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: Advance notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing an Advance Notice of Proposed Rulemaking (ANOPR) presenting potential reforms to improve the electric regional transmission planning and cost allocation and generator interconnection processes. The Commission invites all interested persons to submit comments on the potential reforms and in response to specific questions.

DATES: Comments are due October 12, 2021 and Reply Comments are due November 9, 2021.

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 U.S. Postal Service mail or by hand (including courier) delivery.
  - *Mail via U.S. Postal Service only:* Addressed to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE, Washington, DC 20426.
  - *For delivery via any other carrier (including courier):* Deliver to: Federal Energy Regulatory Commission, Office of the Secretary, 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. Pursuant to its authority under section 206 of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission (Commission) is considering the potential need for reforms or revisions to existing regulations to improve the electric regional transmission planning and cost allocation and generator interconnection processes.

2. Approximately 10 years ago, the Commission issued Order No. 1000.[2] That order stated its purpose generally in its introduction:

> The reforms herein are intended to improve transmission planning processes and cost allocation mechanisms under the *pro forma* Open Access Transmission Tariff (OATT) to ensure that the rates, terms and conditions of service provided by public utility transmission providers are just and reasonable and not unduly discriminatory or preferential. This Final Rule builds on Order No. 890,[3] in which the Commission, among other things, reformed the *pro forma* OATT to require each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process. After careful review of the voluminous record in this proceeding, the Commission concludes that the additional reforms adopted herein are necessary at this time to ensure that rates for Commission-jurisdictional service are just and reasonable in light of changing conditions in the industry. In addition, the Commission believes that these reforms address opportunities for undue discrimination by public utility transmission providers.[4]

3. More than a decade after Order No. 1000, we believe it appropriate to review the issues addressed by that order and other transmission-related regulations and determine whether additional reforms to the regional transmission planning and cost allocation and generator interconnection processes or revisions to existing regulations are needed to ensure rates for Commission-jurisdictional service remain just and reasonable, and not unduly discriminatory or preferential. The electricity sector is transforming as the generation fleet shifts from resources located close to population centers toward resources, including renewables, that may often be located far from load centers. The growth of new resources seeking to interconnect to the transmission system and the differing characteristics of those resources are creating new demands on the transmission system. Ensuring just and reasonable rates as the resource mix changes, while maintaining grid reliability, remains the priority in the regional transmission planning and cost allocation and generator interconnection processes.

4. In light of these evolving conditions, we believe it timely and appropriate 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 transmission rates remain just and reasonable and not unduly discriminatory or preferential and that reliability is maintained.[5] Accordingly, we will consider herein whether and which reforms and revisions are necessary to the Commission's regulations on these topics. This Advanced Notice of Proposed Rulemaking (ANOPR) discusses proposals or concepts for changes to existing processes in several broad categories: Regional transmission planning, regional cost allocation, generator interconnection funding, generator interconnection queueing processes and consumer protection, and in several instances the ANOPR also offers a potential rationale or argument for potential proposals. We note that the Commission has not predetermined that any specific proposal discussed herein shall or should be made or in what final form; rather, we seek comment from the public on these proposals and welcome commenters to offer additional or alternative proposals for consideration.

5. We believe it appropriate to review whether there are questions that should be explored and possible solutions proposed regarding any potential shortcomings in the existing regional transmission planning and cost allocation and generator interconnection processes, which may have become evident since the Commission issued Order No. 2003,[6] Order No. 890, and Order No. 1000. We seek comment on several topics across transmission planning and cost allocation and interconnection queue processes, as well as oversight of transmission infrastructure development. Examples

[1] 16 U.S.C. 824e. Section 206 requires that transmission rates be just and reasonable, and not unduly discriminatory or preferential.

[2] *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).

[3] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 118 FERC ¶ 61,119, *order on reh'g,* Order No. 890–A, 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, 126 FERC ¶ 61,228, *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[4] Order No. 1000, 136 FERC ¶ 61,051 at P 1.

[5] 16 U.S.C. 824e.

[6] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, 104 FERC ¶ 61,103 (2003), *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) (*NARUC* v. *FERC*).

of such questions for which we will seek comment in this ANOPR include, among others: (1) Whether the existing regional transmission planning and cost allocation processes appropriately considers the transmission needs of anticipated future generation to drive study assumptions, or instead relies on less comprehensive information, such as existing interconnection requests with completed facilities studies, and whether such current planning criteria are appropriate or should be revised; (2) whether the regional transmission planning and cost allocation processes' consideration of transmission needs driven by reliability, economic considerations, and Public Policy Requirements [7] are inappropriately siloed from one another, and, if so, whether this influences the consideration of potential benefits of a regional transmission facility (and the associated beneficiaries for purposes of allocating the costs of such a facility); [8] (3) whether criteria in addition to those related to reliability, economic, and Public Policy Requirements needs should be planned for and considered in the evaluation of benefits, and used to determine cost allocation in the regional transmission planning process, and these needs should be clear, credibly quantifiable and not speculative; (4) how to appropriately identify and allocate the costs of new transmission infrastructure in a manner that satisfies the Commission's cost-causation principle that costs are allocated to beneficiaries in a manner that is at least roughly commensurate with estimated benefits; (5) whether or not it is appropriate for the costs of state or local public policy-driven transmission facilities to be shifted through regional cost allocation to consumers in non-participating states, or whether changes to current interconnection cost allocation mechanisms may unjustly and unreasonably shift costs to customers of load serving entities; [9] (6) whether and which reforms are necessary to the generator interconnection process to ensure a more purposeful integration with the regional transmission planning and cost allocation processes, a more efficient queueing process, and a more efficient and cost-effective allocation of interconnection costs; (7) whether the regional transmission planning and cost allocation processes may have resulted in transmission facilities addressing an unduly narrow set of transmission needs, including needs located in a single transmission owner's footprint, and having limited region-wide benefits, but that, collectively, may impose significant costs on customers; (8) whether and how to better coordinate between regional and local transmission planning processes to identify more efficient or cost-effective solutions; and (9) whether it is necessary, and how, to more clearly identify the lines of regulatory authority and oversight between states and federal authorities with regard to regional and local transmission facilities to ensure appropriate vetting of transmission infrastructure. In addition, we seek comment regarding whether the current approach to oversight of transmission investment adequately protects customers, particularly given the potentially significant and very costly investments proposed to meet the transmission needs driven by a changing resource mix, and, if customers are not adequately protected from excessive costs, which potential reforms may be required and are legally permissible to ensure just and reasonable rates.

II. Background

A. Regional Transmission Planning and Cost Allocation Process

6. In 1996, the Commission issued Order No. 888 and the accompanying *pro forma* OATT, setting forth certain minimum requirements for transmission planning.[10] In 2007, the Commission issued Order No. 890 to remedy flaws in the *pro forma* OATT, and in so doing, required coordinated, open, and transparent transmission planning on both a local and regional level. Specifically, the Commission required, among other things, that each transmission provider's [11] local transmission planning process 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.[12]

7. In 2011, the Commission issued Order No. 1000 to build on the transmission planning requirements of Order No. 890. Order No. 1000 included a package of reforms to ensure that the transmission planning and cost allocation mechanisms embodied in the *pro forma* OATT were adequate to support the development of more efficient or cost-effective transmission facilities.[13] The reforms in Order No. 1000 fell into the following categories: (1) Regional transmission planning; (2) transmission needs driven by Public Policy Requirements; (3) nonincumbent transmission developer reforms; (4) regional and interregional cost allocation; and (5) interregional transmission coordination. Here we provide a brief overview of the Order No. 1000 regional transmission planning requirements, nonincumbent developer reforms, regional transmission cost allocation rules, and interregional transmission coordination.

1. Regional Transmission Planning Requirements

8. Order No. 1000 requires that each transmission provider participate in a regional transmission planning process that produces a regional transmission plan.[14] Through the regional transmission planning process, transmission providers must evaluate, in consultation with stakeholders,

[7] 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). Order No. 1000, 136 FERC ¶ 61,051 at P 2. The Commission clarified that Public Policy Requirements established by state or federal laws or regulations include duly enacted laws or regulations passed by a local governmental agency, such as a municipal or county government. Order No. 1000–A, 139 FERC ¶ 61,132 at P 319. Order No. 1000 left planning and cost allocation for Public Policy Requirements largely to the discretion of transmission providers. *See also infra* P 16.

[8] A regional transmission facility is a transmission facility located entirely in one transmission planning region. Order No. 1000, 136 FERC ¶ 61,051 at n.374.

