Reliability Corporation (NERC) reliability requirements.[102] Additional regional and local reliability criteria may also apply in specific transmission planning regions. In order to meet applicable reliability planning criteria, the regional transmission planning process focuses on studying and producing a transmission system that is robust enough to withstand a range of probable contingencies (*e.g.,* the sudden loss of a generator or higher-voltage transmission facilities) while reliably serving customer demand and preventing cascading outages.[103] Generally, public utility transmission providers identify areas of the transmission system that they predict will not be in compliance with reliability criteria and develop plans to achieve compliance. Public utility transmission providers examine potential transmission facilities to mitigate identified reliability criteria violations for their feasibility, impact, and comparative costs, culminating in a recommended regional transmission plan.[104]

2. Economic Needs

59. Public utility transmission providers within transmission planning regions also plan transmission facilities to meet economic needs. In Order No. 1000, the Commission recognized that Order No. 890 placed no affirmative obligation on public utility transmission providers to perform economic planning studies absent a request by stakeholders.[105] To remedy this deficiency, the Commission required in Order No. 1000 that, in addition to economic planning studies requested by stakeholders, public utility transmission providers evaluate, through a regional transmission planning process and in consultation with stakeholders, regional transmission facilities that might meet the needs of the transmission planning region more efficiently or cost-effectively than transmission facilities identified by individual public utility transmission providers in their local transmission planning process.[106] These regional transmission facilities could include transmission facilities needed to meet reliability requirements, address economic considerations, and/or meet transmission needs driven by Public Policy Requirements.[107] As Order No. 890 explains, the purpose of economic transmission planning is to plan transmission to alleviate congestion through the integration of new generation resources or an expansion of the regional transmission system, by an amount that justifies its cost, usually by a defined threshold.[108] Examples of regional transmission facilities driven by economic needs include transmission facilities that relieve historical or projected transmission congestion and allow lower-cost power to flow to consumers.

3. Transmission Needs Driven by Public Policy Requirements

60. In Order No. 1000, the Commission required public utility transmission providers to consider transmission needs driven by Public Policy Requirements in their local and regional transmission planning

[99] ANOPR, 176 FERC ¶ 61,024 at P 13.

[100] NERC,Glossary of Terms Used in NERC Reliability Standards (June 28, 2021), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[101] Long-term planning for reliability by RTO/ISO varies as follows: CAISO at least 10 years (CAISO, CASIO eTariff, § 24.2 (Nature of the Transmission Planning Process) (6.0.0)); ISO–NE between 5 and 10 years (ISO–NE, Transmission, Markets and Services Tariff, attach. K (Regional System Planning Process) (27.0.0), § 3.3 (RSP Planning Horizon and Parameters))); MISO maximum of 20 years (MISO, FERC Electric Tariff, attach. FF (Transmission Expansion Planning Protocol) (85.0.0), § I.C.8.a)); NYISO years 4 through 10 (NYISO, NYISO Tariffs, NYISO OATT, § 31.1, attach. Y (New York Comprehensive System Planning Process) (26.0.0)); PJM 10 years (PJM, Intra-PJM Tariffs, OA Schedule 6, § 1.4 (Contents of the Regional Transmission Expansion Plan) (2.1.0), § 1.4.b)); and, SPP 10 and 20 years (Southwest Power Pool, Inc., OATT, attach. Y, § III (The Integrated Transmission Planning Assessment) (8.0.0), § IV (Other Planning Studies) (8.0.0)).

[102] For example, Reliability Standard TPL–001–4 requires that Transmission Planners conduct an annual planning assessment of their region's portion of the bulk electric system and document summarized results of the steady state analyses, short circuit analyses, and stability analyses. TPL–001–4 also requires that Transmission Planners conduct these analyses using a model of their systems operating under a wide variety of potential conditions to see under what, if any, conditions the system will fail to meet reliability criteria. TPL–001–4 lays out the variety of these conditions, including system peak, off-peak, single contingency, multiple contingencies (both sequential and simultaneous), severe contingencies on adjacent systems, sensitivity analyses to underlying model assumptions, and extreme events. Transmission Planner is defined as ''the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.'' NERC, Glossary of Terms Used in NERC Reliability Standards (June 28, 2021), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[103] The regional transmission planning process will identify the necessary transmission system facilities (which have varying costs and lead times for when they can be placed into service) that are needed to achieve reliable transmission system operations.

[104] ANOPR, 176 FERC ¶ 61,024 at P 14.

[105] Order No. 1000, 136 FERC ¶ 61,051 at PP 3, 81, 147.

[106] *Id.* P 148.

[107] *Id.* PP 147–148.

[108] Order No. 890, 118 FERC ¶ 61,119 at P 549.

processes.[109] However, the requirement in Order No. 1000 to consider transmission needs driven by Public Policy Requirements is limited, and the Commission provided public utility transmission providers with flexibility in how to meet the requirement. For example, Order No. 1000 does not require that a separate class of transmission facilities be created in the regional transmission planning process to address transmission needs driven by Public Policy Requirements,[110] nor does it mandate the consideration of any particular transmission need driven by a Public Policy Requirement.[111] In addition, while Order No. 1000 requires that public utility transmission providers consider transmission needs driven by Public Policy Requirements proposed by stakeholders, it provides flexibility on how active public utility transmission providers themselves choose to be in identifying such needs.[112] As a result, the process for identifying and considering transmission needs driven by Public Policy Requirements varies from transmission planning region to transmission planning region.

B. Comments

61. In response to the ANOPR, the Commission received many comments on the need to reform regional transmission planning processes. Many comments support long-term regional transmission planning.[113] Some transmission developers and incumbent public utility transmission providers support efforts to reform aspects of existing regional transmission planning processes, with some recommending that the Commission impose prescriptive planning requirements.[114] Some state commissions and consumer advocates also support the need to reform regional transmission planning processes, but express concern about potential costs and ensuring that such costs are allocated commensurate with estimated benefits.[115]

62. Some RTOs/ISOs assert that their current regional transmission planning processes already incorporate many of the potential reforms discussed in the ANOPR and ask that the Commission provide sufficient flexibility and avoid being too prescriptive should it undertake those reforms.[116] ISO–NE states that forward-looking scenario planning is underway in ISO–NE and asks that the Commission not require a one-size-fits-all approach.[117] NYISO urges the Commission to consider that in NYISO, incremental, yet meaningful, reforms can implement many of the goals of the ANOPR, and asks that the Commission recognize the need for regional variation so that each RTO/ISO can improve its regional transmission planning process in light of its regional needs.[118]

63. The market monitors express mixed views on more comprehensive or long-term transmission planning. The PJM Market Monitor expresses a concern around the lack of certainty and quality of additional information being included in regional transmission planning that may impose additional uncertainty on the regional transmission planning process.[119] Potomac Economics expresses concern regarding mandating long-term regional transmission planning that requires public utility transmission providers to speculate on certain future conditions, but notes improvements could be made to the regional transmission planning process to account for near-term emerging trends that are less uncertain than longer-term factors.[120] In contrast, the SPP Market Monitor expresses a concern that SPP's regional transmission planning process is not planning for generation resources of the future.[121]

C. Proposed Reforms

1. Long-Term Regional Transmission Planning

a. Need for Reform

64. We are concerned that existing regional transmission planning processes may not be planning on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand, leading to the piecemeal and inefficient development of new transmission facilities in a manner that is not more efficient or cost-effective. As discussed above, existing regional transmission planning processes typically look out and plan for transmission needs based on a relatively short time horizon.[122] While some existing regional transmission planning processes may incorporate studies or assessments that have a longer forward-looking period, these are typically for informational purposes and do not result in identification of long-term regional transmission needs, assessment of transmission alternatives to meet

[109] Order No. 1000, 136 FERC ¶ 61,051 at PP 203, 222; Order No. 1000–A, 139 FERC ¶ 61,132 at P 208.

[110] Order No. 1000, 136 FERC ¶ 61,051 at P 220 (explaining that the requirements in Order No. 1000 related to transmission needs driven by Public Policy Requirements are intended to ''provide flexibility for public utility transmission providers to develop procedures appropriate for their local and regional transmission planning processes'').

[111] *Id.* P 215.

[112] Order No. 1000–A, 139 FERC ¶ 61,132 at P 322.

[113] *E.g.,* CAISO Comments at 5; MISO Comments at 41; ISO–NE Comments at 23; NYISO Comments at 26–28; PJM Comments at 3–4; SPP Comments at 6; AEP Comments at 4; Ameren Comments at 5; BP Comments at 3–4; Exelon Comments at 2; National Grid Comments at 4; NextEra Comments at 56; PG&E Comments at 2; Indicated PJM TOs Comments at 3; PSEG Comments at 10–11; SDG&E Comments at 2; SCE Comments at 3–4; Shell Comments at 7; VEIR Comments at 14; Xcel Comments at 19–20; WIRES Comments at 7; EDP Renewables Comments at 4; EDF Comments at 5; EPSA Comments at 6; ITC Comments at 4; New England for Offshore Wind Comments at 1; Certain TDUs Comments at 7; ACORE Comments at 6; ACPA and ESA Comments at 44; AEE Comments at 3; EEI Comments at 12–14; Consumers Council Comments at 9; Harvard ELI Comments at 33; Nature Conservancy Comments at 2–3; PIOs Comments at 60; Resale Iowa Comments at 14; REBA Comments at 17; NARUC Comments at 6; California Public Utility Commission Comments at 5; Michigan Commission Comments at 2–3; Minnesota Department of Commerce Comments at 5; New Jersey Commission Comments at 10–11; District of Columbia Office of the People's Counsel Comments at 22–23; Oregon Public Utility Commission Comments at 1; NEPOOL Comments at 6–7; SPP RSC Comment at 2; NASUCA Comments at 4; Iowa Office Of Consumer Advocate Comments at 2; Massachusetts Attorney General Comments at 2; State of Massachusetts Comments at 2; NESCOE Comments at 5–6; NASEO Comments at 1–2; City of New York Comments at 4; APPA Comments at 9; American Municipal Power Comments at 33–34; California Municipal Utilities Association Comments at 7; Public Systems Comments at 17; U.S. DOE Comments at 12, 16; Association of Fish and Wildlife Agencies Comments at 3; *see also* ACEG Reply Comments, app. A (identifying 174 entities supporting planning for a future resource mix).

[114] For example, AEP, SoCal Edison, and NextEra support a 20-year planning horizon. AEP Comments at 1–2, 7–8; SoCal Edison Comments at 4; NextEra Comments at 70, 79–80. Exelon, PSEG, and NextEra support requirements for public utility transmission providers to include state statutes and goals in their scenarios. Exelon Comments at 12–20; PSEG Comments at 3–6; NextEra Comments at 80. LS Power and Resale Iowa support a requirement that all facilities above 100 kV be regionally planned. LS Power Oct. 12 Comments at 49–60; Resale Iowa Comments at 8. NextEra supports requiring public utility transmission providers to use an expanded set of transmission benefits and to designate renewable energy development zones. NextEra Comments at 92–101. Avangrid supports requiring public utility transmission providers to plan for offshore wind development. Avangrid Comments at 21–23.

[115] District of Columbia's Office of the People's Counsel Comments at 1–5; NARUC Comments at 5–7, 46–47; NASUCA Comments at 3–5; Iowa Consumer Advocate Comments at 2.

[116] CAISO Comments at 3–5; MISO Comments at 2–4.

[117] ISO–NE Comments at 2, 13–16.

[118] NYISO Comments at 2–4.

[119] PJM Market Monitor Comments at 2–3.

[120] Potomac Economics Comments at 4.

[121] SPP Market Monitor Comments at 4.

[122] *Supra* Need for Reform: Unjust and Unreasonable and Unduly Discriminatory and Preferential Commission-Jurisdictional Rates. For example, PJM's Regional Transmission Expansion Plan (RTEP) baseline assessment looks out over a 5-year period, the NorthernGrid Regional Transmission Plan has a 10-year planning horizon, and SPP's Integrated Transmission Plan (ITP) also addresses a 10-year horizon.

those needs, or selection of transmission facilities in the regional transmission plan for purposes of cost allocation.[123] In lieu of such a long-term outlook, transmission needs driven by changes in the resource mix and demand are largely addressed through generator interconnection processes.[124] However, such processes are not designed to evaluate the need for larger, regional transmission facilities to address transmission needs driven by changes in the resource mix and demand, resulting in a piecemeal expansion of the electric transmission system.

65. Implementation challenges associated with long-term transmission planning—such as determining the appropriate time horizon, selecting a set of factors to forecast the future resource mix and demand, and choosing the appropriate method to account for uncertainty—make it unlikely that public utility transmission providers will engage in such transmission planning voluntarily and regularly. However, such challenges do not diminish the importance of long-term transmission planning. Moreover, even if long-term regional transmission planning is performed, failing to consider an adequate time horizon, set of factors to forecast the future resource mix and demand, and sufficient method to account for uncertainty—may result in transmission planning that is inadequate in identifying more efficient or cost-effective transmission facilities due a less comprehensive and accurate understanding of the areas impacted by transmission needs driven by changes in the resource mix and demand. Accordingly, we believe that reforms may be necessary to require public utility transmission providers to identify transmission needs driven by changes in the resource mix and demand.

66. We are also concerned that existing regional transmission planning requirements may be inadequate to ensure that public utility transmission providers adequately assess the benefits of regional transmission facilities planned to meet transmission needs driven by changes in the resource mix and demand. In Order No. 1000, the Commission declined to prescribe particular definitions of or a uniform approach to identifying benefits and beneficiaries, in order to allow flexibility for public utility transmission providers to develop cost allocation methods for their transmission planning regions.[125] However, transmission facilities may provide a wide variety of benefits to transmission customers, particularly for regional transmission facilities addressing large, systemic changes in the electric industry. We recognize that when public utility transmission providers fail to consider a broader set of benefits for transmission facilities meeting transmission needs driven by changes in the resource mix and demand, they may fail to select transmission facilities in their regional transmission plans for purposes of cost allocation that meet the transmission planning region's transmission needs more efficiently or cost-effectively.

67. As described in the ANOPR, existing regional transmission planning and cost allocation processes generally examine categories of transmission needs separately from one another based on the driver of the relevant transmission need, be it reliability, economic considerations, or Public Policy Requirements.[126] As a general matter, public utility transmission providers only calculate the set of benefits specific to that category of transmission need for purposes of determining whether a regional transmission facility meets the criteria for selection. However, the literature and experience demonstrates a panoply of benefits beyond those currently considered by all public utility transmission providers in existing regional transmission planning and cost allocation processes.[127] Failing to provide for the allocation of costs of transmission facilities selected in a regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand in a way that aligns with a reasonable set of benefits through the transmission planning process could lead to needed transmission facilities not being built, adversely affecting ratepayers. Accordingly, we propose a list of benefits for public utility transmission providers to consider when assessing a broader set of benefits during long-term regional transmission planning, and require public utility transmission providers to provide certain information, as described below, about the benefits they will use.

b. Proposed Reform

68. To help to ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates, we propose to require that public utility transmission providers participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning,[128] meaning regional transmission planning on a sufficiently long-term, forward-looking basis to identify transmission needs driven by changes in the resource mix and demand, evaluate transmission facilities to meet such needs, and identify and evaluate 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 such needs.

69. As discussed further below, we propose several specific requirements on how public utility transmission providers would be required to implement the requirement to conduct Long-Term Regional Transmission Planning. Specifically, we propose to require that public utility transmission providers in each transmission planning region: (1) Identify transmission needs driven by changes in the resource mix and demand through the development of Long-Term Scenarios[129] that satisfy the requirements set forth in this NOPR; (2) evaluate the benefits of regional transmission facilities to meet these needs over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities; and (3) establish transparent and not unduly discriminatory criteria to select transmission facilities in the regional transmission plan for purposes of cost

[123] *See infra* P 94.

[124] *See supra* P 36.

[125] Order No. 1000, 136 FERC ¶ 61,051 at PP 624–625.

[126] ANOPR, 176 FERC ¶ 61,024 at P 85.

[127] *See generally* Paul L. Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector,* Economics of Energy & Environmental Policy, Vol. 10, No. 2 (June 2021); Johannes Pfeifenberger et al., *The Value of Diversifying Uncertain Renewable Generation through the Transmission System,* Boston University Institute for Sustainable Energy (Sept. 1, 2020); Johannes Pfeifenberger et al., The Brattle Group, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid* (Apr. 2015); Judy Chang et al., The Brattle Group, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments* (2013).

[128] For example, two features of Long-Term Regional Transmission Planning included in these proposed reforms are the development of scenarios with a 20-year planning horizon to be reassessed and revised every three years, with each such re-assessment providing the basis for identification and evaluation of transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation.

[129] We use the term Long-Term Scenarios in this NOPR to describe a tool to identify transmission needs driven by changes in the resource mix and demand, and enable the evaluation of transmission facilities to meet such needs, across multiple scenarios that incorporate different assumptions about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon.

allocation that more efficiently or cost-effectively address these transmission needs in collaboration with states and other stakeholders. We discuss each of these requirements in greater detail below.

70. Taken together, these proposed requirements would establish a more comprehensive and proactive approach to regional transmission planning, ensuring that public utility transmission providers plan for transmission needs driven by changes in the resource mix and demand. The Long-Term Regional Transmission Planning proposed in this NOPR is meant to require regional transmission planning based on a multitude of drivers of long-term transmission needs, as detailed below, and result in selection of more efficient or cost-effective transmission facilities in the regional transmission plan for purposes of cost allocation to meet those needs.

71. We recognize that benefits from transmission facilities may change over time due to the inherent uncertainty in Long-Term Regional Transmission Planning and actual use of transmission facilities. We note that long-term benefits may be more stable or evenly distributed over time if they are evaluated for a portfolio of transmission facilities rather than for a single transmission facility. We propose to provide public utility transmission providers with the flexibility to propose to use a portfolio approach in the evaluation of benefits and selection of transmission facilities in the regional transmission plan for purposes of cost allocation through their Long-Term Regional Transmission Planning, as discussed below in this NOPR.

72. The reforms proposed in this NOPR inevitably interact with the existing regional transmission planning and cost allocation processes required by Order No. 1000 to more efficiently or cost-effectively meet transmission needs driven by the transmission planning region's reliability, economic, and Public Policy Requirements. With respect to transmission needs associated either with maintaining reliability or for addressing economic considerations and their associated cost allocation, we do not propose in this NOPR to change Order No. 1000's requirements for public utility transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the region's reliability and economic requirements.[130] In other words, public utility transmission providers may continue to rely on their existing regional transmission planning and cost allocation processes to comply with Order No. 1000's requirements related to transmission needs driven by reliability concerns or economic considerations.

73. With respect to transmission needs driven by Public Policy Requirements, while we do not propose to change the existing Order No. 1000 requirement to consider transmission needs driven by Public Policy Requirements in the regional transmission planning process,[131] we propose to clarify that public utility transmission providers will comply with this existing Order No. 1000 requirement through the Long-Term Regional Transmission Planning that we propose to require in this NOPR. Specifically, we propose that public utility transmission providers would be deemed to comply with the existing Order No. 1000 requirement to consider transmission needs driven by Public Policy Requirements in their regional transmission planning process through the proposed requirement to conduct Long-Term Regional Transmission Planning. As discussed in the Factors section below, we propose to require that public utility transmission providers incorporate state or federal laws or regulations, meaning enacted statutes (*i.e.,* passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level,[132] that affect the future resource mix and demand into the development of Long-Term Scenarios. Thus, we preliminarily find that under the reforms proposed herein, public utility transmission providers that comply with the Long-Term Regional Transmission Planning requirements established in any final rule in this proceeding will comply with the requirement in Order No. 1000 that they participate in a regional transmission planning process that considers, and has associated cost allocation provisions related to, transmission needs driven by Public Policy Requirements.

74. That said, we understand that public utility transmission providers in some transmission planning regions have developed processes to consider transmission needs driven by Public Policy Requirements through their regional transmission planning processes that they may wish to retain. Therefore, we propose to allow public utility transmission providers to propose to continue using some or all aspects of the existing regional transmission planning and cost allocation processes they use to consider transmission needs driven by Public Policy Requirements. However, such continued use of existing regional transmission planning and cost allocation processes would not supplant public utility transmission providers' obligations to comply with the Long-Term Regional Transmission Planning requirements established in any final rule in this proceeding. Moreover, in their filing to comply with any final rule, public utility transmission providers seeking to retain existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements through their regional transmission planning processes would have to demonstrate that continued use of any such processes does not interfere or otherwise undermine the Long-Term Regional Transmission Planning that we propose to require in this NOPR by demonstrating that continued use of such processes is consistent with or superior to any final rule issued in this proceeding.

75. Finally, we preliminarily find that public utility transmission providers could propose a regional transmission planning process that plans for reliability needs, economic needs, transmission needs driven by Public Policy Requirements, and transmission needs driven by changes in the resource mix and demand simultaneously through a combined approach. Public utility transmission providers proposing to address all such transmission needs in a single regional transmission planning process would bear the burden of demonstrating continued compliance with Order No. 1000 in addition to compliance with the requirements of any final rule in this proceeding; to do so, they would be required to demonstrate that such process is consistent with or superior to the requirements of both Order No. 1000 and any final rule issued in this proceeding.

76. Further, we propose to require that Long-Term Regional Transmission Planning comply with the following existing Order Nos. 890 and 1000 transmission planning principles: (1) Coordination; (2) openness; (3) transparency; (4) information exchange;

[130] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 11.

[131] *See id.* PP 203–224 (discussing the requirement to consider transmission needs driven by Public Policy Requirements in regional transmission planning processes). This proposal would also leave unchanged the existing requirement for public utility transmission providers to consider transmission needs driven by Public Policy Requirements in their local transmission planning processes.

[132] *See id.* P 2.

(5) comparability; and (6) dispute resolution.[133]

77. We seek comment on the requirements proposed in this section of the NOPR. In particular, we seek comment on the proposed requirement for public utility transmission providers to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.

78. As part of this Long-Term Regional Transmission Planning, we propose to require that public utility transmission providers identify transmission needs driven by changes in the resource mix and demand through the development of Long-Term Scenarios that satisfy the specific requirements that we more fully enumerate below. We propose that public utility transmission providers: (1) Use a transmission planning horizon no less than 20 years into the future in developing Long-Term Scenarios and reassess and revise those scenarios at least once every three years; (2) incorporate into their Long-Term Scenarios a set of Commission-identified categories of factors that may drive transmission needs driven by changes in the resource mix and demand; (3) develop a plausible and diverse set of at least four Long-Term Scenarios; (4) use ''best available data'' in developing their Long-Term Scenarios; and (5) consider whether to identify geographic zones with the potential for development of large amounts of new generation.

i. Development of Long-Term Scenarios for Use in Long-Term Regional Transmission Planning

79. In the ANOPR, the Commission expressed concern that regional transmission planning processes may not adequately model future scenarios to ensure that those scenarios incorporate sufficiently long-term and comprehensive forecasts of future transmission needs.[134] The Commission stated that, to the extent that regional transmission planning processes consider generation development in scenario analyses, they tend to include in their baseline reliability model only those generators that have completed facilities studies, and thus are far along in the generator interconnection process and will likely come online in the short term.[135] The Commission stated that such a short-term outlook may under-forecast longer-term transmission needs and that more efficient or cost-effective transmission facilities that address longer-term needs may never be developed.[136] The Commission sought comment on whether reforms are needed regarding how the regional transmission planning processes model scenarios to ensure they incorporate sufficiently long-term and comprehensive forecasts of future transmission needs.[137]

(a) Comments

80. Many commenters responding to the ANOPR support scenario planning.[138] All RTOs/ISOs express support for long-term scenario-based planning as a current or future practice; some request that the Commission allow for regional flexibility.[139] SERTP states that its ''bottom-up'' regional transmission planning process already assesses a multitude of scenarios as part of each public utility transmission provider's integrated resource planning process and that it could perform additional, hypothetical scenario planning to inform decision makers.[140]

81. Many public utility transmission providers support the idea of scenario planning.[141] Most of these public utility transmission providers support targeted reforms that specify guardrails, or baselines, in scenario planning. For example, some public utility transmission providers list the minimum set of factors they think should be included in a scenario planning requirement.[142] Other public utility transmission providers support scenario planning so long as it is strictly informational, limited, or non-binding.[143] Some public utility transmission providers equate scenario planning to their existing integrated resource plans.[144]

82. NARUC supports scenario planning as a means to evaluate the system needs to integrate state-directed resources.[145] Other state commissions and state representatives express their support for scenario planning as necessary to identify system needs and transmission facilities to address them.[146] A few state commissions do not support the Commission imposing specific scenario planning requirements, or only support the Commission providing guardrails, because they believe state regulatory officials in collaboration with public utility transmission providers are in the best position to evaluate the needs of each region or because they believe the current processes work sufficiently well.[147] The PJM Market Monitor and Potomac Economics do not comment specifically on use of scenarios, but acknowledge the uncertainty associated with transmission planning and accuracy of inputs into the transmission planning process.[148] The SPP Market Monitor states that one of its biggest challenges related to the transmission planning process has been persuading stakeholders to adopt an additional scenario as part of SPP's 10-year Integrated Transmission Planning Assessment.[149]

83. Several consumer and trade organizations support scenario planning to assess uncertainty about future

[133] *See id.* PP 146, 151.

[134] ANOPR, 176 FERC ¶ 61,024 at P 31.

[135] *Id.*

[136] *Id.* P 47.

[137] *Id.* P 46.

[138] *E.g.,* ACEG Comments at 5; ACPA and ESA Comments at 46–47; AEE Comments at 36; AEP Comments at 9–11; Ameren Comments at 5; APPA Comments at 7–9; Arizona Commission Comments at 2; Avangrid Comments at 11–12; Certain TDUs Comments at 11; Consumers Council Comments at 8–9; Union of Concerned Scientists Comments at 42; East Kentucky Comments at 4–7; EDF Comments at 3; EEI Comments at 24–26; Eversource Comments at 8; Exelon Comments at 11–19; Massachusetts Attorney General Comments at 13; NARUC Comments at 10–11; National Grid Comments at 11–17; Nature Conservancy Comments at 2–5; NESCOE Comments at 39–40; New England for Offshore Wind Comments at 2; NextEra Comments at 70–83; Northwest and Intermountain Comments at 6–8; Oregon Commission Comments at 1; PG&E Comments at 5–6; PIOs Comments at 76–81; Indicated PJM TOs Comments at 24–26; Policy Integrity Comments at 25–40; PSEG Comments at 6–18; Resale Iowa Comments at 14; SAFE Comments at 11; SDG&E Comments at 3–4; Shell Comments at 7; State Agencies Comments at 21; State of Massachusetts Comments at 10–15; Tenaska Comments at 12–13; U.S. DOE Comments at 21–22; WIRES Comments at 7–8; VEIR Comments at 13–17; Xcel Comments at 19–20.

[139] CAISO Comments at 42–44; MISO Comments at 7, 49; SPP Comments at 7; NYISO Comments at 27–31; PJM Comments at 41–42, 45–46; ISO–NE Comments at 13–17, 20–22.

[140] *See* SERTP Comments at 8, 14–17; SERTP Reply Comments at 11.

[141] *E.g.,* AEP Comments at 9–11; Ameren Comments at 5; Eversource Comments at 8; Exelon Comments at 11–19; National Grid Comments at 11–17; NextEra Comments at 70–83; PG&E Comments at 5–6; PSEG Comments at 6–18; SDG&E Comments at 3–4; Xcel Comments at 19–20.

[142] *E.g.,* National Grid Comments at 4–9; Exelon Comments at 12–16.

[143] *E.g.,* Southern Comments at 36–37; Arizona Public Service Comments at 2–4; Xcel Comments at 20.

[144] *E.g.,* Berkshire Comments at 12–13.

[145] NARUC Comments at 6, 10–11.

[146] *E.g.,* Arizona Commission Comments at 2; Oregon Commission Comments at 8–9; Massachusetts Attorney General Comments at 5–15.

[147] *E.g.,* Mississippi Commission Comments at 3; Nebraska Commission Comments at 3–4; Michigan Commission Comments at 7.

[148] PJM Market Monitor Comments at 2–3; Potomac Economics Comments at 3–4; *see also Joint Fed.-State Task Force on Elec. Transmission,* Technical Conference, Docket No. AD21–15–000, Tr. 59:17–24 (Andrew French) (Nov. 10, 2021) (November Joint Task Force Tr.) (commenting that in SPP, futures projections of renewables have ''probably not been based on data or reality'' but ''have been more of a consensus of what stakeholders are willing to accept'' with the result being that those projects have been too low).

[149] SPP Market Monitor Comments at 3.

transmission needs.[150] Some commenters call for a national uniform framework for scenario planning.[151]

(b) Proposed Reform

84. We propose to require that public utility transmission providers develop and use Long-Term Scenarios as part of Long-Term Regional Transmission Planning. We propose to define Long-Term Scenarios as a tool to identify transmission needs driven by changes in the resource mix and demand—and enable the evaluation of transmission facilities to meet such transmission needs—across multiple scenarios that incorporate different assumptions about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon. A scenario is a hypothetical sequence of events that includes assumptions used to forecast transmission needs. Assumptions used to forecast transmission needs driven by changes in the resource mix and demand include: Forecasts of the level and pattern (*i.e.,* hourly and seasonal variability) of future electricity demand; the quantity, location, and type of resource additions and retirements; and other relevant forecasts about the electric power system that are used as inputs to the transmission model and determine the need for new transmission facilities over the transmission planning horizon. Other relevant assumptions might include forecasts for natural gas prices, increasing outage trends due to extreme weather and climatic trends, and other future events. We also propose to require that public utility transmission providers use Long-Term Scenarios to evaluate potential regional transmission facilities needed to meet transmission needs driven by changes in the resource mix and demand to identify the more efficient or cost-effective regional transmission facilities.

85. In the next section of this NOPR, we propose specific requirements that public utility transmission providers would need to meet in developing Long-Term Scenarios. We propose to require each public utility transmission provider to amend the regional transmission planning process in its OATT to explicitly describe the open and transparent process that it will use to develop Long-Term Scenarios that meet these requirements.

86. We preliminarily find that requiring public utility transmission providers to develop and utilize multiple Long-Term Scenarios, as further specified below, as part of Long-Term Regional Transmission Planning will allow public utility transmission providers to identify and plan to more efficiently or cost-effectively meet transmission needs driven by changes in the resource mix and demand. Specifically, we believe that using Long-Term Scenarios in the regional transmission planning process will help public utility transmission providers to account for the inherent uncertainty involved in identifying transmission needs driven by changes in the resource mix and demand and evaluating more efficient or cost-effective transmission facilities needed to meet those needs.

87. As discussed above, Long-Term Regional Transmission Planning is critical to ensuring more efficient or cost-effective transmission development to meet transmission needs driven by changes in the resource mix and demand.[152] However, such transmission planning necessarily relies on forecasts of future system conditions, such as the state of the resource mix and the level of demand. These conditions may be reasonably predictable in the near term, but as the transmission planning horizon extends further into the future, they become increasingly imprecise. By utilizing multiple Long-Term Scenarios, public utility transmission providers will have a better understanding of potential future transmission needs under multiple reasonably likely scenarios, allowing them to assess the implications of changing market conditions and policies. They can also manage uncertainties about future system conditions and better identify more efficient or cost-effective regional transmission facilities by evaluating which transmission facilities are beneficial under multiple scenarios. Doing so will mitigate the risks of under-building or over-building transmission facilities that are identified through Long-Term Regional Transmission Planning.

88. We preliminarily find that the development of Long-Term Scenarios as part of the regional transmission planning process will ensure that public utility transmission providers adequately assess the potential benefits of regional transmission facilities that may meet the needs of a transmission planning region more efficiently or cost-effectively than transmission planning without Long-Term Scenarios. We preliminarily find that a regional transmission planning process that does not develop Long-Term Scenarios that meet the requirements described below fails to properly identify transmission needs driven by changes in the resource mix and demand, which may lead to piecemeal and inefficient development of new transmission facilities. In addition, we preliminarily find that failing to develop Long-Term Scenarios means that transmission facilities needed to meet transmission needs driven by changes in the resource mix and demand are more likely to be identified in the generator interconnection process instead of the regional transmission planning process, similarly leading to the increased potential for piecemeal and inefficient transmission development, as described above.[153] For these reasons, we preliminarily find that requiring public utility transmission providers to develop Long-Term Scenarios that meet the requirements described below will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

89. We clarify that we do not propose to require that public utility transmission providers use Long-Term Scenarios in their regional transmission planning processes to address near-term reliability and economic transmission needs. In other words, we do not propose to require that public utility transmission providers modify their existing regional transmission planning processes that plan for reliability and economic transmission needs to incorporate Long-Term Scenarios.

90. We seek comment on the requirements proposed in this section of the NOPR. In particular, we seek comment on whether public utility transmission providers should be required to incorporate some form of scenario analysis into their existing reliability and economic regional transmission planning processes to identify more efficient or cost-effective transmission facilities than are identified through those processes today.

(1) Long-Term Scenarios Requirements

91. We propose to require that public utility transmission providers comply with specified minimum requirements in developing Long-Term Scenarios,

[150] *E.g.,* ACEG Comments at 5; ACPA and ESA Comments at 46; AEE Comments at 36; APPA Comments at 4; Business Council for Sustainable Energy Comments at 4; Union of Concerned Scientists Comments at 42–44; Consumers Council Comments at 8–9; Iowa Consumer Advocate Comments at 32; Nature Conservancy Comments at 3; WIRES Comments at 7.

[151] *See, e.g.,* NARUC Comments at 17; PIOs Comments at 103; Policy Integrity Comments 29–40; U.S. DOE Comments at 33.

[152] *Supra* Need for Reform: Potential Benefits of Long-Term Regional Transmission Planning and Cost Allocation to Identify and Plan for Transmission Needs Driven by Changes in the Resource Mix and Demand.

[153] *Supra* Need for Reform: Deficiencies in the Commission's Existing Regional Transmission Planning and Cost Allocation Requirements.

which we preliminarily find will help to ensure Long-Term Regional Transmission Planning results in Commission-jurisdictional rates that are just and reasonable and not unduly discriminatory or preferential. We expect these proposed minimum requirements will allow public utility transmission providers to better identify transmission needs driven by changes in the resource mix and demand and evaluate regional transmission facilities to more efficiently or cost-effectively meet those needs. Specifically, as discussed further below, we propose to require that public utility transmission providers: (1) Use a transmission planning horizon no less than 20 years into the future in developing Long-Term Scenarios and reassess and revise those scenarios at least once every three years; (2) incorporate a set of Commission-identified categories of factors that may affect transmission needs driven by changes in the resource mix and demand into their Long-Term Scenarios; (3) develop a plausible and diverse set of at least four Long-Term Scenarios; (4) use ''best available data'' (as defined in the Specificity of Data Inputs section below) in developing their Long-Term Scenarios; and (5) consider whether to identify geographic zones with the potential for development of large amounts of new generation.

(i) Transmission Planning Horizon and Frequency

92. The transmission planning horizon is the number of years into the future that public utility transmission providers look when developing Long-Term Scenarios. For example, a transmission planning horizon of 20 years means that the public utility transmission provider develops Long-Term Scenarios to identify and plan to meet transmission needs that will materialize up to 20 years in the future. We believe that, to be just and reasonable, the transmission planning horizon used in Long-Term Regional Transmission Planning should extend far enough into the future that public utility transmission providers can identify transmission needs that could be met with more efficient or cost-effective regional transmission facilities, *i.e.,* the transmission planning horizon should capture the longer-term benefits of addressing transmission needs driven by changes in the resource mix and demand.

93. In addition, we believe that the Long-Term Scenarios used in Long-Term Regional Transmission Planning should not remain static over time. Instead, they should be periodically re-evaluated and re-developed to ensure that they reflect recent forecasts of future system conditions. Frequency is how often public utility transmission providers reassess whether the data inputs and factors included in their previously developed Long-Term Scenarios need to be updated and then revise their Long-Term Scenarios as needed to reflect updated data inputs and factors. Reassessing and revising scenarios is appropriate as technology, markets, and factors that affect the future resource mix and demand change. Frequent scenario reassessment and revision could help address some of the uncertainty and risks associated with under-building or over-building transmission facilities over a long-term transmission planning horizon. However, developing scenarios can be costly and time-consuming for both public utility transmission providers and their stakeholders. Frequent scenario reassessment and revision might also be unnecessary if the data inputs and factors into scenario development do not change much over the time period between studies. Thus, we believe that there may be a need to balance the benefits of updating Long-Term Scenarios with the burdens associated with such updates when deciding how frequently to do so. In order to prevent overlap of Long-Term Scenarios that are developed every three years, we also propose to require that the development of Long-Term Scenarios be completed within three years—*i.e.,* before the next three-year assessment commences.

94. Based on our review of public information and ANOPR comments, our understanding is that some transmission planning regions currently use longer-term transmission planning horizons for regional transmission planning. For instance, CAISO selects transmission facilities in its regional transmission plan for purposes of cost allocation based on a 10-year transmission planning horizon and recently initiated an effort to conduct informational high-level technical studies with a 20-year horizon as part of its regional transmission planning process.[154] NYISO uses a 20-year transmission planning horizon to evaluate scenarios in its regional transmission planning process for transmission needs driven by Public Policy Requirements and for its Outlook.[155] However, NYISO uses a 10-year or shorter transmission planning horizon for its regional transmission planning process for reliability and economic needs. SPP conducts its Integrated Transmission Planning Assessment with a 10-year transmission planning horizon and conducts an informational 20-year assessment using scenarios every five years.[156] MISO's current Long Range Transmission Planning effort uses a 20-year transmission planning horizon.[157] PJM uses a 15-year transmission planning horizon for its long-term analysis as part of its regional transmission planning processes.[158] All other transmission planning regions currently use a 10-year transmission planning horizon for their regional transmission planning processes,[159] consistent with NERC's definition of the Long-Term Transmission Planning Horizon.[160] ISO–NE has stated that it plans to use a longer transmission planning horizon in future transmission planning studies.[161] We understand that transmission planning regions that currently use scenarios with longer-term transmission planning horizons (longer than 10 years) typically do so only for informational purposes or in a limited application and not commonly to select transmission facilities in regional transmission plans for purposes of cost allocation.

(01) Comments

95. Comments in response to the ANOPR support a range of possible transmission planning horizons, from five years to beyond 30 years. Some commenters claim that a transmission planning horizon of 10 years is sufficient because that is typically

[154] CAISO Comments at 44–46.

[155] NYISO Comments at 10, 36–37. The Outlook is a report by which NYISO summarizes the current assessments, evaluations, and plans in its biennial Comprehensive System Planning Process; produces a 20-year projection of congestion on the New York State Transmission System; identifies, ranks, and groups congested elements; and assesses the potential benefits of addressing the identified congestion. *See id.* at 10.

[156] SPP Comments at 3; SPP, OATT, attach. O, § IV.2 (4.0.0), § IV.2.a.

[157] MISO Comments at 36.

[158] PJM Comments at 41.

[159] *E.g.,* Southeastern Regional Transmission Planning, *2021 Regional Transmission Planning Analyses,* at 2 (Nov. 17, 2021), *https://www.southeasternrtp.com/docs/general/2021/2021-SERTP-Regional-Transmission-Planning-Analyses-Summary-Final.pdf;* WestConnect Regional Transmission Planning, *2020–21 Planning Cycle Final Regional Study Plan,* at 7 (Mar. 18, 2020), *https://doc.westconnect.com/Documents.aspx?NID=18668&dl=1;* NorthernGrid, *Regional Transmission Plan for the 2020–2021 NorthernGrid Planning Cycle,* at 5 (Dec. 8, 2021), *https://www.northerngrid.net/private-media/documents/2020-2021_Regional_Transmission_Plan.pdf.*

[160] *See* NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 28, 2021), *https://www.nerc.com/files/glossary_of_terms.pdf* (defining Long-Term Transmission Planning Horizon as the ''[t]ransmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete'').

[161] ISO–NE Comments at 13–17.

enough time to identify, design, and build needed transmission facilities or because it is consistent with NERC standards and some state integrated resource plans.[162] Other commenters claim that a longer transmission planning horizon, most frequently 20 years, is needed to appropriately identify and plan for future transmission needs.[163] Commenters that support a longer transmission planning horizon commonly also support shorter-term interim assessments. Panelists at the November 2021 Technical Conference that supported a specific transmission planning horizon contended that a 20-year transmission planning horizon is appropriate because that transmission planning horizon may be needed for siting, permitting, and construction of transmission facilities or because states have longer-term policy goals.[164] Some panelists stated that such a transmission planning horizon should be used in informational studies and that a shorter transmission planning horizon (*e.g.,* 10 years) should be used to select transmission facilities, while other panelists stated that public utility transmission providers should use a 20-year or greater transmission planning horizon to select transmission facilities.[165]

96. Commenters discussing frequency generally support the Commission requiring that scenarios be reassessed and revised between every two to five years, and up to seven years, to balance the benefits and costs of revisiting the scenarios.[166] AEP recommends that the Commission require all public utility transmission providers to reassess scenarios at the same time to promote consistent results and comparability among regions.[167] Panelists at the November 2021 Technical Conference, including PJM, MISO, and AEP, supported a frequency of at least every three years.[168]

(02) Proposed Requirement

97. We propose to require that public utility transmission providers develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon. In addition, we propose to require that public utility transmission providers develop Long-Term Scenarios at least every three years, by reassessing whether the data inputs and factors incorporated in their previously developed Long-Term Scenarios need to be updated and then revising their Long-Term Scenarios as needed to reflect updated data inputs and factors. We also propose to require that the development of Long-Term Scenarios be completed within three years, before the next three-year assessment commences.

98. We preliminarily find that a 20-year transmission planning horizon requirement strikes a reasonable balance between the current near-term transmission planning horizons used in many transmission planning regions and the 30-year or longer transmission planning horizon proposed by some commenters. The 30-year or longer transmission planning horizon is criticized by other commenters as speculative or too uncertain. We also believe that a 20-year transmission planning horizon requirement may be reasonable because some public utility transmission providers use a 20-year transmission planning horizon in existing regional transmission planning processes. In addition, we believe that a 20-year planning horizon would allow for sufficient time to identify, plan, and obtain siting and permitting approval and to construct regional transmission facilities to meet long-term regional transmission needs including those that may take longer than the average amount of time to go from planning to in-service.[169] Finally, we believe that a 20-year transmission planning horizon would allow public utility transmission providers to better leverage economies of scale by sizing transmission facilities to meet not only nearer-term needs but also longer-term transmission needs driven by changes in the resource mix and demand over time. By assessing transmission needs over a longer time horizon—for example, starting in year six[170] through year 20 of the transmission planning horizon—Long-Term Regional Transmission Planning should be able to identify more efficient or cost-effective regional transmission facilities to address these needs.

99. We preliminarily find that a three-year frequency requirement balances the need of public utility transmission providers to reassess changes in the resource mix and demand as technology, markets, and policies have the potential to rapidly change,[171] with the burden of developing Long-Term Scenarios that can take a year or longer. We believe that this three-year frequency requirement will allow public utility transmission providers to identify new transmission needs driven by changes in the resource mix and demand during the interim years of the transmission planning period, and update previously identified transmission needs, if warranted.

100. We seek comment on whether using a 20-year transmission planning horizon for Long-Term Scenarios is appropriate to allow public utility transmission providers to identify transmission needs driven by changes in the resource mix and demand and to evaluate regional transmission facilities to more efficiently or cost-effectively meet such transmission needs. We also seek comment on whether a frequency of no less than three years for reassessing and revising, as necessary, the data inputs and factors incorporated in previously developed Long-Term Scenarios appropriately balances the benefits and burdens of such updates. In addition, we seek comment on whether a three-year frequency requirement for

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[162] *E.g.,* Exelon Comments at 16–17; NRECA Comments at 19–20. Similarly, ITC supports a 5 to 10-year transmission planning horizon. ITC Comments at 12–13.

[163] For example, BP supports a 15-year transmission planning horizon. BP Comments at 4. Public Systems supports a 15- to 20-year transmission planning horizon. Public Systems Comments at 18–22. NextEra, AEP, Northwest and Intermountain, and the Oregon Commission support a 20-year transmission planning horizon. NextEra Comments at 70; Northwest and Intermountain Comments at 4, 16; Oregon Commission Comments at 8–9. NYISO supports the Commission granting discretion, up to 20 years. NYISO Comments at 34–37. ACPA and ESA, AEE, U.S. DOE, Competitive Energy, District of Columbia's Office of the People's Counsel, Massachusetts Attorney General, and VEIR support a transmission planning horizon longer than 20 years. ACPA and ESA Comments at 43–45; AEE Comments at 32; U.S. DOE Comments at 12–15, 27–28; Competitive Energy Comments at 37–40; District of Columbia's Office of the People's Counsel Comments at 22–25; Massachusetts Attorney General Comments at 5–15; VEIR Comments at 13–17.

[164] November 2021 Technical Conference Transcript (Tr.) at 129–137.

[165] *Id.* at 129–137.

[166] For example, NextEra supports every two years, ITC supports every three to five years, Exelon and Competitive Energy support every five to seven years, AEP supports at least every three years, and the SPP Market Monitor supports a 10-year study every year. NextEra Comments at 79; ITC Comments at 12; Exelon Comments at 17; Competitive Energy Comments at 37–40; SPP Market Monitor Comments at 3–4.

[167] AEP Comments at 10–11.

[168] November 2021 Technical Conference Tr. at 138–140.

[169] The time needed to plan, obtain siting and permitting approval for, and construct regional transmission facilities takes an average of 10 years. *See, e.g.,* MISO, *2021 MISO Transmission Expansion Planning,* at 12 (2021) (''Transmission facilities take an average of 10 years to go from planning to in-service.''). Larger-scale and greenfield transmission facilities may take longer to go from planning to in-service.

[170] As indicated above in this NOPR, NERC defines the long-term transmission planning horizon as covering year six through year 10 and beyond.

[171] For example, the annual capacity of new interconnection requests grew 42% from 2017 to 2020, and 123% since 2015. *See* Lawrence Berkeley National Lab, *Generation, Storage, and Hybrid Capacity in Interconnection Queues Interactive Visualization* (May 2021), *https://emp.lbl.gov/generation-storage-and-hybrid-capacity.*

reassessing and revising, as necessary, the data inputs and factors incorporated in previously developed Long-Term Scenarios allows for public utility transmission providers to update their assumptions in time to assess transmission needs driven by changes in the resource mix and demand, and whether this requirement helps to balance the risks of under-building or over-building regional transmission facilities. Finally, we also seek comment on the proposal to require that the development of Long-Term Scenarios be completed within three years, and whether this proposed requirement prevents the overlap of the three-year assessments.

(ii) Factors

101. Factors shaping the electric power system are used as inputs to develop scenarios for regional transmission planning. Factors represent long-term drivers and trends that inform the expected composition of the future resource mix and demand that may not be captured by the inputs of a basic model of the transmission system. Factors inform changes in the data inputs of models of the transmission system but are not direct data inputs of such models. For example, a state energy law driving procurement of generation is a factor, and technology changes driving a long-term trend towards certain resource types is also a factor, whereas the estimated impact that these factors will have on the future resource mix and demand is a data input of a model of the transmission system. Incorporating the appropriate set of factors to forecast the future resource mix and demand when developing Long-Term Scenarios is essential to ensuring that Long-Term Regional Transmission Planning can identify more efficient or cost-effective regional transmission facilities to meet transmission needs driven by changes in the resource mix and demand. Importantly, incorporating more accurate inputs into Long-Term Scenarios enables a better understanding of transmission needs driven by changes in the resource mix and demand, which in turn allows public utility transmission providers to better evaluate the benefits of regional transmission facilities that would meet those needs. Currently, public utility transmission providers consider different sets of factors in the development of scenarios as part of their regional transmission planning processes, to the extent that they develop scenarios. For example, MISO's Futures study includes federal and state climate and clean energy laws and regulations, federal and state climate and clean energy goals that have not been enacted into law, utility energy and climate goals, assumptions on the potential to electrify various types of technologies/loads, data and forecasts developed by various national labs or U.S. agencies, and assumptions on resource retirements.[172]

102. The ANOPR sought comment on what factors shaping the resource mix are appropriate to use for transmission planning purposes, such as, for example: (1) Federal, state, and local climate and clean energy laws and regulations; (2) federal, state, and local climate and clean energy goals that have not been enacted or promulgated into law or regulation; (3) utility and corporate energy and climate goals; (4) trends in technology costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; and (5) resource retirements.[173]

(01) Comments

103. Commenters in response to the ANOPR generally support the factors that the Commission listed in the ANOPR as shaping the resource mix. Such commenters highlight the importance of: Public policies;[174] decarbonization commitments;[175] resource retirements;[176] the scale, location, and adoption rate of distributed energy resources (including batteries);[177] state-approved utility integrated resource plans;[178] weather trends; climate risk; and reliability or resilience against extreme weather[179] as factors shaping future transmission needs that public utility transmission providers should model in developing scenarios. Additionally, some commenters argue that scenarios should explicitly account for additional load from electrification of transportation and buildings and include an estimation of clean energy demand preferences from transmission customers in the region.[180] Some commenters request that the Commission allow for regional flexibility and not be overly prescriptive on factors for scenario planning.[181] City of New York proposes that New York State's statutory goals should be part of the baseline scenario, rather than an informational scenario or treated as a mere consideration.[182] Exelon states that a state policy ''not enshrined into law'' by the legislature should be one of the possible futures that should be considered, even if somewhat ''discounted'' for being aspirational.[183] ACPA and ESA recommend that the ''business-as-usual'' base case include existing future resource plans of the utilities in the planning area and any local, state, or federal policy requirements,[184] and Berkshire states that many of the factors listed in the ANOPR are already under consideration in states where integrated resource plans are required.[185] Industrial Customers states that transmission investment should not be based on speculative factors.[186] Similarly, Potomac Economics expresses concern with mandating long-term planning studies involving speculation on a

[172] MISO Comments at 41–43.

[173] ANOPR, 176 FERC ¶ 61,024 at P 46.

[174] *E.g.,* EEI Comments at 13–14; ACPA and ESA Comments at 28–29; Competitive Energy Comments at 38; City of New York Comments at 7–9; Union of Concerned Scientists Comments at 41–44; Minnesota Commission Comments at 4; National Grid Comments at 4–9; New Jersey Commission Comments at 13–15; NRECA Comments at 17–19; Indicated PJM TOs Comments at 25–26; SDG&E Comments at 3–4; VEIR Comments at 13–14; WIRES Comments at 8; SEIA Comments at 5.

[175] *E.g.,* ACPA and ESA Comments at 43–45; Amazon Comments at 3; Competitive Energy Comments at 38; City of New York Comments at 7–9; Minnesota Commission Comments at 4; PIOs Comments at 80; RMI Comments at 2–3; SDG&E Comments at 3–4; VEIR Comments at 13–14.

[176] *E.g.,* ACPA and ESA Comments at 43–45; Ameren Comments at 5–8; Competitive Energy Comments at 38; Union of Concerned Scientists Comments at 41–44; EEI Comments at 13–14; NARUC Comments at 10; Northern Virginia Cooperative Comments at 7–8; NRECA Comments at 17–19; NYISO Comments at 27–31; Rail Electrification Comments at 12–13; SEIA Comments at 5.

[177] *E.g.,* EEI Comments at 13–14; NARUC Comments at 10; PG&E Comments at 6; U.S. DOE Comments at 12–15; SEIA Comments at 5.

[178] *E.g.,* ACPA and ESA Comments at 43–45; Entergy Comments at 14–15; NRECA Comments at 11, 17–19; Union of Concerned Scientists Comments at 41–44; Minnesota Commission Comments at 4; OMS Comments at 5–6; Rail Electrification Comments at 12–13.

[179] *E.g.,* AEP Comments at 7–11; AES Ohio Comments at 2–4; Oregon Commission Comments at 9–10; District of Columbia's Office of the People's Counsel Comments at 22–25; East Kentucky Comments at 8; Exelon Comments at 12, 15–16; LS Power Oct. 12 Comments at 41–46; Massachusetts Attorney General Comments at 13–21; PIOs Comments at 80; PJM Comments at 25–26; REBA Comments at 19–26, 33.

[180] *E.g.,* Ameren Comments at 5–8; EEI Comments at 13–14; PIOs Comments at 80–81; PJM Comments at 25–26; Rail Electrification Comments at 12–13; REBA Comments at 19–26, 33; SEIA Comments at 5; Massachusetts Attorney General Comments at 5–15; U.S. DOE Comments at 12–18; *see also* November Joint Task Force Tr. 112:1–10 (Andrew French) (asserting that anything that indicates there is demand should be considered within the transmission planning process).

[181] Duke Comments at 5–7; PJM Comments at 9; ISO–NE Comments at 20–21; MISO Comments at 41.

[182] City of New York Comments at 6–7.

[183] Exelon Comments at 12, 15–16.

[184] ACPA and ESA Comments at 46.

[185] Southern Comments at 3–5; Berkshire Comments at 12–13.

[186] Industrial Customers Comments at 20–33.

variety of factors.[187] The PJM Market Monitor acknowledges the uncertainty associated with transmission planning and accuracy of inputs and expresses concern with planning for anticipated new generation.[188]

(02) Proposed Requirement

104. We propose to require that public utility transmission providers incorporate specific categories of factors in the development of Long-Term Scenarios as part of Long-Term Regional Transmission Planning. Specifically, we propose to require that public utility transmission providers incorporate, at a minimum, the following categories of factors into the development of Long-Term Scenarios: (1) Federal, state, and local laws and regulations that affect the future resource mix and demand; [189] (2) federal, state, and local laws and regulations on decarbonization and electrification; [190] (3) state-approved utility integrated resource plans and expected supply obligations for load serving entities; [191] (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; [192] (5) resource retirements; [193] (6) generator interconnection requests and withdrawals; [194] and (7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand.[195]

105. We preliminarily find that incorporating, at a minimum, these categories of factors in the development of Long-Term Scenarios is appropriate because these categories of factors affect the future resource mix and demand, and their incorporation in Long-Term Scenarios is therefore essential to identifying transmission needs driven by changes in the resource mix and demand through Long-Term Regional Transmission Planning. Directly below, we discuss our proposed requirements governing how public utility transmission providers must incorporate each category of factors into Long-Term Scenarios. We note that we are proposing to require that public utility transmission providers incorporate, at a minimum, these categories of factors into the development of Long-Term Scenarios. To the extent public utility transmission providers would like to incorporate additional categories of factors into the development of Long-Term Scenarios, we propose to require that they demonstrate that the incorporation of more than the minimum is consistent with or superior to any final rule in this proceeding.

106. First, we propose to require that each Long-Term Scenario that public utility transmission providers use in Long-Term Regional Transmission Planning incorporate and be consistent with federal, state, and local laws and regulations that affect the future resource mix and demand; federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans and expected supply obligations for load serving entities. We preliminarily find that it is reasonable to require public utility transmission providers to assume legally binding obligations and state utility regulator-approved plans are followed and expected supply obligations for load serving entities are fully met. Public utility transmission providers may not discount the factors included in the categories of federal, state, and local laws and regulations that affect the future resource mix; federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans and expected supply obligations for load serving entities.

107. Second, we propose to require that each Long-Term Scenario that public utility transmission providers use in Long-Term Regional Transmission Planning include trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; resource retirements; and generator interconnection requests and withdrawals. For these particular categories of factors, we propose to grant public utility transmission factors flexibility in how they incorporate each factor into Long-Term Scenarios so long as public utility transmission providers identify and publish specific factors for each of these categories as further described below. As discussed in the Coordination of Regional Transmission Planning and Generator Interconnection Processes section below, we propose to require that public utility transmission providers consider in their Long-Term Regional Transmission Planning regional transmission facilities that address interconnection-related transmission needs that the public utility transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection request(s). We propose to require that public utility transmission providers must incorporate the specific interconnection-related needs identified through that reform, in addition to one or more factors that more generally characterize generator interconnection withdrawals, as a factor in the generator interconnection requests and withdrawals category of factors in their development of Long-Term Scenarios.

108. Finally, we propose to require that each Long-Term Scenario incorporate utility and corporate goals and federal, state, and local goals that affect the future resource mix. However, we acknowledge that these categories of factors are less binding and more likely to change over time, and therefore their impact on the future resource mix and demand are less certain. For this reason, we preliminarily find that it may be

[187] Potomac Economics Comments at 4.

[188] PJM Market Monitor Comments at 2–3; *see also* November Joint Task Force Tr. at 69:18–22 (Jason Stanek) (discussing the need to account for the fact that there will be some uncertainty if planning on a longer term horizon).

[189] For example, consistent with the Governor's executive order, the New Jersey Board of Public Utilities has developed a solicitation schedule to procure 7,500 MW of offshore wind resources by 2035. *See* New Jersey Commission Comments at 1. New York State Department of Environmental Conservation has promulgated emissions regulations that will cause many of the peaking generating facilities in New York City to retire. *See* City of New York Comments at 8. By ''state or federal laws or regulations,'' we mean enacted statutes (*i.e.,* passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state, municipality, or at the federal level.

[190] For example, five of the six New England states are statutorily required to reduce economy-wide greenhouse gas emissions by at least 80% below 1990 levels by 2050. NESCOE Comments at 8. New York law requires all new passenger cars and trucks in the state to be zero-emissions vehicles by 2035. City of New York Comments at 8.

[191] For example, North Carolina's vertically-integrated investor-owned electric utilities participate in a biennial integrated resource plan process, in which they develop and file with the North Carolina Commission a forecast of load, supply-side resources, and demand-side resources over a 15-year period. North Carolina Commission Reply Comments at 17.

[192] For example, MISO's latest Futures Report included assumptions on the potential to electrify various types of technologies/loads and data on technology costs from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline dataset, the EIA, and DOE. MISO Comments at 43 (citing MISO, *MISO Futures Report,* at 30–38 (Dec. 2021)).

[193] For example, CAISO evaluates potential generation capacity retirements when developing the unified planning assumptions and study plan during phase one of its regional transmission planning process. CAISO Comments at 18.

[194] For example, in 2019, approximately 4.75 of 5 GW of generator interconnection requests that had been a part of the MISO West 2017 study group withdrew from the generator interconnection queue. ACORE Comments, Ex. 2 at 17.

[195] For example, two-thirds of Fortune 100 companies and roughly half of Fortune 500 companies have set renewable energy or related sustainability targets. ACPA and ESA Comments at 28. By ''goal,'' we mean any commitment or statement expressed in writing that is not a law or regulation.

appropriate for public utility transmission providers to discount such goals to account for this uncertainty. In other words, public utility transmission providers would not be required to assume that utility and corporate goals and federal, state, and local goals that affect the future resource mix will be fully met.

109. We propose to require that public utility transmission providers identify and publish on an Open Access Same-Time Information System (OASIS) or other public website a list of the factors that fall into each of the required categories of factors that they will incorporate in their development of Long-Term Scenarios. That is, public utility transmission providers would be responsible for identifying all the factors they know of and are considering incorporating in the development of Long-Term Scenarios as part of Long-Term Regional Transmission Planning. We also propose to require that public utility transmission providers revise the regional transmission planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including states,[196] with a meaningful opportunity to propose potential factors that public utility transmission providers must incorporate in their development of Long-Term Scenarios, such as specific laws, regulations, goals, and commitments, and to provide input on how to appropriately discount factors that are less certain.

110. We note that, under Order No. 1000, public utility transmission providers must already have procedures in their OATTs that give stakeholders a meaningful opportunity to submit proposed transmission needs driven by Public Policy Requirements and that allow public utility transmission providers to identify, out of the larger set of potential transmission needs driven by Public Policy Requirements that stakeholders propose, those needs for which transmission facilities will be evaluated.[197] Therefore, public utility transmission providers may be able to modify and expand these existing procedures for identifying transmission needs driven by Public Policy Requirements to meet these proposed requirements regarding the identification of factors for incorporation into Long-Term Scenarios.

111. We propose this reform because we believe that incorporation of the categories of factors set forth above in developing Long-Term Scenarios would help facilitate the identification of transmission needs driven by changes in the resource mix and demand, which we preliminarily find is necessary to ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates. Absent a requirement to incorporate these categories of factors into the development of Long-Term Scenarios, public utility transmission providers may not incorporate known inputs that will likely affect the future resource mix and demand. Additionally, public utility transmission providers may not adequately identify transmission needs driven by changes in the resource mix and demand and evaluate the potential benefits of regional transmission facilities that may more efficiently or cost-effectively meet such needs. As an additional benefit, this requirement would provide clarity to public utility transmission providers and stakeholders on what factors must be considered in scenario development.

112. We seek comment on whether and how the categories of factors listed above adequately capture factors expected to drive changes in the resource mix and demand.

(iii) Number and Range of Long-Term Scenarios

113. In Long-Term Regional Transmission Planning, the number and range of Long-Term Scenarios developed determines the scope of possible future conditions for the electric power system and allows public utility transmission providers to identify the transmission needs for each possible future reflected in the scenarios. Developing a range of scenarios with different assumptions allows public utility transmission providers to consider a variety of potential scenarios and associated transmission needs driven by changes in the resource mix and demand and, in turn, possibly different regional transmission facilities to more efficiently or cost-effectively meet those needs. However, modeling multiple scenarios requires additional time and effort, and may add to the costs of Long-Term Regional Transmission Planning. We are cognizant of these tradeoffs in developing our proposed reforms.