[9] Under current Commission policy, the costs of interconnection-related network upgrades are either (1) directly assigned to the interconnection customer or (2) funded initially by the interconnection customer and reimbursed through transmission service credits.

[10] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g,* Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[11] In this order, we use the term ''transmission provider'' when referring to a public utility that owns, controls, or operates transmission facilities. The term transmission provider should be read to include the transmission owner when the transmission owner is separate from the transmission provider, as is the case in regional transmission organizations (RTOs) and independent system operators (ISOs).

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

[13] Order No. 1000, 136 FERC ¶ 61,051 at PP 11–12, 42–44; Order No. 1000–A, 139 FERC ¶ 61,132 at PP 3, 4–6.

[14] Order No. 1000, 136 FERC ¶ 61,051 at PP 146, 148.

alternative transmission solutions that might meet the region's reliability, economic, and Public Policy Requirements needs [15] more efficiently or cost-effectively than solutions that transmission providers identified in their local transmission planning processes.[16] Order No. 1000 also requires that the regional transmission planning process satisfy the Order No. 890 transmission planning principles.[17] Therefore, these transmission planning principles, which the Commission adopted with respect to local transmission planning processes in Order No. 890, also apply to the regional transmission planning processes established in Order No. 1000.

2. Nonincumbent Transmission Developer Reforms

9. Order No. 1000 institutes a number of reforms that seek to ensure that nonincumbent transmission developers have an opportunity to participate in the regional transmission development process.[18] In particular, Order No. 1000 requires that each 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.[19] Order No. 1000 defines a transmission facility selected in a regional transmission plan for purposes of cost allocation as one that has been selected because it is a more efficient or cost-effective solution to a regional transmission need.[20]

10. In addition, Order No. 1000 requires that each regional transmission planning process include not unduly discriminatory qualification criteria and information requirements for transmission developers that want to propose a transmission facility for selection in the regional transmission plan for purposes of cost allocation.[21] The regional transmission planning process must also have a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation.[22] Furthermore, the regional transmission planning process must provide a nonincumbent transmission developer with the same eligibility as an incumbent transmission developer to use a cost allocation method(s) for any sponsored transmission facility selected in the regional transmission plan for purposes of cost allocation.[23]

3. Regional Transmission Cost Allocation

11. Order No. 1000 requires each transmission provider to have in place a method, or set of methods, for allocating the costs of new regional transmission facilities selected in the regional transmission plan for purposes of cost allocation.[24] Each regional cost allocation method must satisfy six regional cost allocation principles,[25] including the principle that the cost of transmission facilities must be allocated to those in the transmission planning region that benefit from the facilities in a manner that is roughly commensurate with estimated benefits.[26]

4. Interregional Transmission Coordination

12. Order No. 1000 requires each transmission provider, through its regional transmission planning process, to establish further procedures with each of its neighboring transmission planning regions for the purpose of coordinating and sharing the results of respective regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. The interregional coordination processes must provide for: (1) The sharing of information regarding the respective needs of each region and potential solutions to those needs; and (2) the identification and evaluation of interregional transmission facilities that may be more efficient or cost-effective solutions to those regional needs.[27]

B. Overview of Transmission Planning

13. The next few paragraphs provide an overview of how transmission providers plan their systems to meet their reliability, economic, and Public Policy Requirements needs, consistent with Order Nos. 890 and 1000.

1. Reliability Needs

14. Transmission providers within transmission planning regions conduct reliability planning studies to help ensure the ability of the transmission system to serve firm transmission use. These studies may extend 10 to 15 years into the future depending on the transmission planning region's transmission planning process and tests for violations of established North American Electric Reliability Corporation (NERC) reliability requirements.[28] 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 be able to withstand a range of probable contingencies (*e.g.,* the sudden loss of a generator or high voltage transmission line) while reliably serving customer demand and preventing cascading outages.[29] Generally, transmission providers identify areas not in compliance with planning criteria and develop plans to achieve compliance. Transmission providers examine facilities to mitigate identified reliability criteria violations for their feasibility, impact, and comparative costs, culminating in a recommended regional transmission plan.

2. Economic Needs

15. 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

[15] Order No. 1000's requirement to consider transmission needs driven by Public Policy Requirements is described below.

[16] Order No. 1000, 136 FERC ¶ 61,051 at PP 11, 148.

[17] *Id.* P 151. Order No. 890 explains these transmission planning principles.

[18] For purposes of Order No. 1000, ''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 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 project. *Id.* P 225.

[19] *Id.* P 313.

[20] *Id.* PP 5, 63.

[21] *Id.* PP 225, 323, 325.

[22] *Id.* P 328; Order No. 1000–A, 139 FERC ¶ 61,132 at P 452.

[23] Order No. 1000, 136 FERC ¶ 61,051 at P 332.

[24] *Id.* P 558.

[25] *Id.* P 603.

[26] *Id.* PP 622, 639.

[27] *Id.* P 396.

[28] 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.

[29] 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.

transmission providers to perform economic planning studies absent a request by stakeholders. To remedy this deficiency, Order No. 1000 required that, in addition to economic planning studies requested by stakeholders, transmission providers evaluate, through a regional transmission planning process and in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual transmission providers in their local transmission planning process. These regional transmission solutions could include transmission facilities needed to meet reliability requirements, address economic considerations, and/or meet transmission needs driven by Public Policy Requirements.[30] 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.[31] However, to implement the requirement in Order No. 1000 to affirmatively plan for economic needs, transmission providers implemented thresholds that vary across the regions. 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. Public Policy Requirement Needs

16. Order No. 1000 requires transmission providers to consider transmission needs driven by Public Policy Requirements in their local and regional transmission planning processes.[32] However, the requirement in Order No. 1000 to consider transmission needs driven by Public Policy Requirements is limited, and the Commission provided 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,[33] nor does it mandate the consideration of any particular transmission need driven by a Public Policy Requirement.[34] As a result, the process for identifying and considering such needs varies from transmission planning region to transmission planning region.

4. Local Transmission Facilities in the Regional Transmission Planning Process

17. Generally, the transmission facilities that 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.

C. Overview of Generator Interconnection

18. In Order No. 2003, the Commission recognized a need for a single set of interconnection procedures for jurisdictional transmission providers and a single, uniformly applicable interconnection agreement for large generators.[35] The Commission explained that generator interconnection is a ''critical component of open access transmission service and thus is subject to the requirement that utilities offer comparable service under the OATT.'' [36] The Commission also determined that, because of the inefficiency of addressing generator interconnection issues on a case-by-case basis,[37] it was appropriate to establish a standard set of generator interconnection procedures to ''minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable.'' [38] To this end, the Commission adopted the *pro forma* Large Generator Interconnection Procedures (LGIP) and *pro forma* Large Generator Interconnection Agreement (LGIA) [39] and required that all transmission providers' OATTs incorporate the *pro forma* LGIP and *pro forma* LGIA.

19. In Order No. 2003, the Commission also retained a distinction between interconnection facilities, which are located between the interconnection customer's generating facility and the transmission provider's transmission system, and network upgrades,[40] which include only facilities at or beyond the point where the interconnection customer's generating facility interconnects to the transmission provider's transmission system.[41] This distinction is important because the determination of which entity is ultimately responsible for the cost of a facility can depend on whether that facility is an interconnection facility or an interconnection-related network upgrade.

20. To initiate the generator interconnection process set forth in Order No. 2003,[42] the interconnection customer submits an interconnection request associated with its proposed generating facility that includes preliminary site documentation, certain technical information about the proposed generating facility, and the expected in-service date along with a deposit.[43] The transmission provider uses this information to determine the interconnection facilities and interconnection-related network upgrades necessary to accommodate the interconnection request and their associated costs.[44]

21. After the transmission provider determines that the interconnection request is complete, the interconnection request will enter the interconnection queue with other pending requests, and the transmission provider will assign the request a queue position based on the date and time of receipt. The queue position will determine the order in which the transmission provider will perform three phases of interconnection studies for the interconnection request. The three phases in order are: (1) The feasibility study; (2) the system impact

[30] Order No. 1000, 136 FERC ¶ 61,051 at PP 147–148.

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

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

[33] Order No. 1000, 136 FERC ¶ 61,051 at P 220 (explaining that the Final Rule is intended to ''provide flexibility for public utility transmission providers to develop procedures appropriate for their local and regional transmission planning processes'').

[34] *Id.* P 215.

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

[36] *Id.* P 9 (citing *Tenn. Power Co.,* 90 FERC ¶ 61,238 (2000)).