114. In developing scenarios, it is possible to create a base case scenario that is a business-as-usual scenario, or a most likely scenario, and compare that to alternative scenarios that are considered to be less likely to occur. These alternative scenarios typically depart from the base case by considering different assumptions. For example, an alternative scenario might differ from a base case in how it considers the location and quantity of resource additions or retirements. In addition, it is possible to develop specific scenarios to determine potential transmission needs. For example, it is possible to develop a scenario that assumes a greater amount of distributed energy resource additions compared to a business-as-usual case, a scenario that assesses conditions associated with extreme weather events, or a scenario that explores the possibility of additional resource development in an identified geographic zone, as well as a scenario that combines these assumptions.

115. Currently, MISO developed three scenarios, called futures, that it intends to use as part of its Long-Range Transmission Planning.[198] MISO makes a different assumption about load growth, the extent to which state and utility goals that are not legislated are met, and the future resource mix for each future.[199] CAISO creates a base case scenario reflecting the assumptions about resource locations that are most likely to occur and one or more stress scenarios to compare to the base case scenario.[200] SPP currently develops a base reliability scenario and two scenarios as part of its 10-year Integrated Transmission Planning assessment and four scenarios as part of its 20-year Integrated Transmission Planning assessment.[201] NYISO currently develops multiple scenarios (high/low load, high/low natural gas price, 70% zero-emissions by 2030) for its regional transmission planning process.[202]

116. The ANOPR sought comment on whether consideration should be given to multiple future scenarios and whether and how public utility transmission providers should account for an array of different future scenarios when identifying more efficient or cost-effective transmission facilities in regional transmission plans.[203]

117. The ANOPR also sought comment on how the regional

[196] *See* NARUC Comments at 5–6 (''NARUC . . . supports exploring reforms that will better align regional transmission planning with state needs and ensure meaningful opportunities for the state to provide direction and inputs or otherwise have their law and policies appropriately reflected through the transmission planning process—all while benefitting electricity consumers.'').

[197] Order No. 1000, 136 FERC ¶ 61,051 at PP 206–207; Order No. 1000–A, 139 FERC ¶ 61,132 at P 335.

[198] MISO Comments at 8, 80.

[199] MISO, *MISO Futures Report,* at 4 (Dec. 2021).

[200] CAISO Comments at 45.

[201] SPP, *2020 Integrated Transmission Planning Assessment Report,* at 8 (Oct. 2020); SPP Market Monitor Comments at 3–4; SPP, 2022 20-Year Assessment Scope, at 2–4 (Feb. 2, 2021).

[202] NYISO Comments at 28–29.

[203] ANOPR, 176 FERC ¶ 61,024 at P 48.

transmission planning process should consider the probabilities of scenarios.[204] The Commission also asked ''whether greater use of probabilistic transmission planning approaches may better assess the benefits of regional transmission facilities'' and whether ''more advanced approaches, such as stochastic[205] techniques, may provide an opportunity to consider a broader array of potential future conditions.''[206]

(01) Comments

118. Some commenters responding to the ANOPR discuss the number and range of scenarios that should be used in regional transmission planning. U.S. DOE recommends a national standard set of scenarios, including business-as-usual, high/medium/low load growth, high/medium/low reliance on distributed energy resources and demand response, and high decarbonization.[207] ACPA and ESA recommend a business-as-usual base case and alternative scenarios with adjusted assumptions on increased commitments to decarbonization, increased electrification of transportation and other uses such as home heating, and increased fuel prices.[208] Oregon Commission recommends that the Commission require study of a scenario in which there is a federal-level climate/clean energy policy.[209] Eversource states that regions should have flexibility in defining scenarios, and that states should have a major role in defining scenarios.[210] Nebraska Commission generally opposes the Commission specifying scenario requirements.[211]

119. In terms of the number of scenarios, ACPA and ESA argue that the Commission should require public utility transmission providers to use three to four scenarios, including a business-as-usual case.[212] AEP recommends at least three robust and standardized scenarios.[213] NextEra also recommends that the Commission require public utility transmission providers to consider at least three scenarios ranging from a business-as-usual case to a transformative scenario featuring economy-wide national net zero emissions.[214] And Nature Conservancy contends that the Commission should require at least four.[215] Avangrid proposes the number of scenarios should be sufficient to support reasoned decision-making but not so exhaustive to complicate and slow down planning.[216] LS Power asserts that there is a need for a plan that uses a broad range of plausible scenarios.[217]

120. In terms of probabilistic planning methods in developing scenarios, commenters to the ANOPR identify the benefits of probabilistic planning, which can include the ability to recognize multiple facility outages at a single time, to prepare for and recover from extreme weather events, and to address uncertainties about operational outcomes (like variable generation) and over a long time horizon.[218] In light of these benefits, some commenters recommend that the Commission require public utility transmission providers to adopt probabilistic planning methods.[219] PG&E states that the planning toolkit must now evolve to include more probabilistic tools that appropriately reflect the variable nature of the resource mix and other uncertainties in the forecast.[220] U.S. DOE states that probabilistic planning, along with other factors, is likely to contribute to the development of a transmission system that reliably meets system needs at just and reasonable rates.[221] Other commenters support the use of probabilistic planning methods where feasible or appropriate and do not recommend the Commission require public utility transmission providers to adopt probabilistic planning methods at this time.[222] PJM, CAISO, and MISO identify the value of probabilistic planning methods yet acknowledge that complex issues remain involving data availability, computational intensity, and stakeholder consensus.[223] Minnesota Commission states that probabilistic approaches are likely to be problematic in the stakeholder process because of the uncertainty and wide-ranging stakeholder opinions about the future.[224]

(02) Proposed Requirement

121. We propose to require that public utility transmission providers develop at least four distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning. We propose to require that each of these Long-Term Scenarios incorporate, at a minimum, the categories of factors listed in the requirement above. As discussed in the Factors section above, we propose that each Long-Term Scenario must be consistent with federal, state, and local laws and regulations that affect the future resource mix; federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans. However, each Long-Term Scenario may vary according to assumptions about the remaining categories of factors described above, as well as with respect to other characteristics of the future electric power system. We do not propose to require the development of a specific Long-Term Scenario or specific set of Long-Term Scenarios, nor do we propose to require that public utility transmission providers identify the relative likelihood of different Long-Term Scenarios except where a public utility transmission provider develops a base case scenario, as described more fully below.

122. We preliminarily find that using at least four distinct Long-Term Scenarios is a reasonable lower bound for the number of Long-Term Scenarios that public utility transmission providers must evaluate in Long-Term Regional Transmission Planning. This minimum number of Long-Term Scenarios will help ensure that public utility transmission providers conduct Long-Term Regional Transmission Planning that identifies more efficient or cost-effective regional transmission facilities to meet transmission needs

[204] *Id.*

[205] Stochastic models are frameworks for addressing optimization problems that involve uncertainty.

[206] ANOPR, 176 FERC ¶ 61,024 at P 49.

[207] U.S. DOE Comments at 12–15.

[208] ACPA and ESA Comments at 46.

[209] Oregon Commission Comments at 8–9.

[210] Eversource Comments at 9.

[211] Nebraska Commission Comments at 3–4.

[212] ACPA and ESA Comments at 46.

[213] AEP Comments at 11–12.

[214] NextEra Comments at 71–71, 75–77.

[215] Nature Conservancy Comments at 3.

[216] Avangrid Comments at 12–14.

[217] LS Power Oct. 12 Comments at 33–36.

[218] *E.g.,* California Commission Comments at 71; NARUC Comments at 11 (stating that probabilistic approaches can provide ''more insight into the benefits and risks of different decisions; and the importance and relationship between various uncertainties''); MISO Comments at 36 (stating that ''probabilistic planning has many benefits and should be explored''); PG&E Comments at 3 (stating that probabilistic planning ''appropriately reflect[s] the variable nature of the resource mix and other uncertainties in the forecast'').

[219] AES Ohio Comments at 2–3; PIOs Comments at 79; California Commission Comments at 66; VEIR Comments at 15–16.

[220] PG&E Comments at 3.

[221] U.S. DOE Comments at 20.

[222] EEI Comments at 25; NARUC Comments at 10 (''[P]robabilistic analysis should be used, where feasible without significantly burdening the planning process.''); WIRES Comments at 8–9; National Grid Comments at 71; *see also Joint Fed.-State Task Force on Elec. Transmission,* Technical Conference, Docket No. AD21–15–000, Tr. 71:12–72:5 (Clifford Rechtschaffen) (Feb. 16, 2022) (February Joint Task Force Tr.) (supporting increasing use of probabilistic and other analytical approaches where feasible to account for uncertainty in quantification of benefits and effectively plan for the longer term).

[223] PJM Comments at 64–66; MISO Comments at 46–47; CAISO Comments at 48.

[224] Minnesota Commission Comments at 4.

driven by changes in the resource mix and demand. For example, public utility transmission providers could develop a base case and three alternatives or a low-, medium-, and high-level assumption for the factors that public utility transmission providers (and their stakeholders) believe to be important to conduct Long-Term Regional Transmission Planning to more efficiently or cost-effectively meet transmission needs driven by changes in the resource mix and demand, along with a scenario that accounts for a high-impact, low-frequency event (as discussed below).

123. Furthermore, we propose to require that public utility transmission providers in each transmission planning region develop a plausible and diverse set of Long-Term Scenarios.[225] That is to say, the set of at least four Long-Term Scenarios must be: (1) Plausible, that is they must reasonably capture probable future outcomes, and (2) diverse in the sense that public utility transmission providers can distinguish distinct transmission facilities or distinct benefits of similar transmission facilities in each scenario. If a public utility transmission provider produces a base case scenario, that scenario should be consistent with what the public utility transmission provider determines to be the most likely scenario to occur. Consistent with the Order No. 890 transparency transmission planning principle,[226] we propose to require that public utility transmission providers in each transmission planning region publicly disclose (subject to any applicable confidentiality protections) information and data inputs they use to create each Long-Term Scenario. This transparency requirement will allow stakeholders to understand how each scenario differs. Similarly, consistent with the Order Nos. 890 and 1000 coordination transmission planning principle,[227] we propose to require that public utility transmission providers in each transmission planning region give stakeholders the opportunity to provide timely and meaningful input into the identification of which Long-Term Scenarios are developed. We propose to require that public utility transmission providers revise the regional transmission planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose which future outcomes are probable and can be captured through assumptions made in the development of Long-Term Scenarios. We further propose to require that public utility transmission providers explain on compliance how their process will identify a plausible and diverse set of Long-Term Scenarios.

124. We propose to require that at least one of the four distinct Long-Term Scenarios that public utility transmission providers in each transmission planning region use in Long-Term Regional Transmission Planning must account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events. We propose to allow public utility transmission providers to determine which high-impact, low-frequency event should be modeled in this Long-Term Scenario as part of Long-Term Regional Transmission Planning based on our understanding that each transmission planning region may see a need to evaluate a different type of high-impact, low-frequency event. High-impact, low-frequency events may include extreme weather events or events associated with potential cyber attacks. This Long-Term Scenario accounting for a high-impact, low-frequency event can be developed, for example, by assuming greater-than-expected electricity demand and greater-than-expected generation or transmission outages. We propose that the use of probabilistic transmission planning or stochastic techniques would satisfy this requirement, but do not propose to require either approach at this time.[228]

125. We note that public utility transmission providers can develop sensitivities for every Long-Term Scenario to assess how outcomes modeled in Long-Term Scenarios may depend on an assumption about electric power system model inputs that does not vary across scenarios (*e.g.,* higher natural gas prices).[229] Such sensitivities can provide valuable information about the need for and benefits of potential transmission facilities; however, they can be burdensome to develop if applied to every scenario.

126. We seek comment on whether four Long-Term Scenarios will provide public utility transmission providers with enough information to identify transmission needs driven by changes in the resource mix and demand and evaluate transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation that may more efficiently or cost-effectively meet those needs or whether additional Long-Term Scenarios should be required. In addition, we seek comment on whether public utility transmission providers should be required to develop sensitivities for each Long-Term Scenario to identify more efficient or cost-effective transmission facilities for selection in the regional transmission plan for purposes of cost allocation as part of Long-Term Regional Transmission Planning.

(iv) Specificity of Data Inputs

127. Data inputs are numbers that characterize assumptions about future conditions of the transmission system under each scenario over the

[225] We note that different assumptions about the factors and data inputs used to develop Long-Term Scenarios and other characteristics of the future electric power system determine whether the set of Long-Term Scenarios are plausible and diverse.

[226] The transparency transmission planning principle requires public utility transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Public utility transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies. Order No. 890, 118 FERC ¶ 61,119 at P 471. Order No. 1000 applied this and other Order No. 890 transmission planning principles to regional transmission planning processes. Order No. 1000, 136 FERC ¶ 61,051 at P 151.

[227] The coordination transmission planning principle requires public utility transmission providers to provide customers and other stakeholders with the opportunity to participate fully in the transmission planning process. The transmission planning process must provide for the timely and meaningful input and participation of customers and other stakeholders regarding the development of transmission plans, allowing customers and other stakeholders to participate in the early stages of development. Order No. 890, 118 FERC ¶ 61,119 at PP 451–454.

[228] For the purpose of an improved record, we clarify that we consider probabilistic transmission planning approaches to include any transmission planning approach that uses a probability distribution to assign probabilities to one or more inputs to the transmission model. These inputs can include shorter-term operational inputs (like wind generation or generation outages). *See, e.g.,* Li, W., *Probabilistic Planning of Transmission Systems: Why, How and an Actual Example,* at 1, 2008 IEEE Power and Energy Society General Meeting—Conversion and Delivery of Electrical Energy in the 21st Century (2008). Stochastic techniques include adaptive transmission planning techniques that identify transmission facilities that optimize transmission net-benefits over a time horizon under market and regulatory uncertainty about the future. *See, e.g.,* Ho, J., et al., *Planning transmission for uncertainty: Applications and lessons for the western interconnection,* at 21, The Western Electricity Coordinating Council (2016) (answering ''What is stochastic transmission planning?'').

[229] *See, e.g.,* SPP, *2020 Integrated Transmission Planning Assessment Report,* at 146–154 (Oct. 2020), *https://www.spp.org/documents/63434/2020%20integrated%20transmission%20plan%20report%20v1.0.pdf;* NYISO, *2020 Reliability Needs Assessment,* at 89–92 (Nov. 2020), *https://www.nyiso.com/documents/20142/2248793/2020-RNAReport-Nov2020.pdf.* A sensitivity represents a single assumption about a short-term input or factor (some input with a value that may change throughout a day or year). A scenario represents an assumption about a longer-term input or factor (*e.g.,* resource retirements and additions or public policies). *See, e.g.,* Brattle-Grid Strategies Oct. 2021 Report at 64.

transmission planning horizon. Using reasonable data inputs is key to effective Long-Term Regional Transmission Planning because data inputs can drive the results of transmission planning models, both in terms of the transmission needs identified and the more efficient or cost-effective transmission facilities to address those needs. For example, the long-term load forecast can lead to more planned transmission if the assumed growth rate is increased. Similarly, the assumed dates of generation retirements can be a critical factor in determining when new transmission will be needed. Given how sensitive transmission planning models can be to changes in assumptions, using robust data inputs is critical to identifying more efficient or cost-effective regional transmission facilities.

128. In the ANOPR, the Commission asked what inputs should be considered in modeling anticipated future generation.[230] More specifically, the Commission asked which data inputs public utility transmission providers would need to model to represent new generation sources, such as renewable resources, in order to reflect their actual performance.[231]

(01) Comments

129. In response to the ANOPR, several public utility transmission providers commented on the data inputs used in their existing regional transmission planning processes.[232] PJM recommends that the Commission require disclosure of data inputs and their assumptions.[233] ACEG, AEE, and PIOs advocate for a new rule that specifies that public utility transmission providers use best available data inputs and best practices for load forecasts.[234] Rail Electrification recommends that the Commission insist on best available data and most plausible futures.[235] Union of Concerned Scientists states that the failure to use the best available data will lead to the failure to identify more efficient and cost-effective transmission alternatives.[236] U.S. DOE recommends the Commission consider the need to standardize modeling inputs to increase consistency and comparability across planning processes and lists the potential inputs it thinks the Commission should consider.[237] U.S. DOE also provides information on the array of tools and data developed by national laboratories which can be used as inputs in transmission planning.[238] NARUC states that better sharing of data between states and the RTOs/ISOs would be beneficial.[239] RMI states that state-of-the-art cost data and forecasts are of paramount importance in planning for new transmission.[240] NERC says that improved transmission planning for reliability requires better data collection especially electromagnetic transient data.[241] Entergy believes that the transmission models used should incorporate realistic and objectively reasonable future assumptions.[242] Certain TDUs believes public utility transmission providers should regularly update planning models with the most recent integrated resource plan data available.[243] The PJM Market Monitor asserts that decisions made about the transmission grid must reflect accurate information while remaining flexible enough to incorporate new information as it becomes available.[244]

(02) Proposed Requirement

130. We propose to require that public utility transmission providers use ''best available data inputs'' when developing Long-Term Scenarios. By ''best available,'' we do not imply that there is a single ''best'' value for each data input that public utility transmission providers must use, but rather that best practices are used to develop that data input.

131. We propose to define ''best available data inputs'' as data inputs that are timely[245] and developed using diverse and expert perspectives, adopted via a process that satisfies the transparency planning principle described above,[246] and that reflect the list of factors that public utility transmission providers must incorporate into Long-Term Scenarios. An example of data inputs that could meet this requirement are the long-term load forecasts of demand that RTOs/ISOs currently use for predicting long-term resource adequacy. Another example of data inputs that could meet this requirement are the most recent data on renewable energy potential and distributed energy resources developed by national labs.[247]

132. We propose to require that public utility transmission providers in each transmission planning region update all data inputs each time they reassess and revise, as necessary, their Long-Term Scenarios, which, as explained above, we propose to require they do at least every three years. As indicated in the Long-Term Regional Transmission Planning section above, we also propose to require that the Order Nos. 890 and 1000 transmission planning principles apply to the process through which public utility transmission providers determine which data inputs to use in their Long-Term Scenarios. For example, consistent with the coordination transmission planning principle in Order Nos. 890 and 1000, we propose to require that public utility transmission providers in each transmission planning region give stakeholders the opportunity to provide timely and meaningful input concerning which data inputs to use in Long-Term Scenarios.

133. We preliminarily find that a requirement to use the best available data inputs is necessary to ensure that public utility transmission providers are regularly updating data inputs and then using timely and accurate data inputs to inform Long-Term Scenarios. As stated above, data inputs can drive the results of Long-Term Regional Transmission Planning, and as a result, directly affect which transmission facilities may be selected in the regional transmission plan for purposes of cost allocation and, in turn, Commission-jurisdictional rates.

134. We seek comment on whether the proposed definition of best available data inputs will allow for public utility transmission providers to identify the more efficient or cost-effective transmission facilities for selection in the regional transmission plan for purposes of cost allocation using Long-Term Scenarios. We seek comment on whether the proposed definition of best available data inputs should be expanded to include an evaluation of the data source entities' historical accuracy in identifying and projecting trends that impact the resource mix and demand. We also seek comment as to

[230] ANOPR, 176 FERC ¶ 61,024 at P 48.

[231] *Id.* P 50.

[232] As examples, CAISO and PJM mention generation retirements, MISO mentions forced outage rates, and CAISO, NYISO, and SPP mention load and capacity forecasts. CAISO Comments at 18; MISO Comments at 47; NYISO Comments at 6; PJM Comments at 42; SPP Comments at 3.

[233] PJM Comments, attach. K at 4.

[234] ACEG Comments, attach. C at 10; AEE Reply Comments at 4; PIOs Reply Comments at 43–44.

[235] Rail Electrification Comments at 13.

[236] Union of Concerned Scientists Comments at 31.

[237] U.S. DOE Comments at 12–13.

[238] *Id.* at attach. B.

[239] NARUC Comments at 42.

[240] RMI Comments at 3.

[241] NERC Comments at 10.

[242] Entergy Comments at 17.

[243] Certain TDUs Comment at 11.

[244] PJM Market Monitor Comments at 6.

[245] Timely data inputs are based on the most current information.

[246] *See supra* note 226.

[247] *See, e.g.,* U.S. DOE Comments, attach. B at 79, 94 (discussing NREL's Renewable Energy Potential model and Distributed Generation Market Demand model). We note that such granular data may be useful to public utility transmission providers to the extent public utility transmission providers do not already have such granular data that meet this requirement.

whether stakeholders and public utility transmission providers would find value in or believe it is necessary for the Commission to facilitate the development of data inputs that meet this proposed requirement by identifying or standardizing the best available data inputs that meet this proposed requirement.[248]

(v) Identification of Geographic Zones

135. In the ANOPR, the Commission sought comment on whether it should require public utility transmission providers to establish, as part of their regional transmission planning processes, a process that identifies geographic zones that have the potential for the development of large amounts of new generation, particularly renewable resources. The Commission also sought comment on whether and how such a process might interrelate with existing regional transmission planning and cost allocation processes, and how long-term scenario planning may be used in this process or other relevant regional transmission planning and cost allocation processes.[249] The Commission also noted that the Texas' CREZ initiative, MISO's MVPs, and a Commission-approved CAISO proposal are examples of such identification of geographic zones in transmission planning and development initiatives.[250]

(01) Comments

136. Several commenters responded to the Commission's request for comments related to the identification of geographic zones. Starting with the RTOs/ISOs, CAISO states that, while it supports the idea of finding zones of renewable energy, there are many ways to do this, and each region should be allowed to find its own solution. CAISO states that active involvement and buy-in of state regulators in identifying zones of renewable energy is critical to mitigate the risk of over-building transmission and to facilitate state siting approvals for transmission facilities. CAISO suggests that an open season could be used to identify interest in a new transmission line.[251]

137. NYISO supports the identification of pockets where future generation would be developed and where new transmission is needed. NYISO states that it already has such an identification process.[252]

138. ISO–NE states that it has a process in place to identify regions of renewable energy that it calls ISO–NE Clustering, which it says is similar to the process CAISO used in its Tehachapi approach. ISO–NE states that long-term planning for transmission to renewable-rich areas should not replace the generator interconnection process.[253]

139. PJM argues that if the Commission creates a geographic zone requirement, the RTOs/ISOs should have the flexibility to establish a process for their region.[254] Additionally, PJM suggests that sub-zones of renewable energy could be visualized in a heat map.[255]

140. MISO opposes prescriptive requirements to identify zones of renewable energy because it argues that the regions should have the flexibility to work with stakeholders to identify zones. MISO also argues that there are potential problems in identifying regions of renewable energy because (1) what counts as renewable energy is not clear, and (2) where the zones of renewable energy resources are not clear, in part because a state's desire to develop resources may force generation development in other states with lower resource potential. MISO states that the MVP process was a success, in part, due to the Regional Generation Outlet Study, which was a successful collaboration between MISO and the states within the MISO region that might not have worked as well if MISO and the states had not had the flexibility to develop it the way that they did.[256] MISO states that the MISO MVPs, ERCOT's CREZ, and the CAISO examples all reflect local solutions based on unique factors in each location. MISO points out that ERCOT and CAISO are each single-state RTOs/ISOs, which makes their experience not directly comparable to MISO's.[257]

141. U.S. DOI supports the creation of geographic zones as a means to improve the efficiency of transmission planning overall but cautions that any requirement must consider environmental impacts and habitats of species that are of conservation concern.[258] Similarly, U.S. DOE argues that while the creation of geographic zones is a step in the right direction, additional agreement is needed on which generation resources would actually be developed, which market areas need to be served, and which transmission facilities are needed to connect them reliably and efficiently.[259] However, U.S. DOE states that Texas' CREZ model has worked well since it establishes clear regulatory pathways and cost allocation en masse.

142. Some commenters oppose a geographic zone requirement. Consumer Organizations assert that a ''top down'' approach from the Commission has the potential to saddle customers with unnecessary costs from constructing ''roads to nowhere'' that may never be utilized.[260] East Kentucky argues that a Commission-required geographic zone requirement would create an uneven playing field for generation resources that seek to interconnect outside a designated geographic zone.[261] APPA argues that instead of requiring geographic zones, the Commission should permit load-serving entities to identify geographic zones when developing their resource plans, which is more of a ''bottom up'' approach.[262] OMS and NESCOE both assert that each region already has an existing process to identify zones of renewable resource potential and that the Commission should not require anything further.[263] WIRES states that a requirement to identify zones of renewable energy is not needed and regions should have the flexibility to find their own solutions.[264] Xcel notes that such a requirement exceeds the Commission's authority under the FPA because states have the final say over construction of new generation, as well as transmission facility siting and permitting.[265]

143. Ohio Commission states that the Commission lacks jurisdiction to require the creation of new zones.[266] Michigan

[248] *Id.* at 12–14 (arguing the Commission should standardize modeling input assumptions and establish core scenarios); Harvard ELI Comments at 34 (stating the Commission could work with the U.S. DOE to develop industry-wide standards for scenario planning which would include data inputs).

[249] ANOPR, 176 FERC ¶ 61,024 at P 57.

[250] *Id.* PP 55–56.

[251] CAISO Comments at 49–54.

[252] NYISO Comments at 31–33.

[253] ISO–NE Comments at 21–25 (citing *Cal. Indep. Sys. Operator,* 118 FERC ¶ 61,226, *order on clarification,* 120 FERC ¶ 61,180 (2007) (granting request for waiver to conduct a ''targeted'' cluster study to identify the significant transmission infrastructure necessary to interconnect approximately 4,500 MW of primarily wind resources in the remote Tehachapi Wind Resource Area of the system)).

[254] PJM Comments at 12–13.

[255] *Id.* at 41–42.

[256] MISO Comments at 53–56.

[257] *Id.* at 56–58.

[258] U.S. DOI Comments at 1–3.

[259] U.S. DOE Comments at 24, 74; *see also* November Joint Task Force Tr 108:23–109:8, 110:13–18 (Gladys Brown-Dutrieuille) (suggesting identification of geographic zones as one long-term transmission planning principle FERC could work with states to develop to ''facilitate integration of optimal resources in transmission'').

[260] Consumer Organizations Comments at 21.

[261] East Kentucky Comments at 8–9.

[262] APPA Comments at 17.

[263] OMS Comments at 8–9; NESCOE Comments at 46–47.

[264] WIRES Comments at 41–42.

[265] Xcel Comments at 5–10.

[266] Ohio Commission Comments at 6–10.

Commission cautions that if the Commission requires a geographic zone concept, the notion that geographic zones must be ''rich in renewable resources'' would unreasonably shift costs to consumers that do not receive commensurate benefits.[267] NRECA states that the decision to establish geographic zones should be left to the regional transmission planning processes to resolve, subject to input from state and local governing bodies and to ultimate Commission oversight and approval on a case-by-case basis to ensure that zone selection and cost allocations are consistent with Order No. 1000.[268]

144. LPPC argues that a geographic zone requirement should consider guardrails that will assist in limiting undue risk and financial exposure for those customers that may not use the planned facilities.[269] SoCal Edison argues that geographic zones should entail providing federal funds to disproportionally burdened communities.[270] Shell argues that coastal public utility transmission providers should be required to explain how their transmission planning processes accommodate the unique obstacles impeding offshore wind transmission and generation.[271] Orsted states that the scale and location of future offshore wind generation is well known, and RTOs/ISOs should be required to plan cost-effective transmission to bring offshore wind power to market.[272] Union of Concerned Scientists argue that if the Commission requires geographic zones, it should revise Order No. 1000's provision for local and regional transmission planning processes to explicitly provide for the recognition of Public Policy Requirements established by state or federal laws or regulations, including federal leasing for the development of generation, that will drive transmission and interconnection in resource-rich zones.[273]

(02) Proposed Requirement

145. We propose to require each public utility transmission provider, as part of its regional transmission planning process, to consider whether to: (1) Identify, with stakeholder input, specific geographic zones within the transmission planning region that have the potential for development of large amounts of new generation; (2) assess generation developers' commercial interest in developing generation within the identified geographic zones; and (3) incorporate designated zones, and the identified commercial interest in each zone, into Long-Term Scenarios.

146. We preliminarily find that requiring the consideration and potential identification of geographic zones within Long-Term Scenarios assists public utility transmission providers, transmission developers, and generation developers to coordinate their activities. We believe that public utility transmission providers would be able to better identify transmission needs driven by changes in the resource mix and demand by considering geographic zones that have the potential for the development of large amounts of new generation and where developers have already shown commercial interest. Using the information gained through the process described below to identify such geographic zones, public utility transmission providers in each transmission planning region could then plan transmission facilities that would serve large concentrations of new generation in a more efficient or cost-effective manner.

147. As step one of the geographic zone process, we propose to require that public utility transmission providers consider whether to establish and include in the regional transmission planning process outlined in their OATTs the method that they will use to identify geographic zones within the transmission planning region. We propose to require that this method use best available data, including atmospheric, meteorological, geophysical, and other surveys, to identify geographic zones with potential for development of large amounts of new generation. We also propose to require that public utility transmission providers in each transmission planning region use this information to create a set of draft geographic zones, and that they post on their OASIS or other public websites maps of the draft geographic zones, as well the information used to create the draft geographic zones, for stakeholders' input.

148. As part of proposed step one, after the public utility transmission providers in each transmission planning region identify and post any draft geographic zones and related information, we propose to require them to provide all stakeholders, including relevant federal and state siting authorities, with a meaningful opportunity to provide input on the draft geographic zones. We believe that input from federal and state siting authorities is particularly important because we also propose to require that public utility transmission providers in each transmission planning region use this stakeholder engagement to identify known siting, permitting, or other anticipated development challenges or opportunities associated with the draft geographic zones. We believe that obtaining information related to siting and permitting early in the geographic zone development process will help public utility transmission providers to identify draft zones where the anticipated generation resources are most likely to materialize.

149. In addition, we propose to require that public utility transmission providers in each transmission planning region consider this stakeholder feedback and modify the draft geographic zones as appropriate to produce a final list of designated geographic zones within the transmission planning region.[274] As the final part of proposed step one, we propose to require that public utility transmission providers in each transmission planning region post on their OASIS or other public websites maps of the designated geographic zones and information related to the designation of those zones, including the explanation of changes from the draft to final list.

150. In step two of the geographic zone process, we propose to require that public utility transmission providers in each transmission planning region assess generation developers' commercial interest in developing generation within each designated geographic zone. Specifically, we propose to require that public utility transmission providers include in their OATTs as part of their regional transmission planning process a method to assess generation developers' commercial interest in developing generation within each designated geographic zone that considers the following: (1) The generation developer's existing energy resources within the zone; (2) the number and size of any interconnection requests from developers with completed facilities study agreements for generation located within the zone; (3) a generation developer's leasing agreements with landowners within the zone; (4) a generation developer's letters of credit associated with generation it may develop in the zone; (5) any merchant or other entity commitments to build

[267] Michigan Commission Comments at 12–14.

[268] NRECA Comments at 21–23

[269] LPPC Comments at 14–15.

[270] SoCal Edison Comments at 10.

[271] Shell Comments at 8–9.

[272] Orsted Comments at 8.

[273] Union of Concerned Scientists Comments at 32–37.

[274] We note that, while we refer to multiple ''zones,'' subsequent to stakeholder feedback, the final list may contain only one designated geographic zone.

(including deposits or payments to secure or fund) transmission facilities that would serve generation within the zone; (6) a generation developer's power purchase agreements with a credit-worthy counterparty associated with generation within the zone; and (7) any other factors for which generation developers have provided evidence as indications of commercial interest in developing generation within the zone. We propose this step two requirement because we believe it will indicate how much of the geographic zone's resource hosting potential generation developers are interested in pursuing, which is useful for improving the accuracy of Long-Term Scenarios as public utility transmission providers in each transmission planning region incorporate information about designated geographic zones into such scenarios as part of step three.

151. In step three of the geographic zone process, we propose to require that public utility transmission providers in each transmission planning region incorporate the information from step one and step two regarding the designated geographic zones into their Long-Term Scenarios. We believe this information will be useful to public utility transmission providers in each transmission planning region as they identify and run different Long-Term Scenarios as part of the requirement to conduct Long-Term Regional Transmission Planning to address transmission needs driven by changes in the resource mix and demand. Specifically, we propose to require that public utility transmission providers revise the regional transmission planning process in their OATTs to describe how the designated geographic zones, the information they used to designate the geographic zones, and the information about generation developers' commercial interest in developing generation within each zone are integrated into their Long-Term Scenarios. We believe that integrating this information into Long-Term Scenarios will allow public utility transmission providers in each transmission planning region to better identify transmission needs driven by changes in the resource mix and demand, as well as more efficient or cost-effective regional transmission facilities to meet those needs.

152. We acknowledge that public utility transmission providers in multi-state transmission planning regions may face unique challenges and differing energy policy interests or preferences in complying with this proposed requirement.

153. We seek comment on how public utility transmission providers in multi-state transmission planning regions may reconcile or account for differing energy policy interests or preferences in implementing this proposed requirement, while respecting and not overriding those state preferences.

ii. Coordination of Regional Transmission Planning and Generator Interconnection Processes

154. As discussed above, we preliminarily find that current regional transmission planning processes fail to plan for transmission needs driven by changes in the resource mix and demand. Instead, public utility transmission providers typically account for such transmission needs through interconnection-related network upgrades identified through the generator interconnection process. Based on the comments received in response to the ANOPR, we believe that there may be a need for better coordination between the regional transmission planning and cost allocation and generator interconnection processes. To this end, we propose to require that public utility transmission providers consider as part of their Long-Term Regional Transmission Planning regional transmission facilities that address interconnection-related needs that the public utility transmission provider identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection request(s).

(a) ANOPR

155. In the ANOPR, the Commission asserted that the interaction between a public utility transmission provider's current generator interconnection process and its regional transmission planning and cost allocation processes appears to be limited.[275] The Commission also observed that the primary interaction between a public utility transmission provider's current generator interconnection process and its regional transmission planning and cost allocation processes is that the baseline regional transmission planning models generally only incorporate interconnection projects that are near the end of the generator interconnection process and have completed an interconnection facilities study.[276]

156. The ANOPR sought comment on whether reforms are necessary to improve coordination between the regional transmission planning and cost allocation and generator interconnection processes.[277] In particular, the ANOPR sought comment on whether interconnection requests that trigger the need for interconnection-related network upgrades that may provide regional transmission benefits could be studied in a way that accounts for the potential broader transmission benefits in coordination with the regional transmission planning process.[278] The ANOPR also sought comment on whether it may be possible and beneficial to combine certain aspects of the regional transmission planning and generator interconnection processes.[279]

(b) Comments

157. Each of the RTOs/ISOs filed comments in response to the ANOPR related to the coordination of their regional transmission planning and cost allocation and generator interconnection processes. CAISO states that it includes interconnection-related network upgrades identified during its interconnection study process and that meet specific voltage and/or capital cost thresholds as an input into the regional transmission planning process. CAISO asserts that it does so to ensure that it identifies and approves all major transmission additions and upgrades under a single comprehensive process and allocates the available amount of transmission capacity to the proposed generating facilities in each area.[280] PJM states that it leverages opportunities to address supplemental projects and new interconnection service requests through its baseline transmission projects. For instance, when increasing the capabilities of a regional transmission facility would obviate the need for an interconnection-related network upgrade, PJM factors the interconnection customer's incremental need into the transmission project and the interconnection customer is only responsible for the costs of the incremental portion of the transmission facility.[281] ISO–NE explains how its regional transmission planning and generator interconnection processes are coordinated presently but acknowledges that improvements may be necessary to optimize transmission solutions.[282] NYISO and SPP each identify an ongoing or potential stakeholder process to improve the coordination of the generator interconnection and regional

[275] ANOPR, 176 FERC ¶ 61,024 at P 23.

[276] ANOPR, 176 FERC ¶ 61,024 at P 23. *Id.*

[277] ANOPR, 176 FERC ¶ 61,024 at*Id.* P 65.

[278] ANOPR, 176 FERC ¶ 61,024 at*Id.* P 66.

[279] ANOPR, 176 FERC ¶ 61,024 at P 66. *Id.*

[280] CAISO Comments at 71–72.

[281] PJM Comments at 17–18.

[282] ISO–NE Comments at 25–26.

transmission planning processes.[283] MISO explains how its generator interconnection and regional transmission planning processes are currently related to each other and contends that the regional transmission planning process is the right avenue to determine more holistic transmission needs but considers the generator interconnection process more appropriate to focus on the specific needs associated with interconnecting new generation.[284]

158. Several commenters support better coordination between the regional transmission planning and cost allocation and generator interconnection processes, including the need for similar timelines and assumptions.[285] Anbaric and Public Systems ask the Commission to require a regional transmission planning assessment if an interconnection study identifies significant interconnection-related network upgrades beyond the interconnection facility line needed to reach a substation and any directly interconnected substation upgrades to ''shift the evaluation of development of needed upgrades to the [regional transmission] planning process.'' [286] Anbaric and Public Systems state that the needed upgrades could be eligible for competitive bidding as part of the regional transmission planning process. Similarly, Duke suggests that public utility transmission providers can identify an *ex ante* measure, such as the change in the levelized cost of a transmission network upgrade, to determine whether an interconnection-related network upgrade should be incorporated into its regional transmission plan for purposes of cost allocation according to a defined cost allocation method.[287]

159. Enel outlines a detailed proposal for consolidating the generator interconnection and regional transmission planning processes to limit generator interconnection studies to focus on direct, localized impacts of new generation and directly assign costs for interconnection-related network upgrades to generators when the cost causation relationship is ''strong and justified.'' [288] Under Enel's proposal, interconnection requests that meet significant readiness criteria required by the public utility transmission provider, such as a non-refundable cash deposit or letter of credit in the amount of 100% of the costs of the ''local'' interconnection-related network upgrades, would be included in the regional transmission planning process after the public utility transmission provider conducts a basic interconnection study (*e.g.,* Energy Resource Interconnection Study).[289] AEE states that implementing Enel's proposal would help resolve the cost allocation and market entry barrier problems associated with the current funding paradigm for interconnection-related network upgrades and could also help unburden constrained and backlogged interconnection queues that are creating barriers to entry.[290]

160. Other commenters oppose further coordination of the generator interconnection and regional transmission planning processes.[291] Some consumer groups express a general concern that coordination reforms would shift costs of generator interconnection to consumers.[292] Finally, some commenters expect that a regional transmission planning process that better accounts for anticipated future generation would address generator interconnection issues that are due to a lack of coordination, or co-optimization, of the two processes.[293]

(c) Need for Reform

161. For the reasons set forth below, we believe that there may be a need for better coordination between regional transmission planning and cost allocation and generator interconnection processes to ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates. As the Commission explained in the ANOPR, the interaction between regional transmission planning and cost allocation processes on the one hand and the generator interconnection process on the other appears limited—the baseline regional transmission planning models generally only incorporate interconnection projects that have completed an interconnection facilities study, and are therefore near the end of the generator interconnection process.[294] But where transmission system needs are repeatedly identified through generator interconnection processes, we believe that more efficient or cost-effective transmission expansion could be achieved through regional transmission planning and cost allocation that allocates costs in a manner that is at least roughly commensurate with estimated benefits and eliminates a potential barrier to entry for new generation resources.

162. We are most concerned with the prevalence of interconnection-related network upgrades being repeatedly identified in the generator interconnection process in multiple interconnection queue cycles in a short period of time (*e.g.,* five years) but not being developed because the interconnection request(s) driving the need for the upgrade are all withdrawn. As explained above, there has been a dramatic increase in recent years in the level of spending on interconnection-related network upgrades, driving the cost of interconnecting new generation to the transmission system higher and higher.[295] The evidence suggests that this trend is leading to more and more interconnection customers withdrawing their interconnection requests in the face of significant costs associated with interconnection-related network upgrades. According to a January 2021 report, ''the high cost of interconnection is increasing the rate at which generators drop out of the interconnection queue.'' [296] For example, between January 2016 and July 2020, 245 generation projects in advanced stages in the MISO generator interconnection process withdrew from the queue, with the project developers citing high interconnection-related network upgrade costs as the primary reason for their withdrawal.[297] While interconnection customers may choose to withdraw from the interconnection queue for a number of reasons, in recent

[283] NYISO Comments at 41; SPP Comments at 9–11.

[284] MISO Comments at 75–76.

[285] *See, e.g.,* AEP Comments at 30–31; APPA Comments at 22; Certain TDUs Comments at 18; NARUC Comments at 6, 11, 18; NERC Comments at 17–18; NewSun Comments at 24; Northwest and Intermountain Comments at 33; OMS Comments at 11–13; Indicated PJM TOs Comments at 27; REBA Comments at 2–3; SDG&E Comments at 5.

[286] Anbaric Comments at 23; Public System Comments at 6–7, 19.

[287] Duke Comments at 8–9.

[288] Enel Comments at 3.

[289] Enel Comments, *Id.* attach. 1 (Plugging In) at 12. Enel proposes that the Transfer Distribution Factor is a good metric for determining electrical distance from a generation facility and what constitutes ''local.'' *See* Enel Comments, attach. 1 (Plugging In) *id.* at 6.

[290] AEE Comments at 52–53.

[291] Southern Comments at 38–39; US Chamber of Commerce Comments at 4; *see also* ACORE Comments at 26–27; APPA Comments at 22–23; Berkshire Comments at 10–11; CAISO Comments at 70; LPPC Comments at 18; ITC Comments at 31.

[292] Industrial Customers Comments at 25; Consumer Organizations Comments at 26.

[293] EEI Comments at 37; Exelon Comments at 33–34; Policy Integrity Comments at 27–28; Indicated PJM TOs Comments at 27.

[294] ANOPR, 176 FERC ¶ 61,024 at P 23.

[295] *Supra* section__ and Unreasonable and Unduly Discriminatory and Preferential Commission-Jurisdictional Rates (detailing the sharp rise in total investment in interconnection-related network upgrades along with the jump in the cost per kW for newly interconnecting generators to interconnect).

[296] ACEG Jan. 2021 Interconnection Report at 17.

[297] *Id.* (naming the high cost of interconnection-related network upgrades as the fundamental problem that interconnection queue reform has failed to address thus far).

years, the deciding factor has become the interconnection customer's ''sticker shock'' at its cost responsibility for interconnection-related network upgrades.[298]

163. When interconnection customers withdraw from the interconnection queue, the identified interconnection-related network upgrades associated with those interconnection customers remain unbuilt and the underlying interconnection-related needs go unaddressed. In many cases, when the interconnection-related need is not addressed via development of interconnection-related network upgrades in one interconnection queue cycle, the same interconnection-related need—and oftentimes the same or a substantially similarly interconnection-related network upgrade—will appear in interconnection studies for different interconnection requests or clusters in subsequent interconnection queue cycles. This scenario can occur even if subsequent interconnection requests or clusters vary considerably from previous interconnection requests or clusters in terms of size, fuel type, technical specifications, or location. One study, which analyzed 12 specific interconnection-related network upgrades identified by MISO and SPP, found that SPP identified three of the upgrades in two interconnection queue cycles and one in three interconnection queue cycles, and MISO identified three of the upgrades in two interconnection queue cycles and two in three interconnection queue cycles.[299] In other words, both SPP and MISO were repeatedly identifying the same interconnection-related network upgrades as interconnection customers withdrew from the interconnection queue, leaving next-in-line interconnection customers to address the same interconnection-related needs.

164. Where interconnection-related needs are repeatedly identified in interconnection studies, the implication may be that the area, despite the potentially prohibitive interconnection costs, is otherwise desirable for generators to locate (*e.g.,* it is located close to fuel sources). At the same time, the recurrent need for an interconnection-related network upgrade is unlikely to go away without someone investing in the transmission system in that location. As interconnection customers that have invested time and resources in proposing a project, entering the interconnection queue, and engaging in the generator interconnection process choose to withdraw rather than fund the interconnection-related network upgrades, it becomes more and more likely that it will never be economic for an interconnection customer (or small cluster of interconnection customers) to resolve the interconnection-related need.

165. At the same time, interconnection-related network upgrades can provide widespread transmission benefits that extend beyond the interconnection customer.[300] As a result, planning these transmission upgrades exclusively through the generator interconnection process may result in a mismatch between the beneficiaries of the transmission upgrade and those to whom the costs are allocated. In other words, by upgrading the transmission system in a piecemeal fashion through the generator interconnection process, the current transmission planning paradigm appears to impose costs on interconnection customers for transmission facilities that would provide benefits beyond those received by the interconnection customer. This paradigm can present a potential barrier to entry for new generation resources that might otherwise be economic if not for the cost of interconnection-related network upgrades. We believe that reforms may be necessary to allow for the consideration of transmission facilities to meet interconnection-related needs repeatedly identified in the generator interconnection process through Long-Term Regional Transmission Planning and Cost Allocation process instead, which we believe would result in more efficient or cost-effective transmission expansion, cost allocation for such transmission facilities that is at least roughly commensurate with estimated benefits, and elimination of a barrier to entry for new generation resources. In turn, we expect that these reforms would ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.

(d) Proposed Reform

166. We propose to require that public utility transmission providers consider in their Long-Term Regional Transmission Planning regional transmission facilities that address certain interconnection-related needs that the public utility transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection request(s). In particular, we propose to require that public utility transmission providers evaluate for selection in the regional transmission plan for purposes of cost allocation regional transmission facilities to address interconnection-related needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades where: (1) The public utility transmission provider has identified interconnection-related network upgrades in interconnection studies to address those interconnection-related needs in at least two interconnection queue cycles during the preceding five years (beginning at the time of the withdrawal of the first underlying interconnection request); (2) the interconnection-related network upgrade identified to meet those interconnection-related needs has a voltage of at least 200 kV and/or an estimated cost of at least $30 million; (3) those interconnection-related network upgrades have not been developed and are not currently planned to be developed because the interconnection request(s) driving the need for the upgrade has been withdrawn; and (4) the public utility transmission provider has not identified an interconnection-related network upgrade to address the relevant interconnection-related need in an executed generator interconnection agreement or in a generator interconnection agreement that the interconnection customer requested that the public utility transmission provider file unexecuted with the Commission.

167. We propose to require that public utility transmission providers in each transmission planning region consider regional transmission facilities to address interconnection-related needs pursuant to this reform through the proposed Long-Term Regional Transmission Planning. We recognize that the Long-Term Regional Transmission Planning proposal requires that public utility transmission providers incorporate interconnection queue withdrawals into Long-Term Scenario development. Consequently, we propose to require that public utility transmission providers in each transmission planning region incorporate the specific

[298] *See* ACORE Comments at 12.

[299] ICF Sept. 2021 Report at 25–26.

[300] *See, e.g.,* CAISO Comments at 52–53 (stating that in CAISO ''transmission facilities at 200 kV and above are eligible for regional cost allocation,'' including location-constrained resources interconnection facilities, because ''this voltage threshold . . . recognizes that high voltage transmission facilities support and provide benefits to all customers to the CAISO grid''); Order No. 2003, 104 FERC ¶ 61,103 at P 65 (stating that ''[f]acilities beyond the Point of Interconnection [(*i.e.,* interconnection-related network upgrades)] are part of the Transmission Provider's Transmission System and benefit all users''); ACORE Comments, Ex. 5, at 4–7.

interconnection-related needs identified through this reform as a factor used to develop Long-Term Scenarios.

168. We preliminarily find that this requirement will support the establishment of just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates by addressing a potential barrier to integrating new sources of generation that may otherwise continue to exist absent such requirements in the regional transmission planning process. Additionally, to the extent that such transmission facilities are selected in the regional transmission plan for purposes of cost allocation, this proposal would provide an avenue to allocate these regional transmission facilities' costs more broadly in recognition of their more widespread benefits (as identified through the regional transmission planning process), helping to ensure that their costs are allocated in a manner that is at least roughly commensurate with the estimated benefits that they provide. We believe that the criteria proposed above that the public utility transmission provider must use to identify the interconnection-related needs that should be considered in the regional transmission planning process will help to ensure that the associated interconnection-related network upgrades are likely to have produced benefits beyond those provided to the interconnection customers whose interconnection requests the interconnection-related network upgrades are needed to accommodate. It is important to note that we are not proposing that all interconnection-related needs that satisfy the above criteria must result in transmission facilities being selected in the regional transmission plan for purposes of cost allocation; rather, those regional transmission facilities would have to independently satisfy the criteria for such selection in Long-Term Regional Transmission Planning as the more efficient or cost-effective transmission facility.

169. As noted above, we propose that the first qualifying criterion for this potential reform is that the public utility transmission provider has identified a needed interconnection-related network upgrade in generator interconnection studies to address the same interconnection-related need in at least two interconnection queue cycles during the preceding five years. The five-year look-back for each interconnection-related need would begin on the date that an interconnection customer with an interconnection study that identifies an interconnection-related network upgrade that meets the voltage or cost estimate threshold withdraws its interconnection request.[301] We propose to choose this starting point because, arguably, this is the earliest point at which the transmission provider will have notice that the costs associated with an identified interconnection-related network upgrade may have caused a withdrawal. We also believe that this criterion appropriately limits the scope of this requirement to those interconnection-related needs that are likely to persist, are not unique to a single interconnection customer's request, and have the potential, if evaluated through the regional transmission planning process, to provide more widespread benefits to transmission customers.

170. We propose that the initial five-year time period begin five calendar years prior to the initial effective date of the accepted tariff provisions proposed to comply with this reform. Thus, upon the acceptance of such tariff provisions in a Commission or delegated letter order, the public utility transmission provider would consider interconnection-related network upgrades identified to address the same interconnection-related need in at least two interconnection queue cycles in the five calendar years prior to the effective date established in the order accepting those tariff revisions. Thus, if the Commission adopts this proposal, the public utility transmission provider should not look back to a point earlier than that date and, going forward, this requirement would apply to any repeat identification of an interconnection-related need identified in at least two interconnection queue cycles in the immediately preceding five calendar years. We believe that such a limitation would prevent consideration of regional transmission facilities (more specifically, interconnection-related network upgrades) identified using data that may be stale by the time the public utility transmission providers in a transmission planning region consider regional transmission facilities to address the identified interconnection-related needs in their regional transmission planning process. We believe that five years is short enough to provide public utility transmission providers with accurate information on interconnection-related needs and also long enough for public utility transmission providers to identify the same interconnection-related need, which is likely to persist, in at least two interconnection queue cycles.

171. We do not propose to limit this reform to interconnection-related network upgrades that are identical to those identified in prior interconnection queue cycles. Instead, we propose to focus on the relevant interconnection-related needs that those upgrades are intended to address. To this point, we propose to require that public utility transmission providers in each transmission planning region consider whether the interconnection-related need for which the public utility transmission provider identified the interconnection-related network upgrade is the same in multiple interconnection queue cycles. That is, if an interconnection-related need is driving the identification of an interconnection-related network upgrade on the transmission system in one interconnection queue cycle and an interconnection-related network upgrade with, for example, a different voltage, starting point, or ending point is identified in the next interconnection queue cycle to address the same interconnection-related need, then the first criterion would be satisfied. We believe that this approach will appropriately account for differences in technology, study assumptions, system topology, and/or interconnection requests that may occur over time that may result in different interconnection-related network upgrades to address the same interconnection-related need.

172. We also propose to limit the scope of this reform to those interconnection-related network upgrades that have a voltage of at least 200 kV and/or an estimated cost of at least $30 million. We note that we have previously found a 200 kV voltage threshold to be just and reasonable in the context of an analogous provision in CAISO's tariff.[302] With respect to the

[301] We propose that when an interconnection-related network upgrade is identified for the interconnection of more than one interconnection customer in an interconnection queue cycle, the withdrawal of all interconnection customers assigned to that interconnection-related network upgrade qualifies as one withdrawal. The withdrawal of a single interconnection customer when other interconnection customers assigned to the interconnection-related network upgrade remain in the interconnection queue cycle does not qualify as a withdrawal of an interconnection queue interconnection request for the purposes of this reform.

[302] Section 24.4.6.5 of CAISO's Comprehensive Transmission Planning Process provides that interconnection-related network upgrades identified in the generator interconnection process that are not already included in a signed LGIA may be assessed in the Comprehensive Transmission Planning Process if they ''consist of new transmission lines 200 kV or above, and have capital costs of $100 million or greater; . . . [are] a new 500 kV substation that has capital costs of $100 million or greater; or, . . . have a capital cost

$30 million estimated cost threshold, evidence suggests that requiring interconnection customers to be responsible for this level of costs from a single interconnection-related network upgrade can lead to withdrawal from the interconnection queue, signaling that this level may be an appropriate dividing line for consideration in regional transmission planning processes.[303]

173. To avoid shifting costs inappropriately from generators in the generator interconnection process to transmission customers through the regional transmission planning process, we further propose to limit the scope of interconnection-related needs to be considered in the regional transmission planning process to those interconnection-related needs not addressed by interconnection-related network upgrades memorialized in an executed generator interconnection agreement (or in a generator interconnection agreement that the interconnection customer requested to be filed unexecuted with the Commission). This proposed limitation would ensure that public utility transmission providers only consider in their regional transmission planning process interconnection-related network upgrades that remain unconstructed despite the existence of a demonstrated interconnection-related need. We reiterate that regional transmission facilities identified through this process would have to independently satisfy the public utility transmission provider's criteria for selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective transmission solution.

174. We seek comment on the requirements proposed in this section of the NOPR. In particular, we seek comment on whether this proposed reform could delay the processing of existing interconnection queues and what reforms, if any, would be necessary to ensure that the generator interconnection and regional transmission planning processes are not significantly delayed by this proposed reform. We also seek comment on the appropriateness of the criteria that we propose a public utility transmission provider must use to identify the interconnection-related needs that should be considered in the regional transmission planning process, and whether there are alternative criteria public utility transmissions providers may use to identify significant interconnection-related needs that warrant consideration in the regional transmission planning process. Finally, we seek comment on how this proposed reform should interact with existing regional transmission planning processes and the Long-Term Regional Transmission Planning proposed herein.

iii. Evaluation of the Benefits of Regional Transmission Facilities

175. As discussed above, we propose to require that public utility transmission providers in each transmission planning region identify transmission needs driven by changes in the resource mix and demand using Long-Term Scenarios that meet the requirements proposed above. As explained in this section, once the public utility transmission providers in a transmission planning region have identified the region's transmission needs driven by changes in the resource mix and demand, we propose to require that, as part of public utility transmission providers' identification and evaluation of more efficient or cost-effective regional transmission facilities that may resolve those transmission needs in the regional transmission planning process, public utility transmission providers must: (1) Evaluate the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand, identify which benefits they will use in Long-Term Regional Transmission Planning, explain how they will calculate those benefits, and explain how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand ; and (2) evaluate the benefits of regional transmission facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities. Further, we propose to allow (but not require) public utility transmission providers to evaluate the benefits of a portfolio of regional transmission facilities instead of doing so on a facility-by-facility basis. Finally, we identify and describe a broad set of benefits that we believe public utility transmission providers could consider using in Long-Term Regional Transmission Planning (Long-Term Regional Transmission Benefits) to reasonably capture the benefit of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand.

(a) Evaluations of Long-Term Regional Transmission Benefits

176. In Order No. 1000, the Commission neither prescribed a particular definition of ''benefits'' or ''beneficiaries,'' nor required consideration of any specific benefits. Instead, the Commission stated that the proper context for consideration of such matters would be on review of compliance proposals.[304] The Commission stated that allowing greater flexibility to accommodate a variety of approaches better advanced the goals of Order No. 1000.[305] The Commission also stated that, in determining the beneficiaries of transmission facilities, a regional transmission planning process could consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements.[306] The result is that there are no specific requirements for public utility transmission providers to consider any particular benefit or set of benefits in evaluating transmission facilities for selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective solution to a regional transmission need.

177. In the ANOPR, the Commission sought comment on whether the Commission should require public utility transmission providers to use a minimum set of benefits to identify more efficient or cost-effective regional transmission facilities, and what those benefits should be.[307] The Commission

of $200 million or more.'' CAISO, Tariff, section§ 24.4.6.5 (LGIP Network Upgrades) (1.0.0).

[303] TheAn ACEG Reportreport notes that 3.5 of 5 GW of renewable energy projects in the MISO West 2017 study group dropped out because each project ''faced transmission costs in the range of tens to hundreds of millions of dollars.'' ACEG Report*See* Americans for a Clean Energy Grid, *Disconnected: The Need for New Generator Interconnection Policy,* at 17. (Jan. 2021). We also note that thean ICF Report indicates that the Wichita-Benton 345 kV line in SPP South, which has appeared in two different interconnection queue cycles and has not been constructed, has an estimated cost of $32.1 million. *See* ICF ReportResources, LLC, *Just & Reasonable? Transmission Upgrades Charged to Interconnection Generators are Delivering System-Wide Benefits,* at 5, 26. (Sep. 2021). As a further reference point, wind and solar industry advocates claim that ''the 'implied cost threshold' beyond which new generators are often no longer financially viable is . . . . . . an average of about $100,000 per megawatt of installed capacity.'' *See* American Wind Energy Association, Clean Grid Alliance, and SEIA, *Generator Contributions to Transmission Expansion,* at 2 (AugustAug. 2020), *https://cleangridalliance.org/_uploads/_media_uploads/_source/Generator_Contrib_Xmission-V3a-FINAL.pdf.*

[304] Order No. 1000, 136 FERC ¶ 61,051 at P 624.

[305] *Id.* PP 624–625.

[306] *Id.* P 622.

[307] ANOPR, 176 FERC ¶ 61,024 at P 53.

sought comment as to whether the existing regional transmission planning and cost allocation processes fully accounted for the full suite of benefits, including hard-to-quantify benefits. Further, the Commission sought comment on the types of benefits provided by transmission facilities needed to meet the transmission needs of the changing resource mix, as well as the manner in which those benefits can be quantified, if at all. The Commission also sought comment on how public utility transmission providers can document and account for benefits if those benefits cannot be quantified, but are real.[308]

(1) Comments

178. Many commenters support consideration of a wider set of benefits than those currently used to evaluate transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation.[309] Further, many commenters support the consideration of all possible benefits of regional transmission facilities when discussing benefits in the context of the current approach to separately consider reliability, economic, and public policy benefits—however, even some commenters that support maintaining the Order No. 1000 framework acknowledge that the benefits assessed could be expanded.[310] Commenters that support requiring consideration of an expanded set of transmission benefits argue that existing regional transmission planning processes are unjust and unreasonable because they ignore the full range of transmission benefits and therefore fail to select net beneficial transmission facilities, leading to underinvestment in transmission and higher consumer costs in the long run.[311] PIOs assert that the Commission should conduct a survey of all potential benefits that can result from multi-value, scenario-based planning and should require that public utility transmission providers consider those benefits for regional transmission planning.[312] Numerous commenters point to a list of transmission benefits identified by The Brattle Group as providing a useful framework for delineating a minimum set of benefits that the Commission could require public utility transmission providers to consider when evaluating alternative regional transmission facilities.[313]

179. Many commenters generally request regional flexibility to consider benefits. Ameren opposes requiring a specific set of benefits, arguing that such a reform could lead to controversy and delays.[314] Consumer Organizations and District of Columbia's Office of the People's Counsel express that, if additional benefits are added to the equation, additional costs to communities and landowners (for example, additional farm production costs, local road use, and local emergency services) should be, too.[315] Consumer Organizations and LPPC assert that it is not within the Commission's authority to create ''new speculative benefits'' in an effort to broaden cost allocation.[316] District of Columbia's Office of the People's Counsel urges that greater specificity is needed regarding what is a benefit.[317] APPA does not support considering environmental benefits associated with particular types of resources in planning transmission facilities and allocating costs.[318]

180. MISO states that it has adopted benefit metrics such as avoided/deferred reliability projects and reduced MISO–SPP settlement costs that go beyond adjusted production cost savings. However, MISO states that it has not been able to adopt other metrics explored in the stakeholder process, including: (1) Transmission outage and transmission energy losses; and (2) reduced capacity cost due to reduced peak load losses and future capacity expansion deferral due to increased capacity import and export limits.[319] MISO seeks flexibility on benefits that are considered to reflect changing circumstances but calls for direction or guidance from the Commission on identification and quantification of challenging benefits like resilience.[320]

181. NYISO supports identifying economic benefits when studying reliability projects. NYISO states that the current economic calculation is based on net production cost savings and does not consider other economic benefits such as installed capacity cost savings to load-serving entities.[321]

182. The PJM Market Monitor claims that PJM incorrectly defines the benefits of proposed market efficiency transmission projects, resulting in uneconomic transmission upgrades. In particular, the PJM Market Monitor argues that PJM uses speculative transmission-related benefits over a 15-year period while limiting the analysis to the existing generation fleet and existing patterns of fuel costs and congestion, which eliminates the possibility that new generation could respond to market signals and meet the same needs.[322] The PJM Market Monitor cautions against considering congestion reduction or localized locational marginal price reductions as an economic benefit to a potential transmission project without accurately

[308] *Id.* P 70.