[37] *Id.* P 10.

[38] *Id.* P 11.

[39] The *pro forma* LGIP and *pro forma* LGIA govern large generating facilities, which are generating facilities that have a generating facility capacity of more than 20 MW.

[40] For clarity, this ANOPR will refer to these facilities as interconnection-related network upgrades.

[41] *Id.* P 21.

[42] While we provide a broad description of the generator interconnection process under Order No. 2003 as background here, we recognize that many transmission providers have adopted (and the Commission has accepted) variations to many of the terms in the *pro forma* LGIP and the *pro forma* LGIA. Consequently, some or many of the details of a particular transmission provider's generator interconnection process may vary considerably from the broad description provided here.

[43] *Id.* P 35.

[44] *Pro forma* LGIP Section 3.1.

study; and (3) the facilities study, all of which are necessary to determine the interconnection facilities and interconnection-related network upgrades needed to accommodate the interconnection request and the interconnection customer's cost responsibility for these facilities.[45]

22. At the completion of the facilities study, the transmission provider will issue a report, which includes a ''best estimate of the costs to effect the requested interconnection,'' and provide a draft generator interconnection agreement to the interconnection customer.[46] If the interconnection customer wishes to proceed, after negotiations, the interconnection customer enters into a generator interconnection agreement with the transmission provider or requests that the transmission provider file the agreement with the Commission unexecuted.[47]

D. Interaction Between the Regional Transmission Planning and Cost Allocation and Generator Interconnection Processes

23. The interaction between a transmission provider's current generator interconnection process and its regional transmission planning and cost allocation processes appears to be limited. The primary interaction is that the baseline regional transmission planning models generally only incorporate interconnection projects that are near the end of the interconnection process and have completed a facilities study. In addition, when creating interconnection study models, transmission providers incorporate transmission planning information into the interconnection base cases, but what information is incorporated varies for each transmission provider. The base cases for interconnection studies impact the cost assignment for interconnection customers, often dramatically, and at present, most transmission providers' OATTs do not contain requirements for what information is included in base cases.[48]

E. Current Funding Paradigm

1. Regional Transmission Cost Allocation

24. As noted above, Order No. 1000's cost allocation reforms require each transmission provider to participate in a regional transmission planning process that features a regional cost allocation method or methods for allocating the cost of new regional transmission facilities selected in a regional transmission plan for purposes of cost allocation. The Commission also required that such regional cost allocation methods satisfy six regional cost allocation principles, including the principle that the cost of transmission facilities must be allocated to those in the transmission planning region that benefit from the facilities in a manner that is roughly commensurate with estimated benefits.[49]

2. Local Transmission Facilities

25. In Order No. 1000, the Commission explained that the local transmission planning process is the transmission planning process that a transmission provider performs for its individual retail distribution service territory or footprint pursuant to the requirements of Order No. 890.[50] The outcome of the local transmission planning processes are local transmission facilities. In Order No. 1000, the Commission defined a local transmission facility as a transmission facility located solely within a transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation.[51]

26. The Commission clarified that, if the transmission provider has a retail distribution service territory and/or footprint, then only a transmission facility that it decides to build within that retail distribution service territory or footprint, and that is not selected in a regional transmission plan for purposes of cost allocation, may be considered a local transmission facility. Further, the Commission explained that, in the case of an RTO/ISO whose footprint covers the entire region, local transmission facilities are defined by reference to the retail distribution service territories or footprints of its underlying transmission owing members.[52] The Commission did not require that the transmission facilities in a transmission provider's local transmission plan be subject to approval at the regional or interregional level, unless that transmission provider seeks to have any of those facilities selected in the regional transmission plan for purposes of cost allocation.[53]

27. Moreover, local transmission facilities planned through a local transmission planning process are not eligible to use the Order No. 1000 regional cost allocation method and instead their costs are allocated to the transmission provider in whose retail distribution service territory or footprint the local transmission facility is located. In support of this, the Commission explained that it continues to permit 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 as long as the transmission provider does not receive regional cost allocation for the facilities.[54] Further, the Commission clarified that nothing in Order No. 1000 restricts an incumbent transmission provider from developing a local transmission solution that is not eligible for regional cost allocation to meet its reliability needs or service obligations in its own retail distribution service territory or footprint.[55]

3. Interconnection-Related Network Upgrades

28. The Commission's interconnection pricing policy[56] allows for two general approaches on how to assign the cost of interconnection-related network upgrades, one of which we refer to as the crediting policy and the other as participant funding. We will discuss the rationale that the Commission provided when accepting each of the two approaches in later sections.

29. In Order No. 2003, the Commission established the crediting policy as a requirement of the Commission's interconnection pricing policy. Pursuant to the crediting policy, the interconnection customer is solely responsible for the costs of interconnection facilities, and interconnection-related network upgrades are funded initially by the

[45] Order No. 2003, 104 FERC ¶ 61,103 at PP 35–36. The interconnection customer is responsible for the costs of interconnection studies and any necessary restudies.

[46] *Id.* P 38.

[47] *Id.*

[48] For example, some transmission providers have details regarding what information is included in an interconnection study base case in their tariffs, *see e.g. Sw. Power Pool, Inc.,* 172 FERC ¶ 61,283, at P10 (2020), while others limit that information to the business practices manuals. *See, e.g.,* NYISO Manual 26, Reliability Planning Process Manual at 15–16.

[49] Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 639. The six Order No. 1000 regional cost allocation principles are discussed further below.

[50] *Id.* P 68.

[51] *Id.* P 63.

[52] Order No. 1000–A, 139 FERC ¶ 61,132 at P 429.

[53] *Id.* P 190.

[54] *Id.* PP 366, 379, 425, 428.

[55] Order No. 1000, 136 FERC ¶ 61,051 at P 329.

[56] We use the term interconnection pricing policy to refer collectively to both Order No. 2003's establishment of the crediting policy for financing interconnection-related network upgrades and Order No. 2003's allowance of participant funding for interconnection-related network upgrades in RTOs/ISOs.

interconnection customer (unless the transmission provider elects to fund them) and the transmission provider reimburses the interconnection customer through transmission service credits.[57] The Commission reasoned that ''it is appropriate for the Interconnection Customer to pay initially the full cost of Interconnection Facilities and [interconnection-related] Network Upgrades that would not be needed but for the interconnection.'' [58] While the interconnection customer pays for the costs of the interconnection-related network upgrades upfront, the transmission provider must reimburse the total amount that the interconnection customer paid for interconnection-related network upgrades, plus interest, as credits against the charges for transmission service taken with respect to the interconnection customer's generating facility as such charges are incurred. The transmission provider recovers the cost of interconnection-related network upgrades funded under the crediting policy through its embedded cost transmission rates.[59] The second pricing approach for interconnection-related network upgrades is called participant funding. Participant funding for interconnection-related network upgrades refers to the direct assignment to a particular interconnection customer of the costs of interconnection-related network upgrades that would not be needed but for the interconnection.[60] The Commission has accepted as just and reasonable various participant funding approaches proposed by RTOs/ISOs as independent entity variations from the *pro forma* requirements of Order No. 2003.

[57] Order No. 2003, 104 FERC ¶ 61,103 at P 22.

[58] *Id.* P 694. ''But for'' interconnection-related network upgrades are those interconnection-related network upgrades that would not have been constructed ''but for'' the interconnection request. *See N.Y. Indep. Sys. Operator, Inc.,* 122 FERC ¶ 61,267, at n.3 (2008).

[59] The embedded cost pricing ''attempts to allocate costs among customers based upon usage.'' *Fla. Power & Light Co.,* 70 FERC ¶ 61,158 (1995). Embedded cost rates reflect ''system average costs *including* the cost of the [interconnection-related] network upgrades, and incremental cost rates ''reflect [ ] *just* the cost of the [interconnection-related] network upgrades.'' *See Interstate Power & Light Co.* v. *ITC Midwest, LLC,* 144 FERC ¶ 61,052, at P 36 (2013) (emphasis added).

[60] Order No. 845–B, 166 FERC ¶ 61,092 at P 5; *see also* Order No. 2003, 104 FERC ¶ 61,103 at P 679 (pursuant to a ''policy of participant funding . . . those [that] benefit from a particular project pay for it'').

III. The Potential Need for Reform

A. The Existing Regional Transmission Planning and Cost Allocation and Generator Interconnection Processes May Be Inadequate To Ensure Just and Reasonable Rates

30. As a result of changing circumstances since the Commission issued Order Nos. 890, 1000, and 2003, we believe it is now appropriate to examine whether the existing regional transmission planning and cost allocation and generator interconnection processes adequately account for the transmission needs of the changing resource mix, or whether reforms may be necessary to ensure that transmission rates remain just and reasonable and not unduly discriminatory or preferential.

1. Considering Anticipated Future Generation

31. Expansion of the transmission system generally occurs by design through a transmission provider's transmission planning processes, or ad hoc through its generator interconnection process. At present, it appears 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, including considering the needs of anticipated future generation in identifying needed transmission facilities. Although regional transmission planning processes may include some level of generation development in different future scenarios analyses, it appears that they tend to include in their baseline reliability models only those generators that have completed facilities studies, and thus are far along in the generator interconnection process. These baseline reliability models, by relying only on generators that have completed facilities studies, may only account for generation that will come online in the short term.

32. As a result, the generator interconnection process appears to be the principal means by which infrastructure is built to accommodate new generators. That process, however, focuses on a single interconnection request (or cluster of requests). In other words, the generator interconnection process is not designed to consider how to address anything beyond the reliability interconnection-related network upgrades required for a specific interconnection request or group of interconnection requests.

33. New transmission facilities often have a development lead time that exceeds the interconnection timing needs of those interconnection customers already in the queue. It appears that these types of transmission facilities may not currently be planned and built in advance to meet the needs of anticipated future generation and as a result, interconnection customers are assigned the costs to construct large, high-voltage transmission facilities.

34. In addition, because transmission planning processes generally do not plan for the needs of anticipated future generation, transmission infrastructure that is being developed in order to facilitate new generation is constructed largely through the generator interconnection process, which is unlikely to result in the economies of scale that could more efficiently or cost-effectively meet the needs of the changing resource mix.

35. Likewise, the existing generator interconnection process appears to focus on the limited set of facilities needed to reliably interconnect a single interconnection customer (or cluster of requests) at the interconnection service level that the interconnection customer requests. The generator interconnection process may not adequately consider whether it may be more efficient or cost-effective to consider the interconnection-related network upgrades needed for multiple anticipated future generators that are not in the same cluster or are not yet in the interconnection queue in areas that have abundant wind or solar attributes that could support multiple future generators.[61]

36. In addition, there may be a need for coordination between the regional transmission planning process and the generator interconnection process, the absence of which may result in inefficient investment in transmission infrastructure and ultimately unjust and unreasonable or unduly discriminatory or preferential rates. By considering the transmission needs of anticipated future generation in its regional transmission planning and cost allocation processes, a transmission provider may identify transmission facilities that could facilitate both the interconnection of new generation as well as address other identified transmission system needs—such as mitigating a reliability violation or reducing congestion—at a lower total cost than pursuing two separate transmission projects through the

[61] We note that certain regions do have the ability to share costs of network upgrades with future generation, but this is generally limited to the short term. For example, Midcontinent Independent System Operator, Inc.'s (MISO's) Shared Network Upgrade construct allows interconnection customers to be repaid for portions of an interconnection-related network upgrade's cost if another interconnection customer uses that network upgrade within five years.

generator interconnection and regional transmission planning and cost allocation processes. Without co-optimization of the two processes, however, there appears to be no system in place to jointly assess the benefits and allocate the costs of transmission facilities that yield benefits to both system loads and new generation.

2. Results of Existing Local and Regional Transmission Planning Processes

37. We seek to better understand whether 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. 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. We seek 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.

3. Cost Responsibility for Transmission Facilities and Interconnection-Related Network Upgrades

38. The Commission cannot ensure just and reasonable rates without considering how to allocate the costs of transmission facilities and interconnection-related network upgrades that result from the regional transmission planning and cost allocation and generator interconnection processes to the entities that benefit from those facilities. As the Commission explained in Order No. 1000, the costs of transmission infrastructure must be allocated to its beneficiaries in a manner that is at least roughly commensurate with the benefits that they draw from those facilities.[62] We seek to better understand whether the current approach to allocating the costs of transmission infrastructure, including transmission facilities developed through the regional transmission planning and cost allocation processes and interconnection-related network upgrades planned through the generator interconnection process, continues to appropriately allocate the costs of those transmission facilities to the entities that ultimately benefit from them.

39. The current regional transmission planning process considers transmission needs driven by reliability, economics, and Public Policy Requirements. We seek comment whether, by separating transmission facilities into types, transmission planning processes may fail to take into account the benefits of multi-faceted projects for the purposes of cost allocation.

40. The current approach to allocating the costs of interconnection-related network upgrades may fail to allocate costs in a manner that is roughly commensurate with benefits. As discussed above, the generator interconnection process identifies the interconnection facilities and interconnection-related network upgrades needed to interconnect a single interconnection request (or cluster of requests). Under the participant funding approach to financing the cost of interconnection-related network upgrades, the interconnection customer pays for the costs of such upgrades, even where they would provide benefits to other customers such as resolving congestion on the transmission system. At the time that the Commission issued Order No. 2003, it was less likely that interconnection customers would be assigned significant interconnection-related network upgrades through the interconnection study process. Now, however, there is little remaining existing interconnection capacity on the transmission system, particularly in areas with high degrees of renewable resources that may require new resources to fund interconnection-related network upgrades that are more extensive and, as a result, more expensive. The more significant the interconnection-related network upgrades needed to accommodate a new resource, the greater the potential that such upgrades may benefit more than just the interconnection customer. Where an interconnection customer elects not to pursue a generating facility with system-wide benefits that exceeds such facility's cost, net beneficial infrastructure would not be developed, potentially leaving a wide range of customers worse off as a result.

41. We also note that the cost of interconnection-related network upgrades can depend entirely on both the timing of when and the specific site where the interconnection customer enters the interconnection queue that may result in interconnection customers submitting multiple speculative interconnection requests in an effort to receive a favorable queue position and reduce their interconnection-related network upgrade costs.[63] When interconnection customers "test the waters" in this manner, it may lead to late-stage withdrawals of the excess interconnection requests that can then impede the transmission provider's ability to process its interconnection queue in an efficient manner. Because of the changing interconnection landscape since Order No. 2003, the Commission's interconnection pricing policy, and in particular participant funding, now may result in a situation where interconnection customers have a financial incentive to submit multiple speculative projects. As a result, we believe it may be time to reexamine the rationale behind the Commission's pricing policy established for interconnection-related network upgrades and to consider reforms to generator interconnection processes that would make such processes more efficient, less costly, and ensure that generation projects that are more "ready" than others are not unduly delayed in the queue. In consideration of generator interconnection process reforms, we remain mindful of the need to ensure that interconnection costs are not unjustly and unreasonably shifted to customers of load-serving entities.

42. While a reassessment of Order No. 2003's assumptions pertaining to the Commission's interconnection pricing policy may be necessary, our focus is in line with Order No. 2003's finding that "relatively unencumbered entry into the market is necessary for competitive markets." [64] Furthermore, the purpose of this examination is also consistent with the original objectives of Order No. 2003, namely to "limit opportunities for Transmission Providers to favor their owner generation" and to "facilitate market entry for generation competitors by reducing interconnection costs and time." [65] At the same time, there is reason to question the contention in Order No. 2003 that participant funding provides more "efficient price signals and a more equitable allocation of costs than the crediting approach." [66] Also, while the crediting policy "recognizes the reliability benefits of a stronger

[62] Order No. 1000, 136 FERC ¶ 61,051 at P 10.

[63] *See, e.g., Review of Generator Interconnection Agreements and Procedures,* Technical Conference Transcript, Docket No. RM16–12–000, at Tr. 211:10–21 (May 13, 2016) (Steve Naumann, Exelon Corporation) (filed Aug. 23, 2016) ("We would look at putting let's say new gas fired generation in PJM, it may have four queue positions. And we only intend to go through with one, that's not speculation, that's trying to get information on which is the most viable.").

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

[65] *Id.* P 12.

[66] *Id.* P 695.

transmission infrastructure and more competitive power markets that result from a policy that facilitates the interconnection of new generating facilities,'' [67] we raise questions on whether there are improvements that can be made to the crediting policy or whether a different pricing policy may be more efficient.

43. We note that ensuring just and reasonable rates, while maintaining grid reliability, remain the priorities for regional transmission planning, and cost allocation processes, and generator interconnection processes, and any comments proposing revisions to existing regulations should address their impact on reliability and costs to customers. All proposed reforms or revisions to regulations proposed in this proceeding must be consistent with the Commission's authority under section 206 of the FPA.