[309] ACORE Comments at ii; AEE Comments at 31–32; ACEG Comments at 6–8; ACPA and ESA Comments at 75; AEP Comments at 14; Amazon Comments at 4; Anbaric Comments at 29; Avangrid Comments at 9; Business Council for Sustainable Energy Comments at 2; Citizens Energy Comments at 6–7; City of New York Comments at 3–4; Union of Concerned Scientists Comments at 66–75; Consumers Council Comments at 4, 16; Duke Comments at 12; EDF Comments at 8–10; EEI Comments at 33; ITC Comments at 28–34; Massachusetts Attorney General Comments at 24–25; New Jersey Commission at 13–14, 17–19; NextEra Comments at 83–88; Northwest and Intermountain Comments at 35–38; Orsted Comments at 6–7; PIOs Comments at 30, 60; Policy Integrity Comments at 43; PSEG Comments at 25–27; REBA Comments at 17; RMI Comments at 4; SEIA Comments at 9; Shell Comments at 18–20; State Agencies Comments at 21–22; State of Massachusetts Comments at 16–17; U.S. DOE Comments at 7–9, 23–24; WIRES Comments at 18; *see also Joint Fed.-State Task Force on Elec. Transmission,* Transcript of Feb. 16, 2022 Meeting, Docket No. AD21–15–000, at 19:15–18, 22:9–12 (Comm'r Rechtschaffen) (supporting expanded list of benefits and arguing that a more comprehensive benefit-cost analysis would lead to better transmission planning).

[310] City of New York Comments at 7; PIOs Comments at 81–82; EEI Comments at 24–25; PG&E Comments at 8–9; Anbaric Comments at 29; Union of Concerned Scientists Comments at 38; State of Massachusetts Comments at 16–19; Orsted Comments at 6–7; RMI Comments at 4.

[311] *See, e.g.,* ACEG Comments at 31–32 & app. A; ACORE Comments at 31–32 & Ex. 6; ACPA and ESA Comments at 24–27; NextEra Comments at 84–86; PIOs Comments at 82; PIOs Reply Comments at 55.

[312] PIOs Comments at 30; *see also* Orsted Comments at 6.

[313] *See, e.g.,* ACEG Comments at 34 & app. A; ACORE Comments at 34 & Ex. 6; ACPA and ESA Comments at 24–26; EDF Comments at 9; NextEra Comments at 84–86; PIOs Comments at 34 & Ex. A; RMI Comments at 4; U.S. DOE Comments at 37; WIRES Comments at 2; ACEG Reply Comments at 11; Enel Reply Comments at 3–4; PIOs Reply Comments at 55; *see also* February Joint Task Force Tr 49:8–13 (Ted Thomas) (stating that The Brattle Group list of benefits is ''characterized by rigor'').

[314] Ameren Comments at 9–11.

[315] Consumer Organizations Comments at 18–19; District of Columbia's Office of the People's Counsel Comments at 26–27.

[316] Consumer Organizations Comments at 18; LPPC Comments at 20–23.

[317] District of Columbia's Office of the People's Counsel Comments at 3–4.

[318] APPA Comments at 15–16.

[319] MISO Comments at 23–26.

[320] *Id.* at 52–53; *see also* February Joint Task Force Tr 20:5–8, 21:4–12 (Clifford Rechtschaffen) (suggesting that the reliability category should be expanded to include resilience, particularly in light of extreme events in the West and increasingly intense hurricanes in the East), 51:10–15 (Matthew Nelson) (stating that having commonality in terminology for benefits and where they are considered would be valuable), 69:16–18 (Jason Stanek) (concluding that if there is a fourth category of benefits, it may be resilience), 73:1–4 (Riley Allen) (arguing for not ignoring difficult to quantify benefits but rather for finding sensible ways to quantify them).

[321] NYISO Comments at 27–31, 34–37; *see also* February Joint Task Force Tr 20:9–12 (Clifford Rechtschaffen) (advocating for expanding the economic category to include improved connectivity to lower-cost generation).

[322] PJM Market Monitor Comments at 10.

accounting for how the congestion dollars are or are not returned to load through the financial transmission rights (or their equivalent).[323]

(2) Proposed Reform

183. At this time, consistent with Order No. 1000, we decline to propose to prescribe any particular definition of ''benefits'' or ''beneficiaries,'' nor require use of any specific benefits.[324] Instead, we continue to acknowledge the benefits of regional flexibility, and consistent with Order No. 1000, propose to consider such matters on review of compliance proposals.[325] Nevertheless, we acknowledge the support for the adoption of a common set of minimum benefits, and we propose a list of Long-Term Regional Transmission Benefits described below that public utility transmission providers may consider in Long-Term Regional Transmission Planning and cost allocation processes. In addition, we propose to require that public utility transmission providers identify on compliance the benefits they will use in Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand. As part of this compliance obligation, public utility transmission providers should explain the rationale for using the benefits identified.

184. We believe that the Long-Term Regional Transmission Benefits discussed below account for many of the benefits that regional transmission facilities to address transmission needs driven by changes in the resource mix and demand identified as part of Long-Term Regional Transmission Planning are most likely to provide. However, we clarify that this list of potential benefits is not mandatory or exhaustive and public utility transmission providers would have flexibility to propose what benefits to use as part of their Long-Term Regional Transmission Planning. For example, public utility transmission providers may wish to use benefits previously accepted by the Commission for existing regional transmission planning processes that are not included in the Long-Term Regional Transmission Benefits discussed herein.

185. We believe that the following set of Long-Term Regional Transmission Benefits may be useful in evaluating transmission facilities for selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective solutions to meet transmission needs driven by changes in the resource mix and demand: (1) Avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity.

TABLE 1—LONG-TERM REGIONAL TRANSMISSION BENEFITS

Benefit	Description
Avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement.	Reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities.
Reduced loss of load probability [OR next benefit]	Reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load (if planning reserve margin is constant), resulting in benefit of reduced expected unserved energy by customer value of lost load.
Reduced planning reserve margin [OR prior benefit]	While holding loss of load probabilities constant, system operators can reduce their resource adequacy requirements (*i.e.,* planning reserve margins), resulting in a benefit of reduced capital cost of generation needed to meet resource adequacy requirements.
Production cost savings	Reduction in production costs, including savings in fuel and other variable operating costs of power generation, that are realized when transmission facilities allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies; also reduction in market prices as lower-cost suppliers set market clearing prices; when adjusted to account for purchases and sales outside the region, called adjusted production cost savings.
Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads, thereby reducing total energy necessary to meet demand.
Reduced congestion due to transmission outages	Reduced production costs during transmission outages that significantly increase transmission congestion.
Mitigation of extreme events and system contingencies	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages, through more robust transmission system reducing high-cost generation and emergency procurements necessary to support the system.
Mitigation of weather and load uncertainty	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns.
Capacity cost benefits from reduced peak energy losses	Reduced energy losses during peak load reduces generation capacity investment needed to meet the peak load and transmission losses.
Deferred generation capacity investments	Reduced costs of needed generation capacity investments through expanded import capability into resource-constrained areas.

[323] *Id.* at 11.

[324] *See* Order No. 1000, 136 FERC ¶ 61,051 at PP 624–625.

[325] *See id.* P 624.

TABLE 1—LONG-TERM REGIONAL TRANSMISSION BENEFITS—Continued

Benefit	Description
Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location (*e.g.,* low permitting costs, low-cost sites on which plants can be built, access to existing infrastructure, low labor costs, low fuel costs, access to valuable natural resources, locations with high-quality renewable energy resources).
Increased competition	Reduced bid prices in wholesale electricity markets due to increased competition among generators and reduced overall market concentration/market power.
Increased market liquidity	Reduced transaction costs (*e.g.,* bid-ask spreads) of bilateral transactions, increased price transparency, increased efficiency of risk management, improved contracting, and better clarity for long-term transmission planning and investment decisions through increased number of buyers and sellers able to transact with each other as a result of transmission expansion.

186. Below, we describe each benefit along with examples of how each benefit may be calculated. We clarify that these are just examples, and we are not proposing to require that public utility transmission providers use any specific benefits or calculate those benefits in a particular manner when conducting Long-Term Regional Transmission Planning. At this time, we are only proposing to require public utility transmission providers to identify what benefits they will use in Long-Term Regional Transmission Planning and explain how they will be calculated and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand.

187. We seek comment on each of the Long-Term Regional Transmission Benefits discussed in this section of the NOPR. Additionally, we seek comment on how to ensure that each type of benefit is distinct such that the list of benefits does not ''double count'' benefits. We also seek comment on the application of the Long-Term Regional Transmission Benefits in non-RTO/ISO regions.

188. Finally, we seek comment on whether public utility transmission providers should be required to use some or all of the Long-Term Regional Transmission Benefits as a minimum set of benefits for their Long-Term Regional Transmission Planning process.

(3) Description of Long-Term Regional Transmission Benefits

189. The benefits of transmission facilities identified in Long-Term Regional Transmission Planning may include a set of benefits related to avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement, which we describe as reduced costs on avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities. The Commission has recognized that regional transmission planning could lead to the development of transmission facilities that span the service territories of multiple public utility transmission providers, which in turn would obviate the need for transmission facilities that would otherwise be identified in multiple local transmission plans.[326]

190. The Commission has accepted accounting for such ''avoided costs'' as part of a method for identifying beneficiaries and allocating costs in almost all the regional cost allocation methods in non-RTO/ISO regions. Using this method, public utility transmission providers in a transmission planning region determine the beneficiaries of a regional transmission facility or portfolio of facilities by identifying the local and regional transmission facilities that a new proposed regional transmission facility or portfolio of facilities would displace. The method defines the benefits of the regional transmission facility or facilities as the costs that public utility transmission providers in the transmission planning region ''avoid'' because they no longer need to build the displaced local and regional transmission facilities. The method allocates costs among public utility transmission providers whose local or regional transmission facilities the new proposed regional transmission facility or facilities would displace in proportion to their share of the total benefits (*i.e.,* the total avoided costs). If the new proposed regional transmission facility or facilities do not displace any local or regional transmission facilities in existing local or regional transmission plans, the avoided cost method determines the benefits of the applicable facilities by considering the costs of local or regional transmission facilities that would otherwise be needed to meet the same need that the new proposed regional transmission facility will meet.[327]

191. In calculating this benefit, public utility transmission providers in each transmission planning region could first identify transmission facilities that could defer or replace an identified reliability transmission solution. Avoided cost benefits could be calculated by comparing the cost of transmission facilities required to address the reliability need without the proposed regional transmission facility to the cost of transmission facilities needed to address the reliability need assuming the regional transmission solution were in place.[328]

192. Similarly, this benefit could also include the separate benefits stream caused by a deferral of replacement of other transmission facilities through identification and selection for purposes of cost allocation in the regional transmission plan of a transmission facility or facilities. This could be measured through calculation of the present value savings for the period of deferral of additional replacement transmission facilities multiplied by their estimated capital cost.

193. A number of public utility transmission providers already evaluate the avoided or deferred costs of reliability transmission projects. For example, SPP uses a power flow model to analyze the ability of potential economic and Public Policy transmission facilities to meet the same thermal reliability needs addressed by a potential reliability transmission facility. The costs of these avoided or delayed reliability transmission

[326] Order No. 1000, 136 FERC ¶ 61,051 at P 81.

[327] *See, e.g., S.C. Elec. & Gas Co.,* 143 FERC ¶ 61,058, at P 232 (2013).

[328] Brattle-Grid Strategies Oct. 2021 Report at 37.

facilities are used to determine the reliability benefit of the potential economic or Public Policy Requirements transmission facilities.[329] Public utility transmission providers could also use avoided costs to calculate the benefits of replacing aging transmission facilities. NYISO, for example, estimates the benefits associated with the replacement of aging transmission facilities by quantifying the savings of not having to refurbish the facilities in the future.[330]

194. Another potential benefit of regional transmission infrastructure is reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages (if planning reserve margin is not changed despite lower loss of load events), as well as improved physical reliability benefits by reducing the likelihood of load shed events; or reduced planning reserve margin, which we propose to define as 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. There is an overlap between reduced loss of load probability benefits and reduced planning reserve margin benefits, such that a single transmission facility can either reduce loss of load events if the planning reserve margin is unchanged *or* allow for the reduction in planning reserve margins if loss of load events remain constant, but not both simultaneously.

195. As for reduction in loss of load probability benefits, transmission investments, even those not made to satisfy a reliability need, generally enhance the reliability of the transmission system by increasing transfer capability, which, in turn, reduces the likelihood that a public utility transmission provider will be unable to serve its load due to a shortage of generation over a given period. This enhancement in reliability can be measured as a reduction in loss of load probability, or the likelihood of system demand exceeding generation over a given period. One example of how a reduction of loss of load probability benefit could be calculated can be found in a report by SPP's Metrics Task Force. The report proposes quantifying the incremental increase in system reliability by determining the reduction in expected unserved energy between the base case and the change case, obtaining the value of lost load, and multiplying these two values to obtain the monetary benefit of enhanced reliability associated with a transmission expansion.[331]

196. A lower planning reserve margin requirement is another way to demonstrate a resource adequacy benefit. Investments in transmission capacity can reduce the system-wide planning reserve margin requirement of the system-wide or reserve margin requirement within individual resource adequacy zones of a transmission planning region, which can reduce the need for generation capital expenditures. It is important to note that, due to the overlap between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with loss of load probability, only one of these benefits should be calculated for a transmission investment, but not both simultaneously.

197. RTOs/ISOs have calculated the transmission benefits of reduced planning reserve margins. MISO, for example, calculated a reduction in planning reserves associated with its MVP portfolio, which reduced the need for future generation buildout to meet reserve requirements, by using loss of load expectation reliability simulations. MISO estimated that its MVP portfolio was expected to reduce the required planning reserve margin by up to one percentage point, which translated into a projected savings of $1.0 to $5.1 billion in benefits over 10 years.[332]

198. Another potential benefit of regional transmission infrastructure is production cost savings, which we describe as savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production, as well as a reduction in market prices as lower-cost suppliers set market clearing prices.[333]

199. Most regional transmission planning processes currently estimate production cost savings. Generally, within RTOs/ISOs, security-constrained production cost models simulate the hourly operations of the electric system and the wholesale electricity market by emulating how system operators would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints. The traditional method for estimating the changes in adjusted production costs associated with proposed transmission facilities (or portfolio of facilities) is to compare the adjusted production costs with and without those facilities. Analysts typically call the market simulations without the proposed transmission facilities the ''Base Case'' and the simulations with those facilities the ''Change Case.''

200. Approaches used to calculate production cost savings vary. MISO uses production cost savings (adjusted for import costs and export revenues) to allocate the costs of its Market Efficiency Projects to cost allocation zones based on each zone's share of the total adjusted production cost savings.[334] NYISO and PJM, in contrast, use reductions to load energy payments (adjusted to reflect the reduced value of transmission congestion contracts) to allocate the costs of economic transmission facilities.[335]

201. Non-RTO/ISO regions, without centrally organized energy markets, rely on other tools to perform analyses of production cost savings. For example, WestConnect's regional cost allocation method for regional transmission facilities driven by economic considerations identifies the benefits and beneficiaries of a proposed regional transmission facility or facilities by modeling the potential of the transmission facilities to support more economic bilateral transactions between generators and loads in the region. Specifically, WestConnect considers the transactions between loads and lower-cost generation that a proposed regional transmission facilities could support and, accounting for the costs associated with transmission service, identifies the transactions that are likely to occur. WestConnect then estimates any resulting cost savings (in the form of reductions in production costs and reserve sharing requirements) and

[329] *SPP Benefit Metrics Manual,* SPP Engineering, at 15 (Nov. 6, 2020).

[330] The Brattle Group, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades,* The Brattle Group, at 114 (Sept. 15, 2015).

[331] SPP, *Benefits for the 2013 Regional Cost Allocation Review,* at 25 (Sept. 13, 2012).

[332] MISO, *Proposed Multi Value Project Portfolio: Business Case Workshop,* at 36–38 (Sept. 19 & 29, 2011).

[333] When this calculation is adjusted to account for purchases and sales outside the region, we propose to define this as adjusted production cost savings.

[334] *See* MISO, FERC Electric Tariff, Attach. FF, Benefit Metrics § (I)(A)(1) (33.0.0).

[335] *See PJM Interconnection L.L.C.,*142 FERC ¶ 61,214, at P 416 (2013) (PJM First Regional Compliance Order); *New York Independent System Operator Corp.,*143 FERC ¶ 61,059 at PP 268, 269, n.516 (2013) (NYISO First Regional Compliance Order); NYISO, NYISO Tariffs, OATT, attach. Y, § 31.5 (27.0.0), § 31.5.4.3.2. For high voltage economic transmission facilities, PJM allocates 50% of the costs in accordance with its economic analysis and allocates the other 50% of the costs on a load-ratio share basis.

allocates the costs of the regional transmission facilities on that basis.[336]

202. Another set of potential benefits of regional transmission infrastructure is benefits related to reduced transmission energy losses, which we describe as reduced total energy necessary to meet demand stemming from reduced energy losses incurred in transmittal of power from generation to loads. These benefits include the reduced energy losses incurred when transmitting power from generation to loads.

203. Production cost savings metrics used today typically exclude reduced transmission energy losses and the other three production cost savings-related benefits in our proposed list described further below. Including these additional benefits can produce a more robust set of congestion and production cost benefits that can be quantified and integrated into the method for calculating production cost savings, and, therefore, help to ensure that the more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning.

204. To measure reduced transmission energy losses, public utility transmission providers could: (1) Simulate losses in production cost models; (2) estimate changes in losses with power flow models for a range of hours; or (3) estimate how the cost of supplying losses will likely change with marginal loss charges. For example, American Transmission Company (ATC) measured reduced transmission energy losses based on changes in marginal loss charges and loss refund estimates using the marginal loss component from the PROMOD[337] electric market simulation software simulations for the Paddock-Rockdale 345 kV Access Project,[338] which produced cost reduction benefits using adjusted production cost analysis. Also, SPP's analysis for its Regional Cost Allocation Review (RCAR) process estimated energy loss reductions through post-processing the marginal loss component of the locational marginal prices in PROMOD simulation results.[339]

205. Another set of potential benefits of regional transmission infrastructure is benefits related to reduced congestion due to transmission outages, which we describe as reduced production costs resulting from avoided congestion during transmission outages. Such benefits include reduced production costs during transmission outages that significantly increase transmission congestion. Production cost simulations typically consider planned generation outages and, in most cases, a random distribution of unplanned generation outages. In contrast, they do not generally reflect transmission outages, planned or unplanned.[340] Public utility transmission providers could measure this benefit, for example, by either building a data set of a normalized outage schedule (not including extreme events) that can be introduced into simulations or by inducing system constraints more frequently. In its RCAR process, SPP measured the benefits of reducing congestion resulting from transmission outages. There, SPP modeled outage events and new constraints based on these outages in PROMOD for a 2025 case year, and then conducted PROMOD simulations to calculate adjusted production cost savings for a base case and the change case including the transmission line.[341] In another example, SPP calculated the financial value of reducing congestion caused by outages based on a rerun of its entire day-ahead and real-time market.

206. Another set of potential benefits of regional transmission infrastructure is benefits related to mitigation of extreme events and system contingencies, which we describe as reductions in production costs resulting from reduced high-cost generation and emergency procurements necessary to support the transmission system during extreme events (such as unusual weather conditions, fuel shortages, or multiple or sustained generation and transmission outages) and system contingencies. These benefits include reduced production costs during extreme events facilitated by a more robust transmission system that reduces high-cost generation and emergency procurements necessary to support the system.

207. Public utility transmission providers can measure benefits from the mitigation of extreme events and system contingencies by calculating the probability-weighted production cost savings through production cost simulation for a set of extreme historical market conditions. One example is CAISO's analysis of Devers-Palo Verde Line No. 2 (PVD2), where CAISO modeled several contingencies to determine the value of the line during high-impact, low-probability events.[342] Another example is ATC's production cost simulation analysis of insurance benefits for the ATC Paddock-Rockdale transmission line. ATC found that probability-weighted savings from reducing production and power purchase costs during a number of simulated extreme events offset 20% of total project costs.[343] Finally, a Grid Strategies study found development of an additional 1,000 MW of transmission capacity into Texas would have fully paid for itself over four days during Winter Storm Uri and the same into MISO would have saved $100 million during the same time period.[344]

208. Another set of potential benefits of regional transmission infrastructure is benefits related to mitigation of weather and load uncertainty, which we describe as reduced production costs during higher-than-normal load conditions or significant shifts in regional weather patterns. This is beyond the effects of extreme weather described above and may account for, for example, regional and sub-regional load variances that will occur due to changing weather patterns. This ignores the potential benefit of transmission expansions under more normal system operating conditions, such as when the system experiences higher-than-normal load conditions or significant shifts in

[336] *Pub. Serv. Co. of Colo.,* 142 FERC ¶ 61,206, at P 314 (2013).

[337] PROMOD is a generator and portfolio modeling system. *https://www.hitachienergy.com/us/en/offering/product-and-system/energy-planning-trading/market-analysis/promod.*

[338] ATC explains that the marginal loss component for transmitting internal generation to load is the marginal loss charge differential between load and generation, and the loss refund returns half of that amount. ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137–CE–149, app. C, Ex. 1, at 34–38 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007).

[339] SPP, Regional Cost Allocation Review (RCAR II), at 5 (July 11, 2016), *https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf.*

[340] Brattle-Grid Strategies Oct. 2021 Report at 79.

[341] SPP, Regional Cost Allocation Review (*RCAR II*), at 51–52. To estimate incremental savings associated with mitigation of transmission outage costs, SPP analyzed outage cases in PROMOD for the 2025 study year. SPP developed cases based on 12 months of historical SPP transmission data. SPP said that because of the high volume of historical transmission outage data (approximately 7,000 outage events) and based on the expectation that many outages would not lead to significant increases in congestion, SPP only modeled a subset of outage events. The events selected were those expected to create significant congestion and met at least one of three conditions. *Id.* at 51.

[342] *Opinion Granting Certificate of Public Convenience and Necessity, In the Matter of the Application of Southern California Edison Company (U 338–E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project,* Application 05–04–015 (Cal. Comm'n Jan. 27, 2007).

[343] ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137–CE–149, app. C, Ex. 1, at 4, 50–53 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007).

[344] M. Goggin, Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2020).

regional weather patterns that change the relative power consumption levels across multiple regions or sub-regions.

209. One example of the mitigation of weather and load uncertainty benefits is the simulations that ERCOT performed for normal loads, higher-than-normal loads, and lower-than-normal loads for a Houston import project, which showed increased benefits with a probability-weighted average for all three simulated load conditions.[345] To measure this benefit, production cost model inputs under high and low load conditions can be used to develop regional variations of relative benefits under these conditions. Production cost benefits can then be modeled based upon a probability weighted average anticipating varying load conditions, with the increment over a base case representing additional production cost savings.

210. Another set of potential benefits of regional transmission infrastructure is capacity cost benefits related to reduced peak energy losses, which we describe as reduced generation capacity investment needed to meet peak load.

211. Capacity cost savings from reduced peak energy losses benefits refer to the ability of proposed transmission facilities to lessen the amount of transmission system energy losses during peak-load conditions which, over time, would decrease the need for new generation capacity installations or purchases. To the extent that new transmission facilities result in changes to generation dispatch and flows, transmission system energy losses will also change. If transmission system losses are reduced via the new transmission facilities, public utility transmission providers will not have to construct or procure additional generation to satisfy installed capacity requirements for peak-load conditions. If there is a reduction in energy losses during peak conditions, this would result in, presumably, lowered investments for generation capacity resources to meet the peak load. For example, Entergy found that potential transmission facilities in its footprint could reduce peak-load transmission losses and associated needed generation investment by 2% of total transmission facility costs.[346] We note that capacity cost savings from reduced peak energy losses only attempt to evaluate benefits for peak-load conditions.

212. One potential way to calculate capacity cost savings from reduced peak energy losses is to calculate the present value of capital cost savings associated with the reduction in installed generation requirements.[347] To arrive at the value of capital cost savings associated with these savings, the estimated net cost of new entry (Net CONE) (*i.e.,* the cost of new peaking generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource constrained) would be multiplied by the reduction in installed generation capacity requirements. The resulting value would represent the avoided cost of procuring more generation to cover transmission system losses during peak-load conditions that would be passed on to consumers via lowered generation capacity costs.

213. Another set of potential benefits of regional transmission infrastructure is benefits related to deferred generation capacity investments, which we describe as reduced costs of needed generation capacity investments realized through expanded import capability into resource-constrained areas.

214. Deferred generation capacity investments benefits reflect the value of increased transfer capability, provided by new transmission facilities, that either defers or negates the need to invest in generation capacity resources within a transmission planning region by increasing import capability from neighboring regions into resource-constrained areas. By expanding the transmission system's capacity to deliver energy to load centers, public utility transmission providers may avoid additional generation capacity investments closer to load centers. We note, for example, an ITC study examining transmission facilities between the eastern, non-ERCOT region of Texas that can import energy from Arkansas and Louisiana. The study highlighted that, by enabling imports of surplus energy from Arkansas and Louisiana, additional generation capacity investments were not needed in the eastern, non-ERCOT region of Texas.[348]

215. One potential manner of calculating deferred generation capacity investments is to calculate the present value of generation capacity cost savings resulting from deferred generation investments, based on Net CONE. Specifically, the total value of deferred generation investments could be determined by multiplying the change in the public utility transmission provider's installed capacity requirement by Net CONE. The value of deferred generation capacity investments would ultimately benefit consumers through lower generation capacity costs.

216. Another set of potential benefits of regional transmission infrastructure is benefits related to access to lower-cost generation, which we describe as reduced total cost of needed generation due to the ability to locate generating units in a more economically efficient location (*e.g.,* low permitting costs, low-cost sites on which plants can be built, access to existing infrastructure, low labor costs, low fuel costs, access to valuable natural resources). In other words, this refers to the value of savings that may accrue to consumers who, because of a new regional transmission facility or portfolio of facilities, are able to access lower cost generation resources that they would have been unable to otherwise. For example, if the new regional transmission facilities extend to generation located farther from load centers that may be lower-cost compared to generation located closer to load centers that may be higher-priced, the new regional transmission facilities will provide savings to consumers via increased access lower-cost generation. We note, for example, that CAISO found that its proposed PVD2 transmission project, which provided an additional link between Arizona and California, permitted CAISO to meet reliability requirements through imports of lower-cost, new generation in Arizona.[349]

217. One potential way to calculate benefits from access to lower-cost generation enabled by a regional transmission facility or portfolio of facilities would be calculating them akin to how production cost savings are calculated. Specifically, public utility transmission providers could calculate the reduction in total generation investment costs by comparing the status quo (*i.e.,* higher-cost local generation) to a future (*i.e.,* lower-cost distant generation) where the proposed new regional transmission facilities allow for the import of those lower-cost generation. By allowing for the import of lower-cost generation, consumers

[345] ERCOT, *Economic Planning Criteria: Question 1: 1/7/2011 Joint CMWG/PLWG Meeting,* at 10 (Mar. 4, 2011). The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant Energy estimated probabilities for the same scenarios.

[346] ITC Holdings Co., Joint Application, Docket No. EC12–145–000, at Ex. ITC–600, 77–78 (Test. of Pfeifenberger) (filed Sept. 24, 2012).

[347] *Id.*

[348] *Id.* at 58–59.

[349] *Opinion Granting Certificate of Public Convenience and Necessity, In the Matter of the Application of Southern California Edison Company (U 338–E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project,* Application 05–04–015 (Cal. Comm'n Jan. 27, 2007).

would benefit via reduced total cost of generation.

218. While we acknowledge calculating benefits from access to lower-cost generation may be similar to methodologies for calculating production cost savings, we believe that calculating production cost savings using traditionally used methodologies would not adequately capture benefits associated with capacity cost savings. Such methodologies do not account for capacity cost savings since they do not consider load variances during hotter or colder than normal weather conditions; do not consider transmission system outages or other situations where less than the full transfer capability of the transmission facility is available; do not consider extreme events like multiple generator outages; and do not capture ''real-world'' operational issues such as forecasting errors or unexpected loop flows.[350] Additionally, we believe that calculating access to lower-cost generation benefits, as Brattle Group explains, may require additional or separate analysis by public utility transmission providers since accurately capturing the aforementioned benefits may require a different generation mix than specified in the production cost simulations between the Base Case (*e.g.,* with generation located in lower-quality or higher-cost locations) and the Change Case (*e.g.,* with more generation located in higher-quality or lower-cost locations).[351]

219. Another set of potential benefits of regional transmission infrastructure is benefits related to increased competition. We describe increased competition as reduced bid prices in wholesale electricity markets due to increased competition among generators and reduced overall market concentration. Regional transmission facilities can increase competition in, and the liquidity of, wholesale electric power markets by increasing the number of wholesale electricity suppliers that are able to compete to supply electricity at locations in the transmission network served by the transmission facility,[352] which helps to ensure just and reasonable Commission-jurisdictional rates.

220. More specifically, to the extent that certain portions of a transmission planning region remain import-constrained, such that a single resource, or even a small number of resources, can have an outsized influence on the price of energy paid by load by increasing the price in their offer to sell energy, additional transmission capacity may reduce such influence, and thereby create benefits to transmission customers in the form of reduced energy prices.

221. Some public utility transmission providers have considered this benefit for certain transmission facilities. For example, CAISO evaluated the PVD2 and Path 26 Upgrade projects, and ATC evaluated its Paddock-Rockdale project, for increased competition benefits.[353] We highlight three possible methods to calculate increased competition benefits, all of which ATC employed in evaluating the benefits of the Paddock-Rockdale Project, as examples of how public utility transmission providers could calculate this benefit. The first two methods that ATC employed are similar in that ATC estimated the change in a measure of market concentration (*i.e.,* the extent to which the largest supplier is pivotal)—called the Residual Supplier Index [354]—which assumes a certain percentage of load is subject to market-based pricing, and measured the subsequent effect on generators' ability to offer above their marginal costs (measured as a price-cost markup) and related energy prices. ATC calculated the change in the Residual Supplier Index using an assumed change in import capability to the area served by the new transmission facility.

222. The first method ATC employed to calculate the increased competition benefit, called the ''Modified MISO IMM Method,'' draws from two key assumptions to determine price mark-ups. First, the Modified MISO IMM Method requires an estimate of the pivotal supplier's price-cost markup for the area served by the transmission facility for all times when the supplier is pivotal.[355] Second, this method assumes that the price-cost markup increases linearly as the Residual Supplier Index falls below 1.2,[356] such that there is no price-cost markup where the Residual Supplier Index for an hour is above 1.2 (*i.e.,* no improved competition benefit) and the price markup is half the estimated price-cost markup from the first assumption where the Residual Supplier Index for an hour is less than 1.0. Finally, this method assumes that the pivotal supplier is the marginal resource that sets the energy price when the Residual Supplier Index is below 1.2. The difference in price-cost markup for hours when the Residual Supplier Index is below 1.2 provides the benefits from increased competition.

223. The second potential method to calculate increased competition benefits that ATC employed, the ''Modified CAISO Method,'' estimates the energy price impacts of a new transmission facility by using regression analysis to find the relationship between historical market structure and price-bid markups. CAISO first developed this regression equation and its coefficients in its 2004 report evaluating the economic viability of certain transmission upgrades, including the PVD2 and Path 26 Upgrade projects.357 CAISO's study also used two binary indicator variables: One for the summer period in CAISO and another for peak hours. We note that public utility transmission providers using the Modified CAISO approach may find that coefficients developed using data specific to the transmission planning region where the public utility transmission provider is located are more appropriate and may also wish to include more independent variables specific to their respective transmission planning regions.

[350] TC Holdings, Joint Application, Docket No. EC12–145–000, Ex. No. ITC–600, at 54–55 (filed Sept. 24, 2012) (Pfeifenberger, Direct Testimony on behalf of ITC Holdings).

[351] Brattle-Grid Strategies Oct. 2021 Report at 46–47.

[352] F.A. Wolak, *Managing Unilateral Market Power in Electricity,* Policy Research Working Paper; No. 3691. World Bank, Washington, DC, at 8 (2005).

[353] *Opinion Granting Certificate of Public Convenience and Necessity, In the Matter of the Application of Southern California Edison Company (U 338–E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project,* Application 05–04–015 (Cal. Comm'n Jan. 27, 2007); CAISO, *Transmission Economic Assessment Methodology,* Chapter 4 (Jun. 2004); ATC, *Planning Analysis of the Paddock-Rockdale Project,* at 44–49 (Apr. 5, 2007).

[354] The Residual Supplier Index is calculated as the ratio of residual supply (*i.e.,* total supply minus the capacity of the largest supplier in the market) to the total demand. If the Residual Supplier Index is less than 1.0, it means the largest supplier is ''pivotal,'' meaning that a load cannot be served without the largest supplier making available at least some of its capacity. With inelastic demand, a pivotal supplier theoretically would be able to set the market price at any desired level above the competitive price. *See* von der Fehr, Nils-Henrik & David Harbord, *Spot Market Competition in the UK Electricity Industry,* Economic Journal, at 103, 531–46 (1993); ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137–CE–149, app. C, Ex. 1, at 44 & n.11 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007).

[355] In the case of the Paddock-Rockdale Project, the MISO independent market monitor had designated the area as a ''Narrow Constrained Area'' and estimated that, whenever a resource became pivotal in that area its offer would exceed its marginal costs by up to $36/MWh. While the MISO independent market monitor provided such an estimate for the Paddock-Rockdale Project, we do not suggest that any specific entity conduct the necessary study deriving this estimate (*e.g.,* the public utility transmission providers in a transmission planning region could also conduct such a study).

[356] This assumption is based on a study analyzing summer 2000 peak hourly data from the California Power Exchange. Sheffrin, A., (2002), ''Predicting Market Power Using the Residual Supplier Index,'' Mimeo, Department of Market Analysis, CAISO.

224. The third potential method to calculate increased competition benefits, the ''Bidding Behavior Method,'' relies on a simulation model that optimizes bidding behavior from a supplier perspective given each supplier's supply portfolio and load obligations. This model could be based on the theoretical incentive that suppliers have to increase price-cost markups in proportion to the absolute value of the slope of residual demand (*i.e.,* total demand less the supply of all other resources serving the same load).[358] Public utility transmission providers in a transmission planning region would develop a study estimating market prices for a future period matching the planning horizon as load, generation supply, transmission constraints, and import capability changed. Public utility transmission providers in a transmission planning region would also assume that a percentage of load was exposed to congestion.

225. Finally, another set of potential benefits of regional transmission infrastructure is benefits related to increased market liquidity. We describe increased market liquidity as enabling a larger number of entities, both buyers and sellers, to participate in a market. By increasing the number of market participants, both buyers and sellers, transmission facilities may provide benefits through reduced transaction costs (*e.g.,* bid-ask spreads) of bilateral transactions, increased pricing transparency, increased efficiency of risk management, improved contracting, and better clarity for long-term transmission planning and investment decisions.[359] The primary increased market liquidity benefit to transmission customers is the decrease in energy prices. For example, bid-ask spreads for bilateral trades at less liquid hubs have been found to be between $0.50 to $1.50/MWh higher than the bid-ask spreads at more liquid hubs.[360] Public utility transmission providers could quantify increased market liquidity benefits to transmission customers by estimating (1) how additional transmission facilities may increase liquidity and (2) how increased liquidity may reduce bid-asks spreads or energy prices.

(b) Evaluation of Transmission Benefits Over Longer Time Horizon

(1) Comments

226. Several commenters responding to the ANOPR recommend that the Commission allow or require public utility transmission providers to evaluate the benefits of transmission facilities over a longer time horizon.[361] For example, ACPA and ESA argue that proper economic analysis entails an analysis of the benefits of a proposed transmission facility over the asset's life, which is at least 40 years for transmission lines.[362] Other commenters, however, raise concerns with attempts to forecast future transmission system conditions in order to consider potential benefits on a longer time horizon.[363] For example, Xcel argues that planning for the future is inherently uncertain, and that the benefits of transmission facilities can change over time.[364]

(2) Proposed Reform

227. We propose to require that public utility transmission providers in each transmission planning region evaluate, as part of Long-Term Regional Transmission Planning, the benefits of regional transmission facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities. For example, if Long-Term Regional Transmission Planning identifies transmission facilities that are estimated to be in-service in year 10 of the 20-year long-term transmission planning horizon, then the estimate of benefits for those same transmission facilities will commence at year 10 and cover an additional 20 years. We believe that 20 years may strike an appropriate balance that reasonably illustrates the benefits a transmission facility is likely to provide over its useful life, which can exceed 40 years, while recognizing the inherent difficulties in attempting to predict system conditions too far into the future. Moreover, we note that some public utility transmission providers currently conduct long-term transmission planning over a 20-year horizon, and thus have some experience with modelling and making assumptions over this period, though such modelling is typically for informational purposes and not to select transmission facilities in the regional transmission plan for purposes of cost allocation.[365]

228. We propose to require that public utility transmission providers evaluate benefits over this time horizon in all stages of Long-Term Regional Transmission Planning, which includes evaluating regional transmission facilities, selecting more efficient or cost-effective regional transmission facilities in the regional transmission plan for purposes of cost allocation, and allocating the costs of such transmission facilities in a manner that is at least roughly commensurate with estimated benefits. We also note that for consistency and a matching comparison of benefits and costs over time, to the extent that public utility transmission providers estimate the costs of transmission facilities beyond the in-service date of the transmission facilities, we propose that they should estimate those future costs over the same time horizon as the estimated benefits.

229. Finally, while we propose to establish a minimum requirement for the time horizon over which benefits must be evaluated, we clarify that public utility transmission providers may propose approaches that exceed this minimum requirement. In particular, while we believe that 20 years may strike a reasonable balance, we also believe that a time horizon longer than 20 years for the evaluation of benefits may be consistent with the long life of transmission facilities—

[358] *See, e.g.,* F.A. Wolak, *Measuring the competitiveness benefits of a transmission investment policy: The case of the Alberta electricity market* 86 Energy Policy 426–444 (June 2015); N. Ryan, *The Competitive Effects of Transmission Infrastructure in the Indian Electricity Market,* 13 American Economic Journal: Microeconomic 2, 202–42 (May 2021).

[359] Brattle-Grid Strategies Oct. 2021 Report at 50.

[360] *Id.*

[361] *See, e.g.,* NYISO Comments at 34–37 (stating that NYISO limits consideration of benefits to 10 years and recommending that the Commission grant public utility transmission providers discretion to plan for up to 20 years of needs and benefits); *see also* NextEra Comments at 79–80 (recommending a similar length of time for consideration of benefits as for scenario planning); *see also* February Joint Task Force Tr 20:23–25 (Clifford Rechtschaffen) (arguing that the Commission should extend the timeframe over which benefits are calculated to be 15–20 years or longer), 24:4–8 (Matthew Allen) (advocating for recognizing benefits over at least a 20-year timeframe given the long life of transmission assets).

[362] ACPA and ESA Comments at 44–45; *see also* PIOs Comments at 121–122.

[363] Entergy Comments at 10–11; *see also* EEI Comments at 30–31 (arguing for maintaining the Commission's policies on abandoned plant recovery because of the additional uncertainty inherent in longer-term transmission planning); Minnesota Commerce Comments at 3 (stating that future uncertainty is compounded by the rapid pace of technological change).

[364] Xcel Comments at 20 n.52.

[365] *See* MISO, *LRTP Business Case,* Long Range Transmission Planning Workshop, at slide 7 (Jan. 21, 2022, Revised Feb. 2, 2022), *https://cdn.misoenergy.org/20220121%20LRTP%20Workshop%20Item%2004%20Business%20Case%20Presentation619895.pdf;* CAISO, *20-Year Transmission Outlook* (Draft Jan. 31, 2022), *https://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf;* SPP Engineering, *2021 SPP Transmission Expansion Plan Report* (Jan. 11, 2021), *https://spp.org/documents/56611/2021%20step%20report.pdf.*

which generally exceeds 20 years by a substantial margin—and also consistent with the fact that transmission facilities provide significant benefits over their entire useful life.[366] To the extent public utility transmission providers would like to evaluate transmission benefits beyond the proposed minimum time horizon, we propose to require that they demonstrate that their proposal is consistent with or superior to any final rule in this proceeding.

230. We seek comment on the requirements proposed in this section of the NOPR.

(c) Evaluation of the Benefits of Portfolios of Transmission Facilities

231. In the ANOPR, the Commission sought comment on whether public utility transmission providers would identify more efficient or cost-effective transmission facilities in their regional transmission planning processes if they evaluated the benefits of a portfolio of transmission facilities collectively rather than individual transmission facilities separately.[367]

(1) Comments

232. Many commenters recommend that the Commission permit or require public utility transmission providers to use a portfolio approach when evaluating the benefits of transmission facilities.[368] Under such an approach, public utility transmission providers would evaluate multiple transmission facilities in an aggregated, integrated fashion rather than doing so on a facility-by-facility basis. For example, U.S. DOE argues that a portfolio approach is more likely to result in an accurate evaluation of the benefits of transmission facilities than would an approach requiring evaluation of each facility individually,[369] while PIOs claim that facility-by-facility rather than portfolio-based evaluation underestimates the benefits of regional transmission facilities.[370] Other commenters explain that public utility transmission providers could achieve administrative efficiencies using a portfolio approach, which can help avoid the necessity of running the same analyses on each facility.[371]

(2) Proposed Reform

233. We propose to afford public utility transmission providers in each transmission planning region the flexibility to propose to use a portfolio approach in the evaluation of benefits of regional transmission facilities through their Long-Term Regional Transmission Planning. Evaluating the benefits of a portfolio of regional transmission facilities appears to contain several advantages compared to evaluating the benefits of each proposed regional transmission facility individually. Several commenters explain that future benefits may be more stable or evenly distributed over time if they are evaluated for a portfolio of transmission facilities.[372] These comments are consistent with the fact that benefits from transmission facilities may change over time due to the inherent uncertainty in Long-Term Regional Transmission Planning and actual use of transmission facilities. An example of the evaluation of expanded benefits for a portfolio of transmission facilities is the MISO MVP Portfolio, which is a collection of 17 distinct transmission facilities, for which MISO evaluated a collective distribution of benefits.[373] Given the suite of minimum benefits proposed above, we believe that evaluating these benefits across a portfolio of transmission facilities as opposed to each individual transmission facility may result in significant administrative efficiencies for public utility transmission providers. Moreover, we believe that a more stable or even distribution of benefits from a portfolio of transmission facilities may also facilitate agreement on regional cost allocation that is at least roughly commensurate with estimated benefits.

234. Accordingly, we encourage this practice by public utility transmission providers. We clarify that public utility transmission providers that propose such an approach must include in their OATTs provisions describing how they would analyze the benefits of regional transmission facilities under a portfolio approach and whether the portfolio approach would be used for Long-Term Regional Transmission Planning universally to address transmission needs driven by changes in the resource mix and demand or would be used only in certain specified instances.

235. We recognize that a variety of commenters request that we require the use of a portfolio approach. While we recognize the advantages to a portfolio approach, we also acknowledge that the transition to a portfolio approach may represent a significant change for many public utility transmission providers and that the potential benefits may not warrant such a change in all instances.[374] We seek comment as to whether there are certain circumstances for which the Commission should require the use of a portfolio approach.

iv. Selection of Regional Transmission Facilities

236. Order No. 1000 requires public utility transmission providers to include in their OATTs a transparent and not unduly discriminatory process for evaluating whether to select a proposed regional transmission facility in the regional transmission plan for purposes of cost allocation.[375] Order No. 1000 does not mandate that public utility transmission providers select any transmission facility,[376] and the Commission declined for the most part to set minimum standards for the criteria used to select a transmission facility in a regional transmission plan for purposes of cost allocation. However, the Commission required that a public utility transmission provider's selection criteria be transparent and not unduly discriminatory.[377]

237. In the ANOPR, the Commission sought comment on whether and how public utility transmission providers should use information developed through long-term scenario planning to identify and select transmission facilities that meet future needs. In addition, the Commission sought comment on how public utility transmission providers should evaluate the benefits of proposed transmission facilities in their regional transmission planning processes, and whether the maximization of net benefits is an appropriate criterion for selecting transmission facilities in the regional transmission plan for purposes of cost

[366] ACPA and ESA Comments at 44–45; *see also* WIRES Comments at 7–8 (recommending accounting for benefits of transmission facilities over their useful lives).

[367] ANOPR, 176 FERC ¶ 61,024 at PP 53, 89, 91.

[368] ITC Comments at 11; State Agencies Comments at 21; ELCON Reply Comments at 3–4; *see also* Southern Comments at 13–14 (stating that vertically-integrated utilities already use a portfolio approach).

[369] U.S. DOE Comments at 40–41.

[370] PIOs Comments at 50–51.

[371] ACEG Reply Comments at 5, 8; ITC Comments at 6, 11, 28.

[372] U.S. DOE Comments at 40–41; *see also* February Joint Task Force Tr 24:15–22 (Matthew Allen) (stating his belief that transmission planners should be looking at projects and benefits on a portfolio basis to identify synergies).

[373] MISO, Multi Value Project Portfolio Results and Analyses at 1–6 (2012), *https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf.*

[374] *See, e.g.,* February Joint Task Force Tr. 76:10–12 (Kimberly Duffley) (asking that the Commission recognize regional differences that may result in portfolio projects working for one region but not for all regions).

[375] Order No. 1000, 136 FERC ¶ 61,051 at PP 328–331; Order No. 1000–A, 139 FERC ¶ 61,132 at P 452.

[376] Order No. 1000, 136 FERC ¶ 61,051 at P 331.

[377] *See* Order No. 1000–A, 139 FERC ¶ 61,132 at P 455.

allocation.[378] Finally, the Commission sought comment on whether public utility transmission providers would select more efficient or cost-effective transmission facilities in their regional transmission planning processes if they selected a portfolio of transmission facilities collectively.[379]

(a) Comments

238. With respect to the selection of transmission facilities in a regional transmission plan for purposes of cost allocation, commenters responding to the ANOPR provided a wide range of feedback. Several commenters emphasize that scenario planning should ensure the selection of more efficient or cost-effective transmission facilities,[380] while others argue that scenario planning should be solely for informational purposes.[381] Certain commenters believe that Commission guidance on selection criteria is essential,[382] while others argue that the Commission instead should provide flexibility for public utility transmission providers to adopt selection criteria.[383]

239. Many commenters also recommend that the Commission permit or require public utility transmission providers to use a portfolio approach when selecting transmission facilities.[384] U.S. DOE explains that the benefits of individual transmission facilities typically are distributed unevenly across a region, whereas portfolios of transmission facilities generally would be expected to confer benefits more broadly and evenly.[385]

240. With respect to specific selection criteria or methods, several commenters support an approach that would select transmission facilities with the highest level of net benefits instead of facilities with the highest benefit-cost ratio,[386] whereas other commenters support maintaining the maximum 1.25 benefit-cost ratio permitted by Order No. 1000.[387] Other commenters recommend a ''least-regrets'' approach to selecting transmission facilities, in which public utility transmission providers would select a transmission facility identified through scenario planning as beneficial across many or all scenarios.[388]

(b) Proposed Reform

241. We propose to require that public utility transmission providers, as part of the Long-Term Regional Transmission Planning that we propose to require in this NOPR, include in their OATTs: (1) Transparent and not unduly discriminatory criteria, which seek to maximize benefits to consumers over time without over-building transmission facilities, to identify and evaluate transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation that address transmission needs driven by changes in the resource mix and demand, consistent with the discussion below; and (2) a process to coordinate with the relevant state entities in developing such criteria.

242. Subject to certain minimum requirements, we propose to provide public utility transmission providers the flexibility to propose the selection criteria that they, in consultation with their stakeholders, believe will ensure that more efficient or cost-effective regional transmission facilities to address the region's transmission needs driven by changes in the resource mix and demand ultimately are selected in the regional transmission plan for purposes of cost allocation. As stated in Order No. 1000, to comply with Order Nos. 890 and 1000 transmission planning principles, the evaluation process must result in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand.[389] Further, we propose that the evaluation process and, specifically, the selection criteria must seek to maximize benefits to consumers over time without over-building transmission facilities.

243. We believe that this proposed flexibility would help accommodate the regional differences described in comments in response to the ANOPR, such as the different transmission needs each transmission planning region may have, the factors driving those needs, or market structures. We also believe that providing flexibility to public utility transmission providers in this regard would allow public utility transmission providers, in consultation with their stakeholders, to determine criteria for assessing the efficiency or cost-effectiveness of various regional transmission facilities, whether by reference, for example, to a benefit-cost ratio or by aggregate net benefits.[390]

244. Further, we believe this proposed flexibility would allow public utility transmission providers in each transmission planning region to develop selection criteria that could sufficiently balance individual state interests within each transmission planning region. We believe that providing an opportunity for state involvement in regional transmission planning processes is becoming more important as states take a more active role in shaping the resource mix and demand, which, in turn, means that those state actions are increasingly affecting the long-term transmission needs for which we are proposing to require public utility transmission providers to plan in this NOPR. Given the important role states play and the wide variety of potential approaches to selection criteria, we propose, as part of this requirement, that public utility transmission providers must consult with and seek support from the relevant state entities, as defined below, within their

[378] ANOPR, 176 FERC ¶ 61,024 at P 53.

[379] *See id.* PP 89, 91.

[380] AEP Comments at 10; Ameren Reply Comments at 3; *see also* Anbaric Comments at 32 (recommending that the Commission impose deadlines to ensure that transmission planning processes select offshore wind transmission facilities rather than allowing results to ''languish in protracted stakeholder processes''); AEE Reply Comments at 7–8 (requesting the adoption of transparency and enforcement mechanisms that would ensure the selection of transmission facilities that meet regional needs).

[381] *See* PJM Comments at 44 (stating that PJM's proposed long-term transmission planning process will ''inform stakeholder discussions''); *see also* Xcel Energy Comments at 20 (''The Commission should not require all issues identified in the holistic planning process to result in planned projects.'').

[382] PJM Comments at 46; *see also* City of New York Comments at 11 (arguing that the Commission should adopt common project selection criteria); Policy Integrity Comments at 17 (recommending greater uniformity in selection criteria); Massachusetts Attorney General Comments at 25 (arguing that consumer protection requires that selection criteria be ''clear, real, and objective'').

[383] MISO Comments at 32; National Grid Comments at 14–15; American Municipal Power Comments at 15.

[384] ITC Comments at 9, 11, 33; NARUC Comments at 12; PIOs Comments at 50–51; State Agencies Comments at 21; AEP Reply Comments at 33; ELCON Reply Comments at 3–4; *see also* Southern Comments at 13–14 (stating that vertically-integrated utilities already use a portfolio approach).

[385] U.S. DOE Comments at 40–41.

[386] ITC Comments at 11; ACEG Comments at 5–6; Policy Integrity Comments at 44–46; AEP Comments at 16.

[387] NARUC Comments at 12, 22–24 (advocating for maximizing benefit-cost ratio and retaining the benefit-cost ratio permitted by Order No. 1000); Entergy Comments at 18 (asking the Commission to retain the ability to have a benefit-cost ratio up to 1.25); Mississippi Commission Comments at 13–14 (arguing for a strict benefit-cost ratio of no less than 1.25 for economic projects with the possibility of a higher benefit-cost ratio for specific projects); Entergy Reply Comments at 12–13 (asserting that a higher benefit-cost ratio may be appropriate for a longer-term planning horizon).

[388] National Grid Comments at 16; American Municipal Power Comments at 32; PIOs Comments at 79; Chamber of Commerce Comments at 4; WIRES Comments at 7–8; AEP Comments at 9–10.

[389] Order No. 1000, 136 FERC ¶ 61,051 at P 328.

[390] We do not propose to change the Order No. 1000 requirement that public utility transmission providers may not impose a benefit-cost ratio requirement higher than 1.25. *See id.* P 646.

transmission planning region's footprint to develop the selection criteria. These selection criteria would be used in Long-Term Regional Transmission Planning to evaluate a transmission facility (or a portfolio of regional transmission facilities) for potential selection in the regional transmission plan for purposes of cost allocation.

245. While we propose significant flexibility in the development of selection criteria, we believe that certain minimum requirements must be in place for public utility transmission providers, their stakeholders, and states. The selection criteria must be transparent and not unduly discriminatory, and must aim to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand. Public utility transmission providers should seek to maximize benefits to consumers over time without over-building transmission facilities. Public utility transmission providers should propose specific selection criteria to achieve this balance over time. We note, as discussed above, that regional transmission planning and cost allocation processes generally have resulted in few regionally planned transmission facilities being selected and ultimately built.[391] However, the reforms proposed in this NOPR seek to better ensure that the more efficient or cost-effective regional transmission facilities are identified through Long-Term Regional Transmission Planning and acknowledge commenters' concerns about over-building due to uncertainties of future transmission system conditions.[392] We acknowledge the inherent uncertainty involved in predicting future transmission needs and emphasize that we are not proposing to require public utility transmission providers to achieve, *ex post,* any particular outcome but rather to adopt an evaluation process that, *ex ante,* aims to maximize consumer benefits over time without over-building transmission facilities.

246. Public utility transmission providers would bear the burden on compliance of demonstrating that their proposed selection criteria satisfy the Order Nos. 890 and 1000 transmission planning principles in the context of Long-Term Regional Transmission Planning, even if public utility transmission providers propose to use selection criteria that they also use in their existing regional transmission planning process.[393] Likewise, public utility transmission providers would bear the burden on compliance of demonstrating that their proposed selection criteria seek to maximize benefits to consumers over time without over-building transmission facilities. Moreover, we propose to require that public utility transmission providers demonstrate on compliance that they developed their proposed selection criteria in consultation with the relevant state entities in their transmission planning region's footprint.

247. We propose that, consistent with Order No. 1000, the developer of a transmission facility selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning to address transmission needs driven by changes in the resource mix and demand would be eligible to use the applicable cost allocation method for the Long-Term Regional Transmission Facility.[394] We also propose that the existing transmission developer requirements would apply, including that the developer of the selected regional transmission facility must submit a development schedule that indicates the required steps, such as the granting of state approvals necessary to develop and construct the transmission facility such that it meets the transmission needs of the transmission planning region.[395] To the extent the relevant state entities in a transmission planning region agree to a State Agreement Process, as described in the Regional Transmission Cost Allocation section below, the development schedule should also include relevant steps related to that process.[396]

248. Given the longer-term nature of transmission needs driven by changes in the resource mix and demand, we note that the required development schedule may make it unnecessary for the developer of a transmission facility selected in the regional transmission plan for purposes of cost allocation to take actions or incur expenses in the near-term if the transmission facility will not need to be in service in the near-term. We also note that, with respect to a transmission facility selected in the regional transmission plan for purposes of cost allocation to meet transmission needs driven by changes in the resource mix and demand, public utility transmission providers may make its selection status subject to the outcomes of subsequent Long-Term Regional Transmission Planning cycles, such that a previously selected transmission facility is no longer needed. Public utility transmission providers should include in their selection criteria how they will address the selection status of a previously selected transmission facility based on the outcomes of subsequent Long-Term Regional Transmission Planning cycles.

249. Consistent with our approach to benefits analysis, we clarify that public utility transmission providers would have the flexibility to propose to use a portfolio approach in selecting regional transmission facilities in the regional transmission plan for purposes of cost allocation that address transmission needs driven by changes in the resource mix and demand. Public utility transmission providers that propose such an approach would have to include in their OATTs provisions describing whether the selection criteria would apply to one proposed regional transmission facility or to a portfolio of regional transmission facilities; and whether the portfolio approach would be used for Long-Term Regional Transmission Planning universally to address transmission needs driven by changes in the resource mix and

[391] *Supra* Need For Reform: The Transmission Investment Landscape Today (explaining in some transmission planning regions, regional transmission investment declined after issuance of Order No. 1000, while in other regions, regional transmission planning processes have not resulted in the selection of a single regional transmission facility); *see also* Minnesota Commerce Comments at 3 (arguing the risk of status quo is worse than the risk of over-building).

[392] *See, e.g.,* NASUCA Comments at 3–5; November 2021 Technical Conference Tr. at 29 (testimony of Dr. Patton).

[393] For example, if public utility transmission providers in a transmission planning region propose to use existing selection criteria, they should explain on compliance how those criteria also are just and reasonable with respect to the selection of regional transmission facilities identified to address transmission needs driven by changes in the resource mix and demand.

[394] We note that the applicable cost allocation method for a Long-Term Regional Transmission Facility may not be *ex ante,* as discussed in the Regional Transmission Cost Allocation section below.

[395] Order No. 1000–A, 139 FERC ¶ 61,132 at P 442. The Commission also stated that, as part of the ongoing monitoring of the progress of a transmission facility once it is selected, the public utility transmission providers in a transmission planning region must establish a date by which state approvals to construct must have been achieved that is tied to when construction must begin to timely meet the need that the facility is selected to address. If such critical steps have not been achieved by that date, then the public utility transmission providers in a transmission planning region may ''remove the transmission facility from the selected category and proceed with reevaluating the regional transmission plan to seek an alternative solution.'' *Id.*

[396] *Infra* P 302 (describing cost allocation requirements for Long-Term Regional Transmission Planning).

demand or would be used only in certain specified instances.

250. We preliminarily find that the development and analysis of Long-Term Scenarios cannot remedy the deficiencies in the Commission's existing regional transmission planning requirements without the inclusion of transparent and not unduly discriminatory selection criteria that are used to evaluate transmission facilities (or portfolios of transmission facilities) for potential selection in the regional transmission plan for purposes of cost allocation. Absent such criteria, public utility transmission providers' Commission-jurisdictional rates may be unjust and unreasonable and unduly discriminatory and preferential.

251. As noted above, we recognize the inherent uncertainty involved in predicting future transmission needs, including those driven by changes in the resource mix and demand, and many commenters express concern that imperfect information may lead to selecting transmission facilities in the regional transmission plan for purposes of cost allocation that become stranded assets. However, we believe that there are selection criteria that public utility transmission providers could adopt, following consultation with stakeholders and with relevant state entities in their transmission planning region's footprint, to minimize these risks while allowing for investment in transmission facilities that more efficiently or cost-effectively meet transmission needs driven by changes in the resource mix and demand. For example, under a least-regrets approach, public utility transmission providers in a transmission planning region would select a transmission facility (or portfolio of transmission facilities) in their regional transmission plan for purposes of cost allocation that is net-beneficial in most or all Long-Term Scenarios, even if other transmission facilities have more net benefits or a higher benefit-cost ratio in a single Long-Term Scenario. Another approach is a weighted-benefits approach, in accordance with which public utility transmission providers in a transmission planning region would select a transmission facility (or portfolio of regional transmission facilities) in their regional transmission plan for purposes of cost allocation based on its probability-weighted average benefits, where probabilities have been assigned to each Long-Term Scenario studied.[397]

252. We seek comment on the requirements proposed in this section of the NOPR. In addition, we seek comment on whether relevant state entities should have the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility[398] to enable such facility to satisfy the public utility transmission provider's selection criteria (*e.g.,* any benefit-cost threshold), and if so, whether the Commission's final rule in this proceeding should include requirements to facilitate such an opportunity for the relevant state entities.[399] Commenters on this issue should also address preferred approaches to implement such a voluntary funding opportunity for relevant state entities for Long-Term Regional Transmission Facilities. For example, we seek comment on what mechanism would be appropriate to document agreement from the relevant state entities to voluntarily fund (*e.g.,* commit customers within the state to fund) the cost of, or a portion of the cost of, a Long-term Regional Transmission Facility to enable such facility to satisfy the public utility transmission provider's selection criteria; whether a public utility transmission provider should be required to include a pro forma agreement for such an opportunity in its OATT for facilitation purposes; how the Commission and the public utility transmission providers would be assured that the commitment by the relevant state entity is sufficiently binding; and whether another manner for relevant state entities to make and fulfill such a commitment would be preferable. We also seek comment on what stage in the regional transmission planning process is the most appropriate point for such an opportunity for the relevant state entities. We also seek comment on whether such opportunity for the relevant state entities to voluntarily fund the cost of, or the portion of the cost of, a Long-Term Regional Transmission Facility should be limited to relevant state entities or should be expanded to include interconnection customers.[400]

c. Implementation of Long-Term Regional Transmission Planning

253. We recognize that the timing of the proposed Long-Term Regional Transmission Planning requirement has the potential to overlap with public utility transmission providers' near-term assessment of transmission needs captured by existing regional transmission planning processes. We propose that public utility transmission providers must explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning interacts with existing regional transmission planning efforts. We recognize the possibility that there may be overlap in the time horizon for the proposed Long-Term Regional Transmission Planning and existing near-term regional transmission planning processes and that they will likely inform each other. It is also possible that, in some cases, transmission facilities selected in a regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand may provide near-term reliability or economic benefits and thus potentially displace regional transmission facilities that are under consideration as part of existing regional transmission planning processes.

254. We seek comment on the requirement proposed in this section of the NOPR. In particular, we seek comment on whether there is a need to coordinate the initial timing sequences between Long-Term Regional Transmission Planning and the existing near-term regional transmission planning processes.

255. We also seek comment on whether the Commission should host a periodic forum for public utility transmission providers, transmission experts, relevant federal and state agencies, and other stakeholders to share best practices in implementing Long-Term Regional Transmission Planning as proposed herein. The Commission could, for example, host a tri-annual technical conference focused on topics such as choice of best

[397] Brattle-Grid Strategies Oct. 2021 Report at 59–60.

[398] As noted *infra* note 507, we propose to define a Long-Term Regional Transmission Facility as a transmission facility identified as part of Long-Term Regional Transmission Planning and selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand.

[399] For Long-Term Regional Transmission Facilities, such an opportunity for the relevant state entities could enable them to assign a value to achieving of their particular policy goals while ensuring that their customers bear the corresponding costs. As the New Jersey Commission suggests, ''some states ascribe additional 'value' to the achievement of public policy goals, backed by a willingness to bear the costs associated with those benefits.'' NJ Commission, Comments, Docket No. AD21–15–000, at 4 (filed Apr. 1, 2022). *See also* Maryland Energy Admin Comments at 8–9; Maryland Commission Reply Comments at 2.

[400] We note that some commenters have suggested that interconnection customers similarly be afforded an opportunity to voluntarily contribute funds to a Long-Term Regional Transmission Facility so as to facilitate its selection. Enel Comments at 12–14; ACPA and ESA Comments at 75–79.

available data, principles for developing plausible scenarios, and techniques for evaluating benefits of proposed transmission facilities. We seek comment on the benefits such a forum might provide, and, if implemented, how such a forum should be structured and the frequency on which it should be held.

2. Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices in Long-Term Regional Transmission Planning

a. ANOPR

256. In the ANOPR, the Commission sought comment on whether the development of longer-term scenarios for planning purposes should be pursued and, if so, whether and how Grid-Enhancing Technologies (GETs) [401] should be accounted for in determining what transmission is needed under such scenarios.[402] The Commission solicited input on how it could require greater consideration of GETs and asked commenters to describe any challenges that exist in establishing such a requirement and how they might be addressed.[403]

b. Comments

257. The majority of commenters on the ANOPR support the Commission requiring public utility transmission providers to consider GETs in the regional transmission planning process, emphasizing that advanced technologies can optimize existing transmission corridors and provide cost-effective solutions for consumers.[404] NARUC states that an effective transmission planning process should maximize the use of existing transmission and build new transmission only where necessary or economic, asserting that the transmission planning process needs a clear pathway for consideration of alternative transmission solutions, including GETs.[405]

258. Some commenters, such as Duke, EEI, and MISO Transmission Owners, either oppose the use of GETs in regional transmission planning, do not see it as a fit for regional transmission planning for transmission needs driven by changes in the resource mix and in demand, or urge caution, as they assert that the technologies are not always substitutes for transmission facilities.[406] AEP notes that GETs should be considered as long as they are evaluated on an equal footing, for example, evaluating technology life span on equal footing.[407]

259. Market monitors, such as the PJM Market Monitor, emphasize the value that dynamic line ratings [408] and other GETs could add in maximizing existing transmission capacity but express caution about how they would be implemented and compensated.[409] Potomac Economics sees some benefit to GETs in helping transmission owners avoid inefficient transmission upgrade costs to mitigate congestion but expresses concern about mandating long-term planning studies that would involve RTOs/ISOs or transmission providers ''speculating on'' GETs.[410]

260. RTOs/ISOs generally indicate that they currently consider the use of GETs in the regional transmission planning process. CAISO supports the use of GETs in the regional transmission planning process.[411] MISO indicates that its current regional transmission planning process allows for the consideration of GETs, but also indicates that these technologies alone will not be able to address the changing needs of the transmission system.[412] PJM states that, as part of its regional transmission planning process, it evaluates GETs proposals, to the extent submitted, in a manner not materially different from its evaluation of other project proposals.[413] PJM also notes that it conducts an advanced technology pilot program as a testing ground for new technologies that require integration into PJM operations and markets.[414] Additionally, SPP states that it supports the use of certain GETs where they can be appropriately used in regional transmission planning. It contends that it has considered certain GETs in the regional transmission planning process, but notes that certain technologies, such as dynamic line ratings or topological controls, have historically not lent themselves readily to utilization in the regional transmission planning process.[415]

261. RTOs/ISOs, notably MISO and PJM, also discuss the importance of ensuring that public utility transmission providers understand any GETs that may be deployed on the system and their limitations, as well as understanding the challenges of integrating GETs into existing systems; for example, whether there is a need to change telemetry, modeling, other operating tools, and protocols, all of which necessitate careful consideration.[416] PJM notes the value of its ongoing Advanced Technology Pilot Program in addressing implementation challenges and identifying system risks associated with GETs. Expressing concerns about the deployment of GETs by nonincumbent transmission developers, PJM recommends that the Commission request that the industry, via NERC and/or U.S. DOE, develop a technology application guide addressing where, when, and how to apply GETs.[417] MISO states that it is important not to overstate the capabilities of GETs in the regional transmission planning process, as these technologies generally cannot substitute for long-term investment in transmission facilities that are needed to address the evolving resource mix, and notes the inherent uncertainty in forecasting power flows and congestion longer into the future.[418]

262. A few commenters set forth criteria that public utility transmission providers should be required to consider in the regional transmission planning process to promote the use of GETs. These include: Optimizing the utilization of existing and new transmission facilities; [419] requiring energy efficiency as a design criterion for every transmission capital project; [420] and requiring public utility transmission providers to show where they have incorporated GETs in their

[401] For purposes of a prior workshop, Commission staff stated that GETs increase the capacity, efficiency, or reliability of transmission facilities. Commission staff further stated that these technologies include but are not limited to: (1) Power flow control and transmission switching equipment; (2) storage technologies; and (3) advanced line rating management technologies. *Grid-Enhancing Technologies,* Notice of Workshop, Docket No. AD19–19–000 (issued Sept. 9, 2019).

[402] ANOPR, 176 FERC ¶ 61,024 at P 48.

[403] *Id.* P 158.

[404] *See, e.g.,* National Grid Comments at 32; PJM Comments at 59–62; State of Massachusetts Comments at 20; *see also Joint Fed.-State Task Force on Elec. Transmission,* Transcript of Nov. 10, 2021 Meeting, Docket No. AD21–15–000, at 97:5–11 (Chair Scripps) (supporting consideration of GETs in regional transmission planning).

[405] NARUC Comments at 9.

[406] Duke Comments at 13; EEI Comments at 7; MISO TOs Comments at 46–47.

[407] AEP Comments at 15.

[408] A dynamic line rating is ''a transmission line rating that applies to a time period of not greater than one hour and reflects up-to-date forecasts of inputs such as (but not limited to) ambient air temperature, wind, solar heating, transmission line tension, or transmission line sag.'' *Managing Transmission Line Ratings,* Order No. 881, 177 FERC ¶ 61,179, at PP 235, 238 (2021); 18 CFR 35.28(b)(14).

[409] PJM Market Monitor Comments at 13.

[410] Potomac Economics Comments at 4.

[411] CAISO Comments at 113–114.

[412] MISO Comments at 45–46.

[413] PJM Comments at 59–60.

[414] *Id.* at 60.

[415] SPP Comments at 12.

[416] MISO Comments at 28; PJM Comments at 62–63.

[417] PJM Comments at 60–63.

[418] MISO Comments at 45–46.

[419] Certain TDUs Comments at 22.

[420] CTC Global Comments at 6.

regional transmission planning process where they are cost-effective.[421]

263. Other commenters offer specific suggestions on how GETs could be implemented. TAPS urges the Commission to ''[m]ake more explicit the mandate to consider GETs as part of regional planning processes,'' arguing that Order No. 1000's requirement to consider non-transmission alternatives ''appears insufficient to ensure robust consideration of GETs in the planning process.'' [422] In addition, TAPS recommends that the Commission expand the MISO/PJM Targeted Market Efficiency Process to the regional transmission planning process to promote the use of GETs for quick fixes identified in the regional transmission planning process.[423]

264. PJM suggests that the Commission require RTOs/ISOs and non-RTO/ISO transmission planning regions to ''develop a robust process to account for the potential for [GETs] to be integrated into the planning processes as part of both near-term and long-range expansion options before requiring that new greenfield transmission be built.'' [424] Along similar lines, WATT Coalition suggests that for proposed transmission projects with an initial cost estimate above $10 million, the Commission should require the transmission planning region to show documentation of its evaluation of alternative solutions utilizing GETs.[425]

265. EDF offers a specific application for GETs implementation, suggesting that the Commission encourage and even require that GETs be proposed to address outages that have a material impact on market efficiency, reliability, and resiliency. EDF notes that transmission system upgrades are often associated with multi-month outages, which can have a severe impact on market efficiency and suggests that GETs be proposed in combination with traditional upgrades or to minimize the impact of outages that can result from the construction of transmission upgrades.[426] WATT Coalition builds on this notion, suggesting that the Commission require transmission owners and planning authorities to propose solutions, including GETs, that minimize the impacts of long duration outages.[427]

266. WATT Coalition encourages the Commission to require the periodic publication of a report on grid utilization to show transmission usage data in order to provide system planners with a ''more holistic profile of their system capacity, establishing a new dataset for targeted GETs deployment and associated consumer savings.'' [428] Arizona Commission adds that an independent transmission monitor could use information collected to provide feedback on how public utility transmission providers consider GETs.[429]

c. Need for Reform

267. Since Order No. 1000, commercially available technologies to make transmission systems operate more efficiently or cost-effectively have greatly advanced. This influx of new and improved technologies has the potential to improve the operation of new and existing transmission facilities and defer new transmission investments. As such, the consideration of new technological innovations in regional transmission planning processes could help to ensure that these processes are identifying more efficient or cost-effective regional transmission facilities and in turn, that Commission-jurisdictional rates are just and reasonable.

268. When the Commission issued Order No. 1000, integrating these new technologies was not a major focus of the rule, partly because many new technologies were either still in development or not yet widely in use. After more than a decade, the technologies available today may help to ensure that the transmission system operates more efficiently or cost-effectively. However, Order No. 1000-compliant regional transmission planning processes do not appear to have kept time with technology advancements and potentially need to be updated to ensure that they are appropriately considering these new technologies.

269. Recently, in Order No. 881, which required more accurate transmission line ratings in near-term transmission service through the use of ambient-adjusted transmission line ratings,[430] the Commission highlighted the benefits of dynamic line ratings, including permitting greater power flows than would otherwise be allowed, aiding in the detection of situations where power flows should be reduced to maintain safe and reliable operations, and avoiding unnecessary wear on transmission equipment.[431] Other benefits of dynamic line ratings that the Commission emphasized in Order No. 881 include strategic deployments and targeted applications in which dynamic line ratings can provide net benefits to customers by increasing the accuracy and power carrying capabilities of a line.[432] While the Commission declined to mandate dynamic line ratings in Order No. 881, it required RTOs/ISOs to establish and maintain systems and procedures necessary to allow transmission owners to electronically update transmission line ratings for ambient-adjusted ratings, which could facilitate the use of dynamic line ratings.[433] In addition, the Commission issued a Notice of Inquiry to continue to explore the implementation of dynamic line ratings.[434] This Notice of Inquiry sought comment on: Whether and how the required use of dynamic line ratings is needed to ensure just and reasonable Commission-jurisdictional rates; potential criteria for dynamic line ratings requirements; the benefits, costs, and challenges of implementing dynamic line ratings; the nature of potential dynamic line ratings requirements; and potential timeframes for implementing dynamic line ratings requirements.[435]

270. At a recent workshop held by Commission staff,[436] participants highlighted the benefits of advanced power flow control devices,[437] such as their ability to modify a transmission line's electrical characteristics to increase or decrease power flowing through the line without increasing the capacity of the line. Participants also highlighted that optimal transmission switching acts to completely open or close off routes to power flow. Finally, participants noted that advanced power

[421] PIOs Comments at 97.

[422] TAPS Comments at 2.

[423] *Id.* at 22.

[424] PJM Comments at 63.

[425] WATT Coalition Comments at 4.

[426] EDF Comments at 16–18.

[427] WATT Coalition Comments at 5.

[428] *Id.*

[429] Arizona Commission Reply Comments at 12.

[430] Order No. 881, 177 FERC ¶ 61,179 at P 34.

[431] *Id.* P 253.

[432] *Id.*

[433] *Id.* P 255.

[434] *Implementation of Dynamic Line Ratings,* 178 FERC ¶ 61,110 (2022).

[435] *Id.* P 1.

[436] *Grid-Enhancing Technologies,* Notice of Workshop, Docket No. AD19–19–000 (issued Sept. 9, 2019).

[437] Advanced power flow control devices serve a transmission function. These devices can help the system operator control power flows over a given path and can include phase shifting transformers (also known as phase angle regulators) and devices or systems necessary for implementing optimal transmission switching. Advanced power flow control devices allow power to be pushed and pulled to alternate lines with spare capacity leading to maximum utilization of existing transmission capacity. *See* T. Bruce Tsuchida et al., The Brattle Group, *Unlocking the Queue with Grid-Enhancing Technologies,* at 19–20 (Feb. 1, 2021), *https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.*

flow control devices, including optimal transmission switching, provide the tools to effectively control and route power to lines that have more capacity than those that do not, which can reduce congestion, reduce costs to consumers, and increase reliability of the transmission system.

271. To address the issues described above, we propose reforms to require public utility transmission providers to more fully consider two specific technologies—dynamic line ratings and advanced power flow control devices—in regional transmission planning processes.

d. Proposed Reform

272. In order to help ensure that regional transmission planning processes identify more efficient or cost-effective transmission facilities for selection in the regional transmission plan for purposes of cost allocation, we propose to require that public utility transmission providers in each transmission planning region more fully consider in regional transmission planning and cost allocation processes two specific technologies: The incorporation into transmission facilities of dynamic line ratings and advanced power flow control devices. We believe that selecting transmission facilities that incorporate dynamic line ratings or advanced power flow control devices in the regional transmission plan for purposes of cost allocation may offer a more efficient or cost-effective alternative to other regional transmission facilities in certain instances.

273. Specifically, we believe it is possible that selecting transmission facilities that incorporate such technologies serving a transmission function in the regional transmission plan for purposes of cost allocation could be more efficient or cost-effective than a proposed regional transmission facility that does not use such technologies. For example, selecting in the regional transmission plan for purposes of cost allocation a transmission facility that is designed with the equipment necessary to support dynamic line ratings may provide greater benefits through reduced production costs than a similar transmission facility that does not include such equipment. Likewise, selecting in the regional transmission plan for purposes of cost allocation a transmission facility that incorporates an advanced power flow control device may provide greater production costs benefits under transmission outage scenarios than another transmission facility.

274. To facilitate greater use of these technologies where warranted, we propose to require that public utility transmission providers in each transmission planning region consider for each identified regional transmission need whether selecting transmission facilities in the regional transmission plan for purposes of cost allocation that incorporate dynamic line ratings or advanced power flow control devices would be more efficient or cost-effective than transmission facilities that do not incorporate these technologies. Specifically, such consideration should include first, whether incorporating dynamic line ratings or advanced power flow control devices into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other potential transmission facilities. Second, when evaluating transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation, the public utility transmission providers in the transmission planning region must also consider whether incorporating dynamic line ratings and advanced power flow control devices as part of any potential regional transmission facility would be more efficient or cost-effective. We propose that this requirement apply in all aspects of the regional transmission planning processes, including the existing regional transmission planning processes for near-term regional transmission needs and Long-Term Regional Transmission Planning, as proposed in this NOPR. As is the case for any other transmission facility selected in the regional transmission plan for purposes of cost allocation, we propose that the costs to incorporate dynamic line ratings or advanced power flow control devices that are selected in the regional transmission plan for purposes of cost allocation—whether as an addition to an existing transmission facility or as part of a new regional transmission facility—will be allocated using the applicable regional cost allocation method.

275. As required by Order No. 1000, the evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected in the regional transmission plan for purposes of cost allocation.[438] This process must now include the consideration of dynamic line ratings and advanced power flow control devices and why they were not incorporated into selected regional transmission facilities.

276. As discussed above, the ANOPR requested comment on GETs as a larger category of transmission technologies. While we recognize that there are likely other novel technologies that public utility transmission providers could consider as they develop their regional transmission plans, we are not proposing to mandate their consideration at this time. We believe that there is enough operational experience with dynamic line ratings and power flow control devices such that public utility transmission providers should be able to adequately consider their operations in the regional transmission planning process. In addition, the nature of dynamic line ratings and advanced power flow control devices allows for consideration in regional transmission planning and cost allocation processes in a way that may not be possible for other technologies.[439]

277. We seek comment on the requirements proposed in this section of the NOPR. We also seek comment on whether there are other transmission technologies serving a transmission function that should be considered in regional transmission planning and cost allocation processes. Finally, we seek comment on whether non-RTO/ISO transmission planning regions should be required to update their energy management systems or make other similar changes if dynamic line ratings are identified as a more efficient or cost-effective transmission facility selected in the regional transmission plan for purposes of cost allocation.[440]

V. Regional Transmission Cost Allocation

278. We preliminarily find that reforms to public utility transmission providers' regional cost allocation methods are necessary to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential. As discussed below, we propose to require that public utility transmission providers in each transmission planning region seek the agreement of relevant state entities within the transmission planning region regarding the cost allocation method or methods that will

[438] Order No. 1000, 136 FERC ¶ 61,051 at P 328; Order No. 1000–A, 139 FERC ¶ 61,132 at P 267.

[439] For example, while transmission topology optimization can serve a useful function in optimizing system flows and deferring transmission investment in the short-term, system conditions over 5 to 20 years in the future may be too uncertain to rely on system reconfiguration to address identified transmission needs.

[440] *Cf.* 18 CFR 35.25(g)(13)(i) (requiring each RTO/ISO to maintain systems and procedures to accept and utilize dynamic line ratings data).

apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning and revise their OATTs to include the method or methods.[441]

279. We also propose a reform to facilitate an additional opportunity for involvement of state regulators in decisions about how the costs of transmission facilities selected in a regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning will be allocated. Specifically, this reform would require public utility transmission providers in each transmission planning region to add a time period for states to negotiate an alternate cost allocation method for a transmission facility selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning.

A. Background

280. In Order No. 890, the Commission noted that for a transmission planning process to comply with the final rule, it must address the allocation of costs of new transmission facilities. The Commission required public utility transmission providers and their stakeholders to develop a new cost allocation method, if needed, for any new transmission facilities that did not fall under public utility transmission providers' existing cost allocation methods.[442] The Commission stated that such methods should consider: (1) Whether a proposed cost allocation method fairly assigns costs among participants, including those that cause them to be incurred and those that otherwise benefit from them; (2) whether a proposed cost allocation method provides adequate incentives to construct new transmission; and (3) whether a proposed cost allocation method is generally supported by the region's state authorities and participants.[443]

281. In Order No. 1000, the Commission determined that, while existing cost allocation methods may have sufficed in the past, changing circumstances in the industry led to the need for changes to cost allocation requirements.[444] The Commission observed that, as transmission needs increased, the challenges in allocating the cost of transmission appeared to grow more acute.[445] The Commission further found that, in ''the absence of clear cost allocation rules for regional transmission facilities, there is a greater potential that public utility transmission providers and nonincumbent transmission developers may be unable to develop transmission facilities that are determined by the region to meet their needs.''[446] As a result, the Commission required each public utility transmission provider to have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation and established a set of six cost allocation principles that public utility transmission providers' regional cost allocation methods must satisfy.[447] The Commission determined that this principles-based approach requires the allocation of the costs of new transmission facilities in a manner that is at least roughly commensurate with the benefits received by those that pay those costs while allowing for regional flexibility.[448]

282. The six regional transmission cost allocation principles adopted in Order No. 1000 are: (1) The costs of transmission facilities selected in a regional transmission plan for purposes of cost allocation must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; (2) those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities; (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1; (4) costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs; (5) the method for determining benefits and identifying beneficiaries must be transparent; and (6) there may be different regional cost allocation methods for different types of transmission facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.[449] The Commission declined to require that public utility transmission providers adopt a universal or comprehensive definition of ''benefits'' and ''beneficiaries'' of regional transmission facilities, instead permitting regional flexibility and examining each transmission planning region's definitions on compliance.[450]

283. While the Commission determined that generator interconnection was outside the scope of Order No. 1000, it also stated that public utility transmission providers could propose a regional transmission cost allocation method that allocates costs directly to generators as beneficiaries, but any effort to do so must be consistent with the Order No. 2003 generator interconnection process.[451] No public utility transmission providers have proposed a regional cost allocation method that allocates costs directly to generators, instead allocating all costs of transmission facilities selected in a regional transmission plan for purposes of cost allocation to transmission customers.

284. On compliance, public utility transmission providers in each transmission planning region adopted varying regional transmission cost allocation methods to comply with the cost allocation principles of Order No. 1000. The majority of these methods allocate the costs of transmission facilities selected in a regional transmission plan for purposes of cost allocation that address reliability needs separately from those that address economic needs, and separately from those that address transmission needs driven by Public Policy Requirements.

285. Some public utility transmission providers' Order No. 1000-compliant regional transmission cost allocation methods identify benefits across a portfolio of transmission facilities rather than on a facility-by-facility basis. An example of a transmission planning region accounting for broader benefits is MISO, which accounts for the following benefits in their MVP portfolio:[452]

- Economic: increased market efficiency (congestion and fuel savings and operating reserves), deferred generation investment (system planning

[441] We are not proposing to require any changes to existing interregional cost allocation methods for interregional transmission facilities that are selected in the regional transmission plan for purposes of cost allocation and that the Commission previously accepted as compliant with Order No. 1000.

[442] Order No. 890, 118 FERC ¶ 61,119 at PP 557–558.

[443] *Id.* P 559.

[444] Order No. 1000, 136 FERC ¶ 61,051 at P 497.

[445] *Id.* P 498.

[446] *Id.* P 558.

[447] *Id.*

[448] *Id.* P 10; Order No. 1000–A, 139 FERC ¶ 61,132 at P 647.

[449] Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 637, 646, 657, 668, 685.

[450] *Id.* P 624.

[451] Order No. 1000–A, 139 FERC ¶ 61,132 at P 680.

[452] MISO, *Multi-Value Project Portfolio, Detailed Business Case, https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Detailed%20Business%20Case117056.pdf.* More general benefits requirements for MVP Projects are described at MISO, FERC Electric Tariff, Attachment FF, Section II.C.2, .5.

reserve margins and transmission line losses), and other capital benefits (wind turbine investment and future transmission investment); [453]

• Reliability: transmission line overloads and system voltage constraints mitigated, transient stability benefits, mitigation of fault conditions that could cause system instability, voltage stability, increased transfer capacity, increased transfer capability; [454]

• Policy: reliably enables the delivery of energy in support of policy mandates.[455]

B. ANOPR

286. In the ANOPR, the Commission recognized that reforms to regional transmission planning cannot be successful without ensuring that transmission providers and customers alike are able to identify the types of benefits these transmission facilities can provide and also identify the beneficiaries that would receive those benefits, along with the relative proportion of benefits that accrue to each of those beneficiaries.[456] Acknowledging that cost allocation methods can be ''difficult and controversial,'' particularly for regional transmission facilities that may be both more costly and have potentially broad benefits, the Commission sought comment on whether there should be reforms to cost allocation in regional transmission planning and cost allocation processes.[457]

287. Additionally, the Commission noted that one way to add oversight to the regional transmission planning and cost allocation processes could be to involve state commissions in those processes.[458] For example, the Commission pointed to SPP's Regional State Committee (RSC), which provides collective state regulatory agency input in areas under the RSC's primary responsibilities and on matters of regional importance related to the development and operation of the bulk electric transmission system. Pursuant to the SPP Bylaws, ''with respect to transmission planning, the RSC will determine whether transmission upgrades for remote resources will be included in the regional transmission planning process and the role of transmission owners in proposing transmission upgrades in the regional planning process.'' [459] The Commission sought comment on whether this type of model, or other models that may be proposed, could be expanded to other regions and other topics; for example, whether a state-led committee could, *inter alia,* provide insight into regional transmission facility costs and cost allocation methods.[460]

C. Comments

288. In response to the ANOPR, the Commission received comments from a broad range of stakeholders, generally recognizing the importance of cost allocation to successful development of more efficient or cost-effective regional transmission facilities and advocating different ways to reduce the likelihood that controversy regarding who pays for regional transmission facilities obstructs their development and to ensure the costs of regional transmission facilities are allocated roughly commensurate with benefits.

289. In their comments, many state regulators and groups advocate for increased state involvement in cost allocation decisions.[461] NARUC explains that most states think that more should be done to encourage and incent states with similar public policy profiles to use the State Agreement Approach, which it says has the benefit of being a stakeholder-driven product that enjoys significant state support.[462] NARUC further asserts that planners could provide a platform for states with similar policy objectives to better coordinate and agree upon cost allocation, while urging that regions should ''retain the flexibility to develop innovative approaches to allocating the costs.'' [463] NESCOE asserts that states need to occupy a central role in cost allocation, consistent with applicable state requirements.[464] NESCOE calls for state decision making in the evaluation and selection of projects providing public policy benefits and for a robust role in the regional transmission planning processes.[465] Some commenters note that they are already pursuing cost allocation reforms with transmission planning regions.[466] Arizona Commission contends that, because state commissions are already tasked with ensuring retail rates are just and reasonable for their ratepayers, increased state commission involvement in cost allocation processes would better allow state commissions to establish just and reasonable retail rates.[467] New Jersey Commission states that to enable cost allocation reforms the Commission could mandate public utility transmission providers institute a process for states to submit portions of their public policies for consideration into PJM's RTEP.[468] Mississippi Commission notes that where one or more states have common economic development, environmental, or other goals, and require transmission investment to achieve those goals, the cost of such projects could be allocated to those states in an agreed upon amount.[469] Northwest and Intermountain notes that a strong state role is particularly important in non-RTO/ISO regions.[470] ACPA and ESA state that a Commission approach to cost allocation could include cost contributions from states and interconnection customers.[471]

290. But while there is broad agreement on the importance of states' role in cost allocation, a number of states indicate that it is difficult for them to participate in a timely manner in the regional transmission planning and cost allocation processes to address concerns regarding cost allocation.[472] District of Columbia's Office of the People's Counsel calls for the Commission to facilitate ''the participation of any group that may be subject to cost allocation in early planning stages to determine which outcome best serves the needs of all the customers in that region.'' [473] Other state commissions also call for greater involvement in cost allocation

[453] MISO, *Multi-Value Project Portfolio, Detailed Business Case* at 27.

[454] *Id.* at 17–19.

[455] *Id.* at 21.

[456] ANOPR, 176 FERC ¶ 61,024 at P 84.

[457] *Id.* PP 83–89.

[458] ANOPR, 176 FERC ¶ 61,024 at*Id.* P 176.

[459] ANOPR, 176 FERC ¶ 61,024 at P 176*Id.* (citing SPP, Governing Documents Tariff, Bylaws, Section 7.2 (Regional State Committee) (1.0.0)).

[460] ANOPR, 176 FERC ¶ 61,024 at*Id.* P 177.

[461] Members of the Task Force similarly advocated for state regulatory involvement in cost allocation processes, emphasizing that states are not merely stakeholders. *See, e.g., Joint Fed.-State Task Force on Elec. Transmission,* Transcript of Feb. 16, 2022 Meeting, Docket No. AD21–15–000, at 107:1–6 (Chair French), 108:17–18 (Comm'r Duffley), 109:2 (Chair Nelson), 110:4–5, 15–16 (Chair Stanek), 112:3–5 (Comm'r Rechtschaffen).

[462] NARUC Comments at 25; *see also* Ohio Commission Comments at 15 (noting the PJM State Agreement Approach and related ''hard work and progress that has already been made in incorporating state policy goals into transmission planning in the PJM region.'');''); Pennsylvania Commission Comments at 6 (similarly calling for respect of the State Agreement Approach).

[463] NARUC Comments at 25–26.

[464] NESCOE Comments at 21–25.

[465] *Id.* at 49.

[466] NESCOE Comments*Id.* at 47–48; MISO Comments at 8, 21.

[467] Arizona Commission Comments at 7; *see also* SPP RSC Comments at 10 (urging the Commission to seek approaches that enhance state authority rather than diminishing or diluting it).

[468] New Jersey Commission Comments at 12–15.

[469] Mississippi Commission Comments at 14.

[470] Northwest and Intermountain Comments at 28–30.

[471] ACPA and ESA Comments at 75.

[472] District of Columbia's Office of the People's Counsel Comments at 4–5.

[473] *Id.* at 5.

decisions.[474] Maryland Energy Admin asserts that earlier state involvement in cost allocation for the Artificial Island transmission facility, for example, could have ''avoided significant delays and additional costs, including some that were ultimately assigned to ratepayers.'' [475] Other commenters note that failure to gain state support for selection and cost allocation for transmission facilities can result in states subsequently blocking or delaying transmission facilities selected in regional transmission planning and cost allocation processes through subsequent state siting proceedings.[476]

291. Many commenters support consideration of a wider set of benefits than those currently used to evaluate transmission facilities in the regional transmission plan for purposes of cost allocation.[477] PIOs advocate that the Commission conduct a survey of all potential benefits that can result from multi-value, scenario-based planning and require that public utility transmission providers consider those benefits for regional cost allocation as well as for regional transmission planning.[478] U.S. DOE states that the Commission should establish a minimum set of potential benefits (and costs) to be considered, to ensure that they are taken into account in both project selection and in the allocation of costs for selected projects, adding this practice would help ensure that benefits not currently fully valued will be more appropriately incorporated in the planning process and foster consistency among planning regions.[479] Certain TDUs express that cost allocation reforms must be equitable for consumers.[480]

292. Some RTOs/ISOs support the Commission requiring public utility transmission providers to consider a broader set of transmission benefits. For example, NYISO states that requiring public utility transmission providers to adopt a broader range of evaluation and selection criteria in their transmission planning processes would enable them to consider the reliability, economic, and public policy benefits of proposed solutions to a transmission need regardless of the underlying driver of the need, which would enhance their ability to select the more efficient or cost-effective transmission solution.[481] SPP states that the Commission should adopt a minimum, standardized set of benefit metrics for all public utility transmission providers to ensure that transmission is valued consistently between regions and to allow for an apples-to-apples comparison of potential projects.[482] CAISO and MISO state that the Commission could consider requiring public utility transmission providers to consider the resilience benefits of transmission.[483] If the Commission expands the set of benefits that public utility transmission providers must consider, PJM urges the Commission to provide clear decision criteria on whether and when it is appropriate for public utility transmission planners to order construction of new transmission for anticipated future generation not yet in the interconnection queue.[484] If the Commission requires the consideration of a broader set of transmission benefits, several RTOs/ISOs urge the Commission to provide for regional flexibility.[485]

293. Minnesota Commerce acknowledges that cost allocation is a central factor in determining whether to build needed regional transmission.[486] Many commenters state that existing regional transmission cost allocation methods are sound and/or should continue.[487] At least one commenter suggests that ultimate cost allocation reforms should not unintentionally disrupt settled methods.[488]

294. Some commenters suggest special cost allocation methods for transmission facilities resulting from scenario-based planning. Exelon asserts that the default cost allocation method for transmission projects resulting from scenario-based planning should reflect a load-ratio share method,[489] but that the Commission should allow suitable substitute cost allocations as agreed to by the participating states to reflect the particular aggregation of benefits provided by the portfolio.[490] On the other hand, Michigan Commission notes that postage stamp cost allocation is highly divisive.[491]

295. Some commenters state that further analysis is necessary to determine if prescriptive action by the Commission is necessary and whether alteration of Order No. 1000's six regional transmission cost allocation principles is warranted.[492] AEP urges that benefits and methodologies to measure those benefits should be consistent throughout regions.[493]

296. Some commenters propose cost allocation pursuant to benefits related to anticipated future generation, resilience, and/or climate and environmental benefits.[494] APPA states that, to the extent that regions shift their transmission planning processes to place a greater emphasis on anticipated future generation or otherwise modify existing planning protocols towards a more holistic analysis, it may be appropriate to consider conforming changes to cost allocation methods.[495]

[474] Arizona Commission Comments at 7; Maryland Energy AdministrationAdmin Comments at 2.

[475] Maryland Energy AdministrationAdmin Comments at 3.

[476] Exelon Comments at 31–32.

[477] ACORE Comments at ii; AEE Comments at 31–32; ACEG Comments at 6–8; ACPA and ESA Comments at 75; AEP Comments at 14; Amazon Comments at 4; Anbaric Comments at 29; Avangrid Comments at 9; Business Council for Sustainable Energy Comments at 2; Citizens Energy Comments at 6–7; City of New York Comments at 3–4; Union of Concerned Scientists Comments at 66–75; Consumers Council Comments at 4, 16; Duke Comments at 12; EDF Comments at 8–10; EEI Comments at 33; ITC Comments at 28–34; Massachusetts Attorney General Comments at 24–25; New Jersey Commission Comments at 13–14, 17–19; NextEra Comments at 83–88; Northwest and Intermountain Comments at 35–38; Orsted Comments at 6–7; PIOs Comments at 30, 60; Policy Integrity Comments at 43; PSEG Comments at 25–27; REBA Comments at 17; RMI Comments at 4; SEIA Comments at 9; Shell Comments at 18–20; State Agencies Comments at 21–22; State of Massachusetts Comments at 16–17; U.S. DOE Comments at 7–9, 23–24; WIRES Comments at 18.

[478] PIOs Comments at 30; *see also* Orsted Comments at 6.

[479] U.S. DOE Comments at 23.

[480] Certain TDUs Comments at 5–6.

[481] NYISO Reply Comments at 10–11.

[482] SPP Comments at 14.

[483] CAISO Comments at 85–88; MISO Comments at 85.

[484] PJM Comments at 8.

[485] CAISO Comments at 85; MISO Comments at 85; NYISO Comments at 35–36.

[486] Minnesota Commerce Comments at 6–7 (noting cost allocation is one of the more difficult barriers to new transmission development); *see also* November 2021 Technical Conference Tr. at 79.

[487] *See, e.g.,* NASUCA Comments at 6; North Carolina Commission Comments at 23; Ohio Commission Comments at 12–13; SERTP Comments at 4, 21–23; SoCal Edison Comments at 6.

[488] *See* NESCOE Comments at 50.

[489] Under the load-ratio share regional cost allocation method, the costs of new transmission facilities are allocated based on some measure of system usage, whether at peak or overall. Specifically, load-ratio share cost allocation methods include both demand charge approaches and volumetric (energy) approaches. Under the demand charge approach, costs are allocated in proportion to each transmission customer's contribution to the system peak load (which can be coincident or non-coincident peak). In contrast, under the volumetric approach, costs are allocated based on each transmission customer's share of total system usage. *See* CAISO, *Review Transmission Access Charge Structure Issue Paper,* at 18, tbl. 2: Summary of ISO/RTO approaches to transmission charges (June 30, 2017).

[490] Exelon Comments at 30–31.

[491] Michigan Commission Comments at 20.

[492] *See, e.g.,* EEI Comments at 32–33; NARUC Comments at 22; *see also Joint Fed.-State Task Force on Elec. Transmission,* Transcript of Feb. 16, 2022 Meeting, Docket No. AD21–15–000, at 36:12–13 (Chair Brown Dutrieuille) (reiterating NARUC's comments that the Order No. 1000 cost allocation principles should remain in place).

[493] AEP Comments at 15.

[494] *See, e.g.,* ACEG Comments at 6–7; Consumers Council Comments at 16–17; WIRES Comments at 18–19; PSEG Comments at 5.

[495] APPA Comments at 15–16.

D. Need for Reform

297. The Commission has previously recognized that knowing how the costs of transmission facilities would be allocated is critical to the development of new transmission infrastructure.[496] Without such clarity, the likelihood that transmission facilities selected in a regional transmission plan for purposes of cost allocation will be developed is diminished, undermining the entire purpose of the regional transmission planning process, namely, the development of more efficient or cost-effective transmission facilities.[497] Yet, identifying a cost allocation method that is perceived as fair, especially within transmission planning regions that encompass several states, remains challenging. Litigation contesting regional transmission cost allocation methods persists.[498] Moreover, even where the cost allocation method is reasonably settled, regional transmission facilities face significant uncertainty and risk of not reaching construction if certain stakeholders—in particular, a state regulator responsible for permitting transmission facilities—do not perceive the regional transmission facilities' value as commensurate with their costs.[499]

298. We are concerned that these challenges are likely to be exacerbated in the context of Long-Term Regional Transmission Planning and Cost Allocation. We recognize that, by requiring a longer-term planning horizon, consideration of multiple scenarios, and accounting for the longer-term factors that affect transmission needs, Long-Term Regional Transmission Planning entails a more complex set of considerations as compared to existing regional transmission planning requirements. We are concerned that this increased complexity could make cost allocation decisions more contentious, which may risk undermining the development of more efficient or cost-effective regional transmission facilities to address transmission needs driven by changes in the resource mix and demand. For example, we anticipate that stakeholders, including state regulators, may diverge in their views of which scenarios best reflect future transmission needs, and these conflicting perceptions may lead to disagreements regarding who should pay for selected transmission facilities.

299. For these reasons, we preliminarily find that the cost allocation requirements for transmission facilities identified and selected in the regional transmission plan through Long-Term Regional Transmission Planning proposed in this proceeding may differ in part from those established in Order No. 1000. In particular, we believe that providing state regulators with a formal opportunity to develop a cost allocation method for regional transmission facilities selected through Long-Term Regional Transmission Planning could help increase stakeholder—and state—support for those facilities, which, in turn, may increase the likelihood that those facilities are sited and ultimately developed with fewer costly delays and better ensure just and reasonable Commission-jurisdictional rates.

300. The Commission has long recognized the critical role of states in transmission planning.[500] The Commission recently issued a Policy Statement addressing state efforts to develop transmission facilities through voluntary agreements to plan and pay for those facilities.[501] In the statement, the Commission recognized that such voluntary agreements may allow state-prioritized transmission facilities to be planned and built more quickly than would comparable facilities that are planned through the regional transmission planning process, and encouraged elimination to barriers to such agreements.[502] The Commission has also recently taken action to further federal-state coordination and cooperation in this area through the establishment of the Task Force.[503] The Commission included in the list of topics that the Task Force may consider: (1) ''[E]xploring potential bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multi-state goals;'' and (2) ''[e]xploring opportunities for states to voluntarily coordinate in order to identify, plan, and develop regional transmission solutions.'' [504] The Task Force, comprised of FERC Commissioners and state regulators, discussed the role of states in regional transmission planning and cost allocation processes at two meetings thus far, and numerous state regulators and other stakeholders filed comments in response to the ANOPR on this topic. The general consensus is that involving state regulators when it comes to allocating the costs of new regional transmission facilities is particularly important given states' role in siting those transmission facilities, including consideration of the costs and benefits when making state public interest determinations.[505]

301. We believe that facilitating involvement of state regulators in the cost allocation process, as further described below, would allow states to voluntarily coordinate to advance their policy goals through needed transmission development and may minimize delays and additional costs that can be associated with siting proceedings that follow the regional transmission planning and cost allocation processes at the federal level.[506] We believe that providing an opportunity for state involvement in regional transmission planning cost allocation processes is becoming more important as states take a more active role in shaping the resource mix and demand, which, in turn, means that those state actions are increasingly affecting the long-term transmission

[496] Order No. 1000, 136 FERC ¶ 61,051 at P 496 (discussing findings in Order No. 890).

[497] *Id.*

[498] *See, e.g., Long Island Power Auth.* v. *FERC,* 27 F.4th 705, 709 (D.C. Cir. 2022) (addressing a ''long-running dispute'' over regional transmission cost allocation in PJM); *Pub. Serv. Elec. & Gas Co.* v. *FERC,* 989 F.3d 10 (D.C. Cir. 2021) (addressing dispute over cost allocation for particular transmission upgrades).

[499] *See, e.g., Transource Pa., LLC* v. *Dutrieuille,* Case No. 1:2021cv0110 (filed June 22, 2021, M.D. Pa.) (lawsuit challenging state commission's denial of an application for siting and construction of regional transmission facilities).

[500] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 688 (citing Order No. 890, 118 FERC ¶ 61,119 at P 574). In 2015, the Commission accepted NYISO's proposal to facilitate the timely participation of the New York State Public Service Commission (New York Commission) in review of transmission facilities proposed to address transmission needs driven by Public Policy Requirements. Under NYISO's process, the New York Commission is provided a time period during which it may propose a cost allocation method or negotiate a cost allocation method with the developer of such a proposed transmission facility before the Order No. 1000-compliant *ex ante* regional cost allocation method is applied. *See NY Indep. Sys. Operator, Inc.,* 151 FERC ¶ 61,040, at PP 119–121 (2015).

[501] *State Voluntary Agreements to Plan and Pay for Transmission Facilities,* 175 FERC ¶ 61,225 (2021).

[502] *Id.* PP 2, 6.

[503] *See Joint Fed.-State Task Force on Elec. Transmission,* 175 FERC ¶ 61,224 at PP 1–2 (establishing the Task Force).

[504] *Id.* P 6.

[505] *See* NARUC Comments at 27, 46–47; NESCOE Comments at 21–25; Arizona Commission Comments at 7; SPP RSC Comments at 10; Maryland Energy Admin Comments at 2; *Joint Fed.-State Task Force on Elec. Transmission,* Transcript of Feb. 16, 2022 Meeting, Docket No. AD21–15–000, at 102:13–24 (Chair Thomas), 110:24–111:8 (Comm'r Allen), 111:24–112:5 (Comm'r Rechtschaffen), 134:4–9 (Chair Stanek) (including in the list of three overarching themes from the meeting that of state consultation—soliciting state input, at a minimum—on cost allocation).

[506] *E.g.,* Maryland Energy Admin Comments at 3 (pointing to significant delays and costs associated with the Artificial Island transmission facility); Exelon Comments at 31–32 (speaking generally to states blocking or delaying transmission development through siting).

needs for which we are proposing to require public utility transmission providers to plan in this NOPR.

E. Proposed Reform

1. State Involvement in Cost Allocation for Long-Term Regional Transmission Facilities [507]

302. We propose to require that public utility transmission providers in each transmission planning region revise their OATTs to include either (1) a Long-Term Regional Transmission Cost Allocation Method [508] to allocate the costs of Long-Term Regional Transmission Facilities, or (2) a State Agreement Process [509] by which one or more relevant state entities may voluntarily agree to a cost allocation method, or (3) a combination thereof.[510] We propose to require that the Long-Term Regional Transmission Cost Allocation Method and any cost allocation method resulting from the State Agreement Process for Long-Term Regional Transmission Facilities comply with the existing six Order No. 1000 regional cost allocation principles.[511]

303. In order to comply with this proposed requirement, public utility transmission providers in each transmission planning region would be required to seek the agreement of relevant state entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or a combination thereof. We propose to require public utility transmission providers in each transmission planning region to explain how the proposed Long-Term Transmission Cost Allocation Method, the proposed State Agreement Process, or a combination thereof either: (1) Reflect the agreement of the relevant state entities, or (2) to the extent agreement cannot be obtained, an explanation of the good faith efforts by the relevant public utility transmission provider to seek agreement from such entities. We seek comment below on how to resolve the potential inability of the relevant parties to come to agreement, noting that it will ultimately be necessary for public utility transmission providers to have a cost allocation method on file with the Commission for transmission facilities selected through Long-Term Regional Transmission Planning, and recognizing a State Agreement Process or combination cost allocation method would not comply with this proposed rule unless the relevant public utility transmission providers has obtained agreement from the relevant state entities.

a. Agreement of Relevant State Entities

304. We propose to define relevant state entities for purposes of the Long-Term Regional Transmission Planning cost allocation requirements as 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. Although, as discussed below, we propose to provide public utility transmission providers flexibility in determining what constitutes state agreement, we preliminarily find that, for each state, a single entity should be designated as the voting or representative entity to avoid confusion or over-representation by a single state in a multi-state voting process.

305. We propose to require that public utility transmission providers in each transmission planning region seek agreement from the relevant state entities regarding the approach to cost allocation for Long-Term Regional Transmission Facilities. Specifically, public utility transmission providers in each transmission planning region must seek to determine whether, for all or a subset of Long-Term Regional Transmission Facilities, the relevant state entities agree to (1) a Long-Term Regional Transmission Cost Allocation Method; (2) a State Agreement Process; (3) forgo a role in determining the cost allocation approach for Long-Term Regional Transmission Facilities; or (4) some combination thereof.

306. We further propose to afford public utility transmission providers in each transmission planning region flexibility in the process by which they seek agreement from the relevant state entities. In addition, we propose to require public utility transmission providers to provide the state entities with flexibility with regard to defining what constitutes ‘‘agreement’’ among the relevant state entities on the cost allocation approach for Long-Term Regional Transmission Facilities. For example, states may choose to apply the existing provisions for engaging with the relevant state entities.[512] In other cases, the relevant state entities may elect to engage in new or different ways to reach and communicate agreement regarding a cost allocation approach for Long-Term Regional Transmission Facilities.[513]

307. We note that the relevant state entities may forgo a role in determining the cost allocation approach for all or a subset of Long-Term Regional Transmission Facilities. In the event that the relevant state entities do so, we propose to require public utility transmission providers to propose a Long-Term Regional Transmission Cost Allocation Method consistent with the requirements of Order No. 1000, including the prohibition on relying on voluntary agreement among states or

[507] We propose to define a Long-Term Regional Transmission Facility as a transmission facility identified as part of Long-Term Regional Transmission Planning and selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand.

[508] We propose to define a Long-Term Regional Transmission Cost Allocation Method as an *ex ante* regional cost allocation method that would be included in each public utility transmission provider's OATT as part of Long-Term Regional Transmission Planning. The developer of a Long-Term Regional Transmission Facility would be entitled to use the Long-Term Regional Transmission Cost Allocation Method if it is the applicable method.

[509] We propose to define a State Agreement Process as an *ex post* cost allocation process that would be included in each public utility transmission provider's OATT as part of Long-Term Regional Transmission Planning, which may apply to an individual Long-Term Regional Transmission Facility or a portfolio of such Facilities grouped together for purposes of cost allocation. After a Long-Term Regional Transmission Facility is selected in the regional transmission plan for purposes of cost allocation, the State Agreement Process would be followed to establish a cost allocation method for that facility (if agreement can be reached). If the Commission subsequently approves the cost allocation method that results from the State Agreement Process, the developer of the Long-Term Regional Transmission Facility would be entitled to use that cost allocation method if it is the applicable method.

[510] For example, a ‘‘combination’’ approach may entail (i) providing a Long-Term Regional Transmission Cost Allocation Method for certain types of Long-Term Regional Transmission Facilities and providing a State Agreement Process for others; or (ii) providing for cost allocation for a Long-Term Regional Transmission Facility, portfolio, or type of such facilities partially based on a Long-Term Regional Transmission Cost Allocation Method and partially based on funding contributions in accordance with a State Agreement Process.

[511] We are not proposing to require any changes to existing interregional cost allocation methods for interregional transmission facilities that are selected in the regional transmission plan for purposes of cost allocation and that the Commission previously accepted as compliant with Order No. 1000.

[512] For example, states in ISO–NE may consider NESCOE's by-laws in defining the threshold of agreement among relevant state entities. Likewise, states in MISO may consider OMS procedures to define agreement and rely on existing processes by which OMS conveys its positions to MISO.

[513] As discussed *infra* in Proposed Compliance Procedures, we propose to establish an extended compliance period to accommodate meaningful engagement with states with respect to this Long-Term Regional Transmission Planning cost allocation reform.

participant funding.[514] Relevant state entities may also fail to reach agreement on a cost allocation method for all or a portion of Long-Term Regional Transmission Facilities, and we request comments below on the appropriate outcome in that situation.

308. We clarify that we are not proposing to impose any requirements on states to participate in processes to establish regional cost allocation methods for Long-Term Regional Transmission Facilities. The Commission has no authority over relevant state entities in this regard and, as such, those entities need not engage on a cost allocation approach if they do not wish to do so. Instead, we propose only to require that public utility transmission providers in each transmission planning region seek the agreement of the relevant state entities, and demonstrate in their compliance filings how either the proposed Long-Term Regional Transmission Cost Allocation Method, the proposed State Agreement Process, or combination thereof: (1) Reflects the agreement of the relevant state entities, or (2) to the extent agreement cannot be obtained, reflects good faith efforts by the relevant public utility transmission provider to seek agreement from such entities.

309. We seek comment on whether the proposed definition of relevant state entities is appropriate. We also seek comment on the proposal to afford relevant states entities the flexibility to define agreement among relevant state entities, or whether it is preferable for the Commission to adopt a specific definition of such agreement.

310. We further recognize that it is possible that relevant states entities may seek to agree to a cost allocation approach but be unable to achieve agreement, or may be unwilling to seek agreement to a cost allocation approach but do not agree to forgo their role in developing a cost allocation approach for Long-Term Regional Transmission Facilities. We request comment on the appropriate outcome when the relevant state entities fail to agree on a cost allocation method for all or a portion of Long-Term Regional Transmission Facilities. Specifically, we request comment on whether in such circumstances the public utility transmission providers should be required to establish a Long-Term Regional Transmission Cost Allocation Method, the relevant state entities should be afforded additional time to endeavor to reach agreement, or the Commission should instead have the responsibility to establish the Long-Term Regional Transmission Cost Allocation Method.[515]

b. State Agreement Process

311. We preliminarily find that a State Agreement Process by which one or more relevant state entities voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or portfolio of facilities) after it is selected in the regional transmission plan for purposes of cost allocation may be a just and reasonable approach to cost allocation for such regional transmission facilities. The State Agreement Process may apply to all Long-Term Regional Transmission Facilities or only a subset thereof.

312. We further propose to require that a cost allocation method that results from the State Agreement Process and is filed by the public utility transmission providers must comply with the existing six Order No. 1000 regional cost allocation principles.[516] We preliminarily find that compliance with such principles will help to ensure that Commission-jurisdictional rates resulting from any State Agreement Process will be just and reasonable and not unduly discriminatory or preferential.

313. If the relevant state entities decide on a State Agreement Process, we also propose to require that the public utility transmission providers in each transmission planning region detail the process by which the relevant state entities would reach voluntary agreement regarding the cost allocation for Long-Term Regional Transmission Facilities pursuant to the State Agreement Process, including the timeline for such processes. For example, the public utility transmission providers in each transmission planning region could specify, as part of the Long-Term Regional Transmission Planning in their OATTs the procedures by which such voluntary agreements by the relevant state entities may be filed with the Commission for consideration under FPA section 205. Such procedures should set forth a process by which the relevant state entities would agree to funding contributions and the mechanism by which such costs would be allocated (*e.g.,* through a *pro forma* contract).

314. Finally, we note that, to the extent public utility transmission providers believe their existing cost allocation approaches comply with the requirements adopted in any final rule in this proceeding, including those related to the agreement of relevant state entities, we propose that they may make such demonstration in their compliance filings in response to any final rule. In addition, we propose to apply the cost allocation reforms we propose in this NOPR only to new Long-Term Regional Transmission Facilities and, therefore, these proposed reforms would not provide grounds for re-litigation of cost allocation decisions for transmission facilities that are selected in the regional transmission plan for purposes of cost allocation prior to the effective date of any final rule in this proceeding,[517] nor would they apply to the cost allocation methods associated with regional transmission facilities that address shorter-term transmission needs driven by reliability and/or economic considerations. We believe the proposed cost allocation requirements for Long-Term Regional Transmission Facilities will help to ensure just and reasonable Commission-jurisdictional rates by increasing the likelihood that more efficient or cost-effective regional transmission facilities to address transmission needs driven by changes in the resource mix and demand are developed, and with fewer delays. The proposed reforms would enable relevant state entities, such as state regulators and siting authorities, who seek greater involvement in cost allocation for Long-Term Regional Transmission Facilities an opportunity to do so. Where relevant state entities in a multi-state

[514] Under this proposed requirement, the Long-Term Regional Transmission Cost Allocation Method that public utility transmission providers would be required to submit would only apply to the subset of Long-Term Regional Transmission Facilities for which the relevant state entities did not determine a cost allocation approach.

[515] In Order No. 1000, the Commission determined that, in the event public utility transmission providers in a region fail to reach agreement on a cost allocation method, it would use the record in the compliance filing to determine the cost allocation method. Order No. 1000, 136 FERC ¶ 61,051 at P 607.

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

[517] The Commission took a similar approach with respect to its cost allocation reforms in Order No. 1000. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 565.

transmission planning region are able to agree upon an approach to allocate the costs of Long-Term Regional Transmission Facilities needed to meet these longer-term transmission needs, applying that approach is likely to decrease the controversy over development of such facilities, by, for example, making the relevant state entities more confident that ratepayers in the state are receiving benefits at least roughly commensurate with their share of the cost of such facilities. In so doing, the engagement of relevant state entities may help to reduce instances in which a Long-Term Regional Transmission Facility is selected, has an established *ex ante* cost allocation method that applies to it, but nevertheless fails to be developed because it cannot receive a necessary state regulatory approval. After all, states retain siting authority over transmission facilities and will review whether Long-Term Regional Transmission Facilities are consistent with the public interest and state siting regulations.

315. We recognize that, if states agree to a State Agreement Process instead of a Long-Term Regional Transmission Cost Allocation Method, certain Long-Term Regional Transmission Facilities selected in the regional transmission plan for purposes of cost allocation would lack a clear *ex ante* cost allocation method. We continue to believe that the availability of an *ex ante* cost allocation method helps to ensure the development of more efficient or cost-effective regional transmission facilities identified in the regional transmission planning process.[518] However, given the increased uncertainty of Long-Term Regional Transmission Planning and potential for divergent views on the benefits of meeting transmission needs driven by changes in the resource mix and demand, we believe that applying a cost allocation approach agreed to by the relevant state entities may be just and reasonable and support the viability of Long-Term Regional Transmission Facilities.

316. We recognize that in Order No. 1000, the Commission explained that reliance on participant funding as a regional cost allocation method ''increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development'' and would therefore not comply with the regional cost allocation principles adopted in Order No. 1000.[519]

317. Nevertheless, we preliminarily find that allowing a State Agreement Process for Long-Term Regional Transmission Facilities, where agreed to by the relevant state entities, appropriately balances the concerns about increased free ridership problems against the benefit of greater state involvement in determining the cost allocation of Long-Term Regional Transmission Facilities.[520] As discussed above, we are proposing to require public utility transmission providers to engage in transmission planning over a longer time-horizon than we have previously required. Although we preliminarily find that such reforms are necessary to ensure just and reasonable rates, we recognize that the precise quantification and allocation of the benefits of Long-Term Regional Transmission Facilities may be more uncertain than transmission facilities that are planned on a shorter-term basis and/or based on a more limited set of benefits. As such, we recognize that state entities charged with siting transmission facilities within their state may, at least in certain circumstances, take a more skeptical approach to evaluating applications to site Long-Term Regional Transmission Facilities. We believe that providing relevant state entities an opportunity for involvement in establishing a cost allocation method, including through use of a State Agreement Process, would help to address any such concerns on the part of state regulators, increasing the likelihood that Long-Term Regional Transmission Facilities are actually developed, and without delay. Accordingly, we preliminarily find that this potential benefit outweighs concerns about free-ridership with respect to the reforms proposed herein.

318. We seek comment on the requirements proposed in this section of the NOPR. We also seek comment on whether the Commission should require, instead of the reforms proposed in this section of the NOPR, public utility transmission providers to include a Long-Term Regional Transmission Cost Allocation Method in their OATTs.

2. Time Period in Long-Term Regional Transmission Planning Cost Allocation Processes for State-Negotiated Alternate Cost Allocation Method

319. Additionally, we propose to require that public utility transmission providers establish a process, detailed in their OATTs, to provide a state or states (in multi-state transmission planning regions) a time period to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected for purposes of cost allocation through Long-Term Regional Transmission Planning that is different than any *ex ante* regional cost allocation method that would otherwise apply. During this time period for a state-negotiated alternate cost allocation method, if a state or all states within the transmission planning region in which the selected regional transmission facility will be located unanimously agree on an alternate cost allocation method, the public utility transmission provider may elect to file it with the Commission for consideration under FPA section 205. As discussed above, we anticipate the public utility transmission provider may elect to file an alternate cost allocation method because doing so increases the likelihood that relevant stakeholders perceive the cost allocation as fair and that the needed regional transmission facilities are actually constructed.

320. If the relevant state or states cannot agree on an alternate cost allocation method memorialized in writing within a specified timeframe after a transmission facility is selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning (*e.g.,* 90 days), then the transmission developer will be entitled to use any *ex ante* regional cost allocation method that would otherwise apply for that regional transmission facility.

321. Providing states with a time period to propose alternate cost allocation methods could help facilitate the timely development of more efficient or cost-effective regional transmission facilities. For example, allowing states to negotiate an alternate cost allocation method for selected regional transmission facilities at a time when details of the transmission facilities are known could facilitate agreements on the cost allocation for new regional transmission facilities because states would have better knowledge of relevant facts, including benefits and costs, regarding the transmission facilities for which they are negotiating cost allocation.

[518] *Id.* P 499; Order No. 1000–A, 139 FERC ¶ 61,132 at P 52.

[519] Order No. 1000, 136 FERC ¶ 61,051 at P 723. Under a participant funding approach to cost allocation, the costs of a transmission facility are allocated only to those entities that volunteer to bear those costs. *Id.* P 486 n.375.

[520] *Id.* P 586 (stating regional cost allocation principles, including ''[t]hose that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities.'').

Moreover, state siting proceedings may proceed more efficiently if states have better information about the costs and benefits of such regional transmission facilities.

322. We propose to require that public utility transmission providers add to their OATTs provisions that describe a time period for state involvement in regional cost allocation for transmission facilities selected in Long-Term Regional Transmission Planning, including when this time period will occur, what its duration will be, and that any alternate cost allocation method must be submitted to the Commission for review and approval under FPA section 205 prior to taking effect. When filed, the Commission will evaluate the alternate cost allocation method to ensure that it is just and reasonable and allocates costs in a manner that is at least roughly commensurate with estimated benefits. If the Commission rejects a state-proposed cost allocation method, the transmission developer of the transmission facility selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning would be entitled to use the applicable *ex ante* regional cost allocation method that would have applied to it in the absence of the proposed alternative cost allocation method, just as it would be absent this proposed provision for an alternate cost allocation method.

323. We recognize the tension between a proposal for a time period for state-negotiated cost allocation within an Order No. 1000-compliant regional transmission planning process and the Commission's *ex ante* cost allocation approach, which we do not propose to remove, including the potential for delay as compared to the *ex ante* approach. We propose to prescribe a 90-day time period for state-negotiated cost allocation memorialized in writing, which is consistent with the period for state cost allocation negotiation that the Commission accepted in NYISO's filing described above.

324. We seek comment on the requirements proposed in this section of the NOPR, including the timing and duration of any time period for state-negotiated cost allocation for transmission facilities selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning. We also seek comment on whether there should be a requirement for a time period for state involvement in regional cost allocation for transmission facilities selected in existing near-term reliability and economic regional transmission planning processes.

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

325. We are concerned that the Commission's existing regional transmission planning and cost allocation requirements may result in public utility transmission providers undervaluing the benefits of Long-Term Regional Transmission Facilities for purposes of allocating the costs of such facilities to beneficiaries in a manner that is roughly commensurate with estimated benefits. The current approach of considering only a subset of categories of benefits based on the type of transmission need that is being studied may result in inaccurate valuation of a transmission facility's benefits in Long-Term Regional Transmission Planning. We are also concerned that considering only a subset of benefits in assigning the cost of Long-Term Regional Transmission Facilities may contribute to the risk of free rider problems that impede development of the more efficient or cost-effective regional transmission facilities. At the same time, as discussed above, we consider it important that cost allocation should reflect the views of stakeholders, and the state entities with a role in permitting transmission facilities in particular, and believe that the involvement of states in cost allocation increases the likelihood that Long-Term Regional Transmission Facilities are actually developed.

326. Nevertheless, we acknowledge the support for the adoption of a common set of minimum benefits, and we propose for consideration a list of Long-Term Regional Transmission Benefits described above for public utility transmission providers to apply in Long-Term Regional Transmission Planning and Cost Allocation processes. In addition, we propose to require that public utility transmission providers identify on compliance the benefits they will use in any ex ante cost allocation method associated with Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand. As part of this compliance obligation, public utility transmission providers should explain the rationale for using the benefits identified.

327. We request comment on this proposed requirement. We also request comment on whether the Commission should require that public utility transmission providers account for the full list of benefits described in the Evaluation of the Benefits of Regional Transmission Facilities section above in Long-Term Regional Transmission Planning, or whether no change to the benefits currently used in existing regional transmission planning processes is needed.

VI. Construction Work in Progress Incentive

A. Background

328. In the Energy Policy Act of 2005,[521] Congress added section 219 to the FPA, directing the Commission to establish, by rule, incentive-based rate treatments to promote capital investment in certain transmission infrastructure. The Commission subsequently issued Order No. 679 in 2006, which sets forth processes by which a public utility may seek transmission rate incentives pursuant to FPA section 219.[522]

329. In Order No. 679, the Commission adopted several incentive-based rate treatments to promote capital investment in certain transmission infrastructure and to address impediments faced by those investing in transmission. The Commission found that the long-lead time to construct new transmission and associated cash flow difficulties presented an impediment to new transmission investment.[523] To remove this impediment, the Commission adopted its proposal to allow for the recovery of 100% of CWIP costs in rate base in certain circumstances (CWIP Incentive).[524] Allowing transmission developers to include construction costs in rate base prior to commercial operation provides utilities with additional cash flow in the form of an immediate earned return, rather than delaying recovery of those costs until the plant is placed into service.[525] In Order No. 679, the Commission acknowledged that the CWIP Incentive was a departure from the existing ratemaking doctrine that rates should be based on plant costs that

[521] Public Law 109–58, 1241, 119 Stat. 594 (2005).

[522] *Promoting Transmission Inv. through Pricing Reform,* Order No. 679, 116 FERC ¶ 61,057, *order on reh'g,* Order No. 679–A, 117 FERC ¶ 61,345 (2006), *order on reh'g,* 119 FERC ¶ 61,062 (2007).