IV. Consideration of Potential Reforms and Request for Comment

A. Regional Transmission Planning and Cost Allocation Processes

1. Potential Reforms and Request for Comment

a. Planning for the Transmission Needs of Anticipated Future Generation

44. We seek comment regarding whether transmission providers in each transmission planning region should amend the regional transmission planning and cost allocation processes to plan for the transmission needs of anticipated future generation to meet a changing resource mix, including generation that is not yet in the interconnection queue. We seek comment on whether the existing regional transmission planning and cost allocation processes fail to adequately account for anticipated future generation. We also seek comment on whether the possible failure to account for anticipated future generation results in inefficient investment in transmission infrastructure and causes customers to pay unjust and unreasonable rates for transmission service. We also seek comment on whether, and, if so, how the Commission could structure and implement a framework for considering the transmission needs of anticipated future generation in the regional transmission planning and cost allocation processes. Commenters should address how each suggested reform or revision to existing rules is consistent with the Commission's authority under the FPA.

[67] Order No. 2003–A, 106 FERC ¶ 61,220 at P 584.

45. Below, we describe potential changes to the regional transmission planning and cost allocation processes that may be components of a process that plans for transmission needs associated with anticipated future generation. We seek comment on each of these potential changes, including whether and, if so, how the potential changes may lead to identification of more efficient or cost-effective transmission solutions to meet the needs of anticipated future generation. We also seek comment on whether there exist other potential revisions that could improve regional transmission planning and cost allocation for anticipated future generation, either as alternatives to potential reforms discussed herein or as supplementary reforms.

i. Future Scenarios and Modeling Anticipated Future Generation

46. We seek comment on whether reforms are needed regarding how the regional transmission planning and cost allocation processes model future scenarios to ensure that those scenarios incorporate sufficiently long-term and comprehensive forecasts of future transmission needs. We seek comment on what factors shaping the generation 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 enshrined into law; (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. With regard to each factor that may be considered for inclusion in scenario modeling, we seek comment on the source of the Commission's authority to incorporate that factor in the regional transmission planning and cost allocation processes. In addition, we seek comment on whether the Commission should establish minimum requirements regarding future scenarios for transmission providers to use in their regional transmission planning, including modeling anticipated future generation in those scenarios. Commenters should also address whether and how any reforms or revisions to existing rules could unjustly and unreasonably shift additional costs to customers of load serving entities. Commenters should also address whether the status quo does or does not allocate costs in a manner roughly commensurate with benefits, and whether the status quo leads to rates that are unjust or unreasonable.

47. The current regional transmission planning and cost allocation processes vary regarding how far into the future transmission providers look when evaluating transmission needs driven by reliability, economic considerations, or Public Policy Requirements. In general, however, the extent to which regional transmission planning processes plan for anticipated future generation is often limited to generation in the generator interconnection queue with a completed facilities study, which represents a relatively short-term outlook, and therefore may under-forecast anticipated future generation on a longer-term basis (and the associated transmission needs of that anticipated future generation). As noted, planning and developing the transmission facilities needed to address more efficiently or cost-effectively the transmission needs of a changing resource mix will often take considerably longer than the typical development timeline of a generating facility that has completed a facilities study and by considering such a limited subset of generation resources, more cost-effective transmission facilities that address longer-term needs may never be developed.

48. In light of the above, we seek comment on whether, and if so, how the regional transmission planning process should be restructured to consider a longer-term outlook. We seek comment on whether developing plausible long-term scenarios would lead to the identification of more efficient or cost-effective transmission solutions in regional transmission plans, whether building transmission facilities to accommodate anticipated future generation is required to render rates just and reasonable, and whether there are deficiencies in existing regional transmission planning and cost allocation processes that would be cured by conducting such future scenarios planning. Specifically, we seek comment on whether the development of longer-term scenarios for planning purposes should be pursued and, if so: (1) The number of years into the future the scenarios should consider (including an explanation of how far ahead it is reasonable to forecast anticipated future generation and system requirements); (2) the inputs that should be considered in modeling anticipated future generation; (3) different transmission planning methods, including whether consideration should be given to multiple future scenarios, as well as how the planning process should consider the probabilities of future

scenarios; (4) whether and how transmission providers should account for an array of different future scenarios when identifying more efficient or cost-effective transmission solutions in regional transmission plans; (5) whether and how transmission providers should account for federal, state, local, and individual utility energy and climate goals (including federal, state and local laws and regulations, as well as other policies or goals), and the source of the Commission's authority to account for such laws, regulations, policies and goals; (6) whether and how transmission providers should plan for expected future generator retirements; (7) whether and how Grid-Enhancing Technologies [68] should be accounted for in determining what transmission is needed under such scenarios; (8) how benefits and costs of transmission infrastructure should be accounted for in such models, including how adjusted production costs should be calculated; (9) any other aspects of future scenarios modeling, including planning for anticipated future generation and associated transmission needs that would be useful for the Commission to consider.

49. In addition, we seek comment on whether greater use of probabilistic transmission planning approaches may better assess the benefits of regional transmission facilities. While some transmission providers consider a small number of future scenarios as part of their transmission planning process, more advanced approaches, such as stochastic [69] techniques, may provide an opportunity to consider a broader array of potential future conditions. Accordingly, we seek comment on potential benefits and drawbacks of such techniques in regional transmission planning assessments, including whether these or other new approaches may facilitate the co-optimization of generation siting and transmission development, whether such methods capture savings in generation capital costs as well as production expenses that can be realized from transmission additions, and whether implementing such methods is required to render rates just and reasonable.

50. We also seek comment on which inputs and assumptions transmission providers would need to model to represent new generation sources, such as renewable resources, in order to reflect their actual performance, such as active power-frequency control, reactive power-voltage control, and fault ride-through capabilities, in the planning study cases and any additional studies in order to ensure that transmission planning solutions result in operating reliability for the future.

51. We seek comment on the extent to which anticipated generation and transmission facility retirements are reflected in future scenarios modeled by transmission providers, and whether modifications to regional market rules and coordination processes between local and regional plans could facilitate more accurate regional transmission plans that reflect such anticipated retirements.

52. In addition, should the use of certain long-term scenarios be shown appropriate as part of ensuring just and reasonable rates, we seek comment on whether and how the Commission should ensure that the regional transmission planning and cost allocation processes develop a sufficiently wide range of future scenarios. We seek comment on whether the Commission should consider principles or minimum requirements as a basis for establishing such scenarios. Given that states or other local governing bodies may be uniquely situated in determining how much anticipated future generation is needed, or in providing information related to infrastructure siting or resource mix as influenced by state and local policies, we seek comment on how their input should be reflected by transmission providers in developing a sufficiently wide range of future scenarios, including those for anticipated future generation, and the more efficient or cost-effective transmission facilities that may be necessary to facilitate those future scenarios. We seek comment on whether it is necessary to require transmission providers to modify the regional transmission planning and cost allocation processes, such as requiring additional stakeholder input, to develop future scenarios, including those for anticipated future generation, such that there are sufficient opportunities for stakeholders to assess the reasonableness of the results, as well as for future modifications to the planning process.

53. Finally, we seek comment on whether and how such long-term scenarios should be used in identifying and selecting solutions to meet future transmission needs. For example, as discussed below, should transmission providers focus on a broader set of benefits for transmission facilities and a portfolio of transmission facilities in identifying the more efficient or cost-effective transmission solutions? If so, how should regional planning processes determine the right set of benefits to factor into such an evaluation? Is maximizing net benefits an appropriate criterion to use to identify efficient and cost-effective transmission solutions? Should the willingness of some beneficiaries to pay for certain transmission infrastructure, for example utilities or corporations with renewable resource or zero carbon goals, be considered in determining whether to include the benefits within a broader set of benefits from transmission facilities, and if so then how? Is there a need to establish a minimum set of transmission facility benefits that transmission providers must incorporate into regional transmission planning decisions, and if so, is there also a need to regularly update the minimum set of transmission facility benefits?

ii. Identifying Geographic Zones That Have Potential for High Amounts of Renewable Resource Development To Meet Increased Demand

54. We seek comment on whether the Commission should require transmission providers in each transmission planning region to establish, as part of their regional transmission planning and cost allocation processes, a process to identify geographic zones that have the potential for the development of large amounts of renewable generation and plan transmission to facilitate the integration of renewable resources in those zones.