[523] *Id.* P 9.

[524] The Commission has also provided that any public utility engaged in the sale of electric power for resale can file to include in rate base up to 50% of CWIP, subject to limitations. *Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base,* Order No. 298, FERC Stats. & Regs. ¶ 30,455 (1983), *order on reh'g,* 25 FERC ¶ 61,023 (1983).

[525] Order No. 679, 116 FERC ¶ 61,057 at n.70.

are ''used and useful.'' [526] However, the Commission clarified that ''the Commission can depart from the norm as long as it reasonably balances consumers' interest in fair rates against investors' interest in maintaining financial integrity and access to capital markets.'' [527]

B. Need for Reform

330. As indicated above in this NOPR, under the proposed Long-Term Regional Transmission Planning reforms, we seek to strike a balance between the risk of over- and under-investment regarding the selection of transmission facilities in the regional transmission plan for purposes of cost allocation that address transmission needs driven by changes in the resource mix and demand. We acknowledge that there is likely to be more uncertainty in Long-Term Regional Transmission Planning, *e.g.,* requiring public utility transmission providers to conduct Long-Term Regional Transmission Planning over a minimum of 20 years (compared to the current practice of 6–15 years), than in the existing regional transmission planning processes.

331. In light of the incremental uncertainty associated with the proposed Long-Term Regional Transmission Planning, we preliminarily find that additional protection for ratepayers may be necessary to reasonably balance consumers' interest in just and reasonable rates against investors' interest in earning a return on their investments and reduce the risk to ratepayers of potentially financing over-investment in regional transmission facilities.[528] The Commission previously found that the CWIP Incentive is beneficial to ease the financial pressures associated with transmission development by providing up-front regulatory certainty, rate stability, and improved cash flow, which in turn can result in higher credit ratings and lower capital costs.[529] These benefits mainly accrue to the public utility transmission providers and their shareholders during construction, while ratepayers mainly receive the benefits from completed transmission facilities under a more stable rate environment. Specifically, during the construction of the regional transmission facilities, ratepayers do not receive benefits from the regional transmission facilities, while simultaneously ratepayers directly finance the construction under the CWIP Incentive. Should the regional transmission facilities not be placed in service, then ratepayers will have financed the construction of such facilities that were not used and useful, while ultimately receiving no benefits from such facilities.

332. Given the Long-Term Regional Transmission Planning reforms proposed in this NOPR and the incremental uncertainty and risk that Long-Term Regional Transmission Facilities may not become ''used and useful,'' we are concerned that the CWIP Incentive, if made available for Long-Term Regional Transmission Facilities, may shift too much risk to consumers to the benefit of public utility transmission providers in a manner that renders Commission-jurisdictional rates unjust and unreasonable.

C. Proposed Reform

333. To address the concerns identified above, we propose to not permit public utility transmission providers to take advantage of the CWIP Incentive for Long-Term Regional Transmission Facilities. We note that public utility transmission providers may still book costs incurred during the pre-construction or construction phase as Allowance for Funds Used During Construction (AFUDC) and only recover those costs after the project is in service to customers, in accordance with generally accepted utility accounting principles for AFUDC.[530]

334. We seek comment on the requirements proposed in this section of the NOPR. In particular, we seek comment on whether this proposed reform would reasonably balance consumer and investor interests.

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

335. Order No. 1000 instituted a number of reforms regarding the participation of nonincumbent transmission developers in the regional transmission planning process, which, as a whole, facilitate competition for transmission development.[531] As explained in more detail below, we continue to require compliance with Order No. 1000's nonincumbent transmission developer reforms, and we maintain our commitment to transmission development rules and policies that align with or advance the goals of those reforms, or otherwise ensure just and reasonable Commission-jurisdictional rates and limit opportunities for undue discrimination by public utility transmission providers.

336. However, in light of the experience gained since the issuance of Order No. 1000 and the comments received in response to the ANOPR, we propose to amend Order No. 1000's nonincumbent transmission developer requirements, in part. As described in more detail below, we propose to permit the exercise of federal rights of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider with the federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with the proposal below.

A. Background

1. Order No. 1000's Nonincumbent Transmission Developer Reforms and Federal Right of First Refusal Elimination Mandate

337. In instituting nonincumbent transmission developer reforms, the Commission in Order No. 1000 distinguished between incumbent transmission developers (also called incumbent transmission providers) and nonincumbent transmission developers. An incumbent transmission developer/provider is an entity that develops a transmission facility within its own retail distribution service territory or footprint. A nonincumbent transmission developer refers to two categories of transmission developer: (1) A transmission developer that does not have a retail distribution service territory or footprint; and (2) a public utility transmission provider that proposes a transmission facility outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that facility.[532]

338. Among its nonincumbent transmission developer reforms, Order No. 1000 requires that each public

[526] *Id.* PP 116–117.

[527] *Id.* P 117 (quoting *Jersey Cent. Power & Light Co.* v. *FERC,* 810 F.2d 1168, 1178 (D.C. Cir. 1987)).

[528] *See, e.g., NextEra Energy Transmission Sw., LLC,* 178 FERC ¶ 61,082 (2022) (Christie, Comm'r, concurring).

[529] Order No. 679, 116 FERC ¶ 61,057 at P 115.

[530] We further note that our proposal regarding the CWIP Incentive for Long-Term Regional Transmission Facilities does not affect Commission policy and regulations established before Order No. 679. That is, public utility transmission providers would still be allowed to request 50% CWIP in rate base, as is permitted pursuant to 18 CFR 35.25(c)(3), subject to an FPA section 205 filing detailing how the request meets the requirements of Order No. 298. We believe that the ability to include 50% CWIP in rate base, if requested and granted, reflects a more reasonable sharing of risks and benefits than the CWIP Incentive for Long-Term Regional Transmission Facilities given the greater uncertainty inherent in Long-Term Regional Transmission Planning, as proposed in this NOPR.

[531] *See ISO New Eng. Inc.,* 169 FERC ¶ 61,054, at PP 1–2 (2019) (citations omitted); *see also* Order No. 1000, 136 FERC ¶ 61,051 at PP 225–344.

[532] Order No. 1000, 136 FERC ¶ 61,051 at P 225.

utility transmission provider eliminate provisions in Commission-jurisdictional tariffs and agreements that establish a federal right of first refusal for an incumbent transmission provider with respect to entirely new transmission facilities selected in a regional transmission plan for purposes of cost allocation.[533]

339. This requirement from Order No. 1000 does not apply to local transmission facilities, which are defined as transmission facilities located solely within an incumbent transmission provider's retail distribution service territory or footprint that are not selected in the regional transmission plan for purposes of cost allocation.[534] The requirement also does not apply to the right of an incumbent transmission provider to build, own, and recover costs for upgrades to its own existing transmission facilities, regardless of whether an upgrade has been selected in the regional transmission plan for purposes of cost allocation.[535] In addition, the Commission noted that the requirement does not remove, alter, or limit an incumbent transmission provider's use and control of its existing rights-of-way under state law.[536] The Commission has also permitted exemptions from the federal right of first refusal elimination mandate for immediate need reliability projects.[537]

340. In adopting Order No. 1000's nonincumbent transmission developer reforms, the Commission identified several reasons why it believed that eliminating federal rights of first refusal from Commission-jurisdictional tariffs and agreements was necessary and appropriate to ensure that Commission-jurisdictional rates are just and reasonable. The Commission found that federal rights of first refusal ''creat[e] a barrier to entry,'' and that their existence could lead to the loss of nonincumbent transmission developer investment opportunities to incumbent transmission providers, which ''discourages nonincumbent transmission developers from proposing alternative solutions for consideration at the regional level'' in regional transmission planning processes.[538] The Commission found that administering transmission planning processes with federal rights of first refusal ''may result in the failure to consider more efficient or cost-effective solutions to regional needs'' and thus their elimination may give ''customers . . . the benefits of competition in transmission development, and associated potential savings.'' [539] The Commission also expressed concern that federal rights of first refusal could allow an incumbent transmission provider ''to act in its own economic self-interest,'' which in general would not support permitting ''new entrants to develop transmission facilities, even if proposals submitted by new entrants would result in a more efficient or cost-effective solution to the region's needs.'' [540]

341. The Commission also found that elimination of federal rights of first refusal was ''necessary to address opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within regional transmission planning processes.'' [541] While the Commission did not dispute the claim that incumbent transmission providers may have some inherent advantages over nonincumbent transmission developers in the transmission development context,[542] the Commission found that these claimed incumbent advantages were ''strengths'' that could be deployed by incumbent transmission providers to their benefit in competitive transmission development processes, and not a reason to forgo holding those processes.[543]

342. Importantly, while the Commission declined to eliminate federal rights of first refusal for upgrades to existing transmission facilities and local transmission facilities, among other specific types of transmission facilities,[544] and has permitted exemptions for immediate need reliability projects,[545] the Commission did not otherwise qualify or limit the federal right of first refusal elimination mandate within its defined scope (*i.e.,* as applied to entirely new transmission facilities selected in a regional transmission plan for purposes of cost allocation).[546] Instead, the

[533] *Id.* P 313; Order No. 1000–A, 139 FERC ¶ 61,132 at P 426 (''The concept is that there should not be a federally established monopoly over the development of an entirely new transmission facility that is selected in a regional transmission plan for purposes of cost allocation to others.''). The phrase ''a federal right of first refusal'' refers only to rights of first refusal that are created by provisions in Commission-jurisdictional tariffs or agreements. Order No. 1000–A, 139 FERC ¶ 61,132 at P 415. Before Order No. 1000, some RTO/ISO governing documents and other utility tariffs and agreements included federal rights of first refusal, which ''gave incumbent utilities the option to construct any new transmission facilities in their particular service areas, even if the proposal for new construction came from a third party.'' *S.C. Pub. Serv. Auth.,* 762 F.3d at 72.

[534] Order No. 1000, 136 FERC ¶ 61,051 at PP 63, 226, 258, 318. In addition, the Commission clarified in Order No. 1000–A that a transmission facility whose costs are 100% allocated to the public utility transmission provider in whose retail distribution service territory or footprint the facility is located is not considered to be selected in the regional transmission plan for purposes of cost allocation and could remain subject to a federal right of first refusal. Order No. 1000–A, 139 FERC ¶ 61,132 at PP 423–424; *see also id.* P 427.

[535] Order No. 1000, 136 FERC ¶ 61,051 at PP 226, 319; Order No. 1000–A, 139 FERC ¶ 61,132 at P 426. Upgrades to existing transmission facilities include, for example, tower change outs or reconductoring, regardless of whether or not an upgrade has been selected in the regional transmission plan for purposes of cost allocation. Order No. 1000, 136 FERC ¶ 61,051 at P 319. The Commission clarified in Order No. 1000–A that the term ''upgrade'' means an improvement to, addition to, or replacement of a part of, an existing transmission facility. The term does not refer to an entirely new transmission facility. Order No. 1000–A, 139 FERC ¶ 61,132 at P 426.

[536] Order No. 1000, 136 FERC ¶ 61,051 at PP 226, 319.

[537] *See, e.g., PJM Interconnection, L.L.C.,* 174 FERC ¶ 61,117, at P 3 (2021); *Sw. Power Pool, Inc.,* 171 FERC ¶ 61,213, at P 3 (2020); *Midcontinent Indep. Sys. Operator, Inc.,* 173 FERC ¶ 61,203, at P 1 (2020); *ISO New Eng. Inc.,* 171 FERC ¶ 61,211, at P 1, 3 (2020); *N.Y. Indep. Sys. Operator, Inc.,* 171 FERC ¶ 61,082, at PP 30–34 (2020).

[538] Order No. 1000, 136 FERC ¶ 61,051 at PP 229, 256–257, 284, 320.

[539] *Id.* PP 284–286, 291; *see also id.* PP 229, 315. The Commission reasoned, in part, that ''[g]reater participation by transmission developers in the transmission planning process may lower the cost of new transmission facilities, enabling more efficient or cost-effective deliveries by load serving entities and increased access to resources.'' *Id.* P 291.

[540] *Id.* P 256.

[541] Order No. 1000–A, 139 FERC ¶ 61,132 at P 361; *see also* Order No. 1000, 136 FERC ¶ 61,051 at PP 269, 286. The Commission also reiterated that ''if a regional transmission planning process does not consider and evaluate transmission projects proposed by nonincumbents that regional transmission planning process cannot meet the Order No. 890 transmission planning principle of being 'open.' '' Order No. 1000, 136 FERC ¶ 61,051 at P 229.

[542] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 260 (acknowledging that incumbent transmission providers ''may have unique knowledge of their own transmission systems, familiarity with the communities they serve,'' and other potential transmission development advantages); *see also id.* PP 241, 250 (summarizing other contentions ''that incumbent transmission owners are better situated to build new transmission facilities'').

[543] *Id.* P 260.

[544] *See supra* notes 534–536 and associated text. The Commission explained, in part, that its decision in this regard would ''continue[ ] to permit an incumbent . . . to meet its reliability needs or service obligations'' through local transmission facilities, and the Commission hoped that this exemption would also, in part, address concerns that Order No. 1000's reforms would ''adversely impact the collaborative nature of current regional transmission planning processes.'' *See* Order No. 1000, 136 FERC ¶ 61,051 at PP 258, 262.

[545] *See supra* note 537 and associated text.

[546] *See, e.g.,* Order No. 1000–A, 139 FERC ¶ 61,132 at P 426 (''The concept is that there should not be a federally established monopoly over the development of an entirely new transmission facility that is selected in a regional transmission plan for purposes of cost allocation to others.''); *id.* P 360 (finding on rehearing that ''the Commission's decision to require public utility transmission providers to adopt the nonincumbent transmission developer reforms was an appropriate, and adequately tailored, remedy'' and noting that the Commission did not accept the position of some commenters that ''supported eliminating all federal rights of first refusal'' but rather it ''determined that

Commission ordered, with limited exceptions, the elimination of federal rights of first refusal for entirely new transmission facilities selected in a regional transmission plan for purposes of cost allocation, regardless of the specifics of or the circumstances under which such federal rights of first refusal had been or could be used.

2. Experience Since Order No. 1000

343. Since the Commission issued Order No. 1000, all public utility transmission providers across the country have adopted and many have administered competitive transmission development processes for the selection of transmission facilities in a regional transmission plan for purposes of cost allocation.[547] Though public utility transmission providers in all transmission planning regions must participate in their respective regional transmission planning processes, the degree to which competitive transmission development processes have led to specific transmission facility selection, investment, and development activities since Order No. 1000—and the proportion of such processes that resulted in the selection of a nonincumbent transmission developer's proposal—varies significantly by region.[548]

344. Importantly, recent transmission investment trends suggest that despite increased investment in transmission facilities overall, in many transmission planning regions there has been comparatively limited investment in transmission facilities selected in a regional transmission plan for purposes of cost allocation as a result of a competitive process; transmission investment has instead largely been concentrated in transmission facilities generally not subject to competitive transmission development processes.[549] In particular, recent transmission investment appears to be concentrated in local transmission facility development or regional transmission facilities subject to an exception from competitive transmission development processes, such as immediate need reliability projects or upgrades to existing transmission facilities, as opposed to investment in regional transmission facilities selected in a regional transmission plan for purposes of cost allocation that serve a wider set of transmission needs and are subject to competitive transmission development processes.[550]

3. ANOPR

345. In the ANOPR, the Commission recognized the possibility that ''the current transmission planning processes may be resulting increasingly in transmission facilities addressing a narrow set of transmission needs, often located in a single transmission owner's footprint.'' [551] The Commission also recognized that to ''the extent that the requirements of the regional transmission planning process result in transmission providers expanding predominately local transmission facilities, that process may fail to identify more efficient or cost-effective transmission facilities needed to accommodate anticipated future generation.'' [552] The Commission sought ''to better understand how the reforms of the federal right of first refusal in Order No. 1000 have shaped the type and characteristics of transmission facilities developed through regional and local transmission planning processes, such as a relative increase in investment in local transmission facilities or the diversity of projects resulting from competitive bidding processes.'' [553]

4. Comments

346. In response, many commenters address issues related to competitive transmission development processes, federal rights of first refusal, and how Order No. 1000's reforms may have shaped transmission development decisions and investments in recent years. Included among these comments are critiques of the Commission's Order No. 1000 nonincumbent transmission developer reforms, which contend that those reforms have not achieved their predicted benefits; these critiques tend to associate that track record at least in part with Order No. 1000's federal right of first refusal elimination policy.[554]

347. However, commenters are divided regarding the steps that they believe the Commission should take in response to the concerns and trends described above. Several commenters support increasing the scope and number of competitive transmission development processes by expanding Order No. 1000's federal right of refusal elimination mandate to other types of transmission facilities. For example, the Competition Coalition and the California Commission call for more competition in regional transmission planning, design, and construction, which they predict will lower costs to customers as transmission investment increases.[555] Similarly, LS Power contends that the implementation of current regional transmission planning processes has resulted in increasingly local transmission planning to the detriment of regional transmission planning, that a focus on local transmission needs leads to piecemeal solutions, and that the proper response is to expand competitive transmission development processes to address a greater number of transmission facilities.[556] NARUC similarly recommends that the Commission encourage the use of current competitive processes and discourage over-investment in local transmission facilities to help maximize regional and

incumbent transmission providers should be able to maintain an existing federal right of first refusal for certain types of new transmission projects'').

[547] *See* FERC, Staff Report, *2017 Transmission Metrics,* at 8 (Oct. 6, 2017), *https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf* (describing the two general types of competitive transmission development processes, the ''competitive bidding model'' and the ''sponsorship model''); *see also* Competition Coalition Comments at 14–15 (same).

[548] *See* FERC, Staff Report, *2017 Transmission Metrics,* at 23–26 (Oct. 6, 2017), *https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf; see also* Brattle Apr. 2019 Competition Report at 5, 8 fig. 2, 28 fig. 10 (included as Ex. 2 to LS Power Oct. 12 Comments).

[549] *See* Competition Coalition Comments at 9–10 (describing growth trend in overall transmission investment); NextEra Comments at 99–101 (estimating that only a small fraction of overall transmission investment in RTO/ISO regions between 2013–2020 was awarded as the result of a competitive process); Brattle Apr. 2019 Competition Report at 1, 3, 5–8, 25 (same).

[550] *See* APPA Comments at 20; AEE Comments at 22–23; LS Power Reply Comments at 41–44; *see also* California Commission Comments at 14–16 (discussing investment in ''self-approved projects''); EEI Comments at 6 (referring in part to ''a near standstill in transmission development for regional projects''); Brattle-Grid Strategies Oct. 2021 Report at 19–20 (explaining that concentration on local transmission facilities and the incentives given to transmission owners may create ''a bias against larger regional solutions even if they are more innovative and cost-effective'').

[551] ANOPR, 176 FERC ¶ 61,024 at P 37.

[552] *Id.*

[553] *Id.*

[554] *E.g.,* MISO Comments at 26–27, 29–30 (asserting that ''Order No. 1000 requirements for competitive development of projects selected in a regional plan for purposes of cost allocation [have] . . . seen only limited success'' and describing the challenges MISO has faced in implementing those mandates); WIRES Comments at 11–12, 16 (asserting that the ''introduction of competition . . . has not lived up to expectations'' and addressing the Commission's articulated concerns about the possibility that ''current policies and processes are not appropriately incentivizing the development and construction of larger regional facilities''); Harvard ELI Comments at 17–18, 20–21 (contending that ''Order No. 1000-compliant regional processes . . . have not fulfilled their promise'' and did not ''lead to an increase in regional projects'').

[555] Competition Coalition Comments at 4, 11; *see also id.* at 4 nn.4–5 (citing Brattle Apr. 2019 Competition Report at 13, 19); California Commission Comments at 24–25, 34–35, 42–43.

[556] LS Power Oct. 12 Comments at 28, 31–33, 35, 85–111 (citations omitted); *see also* LS Power Reply Comments at 2–39 (collecting statements from similar comments (citations omitted)).

interregional benefits.[557] PIOs assert that the Commission must require public utility transmission providers to plan for local transmission needs as part of the regional transmission planning process.[558] The PJM Market Monitor indicates that there is not yet a transparent, robust, and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets. The PJM Market Monitor claims that the Commission should build upon Order No. 1000 to remove barriers to nonincumbent transmission development and create more opportunities for competition between incumbent transmission providers and nonincumbent transmission providers.[559] The Chairman of the Kentucky Commission states that more transmission facilities and needs should be subject to competition.[560]

348. In contrast, other commenters urge the Commission to move in the opposite direction, arguing that the existence of competitive transmission development processes leads to delays and added costs while the elimination of federal rights of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation has failed to produce the benefits that the Commission expected.[561] For example, EEI urges the Commission to recognize that ''transmission is not being built'' and to act to ''remove the complex and costly competitive processes'' that, in EEI's view, delay transmission development.[562] ITC asserts that significant time and resources are required to conduct competitive transmission development processes, yet those processes ''deliver few if any savings to customers, let alone savings which justify their costs.'' [563] Accordingly, ITC advocates for allowing public utility transmission providers to adopt or reinstate a federal right of first refusal in light of ''the urgency of the need for new transmission investment.'' [564]

B. Need for Reform

349. As noted above, recent investment appears to be concentrated in transmission facilities not subject to Order No. 1000 competitive transmission development processes, which are often developed within individual incumbent transmission provider retail distribution service territories or footprints or address narrow regional transmission needs, as opposed to investment in regional transmission facilities selected in a regional transmission plan for purposes of cost allocation that serve a wider set of transmission needs and are subject to competitive transmission development processes.[565] Indeed, despite the fact that multiple industry studies estimate that regionally planned transmission expansion would yield numerous consumer benefits,[566] transmission investment through the regional transmission planning and cost allocation processes has not necessarily increased since implementation of Order No. 1000; in fact, in some transmission planning regions, investment in regionally planned transmission has declined.[567] The record here further indicates that regional transmission facilities subject to a competitive transmission development process represent only a small portion of total transmission investment in recent years across several transmission planning regions.[568]

350. This trend may be related to Order No. 1000's nonincumbent transmission developer reforms. While Order No. 1000 anticipated and generally sought to facilitate greater and more efficient or cost-effective investment in regional transmission facilities,[569] some observers at the time expressed concern that Order No. 1000's reforms ''could ultimately discourage'' existing ''transmission owners from seeking regional cost allocation for their local projects,'' and thereby unintentionally encourage ''more local transmission projects'' serving more local needs, even where broader regional transmission facilities may be more efficient or cost-effective.[570] Thus, given the investment trends observed since Order No. 1000's implementation, it is possible that the Commission's Order No. 1000 nonincumbent transmission developer reforms may in fact be inadvertently *discouraging* investment in and development of regional transmission facilities to some extent. Incumbent transmission providers, as a result of those reforms, may be presented with perverse investment incentives that do not adequately encourage those incumbent transmission providers to develop and advocate for transmission facilities that benefit more than just their own local retail distribution service territory or footprint. Due to these concerns, we propose to revisit and reform the Commission's rules and policies regarding the elimination of federal rights of first refusal, as described in this section.

C. Proposed Reform

1. Approach To Reform

351. In light of the experience gained since the issuance of Order No. 1000 and the comments received in response to the ANOPR, we propose to amend Order No. 1000's nonincumbent transmission developer reforms in part,

[557] NARUC Comments at 55–56; *see also* Environmental Advocates Comments at 15–18 (arguing, in part, that reliance on projects not subject to competition ''can forestall regional projects by making transmission planning and construction into a piecemeal process'').

[558] PIOs Reply Comments at 13.

[559] PJM Market Monitor Comments at 8. For example, the PJM Market Monitor criticizes the lack of oversight of supplemental projects in PJM, noting that the need for supplemental projects should be clearly defined within PJM's transmission planning process and there should be a transparent, robust, and clearly defined mechanism to permit competition to build supplemental projects. *Id.* at 8–9.

[560] Chairman of the Kentucky Commission Kent A. Chandler Reply Comments at 3–4.

[561] *See* EEI Comments at 21–23; *see also id.* at 23–24 (urging the Commission to recognize that ''transmission is not being built'' and to act to ''remove the complex and costly competitive processes'' that, in EEI's view, delay transmission development); *See* EEI Comments at 21–23; *see also* Eversource Comments at 13–14 (arguing that, in its experience, competitive transmission development processes have created delays, and that it is unclear what benefits can be shown from such processes); Indicated PJM TOs Comments at 4 (arguing in part that Order No. 1000's nonincumbent transmission developer reforms have ''fostered conflict and litigation, with the associated expense and delays'').

[562] EEI Comments at 23–24.

[563] ITC Comments at 13–15 & nn.8–9 (citing Concentric Energy Advisors, *Building New Transmission, Experience to Date Does Not Support Expanding Solicitations* (June 2019) (included as attach. B to EEI Reply Comments)).

[564] *Id.* at 13.

[565] *See supra* note 550 and associated text.

[566] *See, e.g.,* Rob Gramlich & Jay Caspary, Americans for a Clean Energy Grid, *Planning for the Future,* at app. A (Jan. 2021) (included as Ex. 1 to ACORE Comments) (ACEG Jan. 2021 Planning Report); at app. A; Brattle, *Offshore Transmission in New England: The Benefits of a Better Planned Grid* (May 2020), *https://www.brattle.com/wp-content/uploads/2021/05/18939_offshore_transmission_in_new_england_-the_benefits_of_a_better-planned_grid_brattle.pdf* (Brattle Offshore Transmission Study).

[567] *See, e.g.,* ACEG Jan. 2021 Planning Report at 25 & fig. 8 (charting the annual regionally planned transmission investment in RTOs/ISOs from 2010 to 2018); ACORE Comments at 4 (citing Ex. 1, ACEG Jan. 2021 Planning Report at 25). For example, investment in regional transmission facilities in PJM averaged $2.76 billion from 2005 to 2013 and dropped to $1.65 billion from 2014 to 2020. Harvard ELI Comments at 21 & n.92 (citations omitted); *see also* PJM, Transmission Expansion Advisory Committee, *2019 Project Statistics,* at 3 (May 12, 2020), *https://www.pjm.com/-/media/committees-groups/committees/teac/2020/20200512/20200512-item-10-2019-project-statistics.ashx.*

[568] *See, e.g.,* Brattle Apr. 2019 Competition Report at 19 fig. 6.

[569] *See* Order No. 1000, 136 FERC ¶ 61,051 at PP 2–3, 46.

[570] *See, e.g., id.* (Moeller, Comm'r, dissenting in part).

so as to permit the exercise of federal rights of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider with the federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with the proposal below. We propose to use the discretion afforded by FPA section 309 to ''amend, and rescind such orders, rules, and regulations as [the Commission] may find necessary or appropriate'' in implementing the FPA, including FPA section 205,[571] to amend Order No. 1000's findings and mandates in part. Specifically, we preliminarily find that Order No. 1000 remains correct regarding the *unconditional* exercise of federal rights of first refusal for entirely new transmission facilities selected in a regional transmission plan for purposes of cost allocation—the unconditional use of federal rights of first refusal for such facilities remains unjust and unreasonable given the likelihood that the presence and exercise of those rights may prevent the realization of more efficient or cost-effective transmission solutions to regional transmission needs.[572]

352. However, in light of the years of experience since the issuance of Order No. 1000 and the comments received in response to the ANOPR, we preliminarily find that Order No. 1000's remedy—requiring the elimination of *all* federal rights of first refusal for entirely new transmission facilities selected in a regional transmission plan for purposes of cost allocation—was overly broad. Order No. 1000 may have overlooked the possibility that, as an alternative to elimination of federal rights of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditions could be applied to the use of federal rights of first refusal for such facilities that would make their exercise just and reasonable and not unduly discriminatory or preferential.

353. Accordingly, we preliminarily find that, while Order No. 1000's nonincumbent transmission developer reforms have a sound theoretical basis,[573] in requiring the elimination of *all* federal rights of first refusal for entirely new transmission facilities selected in a regional transmission plan for purposes of cost allocation, the remedy prescribed by Order No. 1000 failed to recognize that at least some of the most notable expected benefits from competitive transmission development processes (*e.g.,* new transmission developer market entry, greater innovation in and potentially lower costs of transmission development) could be achieved or at least reasonably approximated through other means. We believe that it may be possible that allowing public utility transmission providers to propose conditional federal rights of first refusal consistent with the proposal below may help public utility transmission providers address potentially flawed investment incentives that may be restraining otherwise more efficient or cost-effective regional transmission facility development. Therefore, under FPA sections 309 and 205, we preliminarily find it necessary or appropriate to carry out the provisions of the FPA to amend Order No. 1000 in part as described in this section.

354. Should the Commission proceed to amend Order No. 1000's findings and mandates as described above, following the issuance of any final rule in this docket, we propose to allow public utility transmission providers to propose, pursuant to FPA section 205, new federal rights of first refusal for incumbent transmission providers, provided that such rights are conditioned on the incumbent transmission provider with the federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with the proposal below. We believe that this reform will help to ensure just and reasonable Commission-jurisdictional rates and limit opportunities for undue discrimination by public utility transmission providers. We preliminarily continue to find that unconditional federal rights of first refusal for incumbent transmission providers are unjust and unreasonable, and unduly discriminatory and preferential.

355. In making this proposal, however, we do not intend to require the establishment of any particular federal rights of first refusal. Given the nature of our proposed action, public utility transmission providers would not be obligated to adopt the conditional federal rights of first refusal described in this section. Instead, Order No. 1000's findings and mandates would be amended such that joint ownership conditions may presumptively be found to ensure just and reasonable Commission-jurisdictional rates and limit opportunities for undue discrimination by public utility transmission providers, if imposed upon the exercise of an incumbent transmission provider's federal right of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation. We believe that this approach would permit justified variations from an otherwise one-size-fits-all federal rights of first refusal policy, and thereby would allow for regional flexibility, without imposing new federal rights of first refusal requirements on all public utility transmission providers. Public utility transmission providers would have the opportunity in their regular course of business to consider whether this type of a conditional federal right of first refusal would, if adopted, help improve their particular regional transmission planning process or help address potentially misaligned incentives regarding regional and local transmission facility investment.

356. We also propose to allow public utility transmission providers that establish conditional federal rights of first refusal as recognized in any final rule adopted in this proceeding to make other corresponding adjustments to the timing and procedural requirements of their competitive transmission development processes that are just and reasonable and not unduly discriminatory or preferential. More specifically, to accommodate changes in federal rights of first refusal provisions regarding certain transmission facilities selected in a regional transmission plan for purposes of cost allocation, we propose to permit changes to existing tariff provisions that were adopted to comply with the following requirements

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[571] 16 U.S.C. 825h (''The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this chapter.''); *see also id.* section 824d(a)–(b) (requiring that ''all rules and regulations affecting or pertaining to'' jurisdictional rates ''be just and reasonable'' and free from ''undue preference or advantage''); *Am. Pub. Power Ass'n* v. *FPC,* 522 F.2d 142, 144, 145–47 (D.C. Cir. 1975) (affirming Commission action taken under FPA section 309 to change rules regarding cost basis for wholesale electric power rates, observing in part that ''ratemaking methodologies perceived to produce just and reasonable results in the past may be scrapped in favor of other methodologies now perceived to be preferable'' (citation omitted)); *La.Regional Transmission Organizations,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 30,993 (1999) (cross-referenced at 89 FERC ¶ 61,285) (relying in part on section 205 in a rulemaking order that enabled voluntary reforms), *order on reh'g,* Order No. 2000–A, FERC Stats. & Regs. ¶ 31,092 (2000) (cross-referenced at 90 FERC ¶ 61,201), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish Cty.* v. *FERC,* 272 F.3d 607 (DC Cir. 2001); *La. Pub. Serv. Comm'n* v. *Entergy Corp.,* Opinion No. 519–A, 153 FERC ¶ 61,188, at P 15 (2015) (''The Commission, which is responsible for determining what is 'just and reasonable' under the FPA, necessarily has broad discretion to take into account all factors that affect that determination.'').

[572] *See* Order No. 1000, 136 FERC ¶ 61,051 at PP 5, 7, 226.

[573] *See supra* notes 538 to 541 and associated text.

of Order No. 1000: The federal rights of first refusal elimination requirement;[574] the qualification requirement;[575] the information requirement;[576] and the access to use the regional cost allocation method(s) requirement.[577] The degree to which changes to such tariff provisions will be necessary will depend on the specifics of the future proposal made by a particular public utility transmission provider. In allowing these corresponding adjustments, we intend for public utility transmission providers to provide robust openness and transparency safeguards regarding the exercise of conditional federal rights of first refusal, to help ensure just and reasonable Commission-jurisdictional rates and to limit and detect instances of potential undue discrimination.[578]

357. Also, we envision that conditional federal right of first refusal proposals would seek to establish federal rights of first refusal true to their name—a process whereby an incumbent transmission provider may, at its own election, choose to exercise a right to be designated to use the regional cost allocation method for a particular transmission facility or set of transmission facilities within its retail distribution service territory or footprint that is selected in a regional transmission plan for purposes of cost allocation,[579] subject to applicable conditions. Should the incumbent transmission provider choose not to exercise its right, we envision that a public utility transmission provider would then proceed to follow its competitive transmission development process to select a qualified transmission developer to use the regional transmission cost allocation method for the selected regional transmission facilities.[580]

2. Conditional Federal Rights of First Refusal for Certain Jointly-Owned Transmission Facilities

358. We propose to preliminarily find presumptively just and reasonable and not unduly discriminatory or preferential the establishment of a federal right of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on joint-ownership requirements, as more fully described in this section. We propose that an incumbent transmission provider may establish qualifying joint ownership structures with unaffiliated nonincumbent transmission developers as defined in Order No. 1000,[581] or with another unaffiliated entity, including another incumbent transmission provider, if the joint ownership structure meets the requirements outlined in this section, including the requirement that the joint ownership structure offer a meaningful level of participation and investment in proposed transmission facilities to the incumbent transmission provider's unaffiliated partners.[582] We believe this proposed reform could address the potentially misaligned incentives for regional transmission facility development faced by incumbent transmission providers while still largely ensuring at least some of the potential cost-related benefits of competitive transmission development processes.

a. Background

359. In Order No. 1000, in response to comments requesting that the Commission consider joint transmission ownership as a financing and cost allocation tool, the Commission stated that specific financing techniques such as joint ownership were beyond the scope of that proceeding. While the Commission declined to ''specifically address joint ownership as a cost allocation tool,'' it did note that transmission developers were ''free to consider joint ownership when proposing and developing a transmission project.''[583] The Commission also reiterated its belief that ''there are benefits to joint ownership of transmission facilities, particularly large backbone facilities, both in terms of increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the transmission grid by transmission customers.''[584] Since Order No. 1000, joint proposals or joint ownership arrangements between incumbent transmission providers and nonincumbent transmission developers have been an option generally available to qualified transmission developers participating, pursuant to public utility transmission provider tariffs, in competitive transmission development processes.[585]

b. Comments

360. Although the Commission did not specifically ask about jointly-owned

[574] The federal right of first refusal elimination requirement means the requirement that each public utility transmission provider eliminate provisions in Commission-jurisdictional tariffs and agreements that establish a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities selected in a regional transmission plan for purposes of cost allocation. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 313.

[575] The qualification requirement means the requirement that each public utility transmission provider revise its OATT to demonstrate that the regional transmission planning process in which it participates has established appropriate qualification criteria for determining an entity's eligibility to propose a transmission facility for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a nonincumbent transmission developer. *See id.* P 323.

[576] The information requirement means the requirement that each public utility transmission provider identify in its OATT the information that a prospective transmission developer must submit in support of a transmission project the developer proposes in the regional transmission planning process. *See id.* P 325.

[577] The access to use the regional cost allocation method(s) requirement means the requirement that each public utility transmission provider participate in a regional transmission planning process that provides that a nonincumbent transmission developer has an opportunity comparable to that of an incumbent transmission provider to allocate the cost of a transmission facility selected in the regional transmission plan for purposes of cost allocation through a regional cost allocation method or methods. *See id.* PP 332, 335.

[578] *See, e.g., PJM Interconnection, L.L.C.,* 174 FERC ¶ 61,117 at PP 3–4 (describing the criteria for and process regarding immediate need reliability projects).

[579] *See S.C. Pub. Serv. Auth.,* 762 F.3d at 72 & n.6.

[580] If the competitive transmission development process does not yield a qualified transmission developer to use the regional transmission cost allocation method for the selected regional transmission facilities, and if necessary, the incumbent transmission provider may be obligated to build those selected regional transmission facilities. *See PJM Interconnection, L.L.C.,* 142 FERC ¶ 61,214, at P 224 (2013) (explaining that Order No. 1000 did not limit ''mechanisms to impose an obligation to build transmission facilities in a regional transmission plan''); *e.g.,* CAISO, CASIO eTariff, § 24.6.4, (Inability to Complete the Transmission Solution) (2.0.0) (granting CAISO the discretion, regarding reliability driven transmission solutions an Approved Project Sponsor is unable to construct, to either ''direct the Participating TO in whose PTO Service Territory or footprint either terminus of the transmission solution is located . . . to build the transmission solution, or the CAISO may open a new solicitation for Project Sponsors to finance, own, and construct the transmission solution'').

[581] *See supra* P 337.

[582] *See infra* PP 365, 371.

[583] Order No. 1000, 136 FERC ¶ 61,051 at P 776.

[584] *Id.* (citing Order No. 890, 118 FERC ¶ 61,119 at P 593).

[585] *See, e.g.,* CAISO, CASIO eTariff, § 24.5.2 (Project Sponsor Application and Information Requirements) (6.0.0), § 24.5.2.1 (Opportunity for Collaboration); *id.* 24.15.1 Transmission Additions and Upgrades under TCA (0.0.0), section 24.15.1 (referencing ''transmission additions and upgrades [that] are jointly developed by Participating TOs and non-Participating TOs''); MISO, FERC Electric Tariff, attach. FF (Transmission Expansion Planning Protocol) (85.0.0), § VIII.D.4.2. (Joint-Developer Proposal); PJM, Intra-PJM Tariffs, OA Schedule 6, § 1.5 (Procedure for the Development of the Regional Transmission Expansion Plan) (28.0.0), § 1.5.6(*l*) (''Nothing herein shall prevent any Transmission Owner or other entity designated to construct, own and/or finance a recommended transmission enhancement or expansion from agreeing to undertake its responsibilities under such designation jointly with other Transmission Owners or other entities.'').

transmission facilities in the ANOPR,[586] some commenters address the topic of jointly-owned transmission facilities. For example, SDG&E discusses its partnership with nonincumbent transmission developers to develop and construct two new transmission lines, known as the Sunrise Powerlink and Sycamore-Peñasquitos projects.[587]

361. In its comments, TAPS supports joint transmission ownership arrangements, which TAPS argues have been effective for getting transmission facilities constructed.[588] Among other potential benefits of joint transmission ownership arrangements, TAPS argues that these arrangements improve coordination by leveraging relationships and knowledge among the joint-owning parties for transmission siting, obtaining approval from state-level retail regulators, easing cost allocation issues by spreading or socializing costs among the joint-owning parties, spreading risk more evenly, and likely lessening disputes related to transmission planning and cost allocation that the Commission may otherwise have to adjudicate.[589] Joint ownership arrangements, TAPS explains, can be structured in various ways, including as an inclusive transmission-only company, or shared-system arrangement, or other type of joint venture, including structures where ownership among two or more utilities is held in proportion to each participant's load ratio share of connected customer load.[590]

362. TAPS asserts that while the Commission has previously found that joint transmission ownership arrangements are beneficial and encouraged more entities to consider these types of arrangements,[591] there are few joint transmission ownership arrangements today. TAPS warns that the Commission's objective of modifying transmission planning and expansion requirements to accommodate the changing resource mix, while minimizing costs to consumers, would be thwarted if costs are unnecessarily increased; that objective may also be thwarted if needed transmission projects are not timely built because those projects face greater financial or siting risk without joint ownership, which may relate to federal rights of first refusal requirements.[592]

363. In order to foster joint transmission ownership arrangements, TAPS recommends that the Commission make changes to transmission planning processes, including by permitting public utility transmission providers to bid out the cost of construction and associated capital requirements regarding regional and interregional transmission facilities selected in regional transmission plans, which would be designed to identify ownership partners among the existing load-serving entities in the transmission planning region. TAPS recommends that, to the extent the Commission makes a finding on joint transmission ownership arrangements, the Commission should structure competitive bidding processes such that they provide transmission-dependent utilities in the project's footprint with opportunities to participate in supplying their fair share of capital for certain projects.[593]

364. While TAPS does not explicitly request that the Commission permit the establishment of a conditional federal right of first refusal for constructing transmission facilities under certain joint transmission ownership arrangements, TAPS contends that in general there is significant interest from willing partners that could work together with incumbent transmission providers to construct a transmission facility, and that the structure of competitive transmission development processes should ''advance[ ] the role of inclusive joint ownership.'' [594]

c. Proposed Reform

365. We preliminarily find presumptively just and reasonable and not unduly discriminatory or preferential the establishment of a federal right of first refusal for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider with the federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with this subsection. We propose that an incumbent transmission provider may establish qualifying joint ownership with unaffiliated nonincumbent transmission developers as defined in Order No. 1000,[595] or another unaffiliated entity, including another incumbent transmission provider, if otherwise consistent with this subsection. These potential joint ownership partners could include unaffiliated public power entities, unaffiliated load-serving entities such as transmission-dependent municipally-owned utilities or electric cooperatives, other unaffiliated third parties that do not have (or are operating outside of) their retail distribution service territory or footprint, or another unaffiliated entity, including another incumbent transmission provider.

366. We expect that public utility transmission providers seeking to adopt this reform will need to include in their tariffs a detailed process for the exercise of a conditional right of first refusal for regional transmission facilities that will be jointly owned. Relatedly, we believe that an incumbent transmission provider's conditional federal right of first refusal—whether exercised or not regarding any particular transmission facility—should not significantly delay the regional transmission planning process, nor should it result in prolonged uncertainty regarding which transmission facilities will (or, alternatively, will not) be subject to competitive transmission development processes.

367. We envision, as an example, the following process for the exercise of a conditional federal right of first refusal for regional transmission facilities that will be jointly owned. First, the public utility transmission providers in a transmission planning region will identify a regional transmission need (under the sponsorship model) or identify a regional transmission need and select a transmission facility in the regional transmission plan for purposes of cost allocation to meet that need (under the competitive bidding model).[596]

368. Second, before public utility transmission providers in each transmission planning region initiate competitive transmission development processes, public utility transmission providers in each transmission planning region will give an opportunity for an incumbent transmission provider possessing a relevant conditional federal right of first refusal to indicate its intent to invoke that right and submit a jointly-owned regional transmission facility

[586] *See* ANOPR, 176 FERC ¶ 61,024 at P 37.

[587] SDG&E Comments at 4–5.

[588] TAPS Comments at 8 (citing TAPS 2021 White Paper (June 25, 2021), *https://www.tapsgroup.org/wp-content/uploads/2021/09/TAPS-Inclusive-Joint-Ownership-White-Paper.pdf* (TAPS 2021 White Paper)).

[589] *Id.* at 9–11.

[590] *Id.* at 8–9 & nn.9–11.

[591] *Id.* at 12; TAPS 2021 White Paper at 7–8 (citing in part Order No. 1000, 136 FERC ¶ 61,051 at P 776; *Promoting Transmission Inv. Through Pricing Reform,* Policy Statement, 77 FR 69754 (Nov. 21, 2012), 141 FERC ¶ 61,129 (2012)).

[592] TAPS Comments at 13–15, 52–53.

[593] *Id.* at 13–15.

[594] *Id.* at 12, 14–15, 52–53.

[595] *See supra* P 337.

[596] *See* FERC, Staff Report, *2017 Transmission Metrics,* at 8 (Oct. 6, 2017), *https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf* (describing the two general types of competitive transmission development processes).

proposal in partnership with one or more unaffiliated entities.

369. Third, given that the potentially relevant conditional federal right of first refusal and process for exercising it has been established in Commission-jurisdictional tariffs and agreements, upon receipt of a jointly-owned regional transmission facility proposal, the public utility transmission providers in the transmission planning region would confirm the parties' rights and responsibilities associated with the jointly-owned transmission facility proposal and its conformance with tariff provisions implementing the option proposed in this subsection. Here, we envision that the parties participating in the jointly-owned regional transmission facility proposal would have to demonstrate that their proposal commits the parties to a joint-ownership arrangement consistent with this subsection and that it meets the requirements of the applicable regional transmission planning process as outlined in the public utility transmission providers' tariffs on file with the Commission. For instance, the parties to a jointly-owned regional transmission facility proposal would have to provide sufficient detail to adequately delineate their respective financial interests and relationship as partners, and to demonstrate that the parties either individually or jointly meet all other applicable requirements. Public utility transmission providers in the transmission planning region should, at the conclusion of this step in the process, notify stakeholders and the public (*e.g.,* through posting on a public website) that either the jointly-owned regional transmission facility proposal conforms with tariff provisions implementing the conditional right of first refusal and, thus, a relevant conditional right of first refusal has been exercised, or, alternatively, that the public utility transmission providers in the transmission planning region will proceed to initiate a competitive transmission development process given that the jointly-owned regional transmission facility proposal does not conform with such tariff provisions. If a jointly-owned regional transmission facility proposal is not or cannot be confirmed as conforming with the public utility transmission provider's Commission-jurisdictional tariffs and agreements that relate to the incumbent transmission provider's conditional federal right of first refusal, or otherwise does not qualify for selection in the regional transmission plan for purposes of cost allocation, public utility transmission providers in the transmission planning region shall proceed to follow their otherwise applicable competitive transmission development process.

370. Finally, public utility transmission providers in the transmission planning region would proceed to evaluate the jointly-owned regional transmission facility proposal without going through the competitive transmission development process. In a transmission planning region with a sponsorship model, this means that public utility transmission providers would evaluate in their regional transmission planning process the jointly-owned regional transmission facility proposal for potential selection in the regional transmission plan for purposes of cost allocation without soliciting any sponsored transmission facility proposals. In a transmission planning region with a competitive bidding model, where the transmission facility has already been selected in the regional transmission plan for purposes of cost allocation, this means that public utility transmission providers would evaluate the jointly-owned regional transmission facility proposal through the regional transmission planning process without soliciting other proposals to develop the already-selected regional transmission facility.

371. As part of this proposal and in general, we believe that the benefits of joint ownership would not be achieved if an incumbent transmission provider partnered with an affiliated entity to submit a proposal, or if that incumbent transmission provider limited the input or ownership share of its intended partners to less than a meaningful level. Instead, we intend for incumbent transmission providers pursuing joint-ownership proposals to offer unaffiliated entities a reasonable chance at meaningful participation and investment in the proposed regional transmission facility. Therefore, we propose that to qualify for the presumption advanced in this proposal, incumbent transmission providers with a conditional federal right of first refusal would not be allowed to partner with affiliated entities, and would not be allowed to structure joint-ownership arrangements such that unaffiliated entities were offered less than a meaningful level of participation and investment in the proposed regional transmission facility. While we do not propose to limit potentially qualifying joint ownership structures to those already employed in the industry, we note that a meaningful level of participation and investment in proposed facilities has been or could be offered to unaffiliated entities under various types of joint ownership structures that have been established or proposed.[597]

372. We believe that a conditional federal right of first refusal for jointly-owned transmission facilities as described in this subsection may help facilitate openness in the regional transmission planning process, decrease potential financial and siting risks, and increase the likelihood that transmission facilities selected in a regional transmission plan for purposes of cost allocation are successfully and cost-effectively developed. First, if a conditional federal right of first refusal was available for jointly-owned regional transmission facilities, the greater development certainty that a federal right of first refusal could provide for the development of a transmission facility could help incentivize interested parties (including incumbent transmission providers and potential unaffiliated partners) to consider a jointly-owned transmission facility and leverage the combined transmission development strengths of the parties, potentially including the parties' knowledge of siting and permitting processes or other strengths. Joint ownership arrangements could, consistent with Commission precedent, help increase opportunities for investment in the transmission system, as well as ensure not unduly discriminatory access to the transmission system by transmission customers.[598] Indeed, we believe that jointly-owned regional transmission facilities, which may involve the participation of multiple nearby load-serving entities and potentially those that are public power entities, may increase collaboration within the regional transmission planning process consistent with Order No. 679.[599]

373. Second, given the nature of a joint-ownership arrangement, individual parties working together may achieve efficiencies in addressing their collective transmission needs and, therefore, achieve lower overall costs compared to developing transmission facilities to resolve more individualized needs in a more piecemeal manner as is the case today. Relatedly, the entities in

[597] *See, e.g., supra* PP 360–364 (discussing examples of joint ownership structures employed or identified by ANOPR commenters, including those based on load-ratio share); *see also infra* note 604 and associated text (describing the inclusive transmission-only company or shared-system agreement concepts).

[598] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 776; *see also* Order No. 890, 118 FERC ¶ 61,119 at PP 593–594.

[599] *See Promoting Transmission Inv. through Pricing Reform,* Order No. 679, 71 FR 43294 (July 31, 2006), 116 FERC ¶ 61,057, at PP 354, 355 (2006).

a joint ownership arrangement might bring different strengths to the process of developing a regional transmission facility, potentially reducing the costs for development or leveraging their expertise to design a more efficient or cost-effective transmission facility than the partners would have designed separately, thus benefiting customers. We note, for example, that while SDG&E's Sunrise Powerlink and Sycamore-Peñasquitos projects addressed multiple reliability needs for CAISO's transmission system, these transmission facilities also enabled the transmission facility's other joint owner the option to lease a portion transfer capability of the transmission facility.[600] In short, we believe that this joint ownership proposal may help promote innovative transmission ownership structures for transmission development, as well as innovative regional transmission facilities that more efficiently or cost-effectively address regional transmission needs, which in turn would help ensure just and reasonable Commission-jurisdictional rates.

374. Third, jointly-owned regional transmission facilities, by spreading the risks and responsibilities of developing transmission facilities among multiple parties, may act as a useful hedging tool against expected longer-term, future transmission system development costs by allowing the parties to offset near-term expenditures on constructing transmission facilities necessary to maintain reliability.

375. Thus, we preliminarily find that a conditional federal right of first refusal for regional transmission facilities that will be jointly owned, as described in this subsection, could address the potentially misaligned incentives for transmission facility development faced by incumbent transmission providers while still largely ensuring the potential cost-related benefits of competitive transmission development processes. Given that jointly-owned transmission facilities appear to offer many benefits, we preliminarily find that customers may benefit from such a conditional federal right of first refusal through the selection of more efficient or cost-effective transmission facilities in the regional transmission plan for purposes of cost allocation. Indeed, we believe that joint ownership arrangements may help achieve several of the goals that competitive transmission development processes are intended to serve today.[601]

376. In particular, we believe that this proposal would offer nonincumbent transmission developers and other potential unaffiliated entities the opportunity to partner with an incumbent transmission provider and thereby achieve market entry and greater diversity of participation and perspectives in transmission ownership. Moreover, to exercise their conditional federal right of first refusal under this proposed reform, incumbent transmission providers would be required to share ownership and investment opportunities with other partners, potentially including other transmission developers, limiting an incumbent transmission provider's ability to use federal rights of first refusal to serve only its own economic interests.

377. As described above, we are concerned that today's processes place unintended emphasis on the development of local transmission facilities or other transmission facilities not subject to competitive transmission development processes, potentially at the expense of regional transmission facility development, given trends observed since the issuance of Order No. 1000.[602] We believe that this joint ownership-focused conditional federal right of first refusal proposal may help address that issue while advancing the goals of Order No. 1000.

378. We seek comment on the requirements proposed in this section of the NOPR. In particular, we request that commenters address how this proposed conditional right of first refusal aligns with or advances the goals of Order No. 1000's reforms,[603] or otherwise ensures just and reasonable Commission-jurisdictional rates and limits opportunities for undue discrimination by public utility transmission providers.

379. We also seek comment regarding the administrability of and implementation challenges associated with the establishment and exercise of joint ownership-focused conditional federal rights of first refusal, including what specific requirements the Commission should impose on joint-ownership agreements or on the process of formulating them. We also seek comment on whether limiting this option to proposals that form or expand an inclusive transmission-only company or shared-system arrangement is necessary to ensure just and reasonable Commission-jurisdictional rates and limited opportunities for undue discrimination by public utility transmission providers.[604] We seek comment as well regarding whether all transmission-dependent utilities or load-serving entities in a particular public utility transmission provider's service territory where a proposed regional transmission facility would be located should be given the opportunity to participate in a joint ownership arrangement that allows those transmission-dependent utilities or load-serving entities to supply up to their fair share (*e.g.,* load-ratio share) of capital for certain regional transmission facilities.[605]

380. We also seek comment on the standards, such as ownership share percentages or load-ratio share offer requirements, that should govern whether particular joint ownership arrangements qualify for the presumption identified here because such standards would help achieve the benefits described above. Accordingly, we seek comment on whether any additional requirements beyond those mentioned above would be necessary to prevent the exertion of undue influence over the transmission development process or joint ownership arrangement by any project entity (including an incumbent transmission provider), avoid greater risks of project cancellation or abandonment, or otherwise protect customer interests.

381. Relatedly, we seek comment on eligibility and participation criteria related to jointly-owned transmission facilities and partners that should be permitted to qualify for the presumption proposed in this section, and any

[600] *See* SDG&E Comments at 4–5; *see also* California State Water Project Reply Comments at 12 n.44 (discussing the Sycamore-Peñasquitos Project (citations omitted)); *Citizens Sycamore-Penasquitos Transmission LLC,* 164 FERC ¶ 61,149, at PP 5–6 (2018) (same); *Citizens Sunrise Transmission LLC,* 138 FERC ¶ 61,129, at PP 3–10 (2012) (discussing the Sunrise Powerlink Project); *Citizens Energy Corp.,* 129 FERC ¶ 61,242, at P 5 (2009) (same).

[601] *See supra* notes 538 to 541 and associated text.

[602] *See supra* note 550; *see also* WIRES Comments at 11–12, 16 (asserting that the ''introduction of competition . . . has not lived up to expectations'' and addressing the Commission's articulated concerns about the possibility that ''current policies and processes are not appropriately incentivizing the development and construction of larger regional facilities'').

[603] *See supra* notes 538 to 543 and associated text.

[604] In its comments and related white paper, TAPS cites Vermont Transco LLC and American Transmission Company LLC as inclusive transmission-only companies where instead of retaining direct ownership of separate transmission facilities, investor-owned and public power or cooperative utilities alike own membership units or equity stakes in one jointly-owned transmission company. *See* TAPS Comments at 8 nn.8–9; *see also* TAPS 2021 White Paper at 2. As TAPS further explains, under ''shared-system arrangements, . . . transmission facilities of two or more utilities are planned and operated jointly, as a single system, pursuant to a long-term agreement. Ownership is generally in proportion to each participant's load ratio share of connected customer load, which can be achieved in a variety of ways, *e.g.,* owning an undivided share of the entire joint system; owning discrete facilities; owning new facilities.'' *See* TAPS Comments at 8 n.10.

[605] *See* TAPS Comments at 14–15.

transparency, informational, or screening processes that may be required.[606] While transmission developers already must satisfy qualification criteria to be eligible to use the regional transmission cost allocation method for regional transmission facilities selected in a regional transmission plan for purposes of cost allocation, we seek comment on whether this proposal necessitates specialized eligibility criteria or particular joint ownership partner selection processes to ensure just and reasonable Commission-jurisdictional rates and limit opportunities for undue discrimination by public utility transmission providers.[607]

382. Finally, we seek comment regarding whether the Commission should pursue broader reform to its rules and regulations governing federal rights of first refusal. In particular, we seek comment on whether the Commission should consider fully restoring the federal rights of first refusal eliminated in Order No. 1000 and, if so, how the Commission should go about doing so. We recognize that pursuing reforms focused on joint ownership alone may not fully address the potential issues that commenters have raised regarding competitive transmission development processes. Therefore, we seek comment both on the joint ownership-focused conditional federal rights of first refusal reform proposed above and on whether more significant changes to Order No. 1000's federal right of first refusal elimination mandate would help ensure just and reasonable Commission-jurisdictional rates while limiting opportunities for undue discrimination by public utility transmission providers.

VIII. Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process and Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

A. Background

383. Generally, the transmission facilities that public utility transmission providers include in their individual local transmission plans are incorporated into regional transmission plans as inputs, with minimal opportunity for stakeholder review in the regional transmission planning process. That is because the analysis of local transmission plans in the regional transmission planning process is limited mainly to a reliability analysis to ensure that local transmission plans do not negatively affect the reliability of the regional transmission system.

384. As noted earlier, the Commission in Order No. 1000 defined a local transmission facility as a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation.[608] The Commission did not require that the transmission facilities in a public utility transmission provider's local transmission plan be subject to approval at the regional or interregional level, unless that public utility transmission provider seeks to have any of those facilities selected as regional transmission facilities in the regional transmission plan for purposes of cost allocation.[609]

385. As existing transmission infrastructure ages, transmission owners must assess the state of their transmission systems and the condition of their transmission assets to determine whether and, if so, how to replace existing transmission facilities that have reached the end of their useful lives. The Commission has found that a replacement of an existing transmission facility that does not incrementally increase that facility's capacity is not subject to the transmission planning requirements of Order No. 890 or Order No. 1000 because an in-kind replacement[610] of an existing transmission facility does not represent an expansion or enhancement of the transmission system.[611] Therefore, under this precedent there is no requirement that public utility transmission providers provide information about potential in-kind replacements of existing transmission facilities in either their local or regional transmission planning processes. Some RTO/ISO transmission planning regions may assess a planned in-kind replacement of an existing transmission facility to ensure that it does not cause adverse reliability impacts,[612] but regional transmission planning processes generally do not evaluate whether the planned in-kind replacement transmission facility could be modified to more efficiently or cost-effectively address regional transmission needs. However, we note that some public utility transmission providers do provide stakeholders with reports detailing the justification and quantity of replacement transmission

[606] For example, MISO's tariff requires information regarding the responsibilities and liabilities of each party to a joint-developer transmission project proposal. *See* MISO, FERC Electric Tariff, attach. FF (Transmission Expansion Planning Protocol) (85.0.0), § VIII.D.4.2. (Joint-Developer Proposal); *id.* § VIII.D.5.1.1. (Identification of RFP Respondents).

[607] For example, we note that SDG&E's Sycamore-Peñasquitos Project was developed in partnership with Citizens Energy and required both SDG&E and Citizens Energy to enter into a Development, Coordination, and Option Agreement to provide for their rights, responsibilities, and future options related to the Sycamore-Peñasquitos Project. *See Citizens Sycamore-Penasquitos Transmission LLC,* 164 FERC ¶ 61,149 at P 7.

[608] *Supra* P 17.

[609] Order No. 1000–A, 139 FERC ¶ 61,132 at P 190.

[610] For the purposes of this NOPR, we define an ''in-kind replacement'' as a new transmission facility that does not expand the capacity of the existing transmission facility that is being replaced unless the incidental increase in transmission capacity occurs as a function of advancements in technology of the replaced equipment and is thus not reasonably severable from that replacement. (*e.g.,* a 345 kV transmission facility that is replaced with a 345 kV transmission facility).

[611] *See S. Cal. Edison Co.,* 164 FERC ¶ 61,160, at P 31 (2018) (''While Order No. 890 does not explicitly define the scope of 'transmission planning,' the Commission adopted the transmission planning requirements in Order No. 890 to remedy opportunities for undue discrimination in *expansion* of the transmission grid.'' (citing Order No. 890, 118 FERC ¶ 61,119 at PP 57–58, 421–422)); *Cal. Pub. Utils. Comm'n* v. *Pac. Gas & Elec. Co.,* 164 FERC ¶ 61,161, at P 68 (2018); *PJM Interconnection, L.L.C.,* 172 FERC ¶ 61,136, at PP 12, 89, *order on reh'g,* 173 FERC ¶ 61,225 (2020); *PJM Interconnection, L.L.C.,* 173 FERC ¶ 61,242, at P 54 (2020), *order on reh'g,* 176 FERC ¶ 61,053 (2021). The Commission has further clarified that there may be instances in which a transmission owner's replacement of an existing transmission facility may result in an incidental increase in transmission capacity that is not reasonably severable from that replacement, *e.g.,* that occurs as a function of advancements in technology of the replaced equipment. In such cases, the Commission stated, the incidental increase in transmission capacity would not render the in-kind replacement of an existing transmission facility a transmission expansion that is subject to the transmission planning requirements of Order No. 890. *Cal. Pub. Utils. Comm'n* v. *Pac. Gas & Elec. Co.,* 164 FERC ¶ 61,161 at P 68.

[612] *See, e.g.,* PJM Manual 14B: PJM Regional Transmission Planning Process at 19–20 (''It should also be noted that prior to integrating a Supplemental Project into the RTEP base case PJM performs a 'do no harm study' to evaluate whether a proposed Supplemental Project will adversely impact the reliability of the Transmission System as represented in the planning models used in all other PJM reliability planning studies. If as a result of the do no harm study, system upgrades are required, such upgrades will be considered part of the Supplemental Project and are the responsibility of the Transmission Owner sponsoring the Supplemental Project.''); *see also* MISO Business Practice Manual, Transmission Planning, Manual No. 020 at 22–23 (''In its role as the Planning Coordinator (PC), MISO will evaluate all bottom-up projects submitted by Transmission Owner(s) and validate that the projects represent prudent solutions to one or more identified Transmission Issues.'').

facilities.[613] Further, as discussed above, some public utility transmission providers do assess the benefits of deferred or avoided infrastructure, including asset replacements that would otherwise be needed.[614]

386. The Commission in Order 1000–A clarified that it was not eliminating the right of an owner of a transmission facility to improve its own existing transmission facility.[615] Order No. 1000 also allows an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not selected in a regional transmission plan for purposes of cost allocation.[616] Such transmission facilities' costs are allocated to the retail distribution service territory or footprint in which the facility is located through the incumbent transmission provider's individual transmission service rates in its OATT or though the zonal rates in an RTO/ISO OATT.