55. Examples of transmission planning and development initiatives that have identified geographic zones with the potential for the development of significant amounts of renewable resources and transmission to facilitate the integration of renewable resources in those zones include the Public Utility Commission of Texas's (Texas Commission) Competitive Renewable Energy Zones (CREZ) initiative [70] and MISO's Multi-Value Projects (MVP).[71]

56. California Independent System Operator Corporation (CAISO) offers another example of a regional transmission planning process identifying transmission facilities to accommodate renewable resources in

[68] Grid Enhancing Technologies increase the capacity, efficiency, or reliability of transmission facilities. 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. FERC, *Grid Enhancing Technologies,* Notice of Workshop, Docket No. AD19–9–000 (Sept. 9, 2019).

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

[70] *http://www.ercot.com/committee/crez.*

[71] *https://www.misoenergy.org/planning/planning/multi-value-projects-mvps/.*

geographic zones that have the potential for high amounts of renewable resources. In a petition for declaratory order, the Commission approved a mechanism to facilitate the financing and development of transmission facilities to interconnect multiple resources that met CAISO's eligibility requirements, including a high voltage level and providing access to areas rich in renewable energy.[72]

57. We seek comment on whether the Commission should require transmission providers in each transmission planning region to establish, as part of their regional transmission planning and cost allocation processes, a process that identifies geographic zones that have the potential for the development of large amounts of new generation, particularly renewable resources. We seek comment on whether and how such a process might interrelate with existing regional transmission planning and cost allocation processes within each region, and how long-term scenario planning discussed above may be used in this process or other relevant regional transmission planning and cost allocation processes. In addition, we seek comment on whether reforms to the current interregional transmission coordination process are needed or appropriate for making an approach along these lines effective. We also seek comment on: (1) How the Commission should structure this potential requirement; and (2) any potential best practices, analyses, models, and metrics that could be used to identify such zones, including the amount and type of potential generation that could be located there. As with the future scenarios transmission planning discussed above, we seek comment on whether and how states and local entities may provide input into the identification of such zones. We seek comment on whether, and, if so, how transmission providers can assess whether there is sufficient commercial interest in developing generation in any potential zones and transmission to interconnect the potential generation (for example, through studies or formal declarations of interest). We also seek comment on whether and, if so, what safeguards or incentives might be necessary to ensure that transmission infrastructure is built only to satisfy expected transmission needs and not overly speculative commercial interests. We also seek comment on whether any such requirement is consistent with the FPA's prohibition of unduly discriminatory or preferential rates.

58. We seek comment on whether the Commission should require transmission providers to account for trends in the resource mix in developing energy zones for anticipated future generation as part of planning for transmission needs related to such resources and if so, what would be the best way to do so? We seek comment whether it would be appropriate, as the resource mix further develops, to develop similar zones for the transmission needs driven by the development and interconnection of energy storage resources and how to do so.

59. In order to ensure that the more efficient or cost-effective transmission facilities are selected and that rates are just and reasonable, we also seek comment on whether: (1) Eligibility thresholds or criteria (*e.g.,* voltage levels, amount of new generation located within a given geographic area or load zone, etc.) may be appropriate to determine whether a proposed regional transmission facility should be considered as part of the regional transmission planning and cost allocation process for transmission facilities built for anticipated future generation; (2) whether the CREZ, MISO MVP, CAISO approaches, or other processes for identifying and planning for the needs of anticipated future generation are models for any potential requirements and, if so, which aspects of those initiatives the Commission should consider requiring transmission providers to implement, for example, the CREZ model of requiring future generation to financially commit in advance of construction; (3) whether there is a need for mechanisms to limit the risk to customers from planning for anticipated future generation, for example, we note CAISO's use of an *ex ante* cap on the total cost exposure to transmission customers in addressing generation resource interconnection, as one potential approach;[73] and (4) whether specific proposals are consistent with the Commission's FPA section 206 authority.

60. We also seek comment on whether the regional transmission planning process could be structured in such a way that is more collaborative, relying on the knowledge and experience that transmission providers, project developers, state commissions, and other stakeholders have regarding optimal locations, the topography of the transmission network, and Public Policy Requirements, among other factors that will influence the location and amount of future renewable resources. We note that the CREZ process was highly collaborative, with the Electric Reliability Council of Texas (ERCOT) conducting workshops with stakeholders over a six-month period to consider and evaluate multiple transmission scenarios.[74] In addition to seeking comment on technical and collaborative approaches to identify geographic zones for future renewable resources, we seek comment on potential alternative proposals from stakeholders on how to identify where transmission facilities may be needed to accommodate anticipated future generation. Commenters should address whether, if implemented, such a scenario planning process should be the same or different in non-RTO/ISO versus RTO/ISO regions, and if different, what those differences should be. Commenters should address how any proposed changes to the regional planning and cost allocation processes increase the efficiency, or lower the costs, of such processes and whether such changes will help ensure a reliable power supply and/or will reduce or control the costs of transmission and generation services that are ultimately passed on to customers of load serving entities. Commenters should also address proposed cost allocation.

iii. Incentivizing Regional Transmission Facilities

61. To prioritize regional transmission facilities that may have greater benefit-to-cost ratios than local alternatives, we seek comment on whether and, if so, how to expand or improve any incentives to incent the development of regional transmission facilities that demonstrably may offer a more efficient or cost-effective solution to an identified need than local alternatives. As an example of a possible regional transmission incentive, we seek comment on whether or not any available return on equity adder incentive that may be available for RTO/ISO participation should be limited in applicability only to regional, and not local, transmission facilities, when those regional transmission facilities are selected as the more efficient or cost-effective solution to an identified transmission need.

iv. Enhanced Interregional or State-to-State Coordination

62. We recognize that potential reforms discussed for comment above may require greater interregional or

[72] *Cal. Indep. Sys. Operator Corp.,* 119 FERC ¶ 61,061 (2007).

[73] *Id.* P 6.

[74] *See* Texas Commission, Order on Rehearing, Docket No. 33672, at 3 (Oct. 7, 2008).

state-regional coordination to be fully realized in a just, reasonable and not unduly discriminatory or preferential manner. As a result, we seek comment on whether reforms to the current interregional transmission coordination process, including potentially requiring interregional transmission planning, are needed or appropriate for making the potential approaches discussed above effective, and whether such reforms are consistent with the Commission's authority under section 206 of the FPA.

63. We seek comment on whether, because an interregional project must first be selected in each of the neighboring regions' regional planning processes before being selected in the interregional process, this challenge to the current interregional coordination process is impeding the selection and development of efficient, cost-effective interregional projects and, if so, what revisions are necessary to address that barrier. Should the Commission require joint planning processes, rather than simply joint coordination, for neighboring regions? In light of the potential reforms to regional planning and cost allocation and generator interconnection processes being considered in this ANOPR, are there core principles or approaches that the Commission should also consider when reviewing the existing approach to interregional planning? For example, should the Commission establish interregional reliability planning criteria or consider renewable resource geographic zones during interregional planning? Beyond interregional planning, can and should the Commission provide alternate pathways for transmission facilities that benefit multiple regions to be assigned cost allocation to customers across multiple regions? For example, should the Commission allow for identification of benefits, and allocation of commensurate costs, to one region of a project selected in a neighboring region's regional transmission planning process? Finally, comments should address whether taking any proposed action is consistent with the Commission's authority under section 206 of the FPA.

64. In addition, we seek comment on whether and, if so, 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 regional transmission planning and cost allocation and interregional coordination and cost allocation for transmission needs related to future scenarios, including for anticipated future generation or geographic generation zones.

b. Coordinating Between the Regional Transmission Planning and Cost Allocation and Generator Interconnection Processes

65. We seek comment on whether reforms are needed to improve the coordination between the regional transmission planning and cost allocation and generator interconnection processes. We seek comment on whether the Commission should require transmission providers to operate their regional transmission planning and cost allocation and generator interconnection processes on concurrent, coordinated timeframes, with the same or similar assumptions and methods, and whether such a potential requirement may identify more efficient or cost-effective transmission solutions that could address needs shared between the two processes.

66. We seek comment on how the regional transmission planning and cost allocation and generator interconnection processes could be better coordinated or integrated. For example, would use of similar timeframes and assumptions facilitate more efficient or cost-effective transmission solutions? How could these processes most effectively be co-optimized? We seek comment on whether and, if so, how 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 associated with, for example, resource adequacy, operating reliability, and similar needs, and in coordination with the regional transmission planning process? We seek comment on whether and how relevant information from the generator interconnection process could be integrated into regional transmission planning in a timely manner, and whether and how transmission providers could move beyond using the outputs of each process as a deterministic input into the other rather than optimizing together across approaches. We also seek comment on whether it may be possible and beneficial to combine certain aspects of the transmission planning and generator interconnection processes, and if so, how?