B. ANOPR

387. In the ANOPR, the Commission sought comment on whether individual incumbent transmission provider practices regarding replacement of existing transmission facilities sufficiently align with the directive to ensure evaluation of alternative transmission solutions and whether these practices sufficiently consider the more efficient or cost-effective ways to serve future needs.[617] Additionally, the Commission sought comment on whether sufficient transparency exists around replacement decisions made by transmission providers to allow an assessment of these decisions in the regional transmission planning process.

388. In the ANOPR, the Commission also sought comment on local transmission planning to better understand how the reforms of the federal right of first refusal in Order No. 1000 have shaped the type and characteristics of transmission facilities developed through regional and local transmission planning processes, such as a relative increase in investment in local transmission facilities or the diversity of projects resulting from competitive regional transmission planning processes.[618]

389. The Commission requested comment on whether the current regional and local transmission planning processes provide sufficient transparency for stakeholders to understand how best to obtain information and fully participate in the various processes.[619] The Commission, for example, theorized that in non-RTO/ISO regions, individual transmission owning members' local transmission planning processes may not be as well-publicized or follow as well-understood processes to provide information as in RTO/ISO regions. Based on this example, the Commission inquired whether customers and other stakeholders may benefit from enhanced oversight of local transmission planning.

C. Comments

390. Numerous commenters state that the vast majority of investment for transmission facilities in recent years has increasingly been focused on local level transmission facilities (typically less than 100–250 kV), and in replacing existing transmission facilities.[620]

391. Several commenters generally agree that the process for replacing aging transmission facilities needs additional improvements related to transparency and to increase the potential that multiple transmission system needs are addressed.[621] The California Commission argues that because the decision to order replacement transmission facilities is delegated to incumbent transmission owners, there is no process to evaluate whether replacement transmission facilities could be a ''like-for-like'' replacement or whether the replacement transmission facility may be upgraded via a new design or capacity.[622] NARUC argues that the Commission should require public utility transmission providers to apply Order No. 890 transparency principles to replacement transmission facilities to guard against incumbent public utility transmission providers' incentive to overinvest in replacement transmission facilities.[623] The New Jersey Commission asserts that by evaluating replacement transmission facilities through the regional transmission planning process, a potentially broader transmission solution may be identified thus obviating the need for a smaller-scope replacement transmission facility.[624]

392. ACEG notes that much of the nation's transmission facilities are over 50 years old and that the lack of a broader view of transmission planning in terms of replacement of existing, aging transmission facilities, coupled with a changing generation mix, will lead to a suboptimal transmission infrastructure network.[625] Eversource argues that, going forward, the Commission should encourage flexibility by breaking down transmission planning silos so that an existing or planned transmission facility can be ''upsized'' to address multiple system needs like transmission facility conditions while also anticipating clean energy goals.[626] LS Power argues that the Commission should require NERC to develop a new requirement that transmission providers must give notice when an existing transmission facility has reached the end of its useful life.[627] PIOs explain that the routine of in-kind replacement of aging transmission facilities misses opportunities for better utilizing existing rights-of-way so as to meet multiple transmission system needs, which increases costs and inefficiencies.[628]

393. Likewise, many commenters argue that the current relationship between local and regional transmission planning processes must be reformed. Some consumer groups, state commissions, market monitors, and renewable energy developers and organizations argue that the local transmission planning process is broken.[629] These entities argue that the local transmission planning process lacks transparency and oversight and is inappropriately influenced by incumbent transmission owners. To correct these flaws, these commenters

[613] *See PJM Interconnection, L.L.C.,* 172 FERC ¶ 61,136 at 21.

[614] *Supra* Table 1—Long-Term Regional Transmission Benefits.

[615] Order No. 1000–A, 139 FERC ¶ 61,132 at P 426.

[616] *Id.* PP 366, 379, 425, 428; Order No. 1000, 136 FERC ¶ 61,051 at P 262; Order No. 1000–A, 139 FERC ¶ 61,132 at PP 366, 379, 425, 428.

[617] ANOPR, 176 FERC ¶ 61,024 at P 171.

[618] ANOPR, 176 FERC ¶ 61,024 at P 37.

[619] *Id.* P 162.

[620] ACORE Comments at 19–23; AEE Comments at 41–43; ACPA and ESA Comments at 30; American Municipal Power Comments at 22–24; APPA Comments at 20; California Commission Comments at 31–37; Union of Concerned Scientists Comments at 24–31; Harvard ELI Comments at 20–21; LS Power Oct. 12 Comments at 36–37; Michigan Commission Comments at 8–9; NARUC Comments at 55–56; New Jersey Commission Comments at 3–7; Pennsylvania Commission Comments at 16–17; Policy Integrity Comments at 16.

[621] *E.g.,* District of Columbia's Office of the People's Counsel Comments at 11–12; EDF Comments at 12.

[622] California Commission Comments at 17–18.

[623] NARUC Comments at 15, 48–29.

[624] New Jersey Commission Comments at 12–13.

[625] ACEG Jan. 2021 Planning Report at 18–24.

[626] Eversource Comments at 10.

[627] LS Power Oct. 12 Comments at 43–44.

[628] PIOs Comments at 50 (citing Brattle-Grid Strategies Oct. 2021 Report at 3).

[629] ACEG Comments at 4–6 (citing Brattle Report at 25); AEE Comments at 41–49; Union of Concerned Scientists Comments at 24–31; Eversource Comments at 15–18; New Jersey Commission Comments at 4–6; LS Power Oct. 12 Comments at 49–62; PJM Market Monitor Comments at 9., Harvard ELI Reply Comments at 12–16.

are in favor of lowering voltage thresholds for regional transmission planning processes, such that more transmission facilities would be planned through that process rather than local transmission planning processes.[630] Some of those commenters further urge the Commission to require transmission owners and providers to provide information and metrics about their local systems to the transmission planning process, and to do so within a timeframe that allows opportunity for real engagement with stakeholders, because without such a requirement, transmission owners and providers may be inhibiting the sharing of information relevant to the regional transmission planning processes.[631]

394. The PJM Market Monitor recommends that PJM should clearly define the need for local transmission projects within the regional transmission planning process and that there should be a transparent, robust, and clearly defined mechanism to permit competition to build the project.[632] Some commenters go so far as to argue that there should be no separation between local and regional transmission planning processes at all.[633]

395. Other commenters identify the potential for less significant changes. AEP recommends that, to the extent the Commission reforms local transmission planning processes by increasing transparency and oversight, the Commission apply the practices and principles of PJM's Attachment M–3 process for Supplemental Projects across all other regions, including non-RTO/ISO regions.[634]

396. Alternatively, some commenters contend that existing processes are adequate. Some commenters argue that existing processes adequately address replacements of aging transmission facilities. CAISO notes that, while only participating transmission owners oversee replacement transmission facilities that do not expand the capacity of transmission facilities, CAISO continues to evaluate and approve transmission facilities that do expand the transmission system.[635] MISO TOs assert that replacement transmission facilities are evaluated through the MISO regional transmission planning process already and that MISO is obligated to seek combining replacement transmission facilities with other transmission facility projects where it is efficient and cost-effective to do so.[636] PJM TOs note that they provide PJM with a list of candidates for replacement transmission facilities so that PJM can determine if the replacement transmission project may also address a larger, regional need.[637]

397. Additionally, some commenters argue that existing processes provide for an appropriate level of coordination between regional and local planning. The Alabama Commission, Duke, Southern, the Louisiana Commission, and the Ohio Commission,[638] assert jurisdictional arguments in opposition to enhanced or expanded local transmission planning processes. These commenters argue that the Commission should not intervene in retail activities that are subject to state-level regulatory bodies.

D. Need for Reform

398. We are concerned that local transmission planning processes may lack adequate provisions for transparency and meaningful input from stakeholders, and that regional transmission planning processes may not adequately coordinate with local transmission planning processes.[639] In Order No. 890, the Commission required that public utility transmission providers' local transmission planning processes comply with nine transmission planning principles, including coordination, openness, transparency, and information exchange.[640] The Commission further explained that to satisfy the coordination principle, public utility transmission providers must facilitate the timely and meaningful input and participation of customers in the development of transmission plans and, more specifically, that ''customers must be included at the early stages of the development of the transmission plan and not merely given an opportunity to comment on transmission plans that were developed in the first instance without their input.'' [641] At times, the Commission has found it necessary to review local transmission planning processes to ensure stakeholders' opportunity to engage in them is meaningful.[642] However, implementation of these principles in local transmission planning processes appears to remain uneven, as commenters from regions across the country raise concerns about the transparency of and the opportunity for real engagement in various aspects of local transmission planning processes and their interaction with regional transmission planning processes.[643] We are concerned that the lack of minimal standards or specified procedures to implement these principles may contribute to inadequate transparency and opportunities for stakeholders to engage in local transmission planning processes. In addition, we believe that reforms to better ensure more consistent implementation of these principles may be timely and important in light of the significant investments in transmission that now occur through local transmission planning processes.[644]

399. In addition, we are concerned that, given the age of the nation's transmission infrastructure, many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life without evaluating whether those replacement transmission facilities could be modified (*i.e.,* right sized) to more efficiently or cost-effectively address regional transmission needs, and, more generally, that public utility transmission providers developing

[630] California Commission Comments at 39–43; Competition Coalition Comments at 16; LS Power Oct. 12 Comments at 49–53.

[631] *See e.g.,* Union of Concerned Scientists Comments at 24–31; *see also* Environmental Advocates Comments at 22; Northwest and Intermountain Comments at 49.

[632] PJM Market Monitor Comments at 9.

[633] American Municipal Power Comments at 32; City of New York Comments at 20–21; LS Power Oct. 12 Comments at 61–62; New Jersey Commission Comments at 11–13.

[634] AEP Comments at 43–44 (citing *PJM Interconnection, L.L.C.,* 172 FERC ¶ 61,136 (2020)). Briefly, PJM's Attachment M–3 process for Supplemental Projects refers to the additional transparency and stakeholder input rules around transmission facilities that are not eligible for selection in the regional transmission plan for purposes of cost allocation but, though classified as local transmission facilities, nonetheless impact the identification and selection of regional transmission facilities.

[635] CAISO Comments at 55–56.

[636] MISO TOs Comments at 21–22.

[637] PJM TOs Comments at 13–14.

[638] Alabama Commission Comments at 2; Duke Comments at 2–4; Southern Comments at 22–33; Louisiana Commission Comments at 4–9; Ohio Commission Comments at 1–6.

[639] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 148 (providing that regional planning processes should identify ''alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual utility transmission providers in their local transmission planning process'').

[640] Order No. 890, 118 FERC ¶ 61,119 at PP 418–601.

[641] *Id.* P 454.

[642] *See, e.g., Monongahela Power Co.,* 156 FERC ¶ 61,134 (2016).

[643] NARUC Comments at 14 (stating current planning processes may not be sufficiently transparent ''in every region''); Massachusetts Attorney General Comments at 11 (stating it requires ''herculean'' efforts to review transmission project proposals); Resale Iowa Comments at 7 (claiming ''[c]ustomers and other third parties have little or no input into alternative evaluation and project selection of these local projects''); Northwest and Intermountain Comments at 6 (stating ''local utilities' transmission plans are incorporated into regional transmission planning processes as inputs with little opportunity for stakeholder comment'').

[644] *See supra* P 40; note 63.

regional transmission plans may lack the information necessary to identify the benefits regional transmission facilities may provide in deferring or eliminating the need for in-kind replacements.[645] Specifically, as described in the background section, in-kind replacements of existing transmission facilities are managed by individual incumbent transmission providers according to their company practices; there is no requirement that public utility transmission providers plan these in-kind replacement transmission facilities through an Order No. 890-compliant transmission planning process.[646] While a transmission provider may be able to meet its needs associated with an aging asset through an in-kind replacement, there may be circumstances under which ''right-sizing'' the planned transmission replacement would result in a more efficient or cost-effective transmission facility to meet both the need for the transmission provider to replace the existing transmission facility and transmission needs identified through Long-Term Regional Transmission Planning. Because in-kind replacement of existing transmission facilities is not subject to any transmission planning process, we are concerned that, absent reform, there may be a lack of coordination between regional transmission planning processes and in-kind replacement of existing transmission facilities to identify whether these replacement transmission facilities could be modified to more efficiently or cost-effectively address transmission needs identified through Long-Term Regional Transmission Planning. This lack of coordination may result in a regional transmission planning process that fails to identify opportunities to right size planned in-kind replacement transmission facilities and may result in the development of duplicative or unnecessary transmission facilities that increase costs to consumers and render Commission-jurisdictional rates unjust and unreasonable.

E. Proposed Reform

400. We propose to require that public utility transmission providers in each transmission planning region revise the regional transmission planning process in their OATTs with additional provisions to enhance 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 that process, and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs. Under this proposed reform, public utility transmission providers would be required to establish an iterative process that would ensure that stakeholders have meaningful opportunities to participate and provide feedback on local transmission planning throughout the regional transmission planning process. Leveraging the existing stakeholder processes for regional transmission planning, we propose to require that the regional transmission planning process include at least three stakeholder meetings concerning the local transmission planning process of each public utility transmission provider that is a member of the transmission planning region before each public utility transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models, as described further below.

401. Specifically, prior to the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process, public utility transmission providers in each transmission planning region would be required to convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review the criteria, assumptions, and models related to each public utility transmission provider's local transmission planning (Assumptions Meeting). Next, no fewer than 25 calendar days after the Assumptions Meeting, public utility transmission providers that are members of the transmission planning region would be required to convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review identified reliability criteria violations and other transmission needs that drive the need for local transmission facilities (Needs Meeting). Finally, no fewer than 25 calendar days after the Needs Meeting, public utility transmission providers that are members of the transmission planning region would be required to convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review potential solutions to those reliability criteria violations and other transmission needs (Solutions Meeting). Additionally, we propose to require that all materials for stakeholder review during these three meetings be publicly posted and that stakeholders have opportunities before and after each meeting to submit comments.

402. We preliminarily find that these proposed requirements will result in needed additional transparency into local transmission planning processes, which inform the regional transmission planning process in a transmission planning region. We believe that these proposed requirements are needed to ensure just and reasonable Commission-jurisdictional rates because the information provided will better facilitate the identification of regional transmission facilities that may be more efficient or cost-effective than proposed local transmission facilities through the regional transmission planning process. We also believe that these proposed requirements are needed to ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates because the information provided will enable customers and other stakeholders alike to evaluate or replicate the findings of public utility transmission providers so as to reduce after-the-fact disputes regarding whether local transmission planning has been conducted in an unjust and unreasonable or unduly discriminatory or preferential fashion.[647]

403. We also propose to require that, as part of each Long-Term Regional Transmission Planning cycle, public utility transmission providers in each transmission planning region evaluate whether transmission facilities operating at or above 230 kV that an individual public utility transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be ''right-sized'' to more efficiently or cost-effectively address regional transmission needs

[645] For example, we note a recent PJM analysis estimates that roughly two-thirds of all PJM transmission system assets are more than 40 years old, with some transmission facilities approaching 90 years old. *See* PJM Interconnection, L.L.C., *The Benefits of the PJM Transmission System* at 5 (April 16, 2019), *https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.pdf.https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.pdf.* Moreover, AEP estimates that approximately 30 percent of all its transmission assets will need to be replaced over the next ten10 years. *See* AEP, *Wolfe Utilities, Midstream, & Clean Energy Conference,* at 40 (Sept. 30, 2021), *https://www.aep.com/Assets/docs/investors/eventspresentationsandwebcasts/WolfeConferencePresentation093021.pdf.https://www.aep.com/Assets/docs/investors/eventspresentationsandwebcasts/WolfeConferencePresentation093021.pdf.*

[646] *S. Cal. Edison Co.,* 164 FERC ¶ 61,160 at P 33; *Cal. Pub. Utils. Comm'n* v. *Pac. Gas & Elec. Co.,* 164 FERC ¶ 61,161 at P 68; *PJM Interconnection, L.L.C.,* 172 FERC ¶ 61,136 at PP 12, 89; *PJM Interconnection, L.L.C.,* 173 FERC ¶ 61,242 at P 54.

[647] Order No. 890, 118 FERC ¶ 61,119 at P 471.

identified in Long-Term Regional Transmission Planning. By ''right-sizing'' we mean the process of modifying a public utility transmission provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability. Right-sizing could include, for example, increasing the transmission facility's voltage level, adding circuits to the towers (*e.g.,* redesigning a single-circuit line as a double-circuit line), or incorporating advanced technologies (such as advanced conductor technologies).[648]

404. As part of this proposed reform, first, we propose to require that, at a specified point early in each Long-Term Regional Transmission Planning cycle, each public utility transmission provider submit, as part of the regional transmission planning process, a list of each existing transmission facility operating at or above 230 kV that the public utility transmission provider owns and that it estimates may need to be replaced with a new in-kind transmission facility over the next 10 years, starting from the point in the transmission planning cycle when the list is compiled (which we refer to as ''in-kind replacement estimates'').[649]

405. Second, we propose to require that public utility transmission providers in each transmission planning region, as part of Long-Term Regional Transmission Planning, review and evaluate whether the existing transmission facilities included in each public utility transmission owner's in-kind replacement estimates can be right-sized to address a transmission need identified in Long-Term Regional Transmission Planning.

406. We preliminarily find that an existing transmission facility operating at or above 230 kV that a public utility transmission provider indicates may need to be replaced over the next 10 years is the type of facility that is best suited to be considered for right-sizing as part of Long-Term Regional Transmission Planning. We believe that in-kind replacement transmission facilities that will operate at or above 230 kV are the most likely candidates for right-sizing, *i.e.,* are most susceptible to modification that could more efficiently or cost-effectively meet transmission needs identified through Long-Term Regional Transmission Planning. We also believe that 10 years is an appropriate timeframe to evaluate potential in-kind replacements for right-sizing to balance the long lead times necessary to construct large transmission facilities with the uncertainty associated with the exact timing when aging transmission assets may need to be replaced. A right-sized replacement transmission facility has the potential to both meet the individual public utility transmission provider's responsibility to maintain the reliability of its existing transmission system and address a regional transmission need(s) identified in Long-Term Regional Transmission Planning more efficiently or cost-effectively. In addition, a right-sized replacement transmission facility may defer or displace the need for other transmission facilities, including both new transmission facilities and in-kind replacement of existing transmission facilities, thus representing a benefit to the public utility transmission provider and its customers. We believe that if opportunities for right-sized replacement transmission facilities are not considered, regional transmission planning processes may not select the more efficient or cost-effective transmission facilities in the regional transmission plan for purposes of cost allocation to meet transmission needs identified through Long-Term Regional Transmission Planning.[650]

407. The process under this proposed reform would entail the following steps. First, sufficiently early in each Long-Term Regional Transmission Planning cycle, each public utility transmission provider would submit its in-kind replacement estimates for use in Long-Term Regional Transmission Planning. Then, if a right-sized replacement transmission facility is identified as a potential solution to a Long-Term Regional Transmission Planning need, that right-sized replacement transmission facility would be evaluated in the same manner as any other proposed transmission facility to determine whether it is the more efficient or cost-effective transmission facility to address the transmission need. If a right-sized replacement transmission facility addresses the public utility transmission provider's need to replace an existing transmission facility, meets all the applicable selection criteria included in Long-Term Regional Transmission Planning, and is found to be the more efficient or cost-effective solution to a transmission need identified through Long-Term Regional Transmission Planning, then the right-sized replacement transmission facility may be selected in the regional transmission plan for purposes of cost allocation.[651]

408. Although the right-sized replacement transmission facility may be selected in the regional transmission plan for purposes of cost allocation, it is necessary that a selected right-sized replacement transmission facility be subject to different rules with respect to the elimination of a federal right of first refusal than other regional transmission facilities. Absent reform, if a public utility transmission provider's estimated in-kind replacement were right-sized and then selected in the regional transmission plan for purposes of cost allocation to meet transmission needs identified through Long-Term Regional Transmission Planning, the right-sized replacement transmission facility might then be subject to the transmission planning region's competitive transmission development process. However, the public utility transmission provider would not necessarily be bound by that right-sizing decision made by the region, unless the public utility transmission provider was selected to develop the right-sized replacement transmission facility. This is because nothing in this proposed rule would alter existing law concerning the public utility transmission provider's ability to proceed with developing its planned in-kind replacement transmission facility without the right-sizing, in spite of the potential efficiencies of right-sizing identified in the regional transmission planning process.[652] This may reduce the opportunities for the regional transmission planning process to identify more efficient or cost-effective solutions to transmission needs identified through Long-Term Regional Transmission Planning and potentially lead to duplicative or inefficient transmission development.

[648] Grid Strategies LLC, *Advanced Conductors on Existing Transmission Corridors to Accelerate Low Cost Decarbonization,* at 2 (Mar. 2022), *https://gridprogress.files.wordpress.com/2022/03/advanced-conductors-on-existing-transmission-corridors-to-accelerate-low-cost-decarbonization.pdf.*

[649] We note that in RTOs/ISOs, the RTO/ISO is the public utility transmission provider. Each individual transmission-owning member of the RTO/ISO generally has the responsibility to maintain its own existing transmission facilities and thus would have the obligation to provide replacement estimates to the RTO/ISO.

[650] We note that benefits associated with right-sizing potential replacement transmission facilities to address transmission needs identified through Long-Term Regional Transmission Planning should be evaluated the same as any potential transmission facility that could address that transmission need. *See supra* Regional Transmission Planning: Proposed Reforms, Evaluation of the Benefits of Regional Transmission Facilities.

[651] *See supra* Regional Transmission Planning: Proposed Reforms, Selection of Regional Transmission Facilities.

[652] Similarly, nothing in this proposed rule would alter existing law concerning subsequent proceedings involving an in-kind asset replacement, *e.g.,* state-law siting proceedings.

409. In addition, requiring in-kind replacement estimates to cover the next 10 years, starting from the point in the transmission planning cycle when the list is compiled, may lengthen the time horizon over which in-kind replacement needs are assessed, compared to current practices where in-kind replacement needs may be assessed on a shorter-term or nearer-term basis.[653] Accordingly, areas of uncertainty that could lessen the accuracy of a public utility transmission provider's in-kind replacement estimates should be minimized where possible. In particular, such an approach that looks out over 10 years, would allow the public utility transmission provider to formulate in-kind replacement estimates with greater certainty as to its own future role in meeting that transmission need. Therefore, for any right-sized replacement transmission facility that is selected in the regional transmission plan for purposes of cost allocation to meet transmission needs identified through Long-Term Regional Transmission Planning, we propose to require the establishment of a federal right of first refusal for the public utility transmission provider that included the in-kind replacement transmission facility in its in-kind replacement estimates, which would extend to any portion of such a transmission facility located within the applicable public utility transmission provider's retail distribution service territory or footprint.

410. With respect to cost allocation, we propose that if a right-sized replacement transmission facility is selected in the regional transmission plan for purposes of cost allocation, only the incremental costs of right-sizing the transmission facility will be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method. We propose that the costs the incumbent transmission provider would have otherwise incurred to construct the in-kind replacement transmission facility be allocated in a manner consistent with the allocation that would have otherwise occurred for the in-kind replacement. We preliminarily find that it is just and reasonable and not unduly discriminatory or preferential for only the portion of the costs associated with right-sizing a right-sized replacement transmission facility that is selected in the regional transmission plan for purposes of cost allocation to be eligible to use the Long-Term Regional Transmission Cost Allocation Method because it is the right-sizing of the in-kind replacement transmission facility that allows the transmission facility to meet the transmission need(s) identified in Long-Term Regional Transmission Planning. In addition, the customers of the public utility transmission provider that would be allocated the costs associated with the original in-kind replacement transmission facility would have otherwise been responsible for paying those costs had the replacement transmission facility not been right-sized.

411. We note that Order No. 1000 allows a public utility transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not selected in the regional transmission plan for purposes of cost allocation.[654] Similarly, nothing in the reforms that we propose here alters existing law concerning a public utility transmission provider's existing rights and responsibilities with respect to maintaining, and when necessary replacing, existing transmission facilities. Thus, the proposed requirements for public utility transmission providers to provide greater transparency and stakeholder process surrounding local transmission planning and in-kind replacement estimates would not create an obligation for an incumbent transmission provider to actually replace any existing transmission facilities. We believe that this clarification is important given that decisions related to replacement of existing transmission facilities may change as a public utility transmission provider gets better information about the condition of its transmission facilities.

412. Even if a right-sized replacement transmission facility is selected in the regional transmission plan for purposes of cost allocation to meet transmission needs identified in Long-Term Regional Transmission Planning, that selection does not alter existing law concerning any existing rights and responsibilities a public utility transmission provider may have to replace as needed its existing transmission facilities with in-kind replacement transmission facilities. For example, a public utility transmission provider could inform the transmission planning region that, notwithstanding the selection of a right-sized replacement transmission facility in the regional transmission plan for purposes of cost allocation, the public utility transmission provider has chosen to build the original in-kind replacement transmission facility instead. In such cases, as we explain earlier,[655] we understand that, depending on the rules of the particular regional transmission planning process, the in-kind replacement transmission facility may be *included* in the regional transmission plan for informational purposes, but not *selected* in the regional transmission plan for purposes of cost allocation.

413. Our proposal to only allow the incremental costs of right-sizing replacement transmission facilities to be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method emphasizes the need for transparency in regional transmission planning processes so as to clearly determine which right-sized replacement transmission facilities have been selected in the regional transmission plan for purposes of cost allocation.[656] Therefore, we propose to require public utility transmission providers in each transmission planning region to amend their regional transmission planning processes to provide transparency with respect to which right-sized replacement transmission facilities have been selected in the regional transmission plan for purposes of cost allocation (and thus found to be a more efficient or cost-effective transmission facility to meet regional transmission needs) and which transmission facilities are simply included in the regional transmission plan for informational (and not cost allocation) purposes. We believe that this additional transparency would inform interested parties, including state regulators, regarding the degree to which a right-sized replacement transmission facility was evaluated through Long-Term Regional Transmission Planning. As such, we believe that this additional transparency ensures just and reasonable Commission-jurisdictional rates because the information provided will enable customers and other stakeholders alike to evaluate or replicate the findings related to right-sized replacement transmission facilities or in-kind

[653] *See, e.g.,* PJM, Intra-PJM Tariffs, OATT, attach. M–3, OATT Attachment M–3 (1.0.0), § (d)(1)(iii) (providing that every year "each Transmission Owner will provide to PJM a Candidate [End-of-Life (EOL)] Needs List comprising its non-public confidential, non-binding projection of up to 5 years of EOL Needs that it has identified under the Transmission Owner's processes for identification of EOL Needs" and that each "Transmission Owner may change its projection as it deems necessary and will update it annually").

[654] Order No. 1000, 136 FERC ¶ 61,051 at P 262; Order No. 1000–A, 139 FERC ¶ 61,132 at PP 366, 379, 425, 428.

[655] *See supra* P 412.

[656] *See supra* Regional Transmission Planning: Proposed Reforms, Selection of Regional Transmission Facilities.

replacement transmission facilities so as to reduce after-the-fact disputes regarding transmission system needs or cost allocation.

414. We seek comment on the requirements proposed in this section of the NOPR. In particular, we seek comment on whether the Commission should impose any requirements regarding how the relevant public utility transmission providers would determine incremental costs of right-sizing the transmission facility.

415. We also seek comment on whether there is additional information from transmission owners that would help public utility transmission providers to identify whether there are estimated in-kind replacements of an existing transmission facility that could be right-sized to address a transmission need identified in Long-Term Regional Transmission Planning. If so, we seek comment what level of burden such a requirement would impose on the transmission owners required to provide that information, and what level of burden is justified given the potential benefits of such information. Moreover, we seek comment on whether there is additional information beyond a list of in-kind replacement estimates that public utility transmission providers need to calculate such benefits and, if so, how that information could be obtained.

IX. Interregional Transmission Coordination and Cost Allocation

416. In the ANOPR, the Commission asked several questions about the value and logistics of reforms to interregional transmission coordination, planning, and cost allocation. The Commission continues to examine those issues, including review of comments to the ANOPR, and to consider possible reforms. As such, we do not, at this time, propose changes to the existing interregional transmission coordination and cost allocation requirements of Order No. 1000. However, we propose to require that public utility transmission providers revise their existing interregional transmission coordination procedures adopted in compliance with Order No. 1000 to apply them to the proposed Long-Term Regional Transmission Planning reforms in this NOPR, as discussed below.

A. Background

417. In Order No. 1000, the Commission set out a number of requirements for interregional transmission coordination and interregional cost allocation.[657] Order No. 1000 requires public utility transmission providers in neighboring transmission planning regions to develop and implement procedures to provide for: (1) The sharing of information regarding the respective transmission needs of each region and potential solutions to those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities needed to meet those regional needs.[658]

418. With regard to the evaluation of interregional transmission facilities, Order No. 1000 requires public utility transmission providers in neighboring transmission planning regions to develop and implement formal procedures to identify and jointly evaluate transmission facilities that are proposed to be located in neighboring transmission planning regions.[659] The Commission clarified that the developer of an interregional transmission facility must first propose its transmission facility in the regional transmission planning processes of each of the neighboring transmission planning regions in which the transmission facility is proposed to be located. The submission of the interregional transmission facility in each regional transmission planning process triggers the procedure under which the public utility transmission providers, acting through their regional transmission planning process, jointly evaluate the proposed transmission project.[660]

419. The Commission further required, *inter alia,* that interregional transmission coordination procedures must have a process by which differences in the data, models, assumptions, planning horizons, and criteria used to study a proposed transmission project can be identified and resolved for purposes of jointly evaluating the proposed interregional transmission facility.[661]

420. With regard to transmission facility selection, Order No. 1000 requires that an interregional transmission facility must be selected in both of the relevant regional transmission plans for purposes of cost allocation in order to be eligible for interregional cost allocation.[662] The Commission further clarified that based on the information gained during the joint evaluation of an interregional transmission project, each transmission planning region will determine, for itself, whether to select those interregional transmission facilities within its footprint in the regional transmission plan for purposes of cost allocation.[663]

421. With respect to interregional cost allocation, the Commission required that each public utility transmission provider in a transmission planning region must have, together with the public utility transmission providers in its own transmission planning region and a neighboring transmission planning region, a common method or methods for allocating the costs of a new interregional transmission facility among the beneficiaries of that transmission facility in the two neighboring transmission planning regions in which the transmission facility is located.[664] The Commission also defined six interregional cost allocation principles that apply to, and only to, a cost allocation method or methods for a new interregional transmission facility.[665]

B. ANOPR

422. In the ANOPR, the Commission asked several questions about the value and logistics of reforms to interregional transmission coordination, planning, and cost allocation. Specifically, the Commission sought comment on whether greater interregional or state-regional coordination is required to address other topics in the ANOPR, including long-term regional transmission planning, identifying geographic zones that have the potential for the development of large amounts of new generation, and incentives for transmission development.[666] The Commission also sought comment on how a regional states committee or other organized body of state officials should participate in the development and evaluation of assumptions or criteria used for interregional transmission coordination.[667] Further, the Commission sought comment on whether to require joint transmission planning processes for neighboring transmission planning regions, rather than simply joint coordination, and

[657] In Order No. 1000, the Commission defined an interregional transmission facility as a transmission facility that is located in two or more transmission planning regions. Order No. 1000, 136 FERC ¶ 61,051 at P 482 n.374.

[658] *Id.* PP 393–399.

[659] *Id.* P 436.

[660] *Id.*

[661] *Id.* P 437; Order No. 1000–A, 139 FERC ¶ 61,132 at PP 506, 510.

[662] Order No. 1000, 136 FERC ¶ 61,051 at P 400; Order No. 1000–A, 139 FERC ¶ 61,132 at P 509.

[663] Order No. 1000, 136 FERC ¶ 61,051 at PP 443, 635.

[664] *Id.* P 578.

[665] *Id.* P 603.

[666] ANOPR, 176 FERC ¶ 61,024 at PP 57, 62–64.

[667] *Id.* P 64.

whether the Commission should establish interregional reliability planning criteria.[668]

C. Comments

423. Some commenters urge the Commission to require substantial changes to the existing interregional transmission coordination requirements established in Order No. 1000.[669] Other commenters instead urge the Commission to maintain the existing interregional transmission coordination requirements.[670]

D. Need for Reform

424. In establishing the Order No. 1000 interregional transmission coordination and cost allocation requirements, the Commission considered the requirements of Order No. 890, determining that the transmission planning requirements of Order No. 890 were too narrowly focused geographically and failed to provide for adequate analysis of the benefits associated with interregional transmission facilities in neighboring transmission planning regions.[671] The Commission stated that ''in the absence of coordination between transmission planning regions, public utility transmission providers may be unable to identify more efficient or cost-effective solutions to the individual needs identified in their respective local and regional transmission planning processes, potentially including interregional transmission facilities.'' [672] Therefore, the Commission concluded that interregional transmission coordination reforms were necessary. The Commission stated that ''[c]lear and transparent procedures that result in the sharing of information regarding common needs and potential solutions across the seams of neighboring transmission planning regions will facilitate the identification of interregional transmission facilities that more efficiently or cost-effectively could meet the needs identified in individual regional transmission plans.'' [673]

425. Based upon our experience since Order No. 1000 and the record in this proceeding, we continue to believe that there is a significant need for interregional transmission coordination. We therefore preliminarily find that it is necessary to revise the existing Order No. 1000 interregional transmission coordination requirements to apply them to the proposed Long-Term Regional Transmission Planning reforms in this NOPR to ensure that interregional transmission coordination is just and reasonable. We believe that the reforms we propose here will ensure that the information sharing and evaluation of interregional transmission facilities required as part of the existing interregional transmission coordination procedures will continue to occur with respect to all aspects of the regional transmission planning process, including the proposed Long-Term Regional Transmission Planning.

E. Proposed Reform

426. We propose to require that public utility transmission providers revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms proposed in this NOPR.[674]

427. Specifically, we propose to require that public utility transmission providers in neighboring transmission planning regions revise their existing interregional coordination procedures (and regional transmission planning processes as needed) to provide for: (1) The sharing of information regarding the respective transmission needs identified in the Long-Term Regional Transmission Planning that we propose to require in that section above, as well as potential transmission facilities 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 transmission needs identified through Long-Term Regional Transmission Planning.

428. We also propose to require that public utility transmission providers in neighboring transmission planning regions 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 transmission needs identified through Long-Term Regional Transmission Planning. We believe that this will align the existing requirement for an entity to propose an interregional transmission facility in the regional transmission planning processes of each of the neighboring transmission planning regions in which the transmission facility is proposed to be located with the proposed requirement for public utility transmission providers to conduct Long-Term Regional Transmission Planning as part of their regional transmission planning processes.

429. This proposed reform aims to ensure that transmission needs driven by changes in the resource mix and demand identified through Long-Term Regional Transmission Planning can be considered in existing interregional transmission coordination and cost allocation processes.[675] Doing so will ensure that there is an opportunity for the public utility transmission providers in neighboring transmission planning regions to consider whether there are interregional transmission facilities that could more efficiently or cost-effectively meet the transmission needs identified through Long-Term Regional Transmission Planning, in turn helping to ensure just and reasonable Commission-jurisdictional rates.

X. Proposed Compliance Procedures

430. Given the necessity to coordinate with the relevant state entities and other stakeholders on the proposed reforms, we propose an extended compliance period. We propose to require that each public utility transmission provider submit a compliance filing within eight months of the effective date of any final rule in this proceeding revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the proposed requirements set forth in

[668] *Id.* PP 62–63.

[669] *See, e.g.,* ACEG Comments at 4–5; ACORE Comments at 27; ACPA and ESA Comments at 51–52; Advanced Power Comments at 2; AEE Comments at 31; AEP Comments at 18–24; Amazon Comments at 2; American Municipal Power Comments at 33; Anbaric Comments at 30–32; Avangrid Comments at 20–21; Arizona Commission Comments at 4; Competition Coalition Comments at 20; Consumers Council Comments at 10–11; EDF Comments at 8; Eversource Comments at 18–19; Kansas Commission Comments at 2; LS Power Oct. 12 Comments at 63; NARUC Comments at 16–19; Nature Conservancy Comments at 9–10; New Jersey Commission Comments at 2; NY TOs Comments at 25–26; Northwest and Intermountain Comments at 30; PG&E Comments at 7; PIOs Comments at 70–72; Policy Integrity Comments at 16–18; REBA Comments at 17; Resale Iowa Comments at 15; RMI Comments at 3–4; State Agencies Comments at 28–30; State of Massachusetts Comments at 21; U.S. DOE Comments at 25–26; Xcel Comments at 22.

[670] *See, e.g.,* APPA Comments at 5; CAISO Comments at 6–8, 59–63; LPPC Comments at 24–26; MISO Comments at 2–3, 15–16; MISO TOs Comments at 16–18; NYISO Comments at 56–57; PJM Comments at 68.

[671] Order No. 1000, 136 FERC ¶ 61,051 at P 369.

[672] *Id.* P 368.

[673] *Id.*

[674] As noted earlier, we are not proposing to require any changes to existing interregional cost allocation methods for interregional transmission facilities that are selected in the regional transmission plan for purposes of cost allocation and that the Commission previously accepted as compliant with Order No. 1000.

[675] *See* Order No. 1000, 136 FERC ¶ 61,051 at PP 99–117 (explaining the Commission's legal basis for requiring interregional transmission coordination and interregional cost allocation).

this NOPR and are included in any final rule in this proceeding.[676]

431. The Commission would assess whether each compliance filing satisfies the proposed requirements outlined above and issue additional orders as necessary to ensure that each public utility transmission provider meets the requirements of any final rule in this proceeding.

432. We propose that transmission providers that are not public utilities would have to adopt the requirements of this NOPR as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[677]

433. The Commission will ensure that jurisdictional entities comply with these NOPR requirements upon final action of the Commission and has the authority to conduct audits to evaluate such compliance. Section 302(C) of the Federal Power Act allows the Commission staff to examine the books, accounts, memoranda, and records of any person who controls directly or indirectly, a licensee or public utility subject to the jurisdiction of the Commission insofar as they relate to transactions with or the business of such licensee or public utility.

XI. Information Collection Statement

434. The information collection requirements contained in this NOPR are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[678] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[679] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

435. This NOPR would, pursuant to section 206 of the FPA, reform the Commission's *pro forma* OATT and the Commission's *pro forma* LGIP to correct deficiencies in the Commission's existing regional transmission planning and cost allocation requirements so that the transmission system can better support wholesale power markets and thereby ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.

436. Interested persons may obtain information on the reporting requirements by contacting Ellen Brown, Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 via email (*DataClearance@ferc.gov*) or telephone (202) 502–8663).

437. The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

438. Please send comments concerning the collections of information and the associated burden estimates to the Office of Information and Regulatory Affairs, Office of Management and Budget, through *www.reginfo.gov/public/do/PRAMain.* Attention: Federal Energy Regulatory Commission Desk Officer. Please identify the OMB Control Numbers 1902–0233 and 1902–0096 in the subject line of your comments. Comments should be sent within 60 days of publication of this notice in the **Federal Register**.

439. Please submit a copy of your comments on the information collections to the Commission via the eFiling link on the Commission's website at *https://www.ferc.gov.* Comments on the information collection that are sent to FERC should refer to Docket No. RM21–17–000.

440. *Title:* Electric Transmission Facilities (FERC–917) and Electric Rate Schedules and Tariff Filings (FERC–516).

441. *Action:* Proposed revision of collections of information in accordance with Docket No. RM21–17–000 and request for comments.

442. *OMB Control Nos.:* 1902–0233 (FERC–917) and 1902–0096 (FERC–516).

443. *Respondents:* Public utility transmission providers, including RTOs/ISOs, and public utility transmission owners.

444. *Frequency of Information Collection:* One time during Year 1. Occasional times during subsequent years, at least once every three years.

445. *Necessity of Information:* The reforms in this Proposed Rule will correct deficiencies in the Commission's existing regional transmission planning and cost allocation requirements so that the transmission system can better support wholesale power markets and thereby ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.

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

447. Our estimates are based on the NERC Compliance Registry as of March 3, 2022, which indicates that there are 48 transmission service providers[680] and 118 transmission owners that are registered within the United States and are subject to this proposed rulemaking.[681]

448. *Public Reporting Burden:* The burden and cost estimates below are based on the need for applicable entities to revise documentation, already required by the Commission's *pro forma* OATT and the Commission's *pro forma* LGIP.

449. The Commission estimates that the NOPR would affect the burden[682] and cost of FERC–917 and FERC–516 as follows:

[676] *See* Appendix B for the proposed *pro forma* Attachment K consistent with this NOPR.

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

[678] 44 U.S.C. 3507(d).

[679] 5 CFR 1320.11.

[680] The transmission service provider (TSP) function is a NERC registration function which is similar to the transmission provider that is referenced in the pro forma OATT. The TSP function is being used as a proxy to estimate the number of transmission providers that are impacted by this proposed rulemaking.

[681] The number of entities listed from the NERC Compliance Registry reflects the omission of the Texas RE registered entities. Note that 41 transmission owners in non-RTO/ISO regions are also transmission service providers, so in total there are 125 entities subject to this proposed rulemaking.

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

PROPOSED CHANGES IN NOPR IN DOCKET NO. RM21–17–000 [683]

Area of modification	Annual number of respondents	Total annual estimated number of responses	Average burden hours & cost [684] per response	Total estimated burden hours & total estimated cost (column C × column D)
A	B	C	D	E
FERC–917, Electric Transmission Facilities (OMB Control No. 1902–0233)				
Participate in Long-Term Regional Transmission Planning, which includes developing Long-Term Scenarios, evaluating the benefits of regional transmission facilities, and establishing criteria in consultation with states to select transmission facilities in the regional transmission plan for purposes of cost allocation.	125 (TSPs and TOs)	125	Year 1: 150 hours; $11,275 .... Subsequent Years: 50 hours per year; $3,758 per year.	Year 1: 18,750 hours; $1,409,363. Subsequent Years: 6,250 hours per year; $469,788 per year.
Revise the regional transmission planning process to enhance transparency of local transmission planning and identifying potential opportunities to right-size replacement transmission facilities.	125 (TSPs and TOs)	125	Year 1: 20 hours; $1,208 .... Subsequent Years: 50 hours per year; $3,758 per year.	Year 1: 2,500 hours; $151,038. Subsequent Years: 6,250 hours per year; $469,788 per year.
Seek agreement from the states to establish a Long-Term Regional Transmission Cost Allocation Method and/or a State Agreement Process.	125 (TSPs and TOs)	125	Year 1: 150 hours; $11,275 .... Subsequent Years: 50 hours per year; $3,758 per year.	Year 1: 18,750 hours; $1,409,363. Subsequent Years: 6,250 hours per year; $469,788 per year.
Consider in the regional transmission planning processes regional transmission facilities that address certain interconnection-related needs.	125 (TSPs and TOs)	125	Year 1: 50 hours; $3,758 .... Subsequent Years: 0 hours per year; $0 per year.	Year 1: 6,250 hours; $469,750. Subsequent Years: 0 hours per year; $0 per year.
Revise interregional transmission coordination procedures to reflect Long-Term Regional Transmission Planning.	125 (TSPs and TOs)	125	Year 1: 50 hours; $3,758 .... Subsequent Years: 25 hours per year; $1,715 per year.	Year 1: 6,250 hours; $469,750. Subsequent Years: 3,125 hours per year; $214,375 per year.
FERC–516, Electric Rate Schedules and Tariff Filings (OMB Control No. 1902–0096)				
Revise LGIP to indicate the consideration in the regional transmission planning processes of regional transmission facilities that address certain interconnection-related needs.	125 (TSPs and TOs)	125	Year 1: 30 hours; $2,058 .... Subsequent Years: 0 hours per year; $0 per year.	Year 1: 3,750 hours; $257,288. Subsequent Years: 0 hours per year; $0 per year.

450. Our estimates conservatively assume the maximum number of respondents and burdens. We acknowledge that the actual burdens for some respondents may be lower than estimated, and that other respondents may incur the maximum burdens. We seek comment on the estimates in the burden table and on the assumptions described here.

XII. Environmental Analysis

451. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[685] We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Proposed Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[686]

XIII. Regulatory Flexibility Act [Analysis or Certification]

452. The Regulatory Flexibility Act of 1980 (RFA) [687] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The Small Business Administration (SBA) sets the threshold for what constitutes a small business. Under SBA's size standards,[688] RTOs/ISOs, planning regions, and transmission owners all fall under the category of Electric Bulk Power Transmission and Control (NAICS code 221121), with a size threshold of 500 employees (including the entity and its associates).[689]

453. The six RTOs/ISOs (SPP, MISO, PJM, ISO–NE, NYISO, and CAISO) each employ more than 500 employees and are not considered small.

454. We estimate that 119 additional transmission providers and transmission owners are affected by the NOPR. Using the list of transmission service providers and transmission owners from the NERC Registry (dated March 3, 2022), we estimate that approximately 68% of those entities are small entities.

683 In the table, Year 1 figures are one-time implementation hours and cost. ''Subsequent years'' show ongoing burdens and costs starting in Year 2.

684 The hourly cost (for salary plus benefits) uses the figures from the Bureau of Labor Statistics (BLS) for three positions involved in the reporting and recordkeeping requirements. These figures include salary (based on BLS data for May 2020, *https://bls.gov/oes/current/naics2_22.htm*) and benefits (based on BLS data for December 2020; issued March 18, 2021, *https://www.bls.gov/news.release/ecec.nr0.htm*) and are Manager (Occupation Code 11–0000, $97.89/hour), Electrical Engineer (Occupation Code 17–2071, $72.15/hour), and File Clerk (Occupation Code 43–4071, $35.83/hour). The hourly cost for the reporting requirements ($85.00) is an average of the hourly cost (wages plus benefits) of a manager and engineer. The hourly cost for recordkeeping requirements uses the cost of a file clerk.

685 *Reguls. Implementing the Nat'l Envt'l Pol'y Act,* Ord. No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

686 18 CFR 380.4(a)(15).

687 5 U.S.C. 601–612.

688 13 CFR 121.201.

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

455. We estimate additional one-time costs associated with the NOPR (as shown in the table above) of:

—$31,274 for each transmission provider and transmission owner (FERC–917)
—$2,058 for each transmission provider and transmission owner (FERC–516)

456. Therefore, the estimated additional one-time implementation cost in Year 1 per entity is $33,332.

457. We estimate additional recurring costs in subsequent years (starting in Year 2) associated with the NOPR (as shown in the table above) of:

—$12,989 for each transmission provider and transmission owner (FERC–917)
—$0 for each transmission provider and transmission owner (FERC–516)

458. Therefore, the estimated recurring costs per entity in subsequent years are $12,989 per year.

459. According to SBA guidance, the determination of significance of impact ''should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors.'' [690] We do not consider the estimated cost to be a significant economic impact. As a result, we certify that the proposals in this NOPR will not have a significant economic impact on a substantial number of small entities.

XIV. Comment Procedures

460. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due July 18, 2022 and Reply Comments are due August 17, 2022. Comments must refer to Docket No. RM21–17–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

461. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's website at *https://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software must be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

462. Commenters that are not able to file comments electronically may file an original of their comment by USPS mail or by courier-or other delivery services. For submission sent via USPS only, filings should be mailed to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE, Washington, DC 20426. Submission of filings other than by USPS should be delivered to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

XV. Document Availability

463. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*https://www.ferc.gov*). At this time, the Commission has suspended access to the Commission's Public Reference Room due to the President's March 13, 2020 proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19).

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

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

By direction of the Commission.

Commissioner Danly is dissenting with a separate statement attached.

Commissioner Christie is concurring with a separate statement attached.

Commission Phillips is concurring with a separate statement attached.

Issued: April 21, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

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

Appendix A: Abbreviated Names of Commenters

Abbreviation	Commenter
Aaron Litz	Aaron Litz.
ACEG	Americans for a Clean Energy Grid.
ACORE	American Council on Renewable Energy.
ACPA and ESA	American Clean Power Association and the U.S. Energy Storage Association.
AEE	Advanced Energy Economy.
Advanced Power	Advanced Power Alliance.
AEP	American Electric Power Service Corporation.
AES Ohio	Dayton Power and Light.
Alabama Commission	Alabama Public Service Commission.
Amazon	Amazon Energy LLC.
Ameren	Ameren Services Company.
American Farmland Trust	American Farmland Trust.
American Municipal Power	American Municipal Power, Inc.
Ample	Ample, Inc.
Anbaric	Anbaric Development Partners, LLC.
APPA	American Public Power Association.
Arizona Commission	Arizona Corporation Commission.
Arizona Public Service	Arizona Public Service Company.
Avangrid	Avangrid.
Berkshire	Berkshire Hathaway Energy Company.

[690] U.S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act,* at 18 (May 2012), *https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.*

Abbreviation	Commenter
BP	BP America Inc.
Bridgelink	Bridgelink Investments, LLC.
Business Council for Sustainable Energy	Business Council for Sustainable Energy.
CAISO	California Independent System Operator Corporation.
California Commission	California Public Utilities Commission.
California Municipal Utilities	California Municipal Utilities Association.
California Water	California Department of Water Resources State Water Project.
CBD	The Center for Biological Diversity.
Center for Sustainable Energy	Center for Sustainable Energy.
Certain TDUs	Alliant Energy Corporate Services, Inc. Consumers Energy Company, DTE Electric Company.
Competitive Energy	Competitive Energy Services, LLC.
Citizens Energy	Citizens Energy Corporation.
City of New York	City of New York.
Competition Coalition	Electricity Transmission Competition Coalition.
Competitive Power	Competitive Power Ventures, Inc.
Consumers	Consumer Organizations.
Electricity Consumers Resource Council	Electricity Consumers Resource Council.
CTC Global	CTC Global Corporation.
District of Columbia's Office of the People's Counsel.	Office of the People's Counsel for the District of Columbia.
Dominion	Dominion Energy Services, Inc.
Duke	Duke Energy Corporation.
Duquesne Light	Duquesne Light Company.
East Kentucky	East Kentucky Power Cooperative, Inc.
EDF	EDF Renewables, Inc.
EDP Renewables	EDP Renewables North America LLC.
EEI	Edison Electric Institute.
El Paso Electric	El Paso Electric Company.
Enel	Enel North America, Inc.
Entergy	Entergy Services, LLC.
Environmental Advocates	Center for Renewables Integration, Defenders of Wildlife, Environmental Law & Policy Center, National Audubon Society, National Wildlife Federation, and Vote Solar.
EPSA	Electric Power Supply Association.
Eversource	Eversource Energy Service Company.
Exelon	Exelon Corporation.
Grid United	Grid United LLC.
Handy Law	Set Handy, Handy Law.
Harvard ELI	Harvard Electricity Law Initiative.
Idaho Power	Idaho Power Company.
Indiana Commission	Indiana Utility Regulatory Commission.
Indicated PJM TOs	PJM Transmission Owners.
Industrial Customers	Industrial Customer Organizations.
Iowa Consumer Advocate	Iowa Office of Consumer Advocate.
ISO–NE	ISO New England Inc.
ITC	International Transmission Company.
Kansas Commission	Kansas Corporation Commission.
Land Trust	Land Trust Alliance.
LPPC	Large Public Power Council.
Law Students	Students of Law at the University of Minnesota Law School.
LG&E/KU	Louisville Gas and Electric Company and Kentucky Utilities Company.
Louisiana Commission	Louisiana Public Service Commission.
LS Power	LS Power Grid, LLC.
Macro Grid	Macro Grid Initiative.
Massachusetts Attorney General	Massachusetts Attorney General Maura Healey.
Massachusetts DOER	Massachusetts Department of Energy Resources.
Maryland Commission	Maryland Public Service Commission.
Maryland Energy Admin	Maryland Energy Administration.
Michigan Commission	Michigan Public Service Commission.
Minnesota Commerce	Minnesota Department of Commerce.
MISO	Midcontinent Independent System Operator, Inc.
MISO TOs	MISO Transmission Owners.
Mississippi Commission	Mississippi Public Service Commission and the Mississippi Public Utilities Staff.
Missouri Farm Bureau	Missouri Farm Bureau Federation.
Montana QF Developers	Clenera, LLC and Greenfields Irrigation District.
NARUC	National Association of Regulatory Utility Commissioners.
NASEO	National Association of State Energy Officials.
NASUCA	National Association of State Utility Consumer Advocates.
National Grid	National Grid Plc.
Nature Conservancy	The Nature Conservancy.
New England for Offshore Wind	New England for Offshore Wind.
Nebraska Commission	Nebraska Power Review Board.
NEPOOL	New England Power Pool Participants Committee.
NERC	North American Electric Reliability Corporation.
NESCOE	New England States Committee on Electricity.

Abbreviation	Commenter
New England Systems	New England Consumer-Owned Systems.
New Jersey Commission	New Jersey Board of Public Utilities.
NewSun	NewSun Energy LLC.
NextEra	NextEra Energy, Inc.
Niskanen	Niskanen Center.
North Carolina Commission	North Carolina Utilities Commission.
North Carolina Commission Staff	North Carolina Utilities Commission Public Staff.
North Dakota Commission	North Dakota Public Service Commission.
Northern VA Coop	Northern Virginia Electric Cooperative.
Northwest and Intermountain	Northwest & Intermountain Power Producers Coalition.
NRECA	National Rural Electric Cooperative Association.
NY Commission and NYSERDA	New York Public Service Commission and New York State Energy Research and Development Authority.
NY TOs	New York Transmission Owners.
NYISO	New York Independent System Operator, Inc.
Ohio Commission	Public Utilities Commission of Ohio's Office of the Federal Energy Advocate.
Ohio Consumers	Ohio Consumers' Counsel.
Oklahoma Commission	Oklahoma Corporation Commission.
Oklahoma Gas and Electric	Oklahoma Gas and Electric Company.
Omaha Public Power	Omaha Public Power District.
OMS	Organization of MISO States.
Oregon Commission	Public Utility Commission of Oregon.
Orsted	Orsted North America.
Pennsylvania Commission	Pennsylvania Public Utility Commission.
PG&E	Pacific Gas and Electric.
Pine Gate	Pine Gate Renewables, LLC.
PIOs	Public Interest Organizations.
PJM	PJM Interconnection, L.L.C.
PJM Market Monitor	Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor of PJM Interconnection, L.L.C.
Indicated PJM TOs	PJM Transmission Owners.
Policy Integrity	Institute for Policy Integrity.
Potomac Economics	Potomac Economics, Ltd.
PPL	PPL Electric Utilities Corporation.
PSEG	PSEG Companies.
Public Citizen	Public Citizen, Inc.
Public Systems	Massachusetts Municipal Wholesale Electric Company, New Hampshire Electric Cooperative, Inc., Connecticut Municipal Electric Energy Cooperative, and Vermont Public Power Supply Authority.
QCo	Q Coefficient, Inc.
R Street	R Street Institute.
Rail Electrification	Rail Electrification Council.
REBA	Renewable Energy Buyers Alliance.
Resale Iowa	Resale Power Group of Iowa.
Resilient Societies	Foundation for Resilient Societies.
RMI	RMI.
Ron Belval	Ron Belval.
SAFE	SAFE.
SoCal Edison	Southern California Edison Company.
SDG&E	San Diego Gas & Electric Company.
SEIA	Solar Energy Industries Association.
SERTP	Sponsors of the Southeastern Regional Transmission Planning Process.
Shell	Shell Energy North America.
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
Sorgo	Sorgo Fuels & Chemicals, Inc.
Southern	Southern Company Services, Inc.
SPP	Southwest Power Pool, Inc.
SPP Market Monitor	Southwest Power Pool Market Monitoring Unit.
SPP RSC	Southwest Power Pool Regional State Committee.
State Agencies	State Agencies (CT, DE, MD, DC, IL, MN, MI, MA, NJ, OR, PA, RI, VT).
State Legislatures	National Conference of State Legislatures.
State of Idaho	Idaho Governor's Office of Energy & Mineral Resources.
State of Massachusetts	Commonwealth of Massachusetts Department of Energy Resources.
State of New York	New York State Department of State Utility Intervention Unit.
State of Tennessee	State of Tennessee.
State of Washington	Jay Inslee, Governor, State of Washington.
State Wildlife Agencies	Association of Fish & Wildlife Agencies.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
Tenaska	Tenaska, Inc.
Tom Pike	Tom R Pike.
Transmission Dependent Utilities	Transmission Dependent Utility Systems.
Union of Concerned Scientists	Union of Concerned Scientists.
US Chamber of Commerce	US Chamber of Commerce.
U.S. DOE	United States Department of Energy.

Abbreviation	Commenter
US DOI	US Department of Interior.
Utah Commission	Utah Public Service Commission.
VEIR	VEIR Inc.
Vermont Electric	Vermont Electric Power Company.
Vistra	Vistra Corp.
WATT Coalition	WATT Coalition.
WIRES	WIRES.
Xcel	Xcel Energy Services Inc.

Appendix B: Pro Forma Open Access Transmission Tariff Attachment K

Note: Proposed deletions are in brackets and proposed additions are in italics.

Attachment K

Transmission Planning Process

Local Transmission Planning

The Transmission Provider shall establish a coordinated, open, and transparent *local transmission* planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider's coordinated, open, and transparent *local transmission* planning process shall be provided as an attachment to the Transmission Provider's Tariff. The Transmission Provider's *local transmission* planning process shall satisfy the following nine principles, as defined in Order No. 890: Coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new *transmission* projects. The *local transmission* planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. The *local transmission* planning process also shall provide a mechanism for the recovery and allocation of *transmission* planning costs consistent with Order No. 890. The description of the Transmission Provider's *local transmission* planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;

(vi) The dispute resolution process;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(ix) The relevant cost allocation method or methods.

Regional Transmission Planning

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000 *and Order No. [final rule].* The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider's regional transmission planning process shall satisfy the following seven principles, as set out and explained in Order Nos. 890 and 1000: Coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The regional transmission planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of ''*transmission* planning costs'' consistent with Order No. 890 and *Order No. 1000.*

The regional transmission planning process shall include a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region. The regional transmission planning process shall be clear that enrollment will subject enrollees to cost allocation if they are found to be beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation. Each Transmission Provider shall maintain a list of enrolled entities in the Transmission Provider's Tariff.

As part of the regional transmission planning process, the Transmission Providers in each transmission planning region will conduct Long-Term Regional Transmission Planning, meaning regional transmission planning on a sufficiently long-term, forward-looking basis to identify transmission needs driven by changes in the resource mix and demand, evaluate transmission facilities to meet such needs, and identify and evaluate 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 such needs. As part of this Long-Term Regional Transmission Planning, the Transmission Providers in each transmission planning region will: (1) Identify transmission needs driven by changes in the resource mix and demand through the development of Long-Term Scenarios that satisfy the requirements set forth in Order No. [final rule]; (2) evaluate the benefits of regional transmission facilities to meet transmission needs driven by changes in the resource mix and demand over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities; and (3) establish transparent and not unduly discriminatory criteria to select transmission facilities in the regional transmission plan for purposes of cost allocation that more efficiently or cost-effectively address transmission needs driven by changes in the resource mix and demand in collaboration with states and other stakeholders.

When developing Long-Term Scenarios, the Transmission Providers in each transmission planning region must: (1) Use a transmission planning horizon no less than 20 years into the future; (2) reassess and revise Long-Term Scenarios including to reassess whether the data inputs and factors incorporated in their previously developed Long-Term Scenarios need to be updated and then revise their Long-Term Scenarios as needed to reflect updated data inputs and factors at least every three years, and complete the development of Long-Term Scenarios within three years, before the next three-year assessment commences; (3) incorporate, at a minimum, the seven categories of factors identified in Order No. [final rule] that may drive transmission needs driven by changes in the resource mix and demand; (4) develop a plausible and diverse set of at least four Long-Term Scenarios; (5) use ''best available data'' (as defined in Order No. [final rule]) in developing Long-Term Scenarios; and (6) consider whether to identify geographic zones with the potential for development of large amounts of new generation. The process through which the Transmission Providers develop Long-Term Scenarios also must comply with the *following six transmission planning principles established in Order No. 890: Coordination; openness; transparency; information exchange; comparability; and dispute resolution.*

The Transmission Providers in each transmission planning region must identify the benefits they will use in Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand. The following set of Long-Term Regional Transmission Benefits may be useful for Transmission Providers in each transmission planning region in evaluating transmission facilities for selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective solutions to meet transmission needs driven by changes in the resource mix and demand: (1) Avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity.