67. We also seek comment on whether and how the Commission could revise transmission planning criteria that transmission providers use in the generator interconnection process so that they could better identify more efficient or cost-effective interconnection-related network upgrades. As indicated earlier, we also seek comment on whether and how transmission providers could incorporate anticipated future generation, including resources in the interconnection queue, in the regional transmission planning and cost allocation processes. In particular, we encourage commenters to discuss how to address concerns regarding uncertainty, including speculative projects, in planning for anticipated future generation.

68. Further, we seek comment on whether and how more effectively accounting for anticipated future generation in transmission planning may reduce the costs of interconnection-related network upgrades. To the extent this is the case, how should such benefits be identified, and should they factor into the regional transmission planning and cost allocation process?

B. Identification of Cost and Responsibility for Regional Transmission Facilities and Interconnection-Related Network Upgrades

69. The Commission has repeatedly recognized that, where cost allocation methods do not appropriately account for benefits associated with new transmission facilities, they may result in rates that are not just and reasonable or are unduly discriminatory or preferential.[75]

70. We seek comment on whether the existing approach to cost allocation in regional transmission planning processes fails to consider the full suite of benefits—and the associated beneficiaries—produced by transmission facilities developed to meet the transmission needs of the changing resource mix. We seek comment on whether the current approach omits relevant benefits of new transmission infrastructure and, if so, thereby fails to consider the entities that receive those benefits in the cost allocation process. What, specifically, are those other benefits that should be considered? In addition, while the regional transmission planning process considers transmission needs driven by reliability, economic considerations, and Public Policy Requirements, these types of transmission needs are, in

[75] *See* Order No. 890, 118 FERC ¶ 61,119 at P 557 (finding that how ''the costs of new transmission facilities are allocated is critical to the development of new infrastructure'' because ''[t]ransmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated cost''); Order No. 1000, 136 FERC ¶ 61,051 at PP 484–487; *see also Ill. Commerce Comm'n* v. *FERC*, 576 F.3d 470, 476 (7th Cir. 2009) (*ICC* v. *FERC*).

many cases, considered in isolation from one another and the cost allocation methods for transmission facilities developed in response to these needs are generally separated by type. We seek comment as to whether the existing regional transmission planning and cost allocation processes may not fully account for the full suite of benefits, including hard-to-quantify benefits, and may impede the allocation of the costs of transmission facilities needed to meet the transmission needs of the changing resource mix in a manner that is at least roughly commensurate with the actual benefits of those facilities. Getting that balance right is important not only to comply with the cost causation principle, but also because efforts to plan the transmission system to meet the needs of the changing resource mix will succeed only if the associated cost allocation methods are transparent, equitable, and practicable.[76]

71. With respect to cost allocation in the generator interconnection process, we seek comment as to whether the participant funding approach for interconnection-related network upgrades required for an interconnection request in RTOs/ISOs may no longer be just and reasonable. Participant funding may result in costly interconnection-related network upgrades being allocated entirely to interconnection customers while failing to account for the significant benefits that these interconnection-related network upgrades may provide to other anticipated future generators seeking to interconnect and/or existing or future transmission customers. We further seek comment on whether the narrow focus of the generator interconnection process results in only a subset of beneficiaries paying for transmission infrastructure that, in practice, may benefit many.

72. We seek comment on whether separating the regional transmission planning and cost allocation and generator interconnection processes may increasingly result in an only partial-accounting of the benefits of new transmission infrastructure, leaving some transmission and interconnection customers potentially bearing a disproportionate cost burden. We seek comment on whether any changes to the criteria used for considering which transmission facilities are selected in the regional transmission plan for purposes of regional cost allocation, as well as the formula for the regional allocation of costs of regional transmission facilities and for the cost of interconnection-related network upgrades, including changes to the definition of beneficiary, hold the potential to unjustly and unreasonably shift costs to customers of load serving entities. We seek comment on how any contemplated reforms or revisions to existing regulations are consistent with the FPA and its requirement for just and reasonable and not unduly discriminatory or preferential rates.

73. In the following sections, we address the relevant court and Commission precedent governing cost allocation and seek comment on a number of potential reforms to address these concerns and ensure that transmission rates remain just and reasonable and not unduly discriminatory or preferential.

1. Relevant Cost Causation Precedent

74. Pursuant to FPA sections 205 and 206, the Commission is responsible for ensuring that the rates, terms, and conditions for transmission of electricity in interstate commerce are just, reasonable, and not unduly discriminatory or preferential.[77] For a cost allocation approach to satisfy this standard, it must satisfy the cost causation principle. The cost causation principle requires that ‘‘all approved rates reflect to some degree the costs actually caused by the customer who must pay them’’ [78] and that costs ‘‘be allocated to those who cause the costs to be incurred and reap the resulting benefits.’’ [79] As the U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit) further explained, to ‘‘the extent that a utility benefits from the costs of new facilities, it may be said to have ‘caused’ a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.’’ [80] Courts ‘‘evaluate compliance with this . . . principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.’’ [81] In *ICC* v. *FERC,* the Seventh Circuit also stated that a cost allocation method can satisfy the cost causation principle if the Commission ‘‘has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with’’ the allocation of the costs.[82] The Seventh Circuit stated, however, that satisfying this requirement does not require exacting precision, and the Commission need not ‘‘calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars.’’ [83]

2. Cost Allocation for Transmission Facilities Planned Through the Regional Transmission Planning Process

75. Potential reforms for which we seek comment in this ANOPR contemplate a more forward-looking approach to the regional transmission planning process that plans for anticipated future generation, potentially producing a different and broader set of benefits and beneficiaries. The following sections seek comment on potential reforms that may be necessary to ensure that the costs of transmission facilities developed to meet the transmission needs of the changing resource mix are allocated in a manner that is roughly commensurate with those benefits, while ensuring that any potential reforms or revisions to existing cost-allocation rules do not unjustly or unreasonably shift costs to any type of market participant or customers of load serving entities. We seek comment on whether certain benefits are not appropriate to account for under the FPA, and whether allocation of costs based on such benefits may be inconsistent with the Commission's statutory mandate.

a. Background

76. In Order No. 1000, the Commission determined that the lack of clear *ex ante* cost allocation methods that identify beneficiaries of proposed regional transmission facilities was

[76] *Cf. BNP Paribas Energy Trading GP* v. *FERC,* 743 F.3d 264, 268–269 (D.C. Cir. 2014) (*BNP Paribas Energy*) (‘‘[T]he cost causation principle itself manifests a kind of equity. This is most obvious when we frame the principle (as we and the Commission often do) as a matter of making sure that burden is matched with benefit.’’ (citing *Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d 1361, 1368 (D.C. Cir. 2004) *and Se. Mich. Gas Co.* v. *FERC,* 133 F.3d 34, 41 (D.C. Cir. 1998))); Order No. 1000, 136 FERC ¶ 61,051 at P 669 (explaining that requiring cost allocation methods be open and transparent ensures that such methods are just and reasonable and not unduly discriminatory or preferential, aids in development and construction of new transmission, and may avoid contentious litigation or prolonged stakeholder debate); *KN Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300–01 (D.C. Cir. 1992) (describing properly designed rates as producing revenues ‘‘‘*which match, as closely as practicable, the costs to serve each class or individual customer*’’’ (emphasis in original)) (quoting *Ala. Elec. Coop., Inc.* v. *FERC,* 684 F.2d 20, 27 (D.C. Cir. 1982)); *Pub. Serv. Co. of Colo.,* 163 FERC ¶ 61,204, at P 14 (2018) (recognizing that ‘‘feasibility’’ is part of ratemaking, such that the Commission may appropriately ‘‘balance maximally reflecting cost causation with other competing policy goals,’’ such as promoting more efficient or cost-effective regional transmission planning).

[77] 16 U.S.C. 824d, 824e.

[78] *KN Energy, Inc.* v. *FERC,* 968 F.2d at 1300.

[79] *S.C. Pub. Serv. Auth.,* 762 F.3d at 87 (quoting *NARUC* v. *FERC,* 475 F.3d at 1285).

[80] *ICC* v. *FERC,* 576 F.3d at 476.

[81] *Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d at 1368.

[82] 576 F.3d at 477.