Table 1—Long-Term Regional Transmission Benefits

Benefit	*Description*
Avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement.	*Reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities.*
Reduced loss of load probability [OR next benefit]	*Reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load (if planning reserve margin is constant), resulting in benefit of reduced expected unserved energy by customer value of lost load.*
Reduced planning reserve margin [OR prior benefit]	*While holding loss of load probabilities constant, system operators can reduce their resource adequacy requirements (i.e., planning reserve margins), resulting in a benefit of reduced capital cost of generation needed to meet resource adequacy requirements.*
Production cost savings	*Reduction in production costs, including savings in fuel and other variable operating costs of power generation, that are realized when transmission facilities allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies; also reduction in market prices as lower-cost suppliers set market clearing prices; when adjusted to account for purchases and sales outside the region, called adjusted production cost savings.*
Reduced transmission energy losses	*Reduced energy losses incurred in transmittal of power from generation to loads, thereby reducing total energy necessary to meet demand.*
Reduced congestion due to transmission outages	*Reduced production costs during transmission outages that significantly increase transmission congestion.*
Mitigation of extreme events and system contingencies	*Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages, through more robust transmission system reducing high-cost generation and emergency procurements necessary to support the system.*
Mitigation of weather and load uncertainty	*Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns.*
Capacity cost benefits from reduced peak energy losses	*Reduced energy losses during peak load reduces generation capacity investment needed to meet the peak load and transmission losses.*
Deferred generation capacity investments	*Reduced costs of needed generation capacity investments through expanded import capability into resource-constrained areas.*
Access to lower-cost generation	*Reduced total cost of generation due to ability to locate units in a more economically efficient location (e.g., low permitting costs, low-cost sites on which plants can be built, access to existing infrastructure, low labor costs, low fuel costs, access to valuable natural resources, locations with high-quality renewable energy resources).*
Increased competition	*Reduced bid prices in wholesale electricity markets due to increased competition among generators and reduced overall market concentration/market power.*
Increased market liquidity	*Reduced transaction costs (e.g., bid-ask spreads) of bilateral transactions, increased price transparency, increased efficiency of risk management, improved contracting, and better clarity for long-term transmission planning and investment decisions through increased number of buyers and sellers able to transact with each other as a result of transmission expansion.*

As part of Long-Term Regional Transmission Planning, the Transmission Providers in each transmission planning region must include (1) transparent and not unduly discriminatory criteria, which seek to maximize benefits to consumers over time without over-building transmission facilities, to identify and evaluate transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation that address transmission needs driven by changes in the resource mix and demand; and (2) a process to coordinate with relevant state entities in developing such criteria.

If the Transmission Providers include a portfolio approach in selecting transmission facilities in the regional transmission plan for *purposes of cost allocation that address transmission needs driven by changes in the resource mix and demand, then the Transmission Providers must include provisions describing whether the selection criteria would be used for Long-Term Regional Transmission Planning universally to address transmission needs driven by changes in the resource mix and demand or would be used only in certain specified instances.*

The Transmission Providers in each transmission planning region shall include in their tariffs either (1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities, or (2) a State Agreement Process by which one or more relevant state entities may voluntarily agree to a cost allocation method, or (3) a combination thereof. A Long-Term Regional Transmission Cost Allocation Method is an ex ante regional cost allocation method that applies to a transmission facility identified as part of Long-Term Regional Transmission Planning and selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand (Long-Term Regional Transmission Facility). The developer of a Long-Term Regional Transmission Facility would be entitled to use the Long-Term Regional Transmission Cost Allocation Method if it is the applicable cost allocation method. A State Agreement Process is an ex post cost allocation process, which may apply to an individual Long-Term Regional Transmission Facility or a portfolio of such Facilities grouped together for purposes of cost allocation. After a Long-Term Regional Transmission Facility is selected in the regional transmission plan for purposes of cost allocation, the State Agreement Process would be followed to establish a cost allocation method for that facility (if agreement can be reached). If the Commission subsequently approves the cost allocation method that results from the State Agreement Process, the developer of the Long-Term Regional Transmission Facility would be entitled to use that cost allocation method if it is the applicable method. The Long-Term Regional Transmission Cost Allocation Method and any cost allocation method resulting from the State Agreement Process for Long-Term Regional Transmission Facilities must comply with the existing six Order No. 1000 regional cost allocation principles.

Transmission Providers in each transmission planning region must seek the agreement of relevant state entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process.

The regional transmission planning processes must give a state or states a period of time to negotiate a cost allocation method for a transmission facility that is selected in the Long Term Regional Transmission Plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand that is different than the regional cost allocation method (alternate cost allocation method related to transmission needs driven by changes in the resource mix and demand).

The Transmission Providers in each transmission planning region shall consider in regional transmission planning and cost allocation processes whether selecting transmission facilities in the regional transmission plan for purposes of cost allocation that incorporate dynamic line ratings, as defined in 18 CFR 35.28(b)(14), or advanced power flow control devices would be more efficient or cost-effective than regional transmission facilities that do not incorporate these technologies. Specifically, such consideration must include both: (1) First, whether incorporating dynamic line ratings or advanced power flow control devices into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other potential transmission facilities; and (2) second, when evaluating transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation, the Transmission Providers in each transmission planning region must also consider whether incorporating dynamic line ratings and advanced power flow control devices as part of any potential regional transmission facility would be more efficient of cost-effective.

This requirement applies in all of the Transmission Provider's regional transmission planning processes, including the regional transmission planning processes for near-term regional transmission needs and Long-Term Regional Transmission Planning required in Order No. [final rule]. The costs of transmission facilities that incorporate dynamic line ratings or advanced power flow control devices that are selected in the regional transmission plan for purposes of cost allocation will be allocated using the applicable regional cost allocation method. The Transmission Provider's evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected in the regional transmission plan for purposes of cost allocation. This process must include the consideration of dynamic line ratings and advanced power flow control devices and why they were not incorporated into selected regional transmission facilities.

The description of the regional transmission planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for enrollment in the regional transmission planning process;

(ii) The process for consulting with customers;

(iii) The notice procedures and anticipated frequency of meetings;

(iv) The methodology, criteria, and processes used to develop a transmission plan;

(v) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;

(vi) The obligations of and methods for transmission customers to submit data;

(vii) The process for submission of data by nonincumbent developers of transmission projects that wish to participate in the *regional* transmission planning process and seek regional cost allocation;

(viii) The process for submission of data by merchant transmission developers that wish to participate in the *regional* transmission planning process;

(ix) The dispute resolution process;

(x) The study procedures for economic upgrades to address congestion or the integration of new resources; *and*

[The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and]

(xi) The relevant cost allocation method or methods.

The regional transmission planning process must include a cost allocation method or methods that satisfy the six regional cost allocation principles set forth in Order No. 1000.

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

The regional transmission planning process must include at least three stakeholder meetings concerning the local transmission planning process of each Transmission Provider that is a member of the transmission planning region before each Transmission Provider's local transmission planning information can be incorporated into the transmission planning region's planning models:

(1) A stakeholder meeting to review the criteria, assumptions, and models related to each Transmission Provider's local transmission planning (Assumptions Meeting);

(2) No fewer than 25 calendar days after the Assumptions Meeting, a stakeholder meeting to review identified reliability criteria violations and other transmission needs that drive the need for local transmission facilities (Needs Meeting); and

(3) No fewer than 25 calendar days after the Needs Meeting, a stakeholder meeting to review potential solutions to those reliability criteria violations and other transmission needs (Solutions Meeting).

Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

As part of each Long-Term Regional Transmission Planning cycle, Transmission Providers in each transmission planning region shall evaluate whether transmission facilities operating at or above 230 kV that an individual Transmission Provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be ''right-sized'' to more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Planning. ''Right-sizing'' means the process of modifying a Transmission Provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability. The process to identify potential opportunities to right-size replacement transmission facilities must follow the process outlined in Order No. [final rule].

Interregional Transmission Coordination

The Transmission Provider, through its regional transmission planning process, must coordinate with the public utility transmission providers in each neighboring transmission planning region within its interconnection to address transmission planning coordination issues related to interregional transmission facilities. The interregional transmission coordination procedures must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions (i) with respect to each interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. The interregional transmission coordination procedures shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider must ensure that the following requirements are included in any applicable interregional transmission coordination procedures:

(1) A commitment to coordinate and share the results of each transmission planning region's regional transmission plans *(including information regarding the respective transmission needs identified in Long-Term Regional Transmission Planning and potential transmission facilities to meet those needs)* to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities, as well as a procedure for doing so;

(2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions, *including those that may be more efficient or cost-effective transmission solutions to transmission needs identified through Long-Term Regional Transmission Planning;*

(3) An agreement to exchange, at least annually, planning data and information; and

(4) A commitment to maintain a website or email list for the communication of information related to the coordinated planning process.

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or methods for allocating between the two transmission planning regions the costs of a new interregional transmission facility that is located within both transmission planning regions. Such cost allocation method or methods must satisfy the six interregional cost allocation principles set forth in Order No. 1000 and must be included in the Transmission Provider's Tariff.

Appendix C: *Pro Forma* LGIP

Note: Proposed deletions are in brackets and proposed additions are in italics.

Standard Large Generator Interconnection Procedures (LGIP) Including Standard Large Generator Interconnection Agreement (LGIA); Standard Large Generator Interconnection Procedures (LGIP) (Applicable to Generating Facilities That Exceed 20 MW)

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Section 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Contingent Facilities shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for Re-Studies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by an Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Emergency Condition shall mean a condition or situation: (1) That in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. 791a *et seq.*

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of ''hazardous substances,'' ''hazardous wastes,'' ''hazardous materials,'' ''hazardous constituents,'' ''restricted hazardous materials,'' ''extremely hazardous substances,'' ''toxic substances,'' ''radioactive substances,'' ''contaminants,'' ''pollutants,'' ''toxic pollutants'' or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission Provider's Transmission System. The scope of the study is defined in Section 8 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: The Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Permissible Technological Advancement [Transmission Provider inserts definition here].

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Provisional Interconnection Service shall mean Interconnection Service provided by Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Provisional Large Generator Interconnection Agreement and, if applicable, the Tariff.

Provisional Large Generator Interconnection Agreement shall mean the interconnection agreement for Provisional Interconnection Service established between Transmission Provider and/or the Transmission Owner and the Interconnection Customer. This agreement shall take the form of the Large Generator Interconnection Agreement, modified for provisional purposes.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (1) Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that are not part of an Affected System that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 days of its determination.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

Surplus Interconnection Service shall mean any unneeded portion of Interconnection Service established in a Large Generator Interconnection Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Section 2. Scope and Application

2.1 Application of Standard Large Generator Interconnection Procedures

Sections 2 through 13 apply to processing an Interconnection Request pertaining to a Large Generating Facility.

2.2 Comparability

Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this LGIP. Transmission Provider will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by Transmission Provider, its subsidiaries or Affiliates or others.

2.3 Base Case Data

Transmission Provider shall maintain base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list on either its OASIS site or a password-protected website, subject to confidentiality provisions in LGIP Section 13.1. In addition, Transmission Provider shall maintain network models and underlying assumptions on either its OASIS site or a password-protected website. Such network models and underlying assumptions should reasonably represent those used during the most recent interconnection study and be representative of current system conditions. If Transmission Provider posts this information on a password-protected website, a link to the information must be provided on Transmission Provider's OASIS site. Transmission Provider is permitted to require that Interconnection Customers, OASIS site users and password-protected website users sign a confidentiality agreement before the release of commercially sensitive information or Critical Energy Infrastructure Information in the Base Case data. Such databases and lists, hereinafter referred to as Base Cases, shall include all (1) generation projects and (2) transmission projects, including merchant transmission projects that are proposed for the Transmission System for which a transmission expansion plan has been submitted and approved by the applicable authority.

2.4 No Applicability to Transmission Service

Nothing in this LGIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

Section 3. Interconnection Requests

3.1 General

An Interconnection Customer shall submit to Transmission Provider an Interconnection Request in the form of Appendix 1 to this LGIP and a refundable deposit of $10,000. Transmission Provider shall apply the deposit toward the cost of an Interconnection Feasibility Study. Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests.

At Interconnection Customer's option, Transmission Provider and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the Interconnection Feasibility Study Agreement.

Transmission Provider shall have a process in place to consider requests for Interconnection Service below the Generating Facility Capacity. These requests for Interconnection Service shall be studied at the level of Interconnection Service requested for purposes of Interconnection Facilities, Network Upgrades, and associated costs, but may be subject to other studies at the full Generating Facility Capacity to ensure safety and reliability of the system, with the study costs borne by the Interconnection Customer. If after the additional studies are complete, Transmission Provider determines that additional Network Upgrades are necessary, then Transmission Provider must: (1) Specify which additional Network Upgrade costs are based on which studies; and (2) provide a detailed explanation of why the additional Network Upgrades are necessary. Any Interconnection Facility and/or Network Upgrade costs required for safety and reliability also would be borne by the Interconnection Customer. Interconnection Customers may be subject to additional control technologies as well as testing and validation of those technologies consistent with Article 6 of the LGIA. The necessary control technologies and protection systems shall be established in Appendix C of that executed, or requested to be filed unexecuted, LGIA.

3.2 Identification of Types of Interconnection Services

At the time the Interconnection Request is submitted, Interconnection Customer must request either Energy Resource Interconnection Service or Network Resource Interconnection Service, as described; provided, however, any Interconnection Customer requesting Network Resource Interconnection Service may also request that it be concurrently studied for Energy Resource Interconnection Service, up to the point when an Interconnection Facility Study Agreement is executed. Interconnection Customer may then elect to proceed with Network Resource Interconnection Service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed.

3.2.1 Energy Resource Interconnection Service

3.2.1.1 The Product

Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an ''as available'' basis. Energy Resource Interconnection Service does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery.

3.2.1.2 The Study

The study consists of short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address short circuit issues associated with the Interconnection Facilities. The stability and steady state studies would identify necessary upgrades to allow full output of the proposed Large Generating Facility and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Large Generating Facility without requiring additional Network Upgrades.

3.2.2 Network Resource Interconnection Service

3.2.2.1 The Product

Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service Allows Interconnection Customer's Large Generating Facility to be designated as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur.

3.2.2.2 The Study

The Interconnection Study for Network Resource Interconnection Service shall assure that Interconnection Customer's Large Generating Facility meets the requirements for Network Resource Interconnection Service and as a general matter, that such

Large Generating Facility's interconnection is also studied with Transmission Provider's Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Large Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on Transmission Provider's Transmission System, consistent with Transmission Provider's reliability criteria and procedures. This approach assumes that some portion of existing Network Resources are displaced by the output of Interconnection Customer's Large Generating Facility. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery. The Transmission Provider may also study the Transmission System under non-peak load conditions. However, upon request by the Interconnection Customer, the Transmission Provider must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

3.3 Utilization of Surplus Interconnection Service

Transmission Provider must provide a process that allows an Interconnection Customer to utilize or transfer Surplus Interconnection Service at an existing Point of Interconnection. The original Interconnection Customer or one of its affiliates shall have priority to utilize Surplus Interconnection Service. If the existing Interconnection Customer or one of its affiliates does not exercise its priority, then that service may be made available to other potential Interconnection Customers.

3.3.1 Surplus Interconnection Service Requests

Surplus Interconnection Service requests may be made by the existing Interconnection Customer whose Generating Facility is already interconnected or one of its affiliates. Surplus Interconnection Service requests also may be made by another Interconnection Customer. Transmission Provider shall provide a process for evaluating Interconnection Requests for Surplus Interconnection Service. Studies for Surplus Interconnection Service shall consist of reactive power, short circuit/fault duty, stability analyses, and any other appropriate studies. Steady-state (thermal/voltage) analyses may be performed as necessary to ensure that all required reliability conditions are studied. If the Surplus Interconnection Service was not studied under off-peak conditions, off-peak steady state analyses shall be performed to the required level necessary to demonstrate reliable operation of the Surplus Interconnection Service. If the original System Impact Study is not available for the Surplus Interconnection Service, both off-peak and peak analysis may need to be performed for the existing Generating Facility associated with the request for Surplus Interconnection Service. The reactive power, short circuit/fault duty, stability, and steady-state analyses for Surplus Interconnection Service will identify any additional Interconnection Facilities and/or Network Upgrades necessary.

3.4 Valid Interconnection Request

3.4.1 Initiating an Interconnection Request

To initiate an Interconnection Request, Interconnection Customer must submit all of the following: (i) A $10,000 deposit, (ii) a completed application in the form of Appendix 1, and (iii) demonstration of Site Control or a posting of an additional deposit of $10,000. Such deposits shall be applied toward any Interconnection Studies pursuant to the Interconnection Request. If Interconnection Customer demonstrates Site Control within the cure period specified in Section 3.4.3 after submitting its Interconnection Request, the additional deposit shall be refundable; otherwise, all such deposit(s), additional and initial, become non-refundable.

The expected In-Service Date of the new Large Generating Facility or increase in capacity of the existing Generating Facility shall be no more than the process window for the regional expansion planning period (or in the absence of a regional planning process, the process window for Transmission Provider's expansion planning period) not to exceed seven years from the date the Interconnection Request is received by Transmission Provider, unless Interconnection Customer demonstrates that engineering, permitting and construction of the new Large Generating Facility or increase in capacity of the existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by Transmission Provider by a period up to ten years, or longer where Interconnection Customer and Transmission Provider agree, such agreement not to be unreasonably withheld.

3.4.2 Acknowledgment of Interconnection Request

Transmission Provider shall acknowledge receipt of the Interconnection Request within five (5) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement.

3.4.3 Deficiencies in Interconnection Request

An Interconnection Request will not be considered to be a valid request until all items in Section 3.4.1 have been received by Transmission Provider. If an Interconnection Request fails to meet the requirements set forth in Section 3.4.1, Transmission Provider shall notify Interconnection Customer within five (5) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. Interconnection Customer shall provide Transmission Provider the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by Interconnection Customer to comply with this Section 3.4.3 shall be treated in accordance with Section 3.7.

3.4.4 Scoping Meeting

Within ten (10) Business Days after receipt of a valid Interconnection Request, Transmission Provider shall establish a date agreeable to Interconnection Customer for the Scoping Meeting, and such date shall be no later than thirty (30) Calendar Days from receipt of the valid Interconnection Request, unless otherwise mutually agreed upon by the Parties.

The purpose of the Scoping Meeting shall be to discuss alternative interconnection options, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection. Transmission Provider and Interconnection Customer will bring to the meeting such technical data, including, but not limited to: (i) General facility loadings, (ii) general instability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting. Transmission Provider and Interconnection Customer will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer shall designate its Point of Interconnection, pursuant to Section 6.1, and one or more available alternative Point(s) of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose.

3.5. OASIS Posting

3.5.1

Transmission Provider will maintain on its OASIS a list of all Interconnection Requests. The list will identify, for each Interconnection Request: (i) The maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected In-Service Date; (v) the status of the Interconnection Request, including Queue Position; (vi) the type of Interconnection Service being requested; and (vii) the availability of any studies related to the Interconnection Request; (viii) the date of the Interconnection Request; (ix) the type of Generating Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); and (x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed. Except in the case of an Affiliate, the list will not disclose the identity of Interconnection Customer until Interconnection Customer executes an LGIA or requests that Transmission Provider file an unexecuted LGIA with FERC. Before holding a Scoping Meeting with its Affiliate, Transmission Provider shall post on OASIS an advance notice of its intent to do so. Transmission Provider shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to Transmission Provider's OASIS site subsequent to the meeting between Interconnection Customer and Transmission Provider to discuss the applicable study results. Transmission Provider shall also post any known deviations in the Large Generating Facility's In-Service Date.

3.5.2 Requirement To Post Interconnection Study Metrics

Transmission Provider will maintain on its OASIS or its website summary statistics related to processing Interconnection Studies pursuant to Interconnection Requests, updated quarterly. If Transmission Provider posts this information on its website, a link to the information must be provided on Transmission Provider's OASIS site. For each calendar quarter, Transmission Providers must calculate and post the information detailed in sections 3.5.2.1 through 3.5.2.4.

3.5.2.1 Interconnection Feasibility Studies Processing Time

(A) Number of Interconnection Requests that had Interconnection Feasibility Studies completed within Transmission Provider's coordinated region during the reporting quarter,

(B) Number of Interconnection Requests that had Interconnection Feasibility Studies completed within Transmission Provider's coordinated region during the reporting quarter that were completed more than [timeline as listed in Transmission Provider's LGIP] after receipt by Transmission Provider of the Interconnection Customer's executed Interconnection Feasibility Study Agreement,

(C) At the end of the reporting quarter, the number of active valid Interconnection Requests with ongoing incomplete Interconnection Feasibility Studies where such Interconnection Requests had executed Interconnection Feasibility Study Agreements received by Transmission Provider more than [timeline as listed in Transmission Provider's LGIP] before the reporting quarter end,

(D) Mean time (in days), Interconnection Feasibility Studies completed within Transmission Provider's coordinated region during the reporting quarter, from the date when Transmission Provider received the executed Interconnection Feasibility Study Agreement to the date when Transmission Provider provided the completed Interconnection Feasibility Study to the Interconnection Customer,

(E) Percentage of Interconnection Feasibility Studies exceeding [timeline as listed in Transmission Provider's LGIP] to complete this reporting quarter, calculated as the sum of 3.5.2.1(B) plus 3.5.2.1(C) divided by the sum of 3.5.2.1(A) plus 3.5.2.1(C)).

3.5.2.2 Interconnection System Impact Studies Processing Time

(A) Number of Interconnection Requests that had Interconnection System Impact Studies completed within Transmission Provider's coordinated region during the reporting quarter,

(B) Number of Interconnection Requests that had Interconnection System Impact Studies completed within Transmission Provider's coordinated region during the reporting quarter that were completed more than [timeline as listed in Transmission Provider's LGIP] after receipt by Transmission Provider of the Interconnection Customer's executed Interconnection System Impact Study Agreement,

(C) At the end of the reporting quarter, the number of active valid Interconnection Requests with ongoing incomplete System Impact Studies where such Interconnection Requests had executed Interconnection System Impact Study Agreements received by Transmission Provider more than [timeline as listed in Transmission Provider's LGIP] before the reporting quarter end,

(D) Mean time (in days), Interconnection System Impact Studies completed within Transmission Provider's coordinated region during the reporting quarter, from the date when Transmission Provider received the executed Interconnection System Impact Study Agreement to the date when Transmission Provider provided the completed Interconnection System Impact Study to the Interconnection Customer,

(E) Percentage of Interconnection System Impact Studies exceeding [timeline as listed in Transmission Provider's LGIP] to complete this reporting quarter, calculated as the sum of 3.5.2.2(B) plus 3.5.2.2(C) divided by the sum of 3.5.2.2(A) plus 3.5.2.2(C)).

3.5.2.3 Interconnection Facilities Studies Processing Time

(A) Number of Interconnection Requests that had Interconnection Facilities Studies that are completed within Transmission Provider's coordinated region during the reporting quarter,

(B) Number of Interconnection Requests that had Interconnection Facilities Studies that are completed within Transmission Provider's coordinated region during the reporting quarter that were completed more than [timeline as listed in Transmission Provider's LGIP] after receipt by Transmission Provider of the Interconnection Customer's executed Interconnection Facilities Study Agreement,

(C) At the end of the reporting quarter, the number of active valid Interconnection Service requests with ongoing incomplete Interconnection Facilities Studies where such Interconnection Requests had executed Interconnection Facilities Studies Agreement received by Transmission Provider more than [timeline as listed in Transmission Provider's LGIP] before the reporting quarter end,

(D) Mean time (in days), for Interconnection Facilities Studies completed within Transmission Provider's coordinated region during the reporting quarter, calculated from the date when Transmission Provider received the executed Interconnection Facilities Study Agreement to the date when Transmission Provider provided the completed Interconnection Facilities Study to the Interconnection Customer,

(E) Percentage of delayed Interconnection Facilities Studies this reporting quarter, calculated as the sum of 3.5.2.3(B) plus 3.5.2.3(C) divided by the sum of 3.5.2.3(A) plus 3.5.2.3(C)).

3.5.2.4 Interconnection Service Requests Withdrawn From Interconnection Queue

(A) Number of Interconnection Requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter,

(B) Number of Interconnection Requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of any interconnection studies or execution of any interconnection study agreements,

(C) Number of Interconnection Requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of an Interconnection System Impact Study,

(D) Number of Interconnection Requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of an Interconnection Facilities Study,

(E) Number of Interconnection Requests withdrawn from Transmission Provider's interconnection queue after execution of a generator interconnection agreement or Interconnection Customer requests the filing of an unexecuted, new interconnection agreement,

(F) Mean time (in days), for all withdrawn Interconnection Requests, from the date when the request was determined to be valid to when Transmission Provider received the request to withdraw from the queue.

3.5.3

Transmission Provider is required to post on OASIS or its website the measures in paragraph 3.5.2.1(A) through paragraph 3.5.2.4(F) for each calendar quarter within 30 days of the end of the calendar quarter. Transmission Provider will keep the quarterly measures posted on OASIS or its website for three calendar years with the first required report to be in the first quarter of 2020. If Transmission Provider retains this information on its website, a link to the information must be provided on Transmission Provider's OASIS site.

3.5.4

In the event that any of the values calculated in paragraphs 3.5.2.1(E), 3.5.2.2(E) or 3.5.2.3(E) exceeds 25 percent for two consecutive calendar quarters, Transmission Provider will have to comply with the measures below for the next four consecutive calendar quarters and must continue reporting this information until Transmission Provider reports four consecutive calendar quarters without the values calculated in 3.5.2.1(E), 3.5.2.2(E) or 3.5.2.3(E) exceeding 25 percent for two consecutive calendar quarters:

(i) Transmission Provider must submit a report to the Commission describing the reason for each study or group of clustered studies pursuant to an Interconnection Request that exceeded its deadline (*i.e.*, 45, 90 or 180 days) for completion (excluding any allowance for Reasonable Efforts). Transmission Provider must describe the reasons for each study delay and any steps taken to remedy these specific issues and, if applicable, prevent such delays in the future. The report must be filed at the Commission within 45 days of the end of the calendar quarter.

(ii) Transmission Provider shall aggregate the total number of employee-hours and third party consultant hours expended towards interconnection studies within its coordinated region that quarter and post on OASIS or its website. If Transmission Provider posts this information on its website, a link to the information must be provided on Transmission Provider's OASIS site. This information is to be posted within 30 days of the end of the calendar quarter.

3.6 Coordination With Affected Systems

Transmission Provider will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators and, if possible, include those results (if available) in its applicable Interconnection Study within the time frame specified in this LGIP. Transmission Provider will include such Affected System Operators in all meetings held with Interconnection Customer as required by this LGIP. Interconnection Customer will cooperate with Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an Affected System shall cooperate with Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

3.7 Withdrawal

Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to Transmission Provider. In addition, if Interconnection Customer fails to adhere to all requirements of this LGIP, except as provided in Section 13.5 (Disputes), Transmission Provider shall deem the Interconnection Request to be withdrawn and shall provide written notice to Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify Transmission Provider of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of Interconnection Customer's Queue Position. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during Dispute Resolution, Interconnection Customer's Interconnection Request is eliminated from the queue until such time that the outcome of Dispute Resolution would restore its Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to Transmission Provider all costs that Transmission Provider prudently incurs with respect to that Interconnection Request prior to Transmission Provider's receipt of notice described above. Interconnection Customer must pay all monies due to Transmission Provider before it is allowed to obtain any Interconnection Study data or results.

Transmission Provider shall (i) update the OASIS Queue Position posting and (ii) refund to Interconnection Customer any portion of Interconnection Customer's deposit or study payments that exceeds the costs that Transmission Provider has incurred, including interest calculated in accordance with section 35.19a(a)(2) of FERC's regulations. In the event of such withdrawal, Transmission Provider, subject to the confidentiality provisions of Section 13.1, shall provide, at Interconnection Customer's request, all information that Transmission Provider developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

3.8 Identification of Contingent Facilities

Transmission Provider shall post in this section a method for identifying the Contingent Facilities to be provided to Interconnection Customer at the conclusion of the System Impact Study and included in Interconnection Customer's Large Generator Interconnection Agreement. The method shall be sufficiently transparent to determine why a specific Contingent Facility was identified and how it relates to the Interconnection Request. Transmission Provider shall also provide, upon request of the Interconnection Customer, the estimated Interconnection Facility and/or Network Upgrade costs and estimated in-service completion time of each identified Contingent Facility when this information is readily available and not commercially sensitive.

3.10 Repeat Network Upgrades for Consideration in the Regional Transmission Planning Process

If Transmission Provider: (1) Identifies a Network Upgrade with an interconnection study estimated cost of at least $30 million or with a voltage of at least 200 kV as necessary to accomplish an interconnection and the underlying interconnection request related to such Network Upgrade is withdrawn; (2) if, within five years of that withdrawal, Transmission Provider identifies a Network Upgrade with an interconnection study estimated cost of at least $30 million or with a voltage of at least 200 kV to address a similar interconnection-related need as specified in (1) and the underlying interconnection request with cost responsibility for the second identified Network Upgrade is withdrawn; and (3) a similar interconnection-related need is not addressed by any Network Upgrade described in Appendix A of any executed Large Generator Interconnection Agreement or any Large Generator Interconnection Agreement that an Interconnection Customer has requested that Transmission Provider file with the Commission unexecuted, then Transmission Provider shall consider the interconnection-related need addressed by the Network Upgrade(s) that Transmission Provider identified in the interconnection queue cycles specified in (1) and (2) in Long-Term Regional Transmission Planning.

Section 4. Queue Position

4.1 General

Transmission Provider shall assign a Queue Position based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and Interconnection Customer provides such information in accordance with Section 3.4.3, then Transmission Provider shall assign Interconnection Customer a Queue Position based on the date the application form was originally filed. Moving a Point of Interconnection shall result in a lowering of Queue Position if it is deemed a Material Modification under Section 4.4.3.

The Queue Position of each Interconnection Request will be used to determine the order of performing the Interconnection Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request. A higher queued Interconnection Request is one that has been placed ''earlier'' in the queue in relation to another Interconnection Request that is lower queued.

Transmission Provider may allocate the cost of the common upgrades for clustered Interconnection Requests without regard to Queue Position.

4.2 Clustering

At Transmission Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the Interconnection System Impact Study.

Clustering shall be implemented on the basis of Queue Position. If Transmission Provider elects to study Interconnection Requests using Clustering, all Interconnection Requests received within a period not to exceed one hundred and eighty (180) Calendar Days, hereinafter referred to as the ''Queue Cluster Window'' shall be studied together without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service. The deadline for completing all Interconnection System Impact Studies for which an Interconnection System Impact Study Agreement has been executed during a Queue Cluster Window shall be in accordance with Section 7.4, for all Interconnection Requests assigned to the same Queue Cluster Window. Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Large Generating Facility.

Clustering Interconnection System Impact Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the Transmission System's capabilities at the time of each study.

The Queue Cluster Window shall have a fixed time interval based on fixed annual opening and closing dates. Any changes to the established Queue Cluster Window interval and opening or closing dates shall be announced with a posting on Transmission Provider's OASIS beginning at least one hundred and eighty (180) Calendar Days in advance of the change and continuing thereafter through the end date of the first Queue Cluster Window that is to be modified.

4.3 Transferability of Queue Position

An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change.

4.4 Modifications

Interconnection Customer shall submit to Transmission Provider, in writing, modifications to any information provided in the Interconnection Request. Interconnection Customer shall retain its Queue Position if the modifications are in accordance with Sections 4.4.1, 4.4.2 or 4.4.5, or are determined not to be Material Modifications pursuant to Section 4.4.3.

Notwithstanding the above, during the course of the Interconnection Studies, either Interconnection Customer or Transmission Provider may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to Transmission Provider and Interconnection Customer, such acceptance not to be unreasonably withheld, Transmission Provider shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 6.4, Section 7.6 and Section 8.5 as applicable and Interconnection Customer shall retain its Queue Position.

4.4.1

Prior to the return of the executed Interconnection System Impact Study Agreement to Transmission Provider, modifications permitted under this Section shall include specifically: (a) A decrease of up to 60 percent of electrical output (MW) of the proposed project, through either (1) a decrease in plant size or (2) a decrease in Interconnection Service level (consistent with the process described in Section 3.1) accomplished by applying Transmission Provider-approved injection-limiting equipment; (b) modifying the technical parameters associated with the Large Generating Facility technology or the Large Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of cost allocation and study analysis.

4.4.2

Prior to the return of the executed Interconnection Facility Study Agreement to Transmission Provider, the modifications permitted under this Section shall include specifically: (a) Additional 15 percent decrease of electrical output of the proposed project through either (1) a decrease in plant size (MW) or (2) a decrease in Interconnection Service level (consistent with the process described in Section 3.1) accomplished by applying Transmission Provider-approved injection-limiting equipment; (b) Large Generating Facility technical parameters associated with modifications to Large Generating Facility technology and transformer impedances; provided, however, the incremental costs associated with those modifications are the responsibility of the requesting Interconnection Customer; and (c) a Permissible Technological Advancement for the Large Generating Facility after the submission of the Interconnection Request. Section 4.4.6 specifies a separate technological change procedure including the requisite information and process that will be followed to assess whether the Interconnection Customer's proposed technological advancement under Section 4.4.2(c) is a Material Modification. Section 1 contains a definition of Permissible Technological Advancement.

4.4.3

Prior to making any modification other than those specifically permitted by Sections 4.4.1, 4.4.2, and 4.4.5, Interconnection Customer may first request that Transmission Provider evaluate whether such modification is a Material Modification. In response to Interconnection Customer's request, Transmission Provider shall evaluate the proposed modifications prior to making them and inform Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable under Sections 4.4.1, 6.1, 7.2 or so allowed elsewhere, shall constitute a Material Modification. Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

4.4.4

Upon receipt of Interconnection Customer's request for modification permitted under this Section 4.4, Transmission Provider shall commence and perform any necessary additional studies as soon as practicable, but in no event shall Transmission Provider commence such studies later than thirty (30) Calendar Days after receiving notice of Interconnection Customer's request. Any additional studies resulting from such modification shall be done at Interconnection Customer's cost.

4.4.5

Extensions of less than three (3) cumulative years in the Commercial Operation Date of the Large Generating Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing.

4.4.6 Technological Change Procedures

[Insert technological change procedure here]

Section 5. Procedures for Interconnection Requests Submitted Prior to Effective Date of Standard Large Generator Interconnection Procedures

5.1 Queue Position for Pending Requests

5.1.1

Any Interconnection Customer assigned a Queue Position prior to the effective date of this LGIP shall retain that Queue Position.

5.1.1.1

If an Interconnection Study Agreement has not been executed as of the effective date of this LGIP, then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with this LGIP.

5.1.1.2

If an Interconnection Study Agreement has been executed prior to the effective date of this LGIP, such Interconnection Study shall be completed in accordance with the terms of such agreement. With respect to any remaining studies for which an Interconnection Customer has not signed an Interconnection Study Agreement prior to the effective date of the LGIP, Transmission Provider must offer Interconnection Customer the option of either continuing under Transmission Provider's existing interconnection study process or going forward with the completion of the necessary Interconnection Studies (for which it does not have a signed Interconnection Studies Agreement) in accordance with this LGIP.

5.1.1.3

If an LGIA has been submitted to FERC for approval before the effective date of the LGIP, then the LGIA would be grandfathered.

5.1.2 Transition Period

To the extent necessary, Transmission Provider and Interconnection Customers with an outstanding request (*i.e.,* an Interconnection Request for which an LGIA has not been submitted to FERC for approval as of the effective date of this LGIP) shall transition to this LGIP within a reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term ''outstanding request'' herein shall mean any Interconnection Request, on the effective date of this LGIP: (i) That has been submitted but not yet accepted by Transmission Provider; (ii) where the related interconnection agreement has not yet been submitted to FERC for approval in executed or unexecuted form, (iii) where the relevant Interconnection Study Agreements have not yet been executed, or (iv) where any of the relevant Interconnection Studies are in process but not yet completed. Any Interconnection Customer with an outstanding request as of the effective date of this LGIP may request a reasonable extension of any deadline, otherwise applicable, if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension shall be granted by Transmission Provider to the extent consistent with the intent and process provided for under this LGIP.

5.2 New Transmission Provider

If Transmission Provider transfers control of its Transmission System to a successor Transmission Provider during the period when an Interconnection Request is pending, the original Transmission Provider shall transfer to the successor Transmission Provider any amount of the deposit or payment with interest thereon that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net amount and the deposit or payment required by this LGIP shall be paid by or refunded to the Interconnection Customer, as appropriate. The original Transmission Provider shall coordinate with the successor Transmission Provider to complete any Interconnection Study, as appropriate, that the original Transmission Provider has begun but has not completed. If

Transmission Provider has tendered a draft LGIA to Interconnection Customer but Interconnection Customer has not either executed the LGIA or requested the filing of an unexecuted LGIA with FERC, unless otherwise provided, Interconnection Customer must complete negotiations with the successor Transmission Provider.

Section 6. Interconnection Feasibility Study

6.1 Interconnection Feasibility Study Agreement

Simultaneously with the acknowledgement of a valid Interconnection Request Transmission Provider shall provide to Interconnection Customer an Interconnection Feasibility Study Agreement in the form of Appendix 2. The Interconnection Feasibility Study Agreement shall specify that Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study. Within five (5) Business Days following the Scoping Meeting Interconnection Customer shall specify for inclusion in the attachment to the Interconnection Feasibility Study Agreement the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection. Within five (5) Business Days following Transmission Provider's receipt of such designation, Transmission Provider shall tender to Interconnection Customer the Interconnection Feasibility Study Agreement signed by Transmission Provider, which includes a good faith estimate of the cost for completing the Interconnection Feasibility Study. Interconnection Customer shall execute and deliver to Transmission Provider the Interconnection Feasibility Study Agreement along with a $10,000 deposit no later than thirty (30) Calendar Days after its receipt.

On or before the return of the executed Interconnection Feasibility Study Agreement to Transmission Provider, Interconnection Customer shall provide the technical data called for in Appendix 1, Attachment A.

If the Interconnection Feasibility Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and Re-studies shall be completed pursuant to Section 6.4 as applicable. For the purpose of this Section 6.1, if Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.4.4, shall be the substitute.

If Interconnection Customer and Transmission Provider agree to forgo the Interconnection Feasibility Study, Transmission Provider will initiate an Interconnection System Impact Study under Section 7 of this LGIP and apply the $10,000 deposit towards the Interconnection System Impact Study.

6.2 Scope of Interconnection Feasibility Study

The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Transmission System.

The Interconnection Feasibility Study will consider the Base Case as well as all generating facilities (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) Are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC. The Interconnection Feasibility Study will consist of a power flow and short circuit analysis. The Interconnection Feasibility Study will provide a list of facilities and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

6.3 Interconnection Feasibility Study Procedures

Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Transmission Provider shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than forty-five (45) Calendar Days after Transmission Provider receives the fully executed Interconnection Feasibility Study Agreement. At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If Transmission Provider is unable to complete the Interconnection Feasibility Study within that time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers and relevant power flow, short circuit and stability databases for the Interconnection Feasibility Study, subject to confidentiality arrangements consistent with Section 13.1.

Transmission Provider shall study the Interconnection Request at the level of service requested by the Interconnection Customer, unless otherwise required to study the full Generating Facility Capacity due to safety or reliability concerns.

6.3.1 Meeting With Transmission Provider

Within ten (10) Business Days of providing an Interconnection Feasibility Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Feasibility Study.

6.4 Re-Study

If Re-Study of the Interconnection Feasibility Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to Section 4.4, or re-designation of the Point of Interconnection pursuant to Section 6.1 Transmission Provider shall notify Interconnection Customer in writing. Such Re-Study shall take not longer than forty-five (45) Calendar Days from the date of the notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.

Section 7. Interconnection System Impact Study

7.1 Interconnection System Impact Study Agreement

Unless otherwise agreed, pursuant to the Scoping Meeting provided in Section 3.4.4, simultaneously with the delivery of the Interconnection Feasibility Study to Interconnection Customer, Transmission Provider shall provide to Interconnection Customer an Interconnection System Impact Study Agreement in the form of Appendix 3 to this LGIP. The Interconnection System Impact Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Interconnection System Impact Study. Within three (3) Business Days following the Interconnection Feasibility Study results meeting, Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection System Impact Study.

7.2 Execution of Interconnection System Impact Study Agreement

Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement to Transmission Provider no later than thirty (30) Calendar Days after its receipt along with demonstration of Site Control, and a $50,000 deposit.

If Interconnection Customer does not provide all such technical data when it delivers the Interconnection System Impact Study Agreement, Transmission Provider shall notify Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection System Impact Study Agreement and Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Interconnection System Impact Study Agreement or deposit.

If the Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting and the Interconnection Feasibility Study, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and restudies shall be completed pursuant to Section 7.6 as applicable. For the purpose of this Section 7.2, if Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.4.4, shall be the substitute.

7.3 Scope of Interconnection System Impact Study

The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The Interconnection System Impact Study will consider the Base Case as well as all generating facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced: (i) Are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The Interconnection System Impact Study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. For purposes of determining necessary Interconnection Facilities and Network Upgrades, the System Impact Study shall consider the level of Interconnection Service requested by the Interconnection Customer, unless otherwise required to study the full Generating Facility Capacity due to safety or reliability concerns. The Interconnection System Impact Study will provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

7.4 Interconnection System Impact Study Procedures

Impact Study with any Affected System that is affected by the Interconnection Request pursuant to Section 3.6 above. Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Transmission Provider shall use Reasonable Efforts to complete the Interconnection System Impact Study within ninety (90) Calendar Days after the receipt of the Interconnection System Impact Study Agreement or notification to proceed, study payment, and technical data. If Transmission Provider uses Clustering, Transmission Provider shall use Reasonable Efforts to deliver a completed Interconnection System Impact Study within ninety (90) Calendar Days after the close of the Queue Cluster Window.

At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection System Impact Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If Transmission Provider is unable to complete the Interconnection System Impact Study within the time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer all supporting documentation, workpapers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the Interconnection System Impact Study, subject to confidentiality arrangements consistent with Section 13.1.

7.5 Meeting With Transmission Provider

Within ten (10) Business Days of providing an Interconnection System Impact Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection System Impact Study.

7.6 Re-Study

If Re-Study of the Interconnection System Impact Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to 4.4, or re-designation of the Point of Interconnection pursuant to Section 7.2 Transmission Provider shall notify Interconnection Customer in writing. Such Re-Study shall take no longer than sixty (60) Calendar Days from the date of notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.

Section 8. Interconnection Facilities Study

8.1 Interconnection Facilities Study Agreement

Simultaneously with the delivery of the Interconnection System Impact Study to Interconnection Customer, Transmission Provider shall provide to Interconnection Customer an Interconnection Facilities Study Agreement in the form of Appendix 4 to this LGIP. The Interconnection Facilities Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Interconnection Facilities Study. Within three (3) Business Days following the Interconnection System Impact Study results meeting, Transmission Provider shall provide to Interconnection Customer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection Facilities Study. Interconnection Customer shall execute the Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement to Transmission Provider within thirty (30) Calendar Days after its receipt, together with the required technical data and the greater of $100,000 or Interconnection Customer's portion of the estimated monthly cost of conducting the Interconnection Facilities Study.

8.1.1

Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice.

8.2 Scope of Interconnection Facilities Study

The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facility to the Transmission System. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: The transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Transmission Provider's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities. The Facilities Study will also identify any potential control equipment for requests for Interconnection Service that are lower than the Generating Facility Capacity.

8.3 Interconnection Facilities Study Procedures

Transmission Provider shall coordinate the Interconnection Facilities Study with any Affected System pursuant to Section 3.6 above. Transmission Provider shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study. Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer within the following number of days after receipt of an executed Interconnection Facilities Study Agreement: Ninety (90) Calendar Days, with no more than a ±20 percent cost estimate contained in the report; or one hundred eighty (180) Calendar Days, if Interconnection Customer requests a ±10 percent cost estimate.

At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Facilities Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection Facilities Study. If Transmission Provider is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study report within the time required, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

Interconnection Customer may, within thirty (30) Calendar Days after receipt of the draft report, provide written comments to Transmission Provider, which Transmission Provider shall include in the final report. Transmission Provider shall issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. Transmission Provider may reasonably extend such fifteen-day period upon notice to Interconnection Customer if Interconnection Customer's comments require Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 13.1.

8.4 Meeting With Transmission Provider

Within ten (10) Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study.

8.5 Re-Study

If Re-Study of the Interconnection Facilities Study is required due to a higher queued project dropping out of the queue or a modification of a higher queued project pursuant to Section 4.4, Transmission Provider shall so notify Interconnection Customer in writing. Such Re-Study shall take no longer than sixty (60) Calendar Days from the date of notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.

Section 9. Engineering & Procurement ('E&P') Agreement

Prior to executing an LGIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request and Transmission Provider shall offer the Interconnection Customer, an E&P Agreement that authorizes Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, Transmission Provider shall not be obligated to offer an E&P Agreement if Interconnection Customer is in Dispute Resolution as a result of an allegation that Interconnection Customer has failed to meet any milestones or comply with any prerequisites specified in other parts of the LGIP. The E&P Agreement is an optional procedure and it will not alter the Interconnection Customer's Queue Position or In-Service Date. The E&P Agreement shall provide for Interconnection Customer to pay the cost of all activities authorized by Interconnection Customer and to make advance payments or provide other satisfactory security for such costs.

Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If Interconnection Customer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, Transmission Provider may elect: (i) To take title to the equipment, in which event Transmission Provider shall refund Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment, or (ii) to transfer title to and deliver such equipment to Interconnection Customer, in which event Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.

Section 10. Optional Interconnection Study

10.1 Optional Interconnection Study Agreement

On or after the date when Interconnection Customer receives Interconnection System Impact Study results, Interconnection Customer may request, and Transmission Provider shall perform a reasonable number of Optional Studies. The request shall describe the assumptions that Interconnection Customer wishes Transmission Provider to study within the scope described in Section 10.2. Within five (5) Business Days after receipt of a request for an Optional Interconnection Study, Transmission Provider shall provide to Interconnection Customer an Optional Interconnection Study Agreement in the form of Appendix 5.

The Optional Interconnection Study Agreement shall: (i) Specify the technical data that Interconnection Customer must provide for each phase of the Optional Interconnection Study, (ii) specify Interconnection Customer's assumptions as to which Interconnection Requests with earlier queue priority dates will be excluded from the Optional Interconnection Study case and assumptions as to the type of interconnection service for Interconnection Requests remaining in the Optional Interconnection Study case, and (iii) Transmission Provider's estimate of the cost of the Optional Interconnection Study. To the extent known by Transmission Provider, such estimate shall include any costs expected to be incurred by any Affected System whose participation is necessary to complete the Optional Interconnection Study. Notwithstanding the above, Transmission Provider shall not be required as a result of an Optional Interconnection Study request to conduct any additional Interconnection Studies with respect to any other Interconnection Request.

Interconnection Customer shall execute the Optional Interconnection Study Agreement within ten (10) Business Days of receipt and deliver the Optional Interconnection Study Agreement, the technical data and a $10,000 deposit to Transmission Provider.

10.2 Scope of Optional Interconnection Study

The Optional Interconnection Study will consist of a sensitivity analysis based on the assumptions specified by Interconnection Customer in the Optional Interconnection Study Agreement. The Optional Interconnection Study will also identify Transmission Provider's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or Interconnection Service based upon the results of the Optional Interconnection Study. The Optional Interconnection Study shall be performed solely for informational purposes. Transmission Provider shall use Reasonable Efforts to coordinate the study with any Affected Systems that may be affected by the types of Interconnection Services that are being studied. Transmission Provider shall utilize existing studies to the extent practicable in conducting the Optional Interconnection Study.

10.3 Optional Interconnection Study Procedures

The executed Optional Interconnection Study Agreement, the prepayment, and technical and other data called for therein must be provided to Transmission Provider within ten (10) Business Days of Interconnection Customer receipt of the Optional Interconnection Study Agreement. Transmission Provider shall use Reasonable Efforts to complete the Optional Interconnection Study within a mutually agreed upon time period specified within the Optional Interconnection Study Agreement. If Transmission Provider is unable to complete the Optional Interconnection Study within such time period, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required. Any difference between the study payment and the actual cost of the study shall be paid to Transmission Provider or refunded to Interconnection Customer, as appropriate. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation and workpapers and databases or data developed in the preparation of the Optional Interconnection Study, subject to confidentiality arrangements consistent with Section 13.1.

Section 11. Standard Large Generator Interconnection Agreement (LGIA)

11.1 Tender

Interconnection Customer shall tender comments on the draft Interconnection Facilities Study Report within thirty (30) Calendar Days of receipt of the report. Within thirty (30) Calendar Days after the comments are submitted, Transmission Provider shall tender a draft LGIA, together with draft appendices. The draft LGIA shall be in the form of Transmission Provider's FERC-approved standard form LGIA, which is in Appendix 6. Interconnection Customer shall execute and return the completed draft appendices within thirty (30) Calendar Days.

11.2 Negotiation

Notwithstanding Section 11.1, at the request of Interconnection Customer Transmission Provider shall begin negotiations with Interconnection Customer concerning the appendices to the LGIA at any time after Interconnection Customer executes the Interconnection Facilities Study Agreement. Transmission Provider and Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft LGIA for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study Report. If Interconnection Customer determines that negotiations are at an impasse, it may request termination of the negotiations at any time after tender of the draft LGIA pursuant to Section 11.1 and request submission of the unexecuted LGIA with FERC or initiate Dispute Resolution procedures pursuant to Section 13.5. If Interconnection Customer requests termination of the negotiations, but within sixty (60) Calendar Days thereafter fails to request either the filing of the unexecuted LGIA or initiate Dispute Resolution, it shall be deemed to have withdrawn its Interconnection Request. Unless otherwise agreed by the Parties, if Interconnection Customer has not executed the LGIA, requested filing of an unexecuted LGIA, or initiated Dispute Resolution procedures pursuant to Section 13.5 within sixty (60) Calendar Days of tender of draft LGIA, it shall be deemed to have withdrawn its Interconnection Request. Transmission Provider shall provide to Interconnection Customer a final LGIA within fifteen (15) Business Days after the completion of the negotiation process.

11.3 Execution and Filing

Within fifteen (15) Business Days after receipt of the final LGIA, Interconnection Customer shall provide Transmission Provider (A) reasonable evidence that continued Site Control or (B) posting of $250,000, non-refundable additional security, which shall be applied toward future construction costs. At the same time, Interconnection Customer also shall provide reasonable evidence that one or more of the following milestones in the development of the Large Generating Facility, at Interconnection Customer election, has been achieved: (i) The execution of a contract for the supply or transportation of fuel to the Large Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Large Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Large Generating Facility; (iv) execution of a contract for the sale of electric energy or capacity from the Large Generating Facility; or (v) application for an air, water, or land use permit.

Interconnection Customer shall either: (i) Execute two originals of the tendered LGIA and return them to Transmission Provider; or (ii) request in writing that Transmission Provider file with FERC an LGIA in unexecuted form. As soon as practicable, but not later than ten (10) Business Days after receiving either the two executed originals of the tendered LGIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or the request to file an unexecuted LGIA, Transmission Provider shall file the LGIA with FERC, together with its explanation of any matters as to which Interconnection Customer and Transmission Provider disagree and support for the costs that Transmission Provider proposes to charge to Interconnection Customer under the LGIA. An unexecuted LGIA should contain terms and conditions deemed appropriate by Transmission Provider for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted LGIA, they may proceed pending FERC action.

11.4 Commencement of Interconnection Activities

If Interconnection Customer executes the final LGIA, Transmission Provider and Interconnection Customer shall perform their respective obligations in accordance with the terms of the LGIA, subject to modification by FERC. Upon submission of an unexecuted LGIA, Interconnection Customer and Transmission Provider shall promptly comply with the unexecuted LGIA, subject to modification by FERC.

Section 12. Construction of Transmission Provider's Interconnection Facilities and Network Upgrades

12.1 Schedule

Transmission Provider and Interconnection Customer shall negotiate in good faith concerning a schedule for the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades.

12.2 Construction Sequencing

12.2.1 General

In general, the In-Service Date of an Interconnection Customers seeking interconnection to the Transmission System will determine the sequence of construction of Network Upgrades.

12.2.2 Advance Construction of Network Upgrades That Are an Obligation of an Entity Other Than Interconnection Customer

An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) Were assumed in the Interconnection Studies for such Interconnection Customer, (ii) are necessary to support such In-Service Date, and (iii) would otherwise not be completed, pursuant to a contractual obligation of an entity other than Interconnection Customer that is seeking interconnection to the Transmission System, in time to support such In-Service Date. Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Provider: (i) Any associated expediting costs and (ii) the cost of such Network Upgrades.

Transmission Provider will refund to Interconnection Customer both the expediting costs and the cost of Network Upgrades, in accordance with Article 11.4 of the LGIA. Consequently, the entity with a contractual obligation to construct such Network Upgrades shall be obligated to pay only that portion of the costs of the Network Upgrades that Transmission Provider has not refunded to Interconnection Customer. Payment by that entity shall be due on the date that it would have been due had there been no request for advance construction. Transmission Provider shall forward to Interconnection Customer the amount paid by the entity with a contractual obligation to construct the Network Upgrades as payment in full for the outstanding balance owed to Interconnection Customer. Transmission Provider then shall refund to that entity the amount that it paid for the Network Upgrades, in accordance with Article 11.4 of the LGIA.

12.2.3 Advancing Construction of Network Upgrades That Are Part of an Expansion Plan of the Transmission Provider

An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) Are necessary to support such In-Service Date and (ii) would otherwise not be completed, pursuant to an expansion plan of Transmission Provider, in time to support such In-Service Date. Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Provider any associated expediting costs. Interconnection Customer shall be entitled to transmission credits, if any, for any expediting costs paid.

12.2.4 Amended Interconnection System Impact Study

An Interconnection System Impact Study will be amended to determine the facilities necessary to support the requested In-Service Date. This amended study will include those transmission and Large Generating Facilities that are expected to be in service on or before the requested In-Service Date.

Section 13. Miscellaneous

13.1 Confidentiality

Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of an LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

13.1.1 Scope

Confidential Information shall not include information that the receiving Party can demonstrate: (1) Is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of the LGIA; or (6) is required, in accordance with Section 13.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

13.1.2 Release of Confidential Information

Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this Section 13.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 13.1.

13.1.3 Rights

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

13.1.4 No Warranties

By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

13.1.5 Standard of Care

Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under these procedures or its regulatory requirements.

13.1.6 Order of Disclosure

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of the LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

13.1.7 Remedies

The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Section 13.1. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Section 13.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Section 13.1, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 13.1.

13.1.8 Disclosure to FERC, Its Staff, or a State

Notwithstanding anything in this Section 13.1 to the contrary, and pursuant to 18 CFR 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the LGIP, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, consistent with applicable state rules and regulations.

13.1.9

Subject to the exception in Section 13.1.8, any information that a Party claims is competitively sensitive, commercial or financial information (''Confidential Information'') shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIP or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a subregional, regional or national reliability organization or planning group. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

13.1.10

This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

13.1.11

Transmission Provider shall, at Interconnection Customer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.

13.2 Delegation of Responsibility

Transmission Provider may use the services of subcontractors as it deems appropriate to perform its obligations under this LGIP. Transmission Provider shall remain primarily liable to Interconnection Customer for the performance of such subcontractors and compliance with its obligations of this LGIP. The subcontractor shall keep all information provided confidential and shall use such information solely for the performance of such obligation for which it was provided and no other purpose.

13.3 Obligation for Study Costs

Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Studies. Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded, except as otherwise provided herein, to Interconnection Customer or offset against the cost of any future Interconnection Studies associated with the applicable Interconnection Request prior to beginning of any such future Interconnection Studies. Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study. Interconnection Customer shall pay any such undisputed costs within thirty (30) Calendar Days of receipt of an invoice therefor. Transmission Provider shall not be obligated to perform or continue to perform any studies unless Interconnection Customer has paid all undisputed amounts in compliance herewith.

13.4 Third Parties Conducting Studies

If (i) at the time of the signing of an Interconnection Study Agreement there is disagreement as to the estimated time to complete an Interconnection Study, (ii) Interconnection Customer receives notice pursuant to Sections 6.3, 7.4 or 8.3 that Transmission Provider will not complete an Interconnection Study within the applicable timeframe for such Interconnection Study, or (iii) Interconnection Customer receives neither the Interconnection Study nor a notice under Sections 6.3, 7.4 or 8.3 within the applicable timeframe for such Interconnection Study, then Interconnection Customer may require Transmission Provider to utilize a third party consultant reasonably acceptable to Interconnection Customer and Transmission Provider to perform such Interconnection Study under the direction of Transmission Provider. At other times, Transmission Provider may also utilize a third party consultant to perform such Interconnection Study, either in response to a general request of Interconnection Customer, or on its own volition.

In all cases, use of a third party consultant shall be in accord with Article 26 of the LGIA (Subcontractors) and limited to situations where Transmission Provider determines that doing so will help maintain or accelerate the study process for Interconnection Customer's pending Interconnection Request and not interfere with Transmission Provider's progress on Interconnection Studies for other pending Interconnection Requests. In cases where Interconnection Customer requests use of a third party consultant to perform such Interconnection Study, Interconnection Customer and Transmission Provider shall negotiate all of the pertinent terms and conditions, including reimbursement arrangements and the estimated study completion date and study review deadline. Transmission Provider shall convey all workpapers, data bases, study results and all other supporting documentation prepared to date with respect to the Interconnection Request as soon as soon as practicable upon Interconnection Customer's request subject to the confidentiality provision in Section 13.1. In any case, such third party contract may be entered into with either Interconnection Customer or Transmission Provider at Transmission Provider's discretion. In the case of (iii) Interconnection Customer maintains its right to submit a claim to Dispute Resolution to recover the costs of such third party study. Such third party consultant shall be required to comply with this LGIP, Article 26 of the LGIA (Subcontractors), and the relevant Tariff procedures and protocols as would apply if Transmission Provider were to conduct the Interconnection Study and shall use the information provided to it solely for purposes of performing such services and for no other purposes. Transmission Provider shall cooperate with such third party consultant and Interconnection Customer to complete and issue the Interconnection Study in the shortest reasonable time.

13.5 Disputes

13.5.1 Submission

In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with the LGIA, the LGIP, or their performance, such Party (the ''disputing Party'') shall provide the other Party with written notice of the dispute or claim (''Notice of Dispute''). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

13.5.2 External Arbitration Procedures

Any arbitration initiated under these procedures shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association (''Arbitration Rules'') and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Section 13, the terms of this Section 13 shall prevail.

13.5.3 Arbitration Decisions

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the LGIA and LGIP and shall have no power to modify or change any provision of the LGIA and LGIP in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

13.5.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

13.5.5 Non-Binding Dispute Resolution Procedures

If a Party has submitted a Notice of Dispute pursuant to section 13.5.1, and the Parties are unable to resolve the claim or dispute through unassisted or assisted negotiations within the thirty (30) Calendar Days provided in that section, and the Parties cannot reach mutual agreement to pursue the section 13.5 arbitration process, a Party may request that Transmission Provider engage in Non-binding Dispute Resolution pursuant to this section by providing written notice to Transmission Provider (''Request for Non-binding Dispute Resolution''). Conversely, either Party may file a Request for Non-binding Dispute Resolution pursuant to this section without first seeking mutual agreement to pursue the section 13.5 arbitration process. The process in section 13.5.5 shall serve as an alternative to, and not a replacement of, the section 13.5 arbitration process. Pursuant to this process, a Transmission Provider must within 30 days of receipt of the Request for Non-binding Dispute Resolution appoint a neutral decision-maker that is an independent subcontractor that shall not have any current or past substantial business or financial relationships with either Party. Unless otherwise agreed by the Parties, the decision-maker shall render a decision within sixty (60) Calendar Days of appointment and shall notify the Parties in writing of such decision and reasons therefore. This decision-maker shall be authorized only to interpret and apply the provisions of the LGIP and LGIA and shall have no power to modify or change any provision of the LGIP and LGIA in any manner. The result reached in this process is not binding, but, unless otherwise agreed, the Parties may cite the record and decision in the non-binding dispute resolution process in future dispute resolution processes, including in a section 13.5 arbitration, or in a Federal Power Act section 206 complaint. Each Party shall be responsible for its own costs incurred during the process and the cost of the decision-maker shall be divided equally among each Party to the dispute.

13.6 Local Furnishing Bonds

13.6.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds

This provision is applicable only to a Transmission Provider that has financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code (''local furnishing bonds''). Notwithstanding any other provision of this LGIA and LGIP, Transmission Provider shall not be required to provide Interconnection Service to Interconnection Customer pursuant to this LGIA and LGIP if the provision of such Transmission Service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance Transmission Provider's facilities that would be used in providing such Interconnection Service.

13.6.2 Alternative Procedures for Requesting Interconnection Service

If Transmission Provider determines that the provision of Interconnection Service requested by Interconnection Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such Interconnection Service, it shall advise the Interconnection Customer within thirty (30) Calendar Days of receipt of the Interconnection Request.

Interconnection Customer thereafter may renew its request for interconnection using the process specified in Article 5.2(ii) of the Transmission Provider's Tariff.

Appendix 1 to LGIP—Interconnection Request for a Large Generating Facility

1. The undersigned Interconnection Customer submits this request to interconnect its Large Generating Facility with Transmission Provider's Transmission System pursuant to a Tariff.

2. This Interconnection Request is for (check one):

____ A proposed new Large Generating Facility.

____ An increase in the generating capacity or a Material Modification of an existing Generating Facility.

3. The type of interconnection service requested (check one):

____ Energy Resource Interconnection Service

____ Network Resource Interconnection Service

4. ____ Check here only if Interconnection Customer requesting Network Resource Interconnection Service also seeks to have its Generating Facility studied for Energy Resource Interconnection Service

5. Interconnection Customer provides the following information:

a. Address or location or the proposed new Large Generating Facility site (to the extent known) or, in the case of an existing Generating Facility, the name and specific location of the existing Generating Facility;

b. Maximum summer at ____ degrees C and winter at ____ degrees C megawatt electrical output of the proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of an existing Generating Facility;

c. General description of the equipment configuration;

d. Commercial Operation Date (Day, Month, and Year);

e. Name, address, telephone number, and email address of Interconnection Customer's contact person;

f. Approximate location of the proposed Point of Interconnection (optional);

g. Interconnection Customer Data (set forth in Attachment A) and

h. Primary frequency response operating range for electric storage resources.

i. Requested capacity (in MW) of Interconnection Service (if lower than the Generating Facility Capacity).

6. Applicable deposit amount as specified in the LGIP.

7. Evidence of Site Control as specified in the LGIP (check one)

____ Is attached to this Interconnection Request

____ Will be provided at a later date in accordance with this LGIP

8. This Interconnection Request shall be submitted to the representative indicated below: [To be completed by Transmission Provider]

9. Representative of Interconnection Customer to contact: [To be completed by Interconnection Customer]

10. This Interconnection Request is submitted by:

Name of Interconnection Customer:

____

By (signature): ________________________

Name (type or print): ___________________

Title: ________________________________

Date: ________________________________

Attachment A to Appendix 1 Interconnection Request

Large Generating Facility Data Unit Ratings

kVA ______ °F ______ Voltage ______

Power Factor ______

Speed (RPM) ______ Connection (*e.g.,* Wye) ______

Short Circuit Ratio ______ Frequency, Hertz ______

Stator Amperes at Rated kVA ______ Field Volts ______

Max Turbine MW ______ °F ______

Primary frequency response operating range for electric storage resources:

Minimum State of Charge: ______ __________

Maximum State of Charge: ______ __________

Combined Turbine-Generator-Exciter Inertia Data

Inertia Constant, H = ______ kW sec/kVA

Moment-of-Inertia, WR^2 = ______ lb. $ft.^2$

Reactance Data (Per Unit-Rated KVA)

	Direct axis	Quadrature axis
Synchronous—saturated	X_{dv} ______	X_{qv} ______
Synchronous—unsaturated	X_{di} ______	X_{qi} ______
Transient—saturated	X'_{dv} ______	X'_{qv} ______
Transient—unsaturated	X'_{di} ______	X'_{qi} ______
Subtransient—saturated	X''_{dv} ______	X''_{qv} ______
Subtransient—unsaturated	X''_{di} ______	X''_{qi} ______
Negative Sequence—saturated	$X2_v$ ______	
Negative Sequence—unsaturated	$X2_i$ ______	
Zero Sequence—saturated	$X0_v$ ______	
Zero Sequence—unsaturated	$X0_i$ ______	
Leakage Reactance	Xl_m ______	

Field Time Constant Data (SEC)

Open Circuit	T'_{do} ______	T'_{qo} ______
Three-Phase Short Circuit Transient	T'_{d3} ______	T'_{q} ______
Line to Line Short Circuit Transient	T'_{d2} ______	
Line to Neutral Short Circuit Transient	T'_{d1} ______	
Short Circuit Subtransient	T''_{d} ______	T''_{q} ______
Open Circuit Subtransient	T''_{do} ______	T''_{qo} ______

Armature Time Constant Data (SEC)

Three Phase Short Circuit—T_{a3} ______
Line to Line Short Circuit—T_{a2} ______
Line to Neutral Short Circuit—T_{a1} ______

Note: If requested information is not applicable, indicate by marking ''N/A.''

MW Capability and Plant Configuration Large Generating Facility Data

Armature Winding Resistance Data (Per Unit)

Positive—R_1 ______
Negative—R_2 ______
Zero—R_0 ______
Rotor Short Time Thermal Capacity I_2^2t = ______
Field Current at Rated kVA, Armature Voltage and PF = ______ amps
Field Current at Rated kVA and Armature Voltage, 0 PF = ______ amps
Three Phase Armature Winding Capacitance = ______ microfarad
Field Winding Resistance = ______ ohms ______ °C
Armature Winding Resistance (Per Phase) = ______ ohms ______ °C

Curves

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

Generator Step-Up Transformer Data Ratings

Capacity; Self-cooled/Maximum Nameplate ______/______ kVA
Voltage Ratio (Generator Side/System side/Tertiary)
______/______/______ kV
Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
______/______/______
Fixed Taps Available ______ ______________
Present Tap Setting ______ ______________

Impedance

Positive; Z_1 (on self-cooled kVA rating) ______ % ______ X/R
Zero; Z_0 (on self-cooled kVA rating) ______ % ______ X/R

Excitation System Data

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

Governor System Data

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

Wind Generators

Number of generators to be interconnected pursuant to this Interconnection Request:
____
Elevation: __________ ____________________
____
Single Phase ____________________________
____________ Three Phase
Inverter manufacturer, model name, number, and version:
____________ ____________________________
List of adjustable setpoints for the protective equipment or software:
____________ ____________________________

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

Induction Generators

(*) Field Volts: ____________________
(*) Field Amperes: ____________________
(*) Motoring Power (kW): ____________________
(*) Neutral Grounding Resistor (If Applicable): ____________________
(*) I_2^2t or K (Heating Time Constant): ______
(*) Rotor Resistance: ____________________
(*) Stator Resistance: ____________________
(*) Stator Reactance: ____________________
(*) Rotor Reactance: ____________________
(*) Magnetizing Reactance: ________________
(*) Short Circuit Reactance: ________________
(*) Exciting Current: ____________________
(*) Temperature Rise: ____________________
(*) Frame Size: ____________________
(*) Design Letter: ____________________
(*) Reactive Power Required In Vars (No Load): ____________________
(*) Reactive Power Required In Vars (Full Load): ____________________
(*) Total Rotating Inertia, H: ____________ Per Unit on KVA Base ____________________

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required.

Appendix 2 to LGIP—Interconnection Feasibility Study Agreement

This agreement is made and entered into this ____ day of ____________, 20 ____ by and between ____________, a ____________ organized and existing under the laws of the State of ____________, (''Interconnection Customer,'') and ____________ a ____________ existing under the laws of the State of ____________, (''Transmission Provider ''). Interconnection Customer and Transmission Provider each may be referred to as a ''Party,'' or collectively as the ''Parties.''

Recitals

Whereas, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ____________; and

Whereas, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System; and

Whereas, Interconnection Customer has requested Transmission Provider to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Large Generating Facility to the Transmission System, and of any Affected Systems;

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed an Interconnection Feasibility Study consistent with Section 6.0 of this LGIP in accordance with the Tariff.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study shall be based on the technical information provided by Interconnection Customer in the Interconnection Request, as may be modified as the result of the Scoping Meeting. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with Section 3.4.4 of the LGIP. If, after the designation of the Point of Interconnection pursuant to Section 3.4.4 of the LGIP, Interconnection Customer modifies its Interconnection Request pursuant to Section 4.4, the time to complete the Interconnection Feasibility Study may be extended.

5.0 The Interconnection Feasibility Study report shall provide the following information:

—Preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
—preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection; and
—preliminary description and non-bonding estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit and power flow issues.

6.0 Interconnection Customer shall provide a deposit of $10,000 for the performance of the Interconnection Feasibility Study.

Upon receipt of the Interconnection Feasibility Study Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study.

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Miscellaneous. The Interconnection Feasibility Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP and the LGIA.

In witness whereof, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ____________________
Title: ____________________
Date: ____________________
By: ____________________
Title: ____________________
Date: ____________________

[Insert name of Interconnection Customer]

By: ____________________
Title: ____________________
Date: ____________________

Attachment A to Appendix 2—Interconnection Feasibility Study Agreement

Assumptions Used in Conducting the Interconnection Feasibility Study

The Interconnection Feasibility Study will be based upon the information set forth in the Interconnection Request and agreed upon in the Scoping Meeting held on ___________:

Designation of Point of Interconnection and configuration to be studied.

Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer and Transmission Provider]

Appendix 3 to LGIP—Interconnection System Impact Study Agreement

This Agreement is made and entered into this ____ day of ___________, 20____ by and between ___________, a ___________ organized and existing under the laws of the State of ___________, (''Interconnection Customer,'') and ___________ a ___________ existing under the laws of the State of ___________, (''Transmission Provider ''). Interconnection Customer and Transmission Provider each may be referred to as a ''Party,'' or collectively as the ''Parties.''

Recitals

Whereas, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ___________; and

Whereas, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System;

Whereas, Transmission Provider has completed an Interconnection Feasibility Study (the ''Feasibility Study'') and provided the results of said study to Interconnection Customer (This recital to be omitted if Transmission Provider does not require the Interconnection Feasibility Study.); and

Whereas, Interconnection Customer has requested Transmission Provider to perform an Interconnection System Impact Study to assess the impact of interconnecting the Large Generating Facility to the Transmission System, and of any Affected Systems;

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed an Interconnection System Impact Study consistent with Section 7.0 of this LGIP in accordance with the Tariff.

3.0 The scope of the Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study and the technical information provided by Interconnection Customer in the Interconnection Request, subject to any modifications in accordance with Section 4.4 of the LGIP. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Customer System Impact Study. If Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the Interconnection System Impact Study may be extended.

5.0 The Interconnection System Impact Study report shall provide the following information:

—identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
—identification of any thermal overload or voltage limit violations resulting from the interconnection;
—identification of any instability or inadequately damped response to system disturbances resulting from the interconnection and
—description and non-binding, good faith estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues.

6.0 Interconnection Customer shall provide a deposit of $50,000 for the performance of the Interconnection System Impact Study. Transmission Provider's good faith estimate for the time of completion of the Interconnection System Impact Study is [insert date].

Upon receipt of the Interconnection System Impact Study, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection System Impact Study.

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Miscellaneous. The Interconnection System Impact Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, that are consistent with regional practices, Applicable Laws and Regulations and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP and the LGIA.]

In witness thereof, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ____________________
Title: ____________________
Date: ____________________
By: ____________________
Title: ____________________
Date: ____________________

[Insert name of Interconnection Customer]

By: ____________________
Title: ____________________
Date: ____________________

Attachment A To Appendix 3—Interconnection System Impact Study Agreement

Assumptions Used in Conducting the Interconnection System Impact Study

The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study, subject to any modifications in accordance with

Section 4.4 of the LGIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied.

Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer and Transmission Provider]

Appendix 4 to LGIP—Interconnection Facilities Study Agreement

THIS AGREEMENT is made and entered into this day ____ of ___________, 20____ by and between ___________, a ___________ organized and existing under the laws of the State of ___________, (''Interconnection Customer,'') and ___________ a ___________ existing under the laws of the State of ___________, (''Transmission Provider ''). Interconnection Customer and Transmission Provider each may be referred to as a ''Party,'' or collectively as the ''Parties.''

Recitals

Whereas, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ___________; and

Whereas, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System;

Whereas, Transmission Provider has completed an Interconnection System Impact Study (the ''System Impact Study'') and provided the results of said study to Interconnection Customer; and

Whereas, Interconnection Customer has requested Transmission Provider to perform an Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Large Generating Facility to the Transmission System.

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause an Interconnection Facilities Study consistent with Section 8.0 of this LGIP to be performed in accordance with the Tariff.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.

4.0 The Interconnection Facilities Study report (i) shall provide a description, estimated cost of (consistent with Attachment A), schedule for required facilities to interconnect the Large Generating Facility to the Transmission System and (ii) shall address the short circuit, instability, and power flow issues identified in the Interconnection System Impact Study.

5.0 Interconnection Customer shall provide a deposit of $100,000 for the performance of the Interconnection Facilities Study. The time for completion of the Interconnection Facilities Study is specified in Attachment A.

Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice.

6.0 Miscellaneous. The Interconnection Facility Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP and the LGIA.

In witness whereof, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ___________________________
Title: ___________________________
Date: ___________________________
By: ___________________________
Title: ___________________________
Date: ___________________________

[Insert name of Interconnection Customer]

By: ___________________________
Title: ___________________________
Date: ___________________________

Attachment A To Appendix 4—Interconnection Facilities Study Agreement

Interconnection Customer Schedule Election for Conducting the Interconnection Facilities Study

Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer within the following number of days after of receipt of an executed copy of this Interconnection Facilities Study Agreement:

—Ninety (90) Calendar Days with no more than a ±20 percent cost estimate contained in the report, or

—one hundred eighty (180) Calendar Days with no more than a ±10 percent cost estimate contained in the report.

Attachment B to Appendix 4—Interconnection Facilities Study Agreement

Data Form To Be Provided by Interconnection Customer With the Interconnection Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections:

On the one line diagram indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line diagram indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

Will an alternate source of auxiliary power be available during CT/PT maintenance? ____Yes ____No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? ____Yes ____No (Please indicate on one line diagram).

What type of control system or PLC will be located at Interconnection Customer's Large Generating Facility?

____

What protocol does the control system or PLC use?

____

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

Physical dimensions of the proposed interconnection station:

____

Bus length from generation to interconnection station:

____

Line length from interconnection station to Transmission Provider's transmission line.

____

Tower number observed in the field. (Painted on tower leg) *

____

Number of third party easements required for transmission lines *:

____

* To be completed in coordination with Transmission Provider.

Is the Large Generating Facility in the Transmission Provider's service area? ____Yes ____No

Local provider:

____

Please provide proposed schedule dates:
Begin Construction:
Date: ___________________________
Generator step-up transformer receives back feed power
Generation Testing ___________________________
Date: ___________________________
Commercial Operation
Date: ___________________________

Appendix 5 to LGIP—Optional Interconnection Study Agreement

This Agreement is made and entered into this ____ day of ___________, 20____ by and between ___________, a ___________ organized and existing under the laws of the State of ___________, (''Interconnection Customer,'') and ___________ a ___________ existing under the laws of the State of ___________, (''Transmission Provider ''). Interconnection Customer and Transmission Provider each may be referred to as a ''Party,'' or collectively as the ''Parties.''

Recitals

Whereas, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ___________;

Whereas, Interconnection Customer is proposing to establish an interconnection with the Transmission System; and

Whereas, Interconnection Customer has submitted to Transmission Provider an Interconnection Request; and

Whereas, on or after the date when Interconnection Customer receives the Interconnection System Impact Study results, Interconnection Customer has further requested that Transmission Provider prepare an Optional Interconnection Study;

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause an Optional Interconnection Study consistent with Section 10.0 of this LGIP to be performed in accordance with the Tariff.

3.0 The scope of the Optional Interconnection Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Optional Interconnection Study shall be performed solely for informational purposes.

5.0 The Optional Interconnection Study report shall provide a sensitivity analysis based on the assumptions specified by Interconnection Customer in Attachment A to this Agreement. The Optional Interconnection Study will identify Transmission Provider's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or interconnection service based upon the assumptions specified by Interconnection Customer in Attachment A.

6.0 Interconnection Customer shall provide a deposit of $10,000 for the performance of the Optional Interconnection Study. Transmission Provider's good faith estimate for the time of completion of the Optional Interconnection Study is [insert date].

Upon receipt of the Optional Interconnection Study, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Optional Study.

Any difference between the initial payment and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Miscellaneous. The Optional Interconnection Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP and the LGIA.

In witness whereof, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ______________________________
Title: ______________________________
Date: ______________________________
By: ______________________________
Title: ______________________________
Date: ______________________________

[Insert name of Interconnection Customer]

By: ______________________________
Title: ______________________________
Date: ______________________________

Appendix 6 to LGIP—Large Generator Interconnection Agreement (See LGIA)

Appendix 7—Interconnection Procedures for a Wind Generating Plant

Appendix 7 sets forth procedures specific to a wind generating plant. All other requirements of this LGIP continue to apply to wind generating plant interconnections.

A. Special Procedures Applicable to Wind Generators

The wind plant Interconnection Customer, in completing the Interconnection Request required by section 3.3 of this LGIP, may provide to the Transmission Provider a set of preliminary electrical design specifications depicting the wind plant as a single equivalent generator. Upon satisfying these and other applicable Interconnection Request conditions, the wind plant may enter the queue and receive the base case data as provided for in this LGIP.

No later than six months after submitting an Interconnection Request completed in this manner, the wind plant Interconnection Customer must submit completed detailed electrical design specifications and other data (including collector system layout data) needed to allow the Transmission Provider to complete the System Impact Study.

United States of America—Federal Energy Regulatory Commission

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection

Docket No. RM21–17–000

(Issued April 21, 2022)

DANLY, Commissioner, *dissenting:*

1. I welcome long term transmission planning reform. I would prefer that Regional Transmission Organizations (RTOs) and other interested public utilities simply file their own proposals under section 205 of the Federal Power Act (FPA). They are fully capable of proposing rate changes and reforms on their own.[1]

2. This Notice of Proposed Rulemaking (NOPR) goes far beyond that. It contemplates a Federal Power Act section 206 finding that existing transmission planning across the nation—in every region, for every utility and market—is so unjust and unreasonable that it must be replaced with mandatory, pervasive, and invasive ''reforms.'' [2] But let us be clear. The NOPR's primary purpose is to achieve narrow environmental policy objectives, not to address legitimate requirements under the Federal Power Act like ensuring just and reasonable rates or reliability. After all, as the NOPR itself repeatedly admits, it is ''driven by changes in resource mix and demand,'' [3] notwithstanding its references to genuine problems with existing transmission planning.[4]

3. The majority seeks to establish policies designed to encourage the massive transmission build-out that will doubtless be required to transition to an aspirational renewable future. To do so, they need to socialize the costs of this transmission across as broad a population of ratepayers as possible. Thus, they seek to use the FPA, a statute that sounds in rate regulation and reliability, as a tool to achieve a particular (and inapposite) policy goal. In this regard, it is much like the majority's recent foray into transforming our pipeline certification process into a comprehensive environmental review.[5] Accordingly, I must dissent.

[1] *See, e.g.,* New England Power Pool Participants Committee October 12, 2021 Comments at 4–8 (detailing past and current transmission planning activities).

[2] *Building for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection,* 179 FERC ¶ 61,028 (2022) (''NOPR''); *see also Building for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection,* 176 FERC ¶ 61,024 (2021) (''ANOPR'').

[3] The NOPR uses the phrase ''driven by changes in the resource mix and demand'' 116 times. These are code words for ''renewables.'' *See* NOPR, 179 FERC ¶ 61,028 at P 45 (detailing ''[t]hese changes in the resource mix and demand,'' almost all of which involve the transition to renewable resources).

[4] *See id.* PP 37–41, 48–49. Nearly every other preliminary finding related to current transmission planning is tied to ''changes in the resource mix and demand.''

[5] *See Certification of New Interstate Nat. Gas Facilities,* 178 FERC ¶ 61,107, *order dismissing reh'g requests, Certification of New Interstate Nat.*

Continued

4. I normally would not oppose a NOPR. What is wrong with asking questions and seeking a record to consider reforms? But this NOPR is a boondoggle. It seeks to change virtually all aspects of transmission planning, including in non-RTO regions and it does so for the specific, though unstated, purpose of suborning the transmission planning process so it can be wielded as a tool to support the development of a specific set of favored generation resources. How does it do this? The NOPR proposes to require regions to factor in any state or even ''local'' (!) public policy (read, renewable) goals, no matter how far-fetched.[6] If San Francisco, for example, passes an ordinance that all its energy must be solar no matter the cost, CAISO and perhaps all western regional planning now must take that into account in their transmission plans. And what if the local policy is unreasonable? Or what if a state has far more aggressive goals than another state? No matter: All must plan for the dreams of others.

5. The Federal Power Act requires just and reasonable rates. That prohibits the Commission from charging ratepayers for unneeded transmission projects to accommodate someone else's view of what types of generation might be preferable. And we are not talking about economic or reliability projects. The transmission at issue here is that required to accommodate state and local laws establishing the composition of their generation fleets. Choosing their own generation mix is undoubtedly their right, since such choices are unambiguously reserved to the states under the FPA, but the FPA does not require the Commission to accommodate these policies under either of its core statutory obligations: To ensure just and reasonable rates and to ensure reliability. In fact, it is quite the opposite, the NOPR risks further undue discrimination. Nevertheless, the NOPR starts from the premise that such projects must be considered in regional planning.

6. Even if no transmission projects are ever selected under the new regional planning regime, the process imposed by the NOPR itself will substantially increase customer costs. As Arizona's largest utility commented in the record, ''[w]hile [Arizona Public Service Company] acknowledges the Commission's desire to construct transmission for a quicker transition to a clean energy mix, unbound[ed] study work would lengthen timelines, thereby increasing the associated costs, for both the transmission planning process and the generator interconnection process.'' [7]

7. The NOPR not only is too expansive, it also is too specific. It proposes scores of detailed mandates. One such mandate, for example, is that four is the minimum number of planning scenarios a public utility must study, and that if one of the scenarios is a ''base case,'' that one must be ''most likely.'' [8] ''[A]t least one of the four distinct'' scenarios ''must account for uncertain operational outcomes . . . during high-impact, low-frequency events'' but we do ''allow'' utilities ''to determine *which* . . . high-impact, low-frequency event should be modeled.'' [9] Woe unto the utility that conducts long term planning by considering a fewer number of scenarios, but you do get to pick your favorite high-impact, low-frequency event.

8. Entire sections of the NOPR read like a think tank's wish list rather than a rigorous analysis of whether such Nice-to-Have ideas are required for just and reasonable, non-discriminatory ratemaking. For some reason, the NOPR proposes that dynamic line ratings and advanced power flow control devices must be the default when studying any new transmission or generation solution ''in all aspects of the regional transmission planning processes, including the existing regional transmission planning processes for near-term regional transmission needs.'' [10] Never mind that we already have a Notice of Inquiry on dynamic line ratings.[11] And I thought this proceeding was about long-term planning? For some other reason, the NOPR has a section on ''Specificity of Data Inputs'' [12] which defines the ''best available data'' everyone in the industry must use in their planning, particularly endorsing ''the most recent data on renewable energy potential and distributed energy resources developed by national labs.'' [13] The NOPR also considers a mandate to establish a ''periodic forum'' to study best practices and additional reforms.[14] Why would this need to be mandated? Must the Commission control everything? Is no one in the industry capable of such foresight absent our intervention? And, by the way, the NOPR also proposes (in the name of ''transparency'') to require new levels of ''enhancements'' and oversight for local transmission planning, by requiring utilities to incorporate detailed tariff amendments to describe their local planning processes.[15] It also obligates them to consider, among other things, requirements for how utilities should be ''right-sizing'' transmission facilities, and whether we should mandate information requirements on ''estimated in-kind replacements of . . . existing transmission.'' [16] Does this not seem like overly prescriptive regulatory meddling?

9. And yet—notwithstanding its bulk and granularity—the NOPR fails to clarify the single most critical question confronting individual states and consumers: Will unwilling states' ratepayers be required to pay for their neighboring state's new transmission project which is being built solely for the purpose of achieving that neighboring state's (or locality's) public policy goals? The NOPR leaves open what happens if states cannot voluntarily agree on such issues,[17] but many will seek to have the RTO allocate costs as it sees fit, including to unwilling states. I oppose forcing the ratepayers in states with different public policy goals to pay for another state's plans.

10. According to a 2018 summary by the National Conference of State Legislatures, 24 states either did not have any renewable portfolio standard or it had expired or was set to expire: Alabama, Alaska, Arkansas, Florida, Georgia, Idaho, Iowa (expired), Kansas (expired), Kentucky, Louisiana, Michigan (expired in 2021), Mississippi, Missouri (expired in 2021), Montana (expired), Nebraska, North Carolina (expired in 2021), North Dakota (expired), Oklahoma (expired), Pennsylvania (expired in 2021), South Dakota (expired), Tennessee, West Virginia, Wisconsin (expired), and Wyoming.[18] Renewable standards in an additional 3 states were voluntary: Indiana, South Carolina, and Utah.[19] That 27 states lack mandatory renewable portfolio standards rather suggests that the country is divided on this issue.

11. Not surprisingly, states are among the primary opponents of the reforms contemplated in the ANOPR, many of which have survived through to the issuance of today's NOPR. The Utah Public Service Commission correctly commented ''that FERC seeks to reshape transmission planning and cost allocation for the purpose of expanding the transmission system 'in areas with high degrees of renewable resources' that require 'extensive' and 'more expensive' new transmission facilities.'' [20] The Utah Public Service Commission explained that:

> [I]ncreased development and integration of renewable generation is a highly charged political question and a matter of significant political interest. Different states' legislatures have made different policy choices. Some states, like California, have enacted very ambitious laws that require revolutionary changes to their generation mixes. As the [ANOPR] makes clear, these changes require significant investment in, among other things, new transmission infrastructure to wheel renewable generation.
>
> * * * * *
>
> The [Utah Public Service Commission] is deeply concerned the [ANOPR] advertises an interest in rewriting the rules governing transmission planning and cost allocation to better facilitate policy choices, not of Congress, but of particular state legislatures. More specifically, the [Utah Public Service Commission] is opposed to any rule change that would allow such preferences to impose costs on ratepayers in other states.[21]

12. Different policy goals are a critical reason for state opposition to a federal transmission planning regime, but certainly not the only one. The Louisiana Public Service Commission explained:

Gas Facilities, 179 FERC ¶ 61,012 (2022); *see also Certification of New Interstate Nat. Gas Facilities,* 178 FERC ¶ 61,197 (2022).

[6] NOPR, 179 FERC ¶ 61,028 at PP 104, 106.

[7] Arizona Public Service Company October 12, 2021 Comments at 4.

[8] NOPR, 179 FERC ¶ 61,028 at P 123.

[9] *Id.* P 124 (emphasis added).

[10] *Id.* P 274.

[11] *Implementation of Dynamic Line Ratings,* 178 FERC ¶ 61,110 (2022).

[12] NOPR, 179 FERC ¶ 61,028 at PP 91, 127–134.

[13] *Id.* P 131 & n.247 (citing National Renewable Energy Laboratory's Renewable Energy Potential model and Distributed Generation Market Demand model).

[14] *Id.* P 255.

[15] *Id.* PP 7, 400–415.

[16] *Id.* PP 414–415.

[17] *Id.* P 310.

[18] *See State Renewable Portfolio Standards & Goals,* National Conference of State Legislatures (Aug. 13, 2021), *https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.*

[19] *See id.*

[20] Utah Public Service Commission October 8, 2021 Comments at 2 (citing ANOPR, 176 FERC ¶ 61,024 at P 40).

[21] *Id.* at 2–3.

the Commission proposes to change transmission planning and cost allocation to support a new fleet of renewable generating resources in preference to other types of generation. But it is not within the Commission's FPA authority, or within the ambit of sound transmission planning, to dictate the choice of generating resources and then determine what planning and cost allocation metrics will lead to the appearance of an economic transmission build-out to support those resources. This approach interferes with the jurisdiction and authority of the states, fails to recognize regional differences, and could stifle innovation and the development of the most reliable and beneficial solutions at the least delivered energy and capacity cost.

Many of the ANOPR's proposals would not achieve just and reasonable rates, and, in fact, could lead in the opposite direction. They would dramatically increase costs imposed on consumers while potentially jeopardizing the reliability of the grid. Renewable resources are inherently intermittent and not dispatchable. They do not and will not have the same reliability benefits as thermal generation without significant technological investment and/or duplicative back-up power costs. Consumer costs should not increase without a corresponding benefit, and certainly not in the face of diminished reliability, one of the bedrock principles of electric rate regulation.[22]

13. I also attended the meetings of the joint federal-state task force on electric transmission in which numerous state commissioners voiced their concern that federal transmission planning regimes would be imposed upon the states, that the Commission would insist on uniformity throughout the country, and most importantly, that the Commission might require their state's ratepayers to shoulder the costs of another state's transmission projects.[23] It should go without saying that the Commission would be wise to proceed with caution before acting in the face of state opposition.

14. The NOPR raises another serious issue: I do not know how most of these proposals are supposed to work in non-RTO regions. Nor, apparently, does anyone else. This may explain the repeated entreaties for the Commission to allow regional variation in transmission planning. For example:

the [Sponsors of the Southeastern Regional Transmission Planning Process (SERTP Sponsors)] are concerned that a one-size-fits-all adoption of some of the items contemplated in the ANOPR could prove counter-productive or unworkable in the SERTP's expansive, twelve-state, non-RTO footprint. The SERTP Sponsors respectfully submit that the Commission's rules concerning regional transmission planning should continue to accommodate varying approaches to transmission and system planning in recognition of the inherent variability of existing market structures, state policies and requirements, locally available resources, and customer needs that prevail throughout the country.[24]

15. It likewise is doubtful that many of the problems highlighted in the NOPR apply to the entire country or even extend beyond certain RTOs. In the southeast, at least, where there is no RTO, public utilities added 3,158 miles of new transmission and 6,989 miles of uprates between 2015–2020, representing 12% of all transmission in the region.[25] This non-RTO region provided detailed record evidence that strongly suggests it is managing transmission expansion and renewable integration as well as or better than any RTO.[26] Somehow this evidence evaded discussion in the NOPR and the Commission, regardless of the record evidence, seems intent on subjecting all public utilities, even those outside of the RTOs, to the same planning requirements.[27]

16. Even RTOs are calling for the Commission to recognize regional differences and not to impose uniform federal mandates. The New England Power Pool, for example, tells us in its ANOPR comments that ''[t]he Commission should allow ISO–NE, NEPOOL, the [transmission owners in New England] and the New England States to continue to have the flexibility to develop solutions in planning, cost allocation and generator interconnection that work best for New England . . . .''[28]

17. I recognize that there are at least some stakeholders, particularly in RTOs, that want guidance or direction from the Commission to address the current or potential lack of stakeholder consensus for transmission planning reforms. But replacing the stakeholder process with FERC-driven mandates only pleases the subset of stakeholders who agree with the mandates. It is another way to overrule voices in opposition.

18. The numerous comments in response to the ANOPR requesting the continued recognition of regional differences underscore one of my primary concerns. I simply disagree that the record before us supports the scope and profundity of change the Commission seeks to impose. Other broad Commission rulemakings have had sufficient record support to satisfy our statutory obligations. Here, I am doubtful. I agree with the comments of the U.S. Chamber of Commerce which stated that:

the Commission should seriously consider the gravity of this undertaking and its potential significant impacts on both the reliability and the cost of electricity for businesses and consumers across the country. Many of the policies and procedures subject to revaluation in this docket have served their intended purposes. They should not be abruptly jettisoned without a thorough evaluation of the costs and benefits resulting from any significant transmission planning and interconnection policy changes.[29]

19. In the same vein, the Large Public Power Council ''asks the Commission to be careful not to disrupt planning and cost allocation principles within and outside ISOs/RTO structures *that are currently working, and pursuant to which transmission is being planned and developed.*''[30] Again, there is no mention of this argument or the supporting evidence in the NOPR.

20. The NOPR solicits further comment, but it also plainly anticipates rule changes for which my own review of the record indicates only partial, or lukewarm, or minimal support. The most common comment I have seen in the record, and at the task force meetings, as I have already highlighted above, is some variation of ''regional planning is a good idea, and reform is needed, but please do not tell us what to do.'' Well, here are 450 pages of the Commission proposing to tell you what to do.

21. I freely acknowledge that the NOPR includes several potentially reasonable ideas for reform. But that is not the test under section 206 of the FPA. We are not the Good Ideas Commission. We must have substantial record evidence that the existing rate is unjust and unreasonable. We must find that the current planning processes are so unacceptable that the existing system essentially must be scrapped. We must also have record evidence that the replacement rate—the final rule to follow the NOPR—is just and reasonable. We owe it to the jurisdictional entities and the ratepayers to assure ourselves that each of the prescriptive requirements we seek to impose are actually necessary to ensure a just and reasonable, non-discriminatory replacement rate. I certainly do not see the required evidentiary support in the record we have compiled to date and I am skeptical that I will ever see it.

22. Every single party with an interest should file in this docket. And many parties will. The sheer scope of the NOPR means that there is likely to be at least some support in the record for just about anything. I must therefore underscore that it is critical for parties filing comments in response to the NOPR to be *direct and clear.* This can be as simple as styling comments as ''Comments in Opposition'' when the filing party opposes any significant part of the NOPR. For example, if you are one of the numerous parties that filed comments in the ANOPR proceeding requesting that ''[i]n any final rule that comes out of this rulemaking proceeding the Commission should allow for regional variations and flexibility in compliance for RTO/ISO regions,''[31] or for

[22] Louisiana Public Service Commission October 12, 2021 Comments at 2–3.

[23] *See, e.g., Joint Fed.-State Task Force on Elec. Transmission,* 175 FERC ¶ 61,224 (2021) (establishing task force); *see Joint Fed.-State Task Force on Elec. Transmission,* FERC (last updated Apr. 4, 2022), *https://www.ferc.gov/TFSOET.*

[24] Sponsors of the Southeastern Regional Transmission Planning Process October 12, 2021 Comments at 2.

[25] *See id.* at 11.

[26] *See id.* at 12–14 (detailing renewable integration in the southeast on a state-by-state basis).

[27] *See, e.g.,* NOPR, 179 FERC ¶ 61,028 at P 3 (''the reforms proposed in this NOPR would require *public utility transmission providers*'' to amend their tariffs) (emphasis added).

[28] New England Power Pool Participants Committee October 12, 2021 Comments at 8.

[29] Chamber of Commerce of the United States of America October 12, 2021 Comments at 1.

[30] Large Public Power Council October 12, 2021 Comments at 5 (emphasis added).

[31] New England Power Pool Participants Committee October 12, 2021 Comments at 7.

non-RTO regions, then I strongly suggest that you file ''Comments in Opposition'' to the NOPR. The NOPR appears to anticipate only limited regional flexibility.[32]

23. I further specifically request itemized lists from each commenting party indicating whether it supports, opposes, or abstains as to each of the NOPR's preliminary findings and proposed reforms. The Commission's ultimate findings cannot rest merely on a tally of votes, but the scope of this proceeding would make such basic summaries of the comments immensely helpful and will aid the Commission in its review of the (already) voluminous record.

24. To the extent possible, every part of a comment should directly respond to a particular preliminary finding or proposal in the NOPR. The ANOPR comments have been filed and reviewed. The time for generic comments, ''principles'' of planning, the voicing of general support and the like is over and such comments will be nearly without value in the face of page after page of detailed, specific preliminary findings and proposed requirements. Do you support the finding or not? Do you support the proposal or not?

25. And in voicing your support or opposition, I also remind commenting parties to submit hard data whenever possible, including in affidavits, to help the Commission meet—or not—both of the required legal showings for this section 206 proposal (that existing rates are unjust and unreasonable, and that the proposed replacement rate is just and reasonable). I am fully aware that parties have limited resources to comment on the Commission's generic proceedings. And while the scope of this NOPR will inevitably make this an expensive and burdensome endeavor for commenters, I urge you not to rest solely on your ANOPR comments. Support or opposition to the specific proposals in the NOPR is necessary. It will be worth the effort. After all, the only thing at stake in this proceeding is nearly everything connected with transmission planning.

26. Parties should remember that this is not the final rule. The Commission can issue a final rule that contains any provision based on substantial evidence and that is a ''logical outgrowth'' [33] of the provisions in today's proposed rule. That gives wide berth for any number of ultimate outcomes. In other words, this rule, when finalized, could be substantially different. Given what is at stake, be certain to inform the Commission of your positions on every element of the NOPR that could possibly be of concern to you.

27. In this regard, I strongly object to our 75- and 30-day comment and reply periods. Commenting parties presumably do not have hundreds of hours to wade through 450 pages of detailed proposals and to marshal evidence and legal argument for or against every potential change. I am not sure how the same Commission that just set up an Office of Public Participation thinks anyone can reasonably comment on every detail in this tome in 6 months, let alone 75 days. In another proceeding today, we provide RTOs with 6 months to file reports on potential ''modernizing'' reforms to electricity markets, yet here, where no less than the entirety of transmission planning is at stake, we suddenly are in a rush.[34]

28. Do not forget that we are also actively considering interconnection queue reforms, albeit separately, which might be an even greater priority. If we are going to propose comprehensive transmission planning changes in a rulemaking, regional planning and transmission interconnection queue reform should not be considered in silos.

29. While I think this NOPR is a mistake, I am happy to be convinced that particular reforms are justified by sound legal argument and solid record evidence. Where reform is needed to ensure just and reasonable rates and reliable service, and the reform itself is just and reasonable, I can be persuaded that it is worthy of support. I nevertheless reiterate my strong preference that we allow public utilities to file their own transmission planning solutions under FPA section 205. The Commission does not need to issue rules to change everything. Sometimes it is better to build incrementally to improve the current system, rather than to scrap everything and start from scratch. In my view, if an RTO or public utility wants to ''enhance'' its regional planning, it can figure out how to do so. And if the Commission really believes that we cannot rely on public utilities to seek more efficient transmission planning of their own volition, my second option would be to issue section 206 orders requiring the RTOs to show cause why their existing transmission planning processes are just and reasonable. Whether you agree or disagree with these alternative procedural vehicles for change, please say so in your comments.

30. I conclude with a note of caution. A transmission planning revolution opposed by half of the country risks becoming a transmission planning civil war. The Commission should not cram ''reforms'' down the throats of opponents on issues of such deep division, such as whether we can force utilities in unwilling states to consider the transmission needs of other states' policy aspirations. The result will be protracted proceedings, litigation, and risk. Who is going to fund a transmission project in such an environment, in the face of the perpetual risk that it might have its costs ''reallocated''?

For these reasons, I respectfully dissent.

James P. Danly,

Commissioner.

[32] *See* NOPR, 179 FERC ¶ 61,028 at PP 183, 355.

[33] *See, e.g., Sierra Club* v. *Costle,* 657 F.2d 298, 352 (D.C. Cir. 1981).

[34] *See Modernizing Wholesale Elec. Mkt. Design,* 179 FERC ¶ 61,029 at P 1 (2022).

United States of America Federal Energy Regulatory Commission

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection

Docket No. RM21–17–000

(Issued April 21, 2022)

CHRISTIE, Commissioner, *concurring:*

1. The broad purpose of this Commission's oversight of transmission planning under the Federal Power Act (FPA) is to provide consumers with reliable power at just and reasonable rates. I am voting for this Notice of Proposed Rulemaking (NOPR) because I believe it contains some very good proposals that could protect consumers from paying unjust and unreasonable rates for transmission service while also supporting the delivery of reliable power to those consumers. I also believe it comports with our legal authority under the FPA.

2. First, the legal framework: While the FPA gives this Commission authority over ''the transmission of electric energy in interstate commerce,'' [1] the Commission has no authority to encroach on matters regulated by the states.[2] The planning, approval and siting of the *generation* resources necessary to meet the needs of customers in a state are under the regulatory authority of the states, not the Commission.[3] States can prefer, mandate or subsidize specific types of generation resources, but the Commission cannot use its authority over transmission to pressure, steer or require regional planning entities to act as the Commission's agents and do indirectly what the Commission cannot do directly. The Commission is not a national integrated resource planner. Order No. 1000, to its credit, recognized this clear delineation between federal and state authority.[4]

3. Further, under the FPA our authority over transmission planning and cost allocation must ensure that wholesale transmission rates are not unjust and unreasonable.[5] We also have the authority to promote the reliability of the bulk power grid.[6] Those are *consumer protection* functions, not a license to promote the policy goals of any presidential administration or of any corporate or special-interest group that have not been enacted into law in the FPA or any other federal statute.

4. With that legal framework in mind, I am voting in favor of issuing this NOPR at this time and in this form because, on the whole, I find the current draft is consistent with our authority under the FPA and contains some important and constructive proposals that will serve the consumer protection goals of just and reasonable rates and reliability.

5. For example, and as described more fully below, this NOPR will *formally* put the states—for the first time—at the center of regional transmission planning and cost allocation decision-making for policy-driven projects in *all* regional transmission entities,

[1] 16 U.S.C. 824(b)(1).

[2] *Id.* § 824(a).

[3] *Id.* § 824(b)(1).

[4] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, 136 FERC ¶ 61,051, at P 154 (2011), *order on reh'g,* Order No. 1000–A, 139 FERC ¶ 61,132, *order on reh'g and 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 (DC Cir. 2014) (''*[T]he regional transmission planning process is not the vehicle by which integrated resource planning is conducted;* that may be a separate obligation imposed on many public utility transmission providers and *under the purview of the states.*'') (emphases added); *see also id.* PP 107, 156.

[5] 16 U.S.C. 824e(a).

[6] *Id.* § 824o.

if the states choose.[7] As another valuable example, also described below, the NOPR will shift the risk of financing policy-driven projects from consumers back to developers, where it should be.

6. Let me also emphasize that this is a NOPR—the ''P'' stands for ''Proposed''—it is not a final rule. This is only another step in a long process. I look forward to reviewing the comments reacting to it, which I suspect will come in significant quantities. My vote on any final rule will, of course, be based on the text of that final rule. I will not support any final rule that exceeds our FPA authority and/or threatens to cause unjust and unreasonable rates to consumers.

7. When we issued the ANOPR last summer,[8] I said:

This ANOPR contains a number of good proposals, some *potentially* good proposals (depending on how they are fleshed out), and frankly, some proposals that are not—and may never be—ready for prime time, or could potentially cause massive increases in consumers' bills for little to no commensurate benefit or inappropriately expand the role of federal regulation over local utility regulation.

Fortunately, this NOPR contains some very good proposals and leaves out the worst of the ''not ready for prime time'' ideas of the ANOPR. While it still contains some features I would not choose,[9] on balance I am comfortable in voting for it in this form and putting it out for additional comment. Here are some of the best features of this NOPR:

8. First, it leaves unchanged the planning criteria and cost allocation frameworks for Reliability and Economic projects.[10] Reliability and Economic projects are the meat and potatoes of regional transmission planning. These categories of projects are, by definition, integral to the primary duty of utilities *to serve retail customers (load).* Reliability projects are essential to keep the lights on. Economic projects are constructed to reduce quantifiable and definable congestion costs. When these projects are needed, they should be expeditiously built.[11] The NOPR wisely does not disturb existing criteria for timely planning, constructing and paying for these two categories of projects.

9. Second, the NOPR proposes to create a separate category of projects, which we can label ''Long-Term Regional Transmission Facilities,'' [12] or ''LTRT projects.'' This new category replaces Order No. 1000's ''public policy projects.'' [13] As with these public policy projects, the new category of LTRT projects are mostly driven, in whole or in part, directly or indirectly, by public policies, such as projects that would accommodate a state's legislated preferences for certain resources, or projects that could accommodate generation growth and retirements resulting from states' implementation of their own integrated resource plans (IRP), or corporate goals recognized in state utility regulation.

10. For this new category of LTRT projects, the NOPR proposes to require a planning *process* extending out 20 years, based on the premise that a 20-year projection of the expected generation mix, costs of generation, and/or load has validity. Based on my experience as a state regulator with IRPs and computer models purporting to predict the future two or more decades down the road, I regard 20-year projections of this sort as, at best, occasionally interesting, but they certainly provide no basis whatsoever for saddling consumers with the costs of a billion-dollar transmission line. However, while this NOPR does propose to require a 20-year planning *process* for LTRT projects, it does *not* propose to require that any individual LTRT project or group of projects must be approved for inclusion in any regional transmission expansion plan. Indeed, there are *no* mandated LTRT projects in this NOPR, nor any planning-cycle quotas that regional entities must meet for including these types of projects in regional plans.

11. Even more importantly though, for these LTRT projects, the NOPR proposes to require the regional planning entities to consult with *and seek the agreement of* the relevant states to *both* the selection criteria for these projects *and* to the regional cost allocation arrangements. State approval is especially important in a multi-state region, where different states have different policies. The NOPR proposes to provide the maximum opportunity for creativity and flexibility to the states and regional entities in developing the process for designing and approving regional selection criteria and cost allocation arrangements. States can agree to an *ex ante* formula for regional cost allocation of these types of projects—such as, for example, the ''highway-byway'' formula approved by the SPP Regional State Committee—or states can agree to a process for a project-by-project agreement on cost allocation among one or several states—such as, for example, the State Agreement Approach in PJM—or states may choose some combination of both.[14] States in a multi-state RTO or ISO can even agree to defer the decision on cost allocation to the governing board of the RTO/ISO.[15] The result is, while we are proposing to require regional planning entities to study and evaluate a broad, forward-looking array of information—including information addressing states' individual energy policies and goals—any projects identified through this new process will not be built, or more importantly, paid for by consumers, until the states representing such consumers have agreed that such projects are indeed needed and wanted by those same consumers.

12. And let me emphasize two points: First, as stated above, the Commission cannot *impose* a preference for certain types of generation *nor require* regional entities to plan transmission designed to prefer or facilitate one type of generation over another. Second, regardless of any ultimate cost allocation arrangement agreed to in a regional entity, no individual state's consumers can be forced to bear the costs of another state's policy-driven project or element of a project against its consent.[16] That would be inconsistent with the cost-allocation principles of Order No. 1000, which this NOPR explicitly proposes to preserve.[17]

13. States did not join RTOs [18] to pay for other states' public policies or to pay for the public policy goals of huge multinational corporations or asset managers.[19] States joined to provide their retail consumers with the promised benefits of lower transmission costs and strengthened reliability through regional planning of core Reliability projects. Some may say that state regulators should have no more special right to consent to planning criteria and cost allocation for these projects than other stakeholders in the RTO/ISO. But states are not just ''stakeholders.'' State regulators have the duty to act in the *public interest* and states alone are sovereign authorities with inherent police powers to regulate utilities through their designated state officers. The FPA itself explicitly recognizes state authority. So it is perfectly fitting for state regulators to have the

[7] States have long played an informal advisory and advocacy role through organizations such as the Organization of PJM States, Inc. (my alma mater) and the Organization of MISO States. In Southwest Power Pool, Inc. (SPP) and ISO New England Inc. states have played what could be perhaps described as a more formal role in the decision-making processes of the regional entity, through the SPP Regional State Committee and the New England States Committee on Electricity, respectively. In single-state RTOs/ISOs such as New York Independent System Operator, Inc. (NYISO) and California Independent System Operator Corporation, state policies and policy-makers already heavily influence transmission planning and cost allocation. *See, e.g., N.Y. Indep. Sys. Operator, Inc.,* 178 FERC ¶ 61,179 (2022) (Christie, Comm'r, concurring) (''The specific [transmission] projects at issue in this proceeding are designed to implement the public policies of the State of New York, which are ultimately the responsibility of New York's elected legislators. . . . NYISO is a single-state ISO that is attempting to act in accordance with the public policies of the state.''). The states, as sovereign entities, must choose to embrace the heightened role offered by this NOPR; no state can be compelled to do so, as the NOPR makes clear. *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 179 FERC ¶ 61,028, at P 308 (2022) (NOPR).

[8] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 176 FERC ¶ 61,024 (2021) (Christie, Comm'r, concurring, at P 5).

[9] For example, I agree with Commissioner Danly's dissent that many of the specific long-term planning directives proposed in the NOPR may be far too prescriptive and may need to be revised in any final rule to permit more regional variation and flexibility.

[10] NOPR, 179 FERC ¶ 61,028 at PP 3, 89, 314.

[11] I recognize that, with regard to projects to relieve congestion costs, in some circumstances there may be cheaper solutions available through new builds of generation.

[12] NOPR, 179 FERC ¶ 61,028 at P 4 & n.6; *see also id.* n.507.

[13] Order No. 1000 described these types of projects as those that address ''transmission needs driven by Public Policy Requirements.''

[14] NOPR, 179 FERC ¶ 61,028 at PP 302–303, 305.

[15] *Id.* PP 305, 307.

[16] *See, e.g., id.* PP 302, 312.

[17] *Id.*

[18] I am aware that states *qua* states do not join RTOs/ISOs. Rather, they use their regulatory power to allow or require their regulated transmission-owning utilities to join.

[19] *See, e.g.,* Google, *A Policy Roadmap for 24/7 Carbon-Free Energy* (Apr. 14, 2022), *https://cloud.google.com/blog/topics/sustainability/a-policy-roadmap-for-achieving-247-carbon-free-energy; see also BlackRock, Inc.,* 179 FERC ¶ 61,049 (2022) (Christie, Comm'r, concurring).

important roles proposed in this NOPR, without preempting the regional planning entities from seeking additional input through their existing stakeholder processes.

14. The bottom line for me is this: I believe that elevating the role in planning and cost allocation of state regulators—who are, as a group, deeply concerned about the monthly bills paid by consumers, of which transmission is a rapidly growing component—will make it *more likely, not less,* that necessary transmission can get built while ensuring that rates resulting from these types of policy-driven projects will not be unjust and unreasonable, which they clearly have the potential to be.

15. There is a third feature of this NOPR I also find very important. For LTRT projects the NOPR proposes to end the Commission's long practice of awarding, as an incentive, cost recovery for Construction Work in Process (CWIP); instead it will propose to require the booking of these pre-service costs as Allowance for Funds Used During Construction (AFUDC).[20] CWIP is the award of cost recovery of construction costs during the pre-construction and construction phases to the developer. CWIP is, of course, passed through as a cost to consumers, making consumers effectively an involuntary lender to the developer. By contrast, AFUDC is booked during the pre-service phases, but *cannot* be recovered from customers until the project is completed and actually serving customers, *i.e.,* ''used and useful.'' The NOPR proposal is simply in keeping with traditional good utility ratemaking principles. Booking these costs as AFUDC also recognizes the reality that just because an LTRT project is selected for a regional plan, it still has to obtain all state siting, certificate of public convenience and necessity and other, including environmental, approvals, and survive what may be the subsequent litigation, before it is actually built.[21] Consumers should be protected from paying CWIP costs during this potentially long period before a project actually enters service, if it ever does. This NOPR proposal represents a major step forward in consumer protection and is a big reason I am voting for it.

16. Finally, let me note again that this is a NOPR—a continuing work in progress with more work ahead. For example, the section on planning of local projects[22] seeks to address a concern expressed by many commenters, that local projects may not be getting sufficiently vetted by regional planning entities. In response, the NOPR essentially proposes PJM's procedures for vetting and transparency of local projects, but I welcome additional comment from other regional entities as to whether there are more conducive measures for such vetting that may fit their own regions better. Most importantly, on the broader issue of whether local projects are being properly scrutinized, as a former state regulator who sat on scores of local-project cases, I would point out that no local project is going to be built unless a state agency approves a certificate or its equivalent. While the commenters note that procedures differ greatly from state to state, and some state utility commissions have more authority than others,[23] there is no question that states have within their inherent police powers the authority to regulate utilities and that includes the power to vet local projects both as to need and cost *before* approving them, just as states have the siting authority. If states are not using these powers to vet fully such local projects, they should review their own state laws and procedures. And if states believe they need more information from the RTOs/ISOs to make more informed decisions in their vetting processes, please comment on what additional information would be helpful for the RTOs and ISOs to provide. States should be a full partner in the process for vetting and approving local projects and I invite comment on how to strengthen state oversight of these projects to get the best deal for the consumer.

For these reasons cited above, I concur in the issuance of the NOPR.

Mark C. Christie,

Commissioner.

United States of America Federal Energy Regulatory Commission

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection

Docket No. RM21–17–000

(Issued April 21, 2022)

PHILLIPS, Commissioner, *concurring:*

1. I concur in today's Notice of Proposed Rulemaking (NOPR) to emphasize the importance of our action today and to call attention to the work that remains. I believe today's NOPR represents a critical first step toward ensuring a 21st century electric grid that is capable of reliably and affordably accommodating new generation.

2. Most commenters urge the Commission to reexamine the transmission planning and cost allocation policies adopted in Order No. 1000 over a decade ago.[1] While Order No. 1000 was well intentioned, commentors argue that it fell short of its goal to spur competitive transmission buildout. Under section 206 of the Federal Power Act,[2] the Commission must ensure that transmission rates are just and reasonable. If there are deficiencies in the Commission's existing regional transmission planning and cost allocation requirements, we must endeavor to remedy those deficiencies. For this reason, I support the NOPR's proposal to revisit our existing policies.

3. This NOPR acknowledges the facts on the ground. It is an inescapable fact that our resource mix is changing, which is a key factor leading to a greater need for transmission. Due in large part to economies of scale, the cost of renewable energy has fallen rapidly over the last decade while the demand for those resources has increased.[3] As of the end of 2020, there were over 800 GW of wind, solar, and energy storage capacity seeking interconnection in the United States.[4] That figure has now risen to 1,300 gigawatts of wind, solar and storage capacity proposed for interconnection as of the end of 2021.[5] At the same time as the resource mix is changing, severe weather events and wildfires are becoming more frequent and extreme.[6] These are just a few of the factors contributing to a greater need for expansion of our nation's grid.[7]

4. The record here appears to show that transmission expansion is increasingly occurring in a piecemeal and inefficient fashion outside of the regional transmission

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[20] NOPR, 179 FERC ¶ 61,028 at P 333 & n.530.

[21] *See e.g., Nat'l Wildlife Refuge Ass'n* v. *Rural Utils. Serv.,* Nos. 21–cv–096-wmc & 21–cv–306, 2021 WL 5050073 (W.D. Wis. Nov. 1, 2021) (enjoining on environmental grounds construction of a segment of a transmission project intended to bring wind-generated power from generators in Iowa to Wisconsin); *see also* Clark Mindock, *Wis. Judge Blocks $500M Power Line From Wildlife Refuge,* LAW360 (Mar. 2, 2022), *https://www.law360.com/articles/1469697* (''The CHC Project is a proposed 102-mile high-voltage transmission line in the Midwest that was proposed as a way of connecting parts of Milwaukee and Chicago to cheap wind power by connecting Dubuque, Iowa, to southwestern Wisconsin.'').

[22] NOPR, 179 FERC ¶ 61,028 at PP 383–415.

[23] *See, e.g.,* Ohio Consumers' Counsel Comments at 13 (explaining that the Ohio Power Siting Board (OPSB) does not review local projects ''for need, prudence, or cost efficiency''); Ohio Consumers' Counsel Reply Comments at 8 (''the OPSB rejected [Ohio Consumers' Counsel's] recommendation that the OPSB report to the General Assembly that the state legislature should pass new statutory authority for OPSB that would require the agency to regulate the siting of, need for and cost-effectiveness of any proposed new transmission facilities in Ohio rated at 69 kV and above.'').

[1] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g,* Order No. 1000–A, 139 FERC ¶ 61,132, *order on reh'g and 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).

[2] 16 U.S.C. 824e.

[3] For instance, after an 85% cost decline over the past decade, solar photovoltaic systems are among the most cost-competitive energy resources in the market. *See* Deloitte, 2022 Renewable Energy Outlook, *https://www2.deloitte.com/us/en/pages/energy-and-resources/articles/renewable-energy-outlook.html.*

[4] *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2020,* Lawrence Berkeley National Laboratory, at 22 (May 2021).

[5] *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021,* Lawrence Berkeley National Laboratory, at 3 (April 2022).

[6] As outlined in the November 2021 FERC–NERC–Regional Entity Staff Report on Winter Storm Uri, interregional transfers played a critical role in helping MISO and SPP compensate for generation outages during the event. *The February 2021 Cold Weather Outages in Texas and the South Central United States,* FERC, NERC and Regional Entity Staff Report, at 98 (November 2021).

[7] *See* National Association of Regulatory Utility Commissioners (NARUC) Comments at 17 (''Because certain clean energy resources are diffuse by nature, meaning the resources exist at disparate locations and cannot simply be placed near existing load centers, new transmission facilities may need to be developed to gather and transport energy from generation rich areas to load.''); Harvard Electricity Law Initiative Comments at 17 (''Transmission is needed to connect these location-constrained resources and to ensure that the system remains reliable with a larger share of intermittent generation.'').

planning process, which may not be cost-effective for consumers in the long run.[8] While commenters' views vary on how best to address this problem, nearly all commenters endorse some form of proactive planning for the future resource mix and demand.[9] I believe the NOPR proposal to require long-term scenario planning, including accounting for extreme weather events, is necessary to maintain the reliability of the grid and to ensure that transmission costs are just and reasonable. I also note that while this NOPR proposes to require the evaluation of benefits of long-term regional transmission facilities over a 20-year time horizon, it does not propose to prescribe any particular definition of ''benefits'' or ''beneficiaries,'' nor require use of any specific benefits.[10] Instead, we continue to acknowledge the benefits of regional flexibility. Nor does it propose to require that transmission providers select any particular transmission projects, instead proposing to provide transmission providers the flexibility to propose the selection criteria that they, in consultation with their stakeholders and states, believe will ensure that more efficient or cost-effective long-term regional transmission facilities ultimately are selected.[11] And I support the proposal to require transmission providers to consult with and incorporate states' views in project selection and cost allocation. I invite comment on the value of such state involvement for increasing the likelihood that those facilities are sited and ultimately developed with fewer costly delays.

5. I also strongly support the NOPR proposal for greater consideration of dynamic line ratings and advanced power flow control devices in regional transmission planning processes. Grid-enhancing technologies (GETs) can optimize our existing transmission infrastructure and provide cost-effective solutions for consumers. For example, by allowing the measurement of transmission capacity in real-time, dynamic line ratings can provide net benefits to customers by allowing increased power flow and reducing congestion costs, as well as by detecting when power flows should be reduced to avoid unnecessary wear on transmission equipment. The role that these and other GETs could play in delaying or eliminating the need for new transmission facilities cannot be ignored. I urge the Commission to consider further reforms to incentivize the adoption and deployment of GETs.

6. Many commenters raise concerns about delays and significant backlogs in interconnection queues across the country.[12] Currently, less than a quarter of generator interconnection applications actually result in an interconnection.[13] Interconnection applicants submitting speculative interconnection requests can linger in the queue, only to withdraw at late stages, often necessitating the study of non-viable projects as well as restudies due to withdrawals. These often result in delays and cost risks for commercially viable projects that are otherwise ready to interconnect. Although the reforms we propose in this NOPR may help mitigate these issues in the long term, they are not enough to alleviate existing backlogs in the near term. While I recognize and commend the ongoing efforts in some regions to address the large volume of interconnection requests,[14] I encourage my colleagues to consider whether it is necessary to require certain best practices, such as first-ready, first-served cluster study approaches, to process interconnection requests more efficiently.

7. Similarly, many commenters have highlighted the importance of adopting interregional coordination and planning reforms, particularly for reliability.[15] Today's NOPR does not, at this time, propose changes to the existing interregional transmission coordination and cost allocation requirements of Order No. 1000. As we continue to examine those issues, I urge the Commission to act expeditiously to propose interregional reliability planning reforms. Looking beyond regional boundaries is important so that cost-efficient regional and interregional projects can be considered and studied together. We should consider whether neighboring regions should adopt common planning assumptions and methods that allow for region-specific inputs. Additionally, I believe we must consider whether to adopt a requirement for a minimum amount of interregional transfer capacity to protect against generation shortfalls, especially during extreme weather events.

8. Finally, I note that this NOPR is merely a proposal and I am looking forward to reviewing the comments in response. In addition, I emphasize that the reforms in this NOPR are not intended to be one-size-fits-all, nor would I support such an approach. Recognizing the unique needs and characteristics of individual markets and regions, I am particularly interested in comments on whether the reforms proposed in this NOPR allow for a sufficient level of regional flexibility.

For these reasons, I respectfully concur.

Willie L. Phillips,

Commissioner.

[FR Doc. 2022–08973 Filed 5–3–22; 8:45 am]

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[8] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 179 FERC ¶ 61,028, at P 38 (2022) (NOPR) (discussing the dramatic increase in cost, size, and scope of interconnection-related network upgrades).

[9] *See* Americans for a Clean Energy Grid Reply Comments, Appendix A (listing 174 commenters).

[10] *See* NOPR, 179 FERC ¶ 61,028 at P 183.

[11] *Id.* P 242.

[12] *See, e.g.,* Advanced Energy Economy Reply Comments at 17–23; American Electric Power Service Corporation Comments at 36–38; American Public Power Association Comments at 27; Edison Electric Institute Reply Comments at 27–30; NextEra Energy, Inc. Comments at 12.

[13] *See Queued Up . . . But in Need of Transmission Unleashing the Benefits of Clean Power with Grid Infrastructure,* U.S. Department of Energy, at 2 (April 2022).

[14] *See, e.g.,* California Public Utilities Commission Comments at 70 (noting that California Independent System Operator Corporation is undertaking a stakeholder process focused on increasing efficiency of the interconnection study process); PJM Interconnection, L.L.C. Comments at 47–49.

[15] *See, e.g.,* NARUC Comments at 8 (''The planning process should share system planning information on an interregional level whenever appropriate.''); *id.* at 19 (describing how during Winter Storm Uri, ''usually a net exporter of energy, SPP relied significantly on imported energy to serve load during the winter event'' and that ''effective planning should strive to quantify benefits associated with enhancing interregional import and export capabilities, given the likelihood of future extreme weather events and related energy shortages. Further analysis and process improvements in interregional transmission development and imports and exports capability will be necessary, not only to accommodate demand for a clean energy transition, but also for reliability and defined resiliency benefits.''); PJM Interconnection, L.L.C. Comments at 72–73 (stating that greater interregional transfer capability has a significant reliability benefit as demonstrated by the February 2021 Cold Snap and the 2014 Polar Vortex, and the Commission should approach the issue of strengthening interregional ties as a broad reliability-based benefit); New York Independent System Operator, Inc. Comments at 55 (''Interconnections with neighboring systems are important tools to support grid reliability, resiliency, and market efficiency by providing opportunities for the exchange of capacity and energy.'').