[83] *Id.* (citing *Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d at 1369).

impairing the ability of transmission providers to implement more efficient or cost-effective transmission solutions identified in the regional transmission planning process. According to the Commission, the failure to address cost allocation in a way that aligns with the benefits of new transmission facilities could lead to needed transmission facilities not being built, adversely impacting ratepayers.[84] The Commission therefore required transmission providers to have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation. To guide transmission providers, the Commission established a set of cost allocation principles that transmission providers' cost allocation methods must satisfy, with the goal of ensuring that the costs of transmission solutions chosen to meet regional transmission needs would be allocated to those that received benefits from them.[85] The Commission determined that this principles-based approach would result in 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.[86]

77. The six regional cost allocation principles that the Commission adopted in Order No. 1000 are: (1) Costs of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; (2) those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities;[87] (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1;[88] (4) costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs;[89] (5) the method for determining benefits and identifying beneficiaries must be transparent;[90] and (6) there may be different methods for different types of transmission facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.[91] Although the Commission required the regional cost allocation methods to determine benefits and identify beneficiaries in a transparent manner, the Commission also recognized that ''identifying which types of benefits are relevant for cost allocation purposes, which beneficiaries are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial.''[92] Consistent with this notion, the Commission declined to require transmission providers to adopt a universal or comprehensive definition of ''benefits'' and ''beneficiaries''[93] of regional transmission facilities, instead allowing for regional flexibility and examining each region's definitions on compliance.

78. The result is that transmission providers in each transmission planning region have implemented varying regional transmission cost allocation methods to comply with the cost allocation principles of Order No. 1000, the majority of which allocate the costs of regional transmission facilities that address reliability needs separately from those that address economic needs and separately from those that address Public Policy Requirements. In other words, most regional transmission cost allocation methods do not consider whether a regional transmission facility addresses more than one category of needs, and therefore provides more than one category of transmission benefits.

79. That said, some transmission providers' Order No. 1000-compliant regional transmission cost allocation methods may recognize a broader number of benefits than others and identify the broader benefits across a portfolio of transmission facilities rather than on a facility-by-facility basis, whereas others may be more constrained. For example, MISO's MVP process is designed to identify a portfolio of regional transmission facilities that: (1) Reliably and economically enable regional public policy needs; (2) provide multiple types of regional economic value; and/or (3) provide a combination of regional reliability and economic value. Specifically, MISO MVPs must be above 100 kV, have a project cost of $20 million or more, and have a combined benefit-to-cost ratio greater than 1.0 and must be evaluated as part of a portfolio of transmission projects.[94] The costs of this MVP portfolio are allocated on a postage stamp basis across the MISO region.[95]

80. Southwest Power Pool's (SPP) Balanced Portfolio process similarly considers broader transmission benefits.[96] SPP evaluates economic benefits of a portfolio of transmission facilities to achieve a balance where the benefits of the portfolio to each zone (as measured by adjusted production cost savings) equal or exceed the costs allocated to each zone over a 10-year period. By allocating costs such that the benefits to each zone will equal or exceed those costs, the Balanced Portfolio process ensures that SPP allocates costs in a manner that is least roughly commensurate with benefits by design. In addition, SPP may reallocate costs to ensure that the portfolio is balanced and, under certain conditions, including cancellation of a transmission facility or unanticipated decreases in benefits or increases in costs, may review a previously approved Balanced Portfolio and recommend reconfiguring the portfolio.[97]

81. As for allocating the costs of regional transmission facilities to generators, in Order No. 1000, while commenters requested that the Commission allow such costs to be allocated to generators as beneficiaries, the Commission determined that generator interconnection was outside the scope of the rulemaking.[98] However, the Commission also stated that 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 not be inconsistent with the Order No. 2003 generator interconnection process. The Commission noted that in not addressing these issues, it was neither minimizing the importance of evaluating the impact of generator interconnection requests during transmission planning, nor limiting the ability of transmission providers to use requests for generator interconnections in developing assumptions to be used in

[84] Order No. 1000, 136 FERC ¶ 61,051 at P 499.

[85] *Id.* PP 9, 482–83.

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

[87] Order No. 1000, 136 FERC ¶ 61,051 at P 637.

[88] *Id.* P 646.

[89] *Id.* P 657.

[90] *Id.* P 668.

[91] *Id.* P 685.

[92] *Id.* P 501.

[93] Order No. 1000–A, 139 FERC ¶ 61,132 at P 679 (explaining that Order No. 1000 does not define benefits and beneficiaries but rather requires transmission providers to be definite about benefits and beneficiaries for purposes of their cost allocation methods).

[94] MISO, FERC Electric Tariff, Attachment FF, Section II.C (85.0.0).

[95] *Id.* Section III.A.2.g.

[96] SPP's Balanced Portfolio was an initiative to develop a group of economic transmission projects that benefit the entire SPP region and to allocate those transmission project costs regionally. The SPP Board of Directors approved the Balanced Portfolio transmission projects in April 2009.

[97] SPP OATT, attach. J (Recovery of Costs Associated With New Facilities), Section III.D.

[98] Order No. 1000, 136 FERC ¶ 61,051 at P 760.

the regional transmission planning process.[99]

82. Nevertheless, at least one transmission provider considers interconnection customers as beneficiaries of new transmission facilities. The Commission approved CAISO's proposal whereby transmission customers initially fund the transmission expansion needed to facilitate interconnection through the transmission revenue requirement of the constructing transmission provider, and interconnection customers are assigned their pro rata share of the going-forward costs of using the transmission facility as their generators interconnect to the transmission system. Under CAISO's proposal, all transmission system users pay the costs of the unsubscribed portion of a new transmission facility until the line is fully subscribed.[100] The CAISO approach also includes an *ex ante* cap on the total cost exposure to transmission customers, which was set at 15% of the sum total of the net high-voltage transmission plant of all transmission providers, as reflected in their transmission revenue requirements and in the CAISO transmission access charge.[101]

b. Potential Need for Reform

83. This statement in Order No. 1000 rings as true today as it did then—''identifying which types of benefits are relevant for cost allocation purposes, which beneficiaries are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial.'' [102] This is especially true for larger, regional transmission facilities that are both costly and could have potentially broad benefits. As the Commission recognized in Order No. 890, the manner in which the costs of new transmission facilities are allocated is ''critical'' to developing those facilities as is identifying the types of benefits and the associated beneficiaries of those facilities.[103]

84. The possible reforms for which we seek comment in this ANOPR seek to ensure the development of regional transmission facilities needed to meet the transmission needs of the changing resource mix occurs in a more efficient or cost-effective manner, at just and reasonable rates. Commenters should also address whether and how any reforms or revisions to existing rules could unjustly and unreasonably shift additional costs to customers of load serving entities. These reforms cannot be successful without ensuring that transmission providers and customers alike are able to identify the types of benefits of 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. The failure to account for all the benefits of a transmission facility while taking into account all the costs of the transmission facility does not allow for a fair examination of whether the costs are allocated roughly commensurate with the benefits. We seek comment on whether ignoring benefits of these transmission facilities may impair more efficient or cost-effective transmission development by limiting the number of facilities that overcome the cost-benefit threshold needed to justify the cost of new transmission, and if so, what the appropriate standard should be for identifying such benefits. This potential concern goes to the need to not only identify the types of benefits of these new transmission facilities, and to quantify those benefits where possible, but likewise to the need for transparent methods to calculate benefits and ascertain beneficiaries without being so burdensome that the methods hinder transmission development. We seek comment on whether customers of load serving entities should be required to pay the costs of regional transmission facilities that provide them only with unquantifiable or purported benefits, or be required to pay for costs driven by the public policies of state and local governments in states other than their own.[104]

85. Currently, most regional cost allocation methods do not consider whether a regional transmission facility addresses more than one category of needs, thereby providing more than one category of transmission benefits. Specifically, although the regional transmission planning process considers transmission needs driven by reliability, economic considerations, and Public Policy Requirements,[105] these types of transmission needs are generally considered in a silo from one another; the cost allocation methods for regional transmission facilities developed in response to these needs are similarly for the most part separated by type. We seek comment on whether the result is a paradigm that may potentially fail to consider the suite of benefits that transmission facilities provide and therefore fails to allocate the costs of such facilities roughly commensurate with the benefits.

86. We seek comment as to whether a shift to a more integrated and holistic process for regional transmission planning and cost allocation is appropriate. Such a shift may raise novel questions around which customers should pay for new transmission facilities and concerns about free riders benefitting from the transmission expansion without paying for their fair share. Under the potential reforms for which we seek comment in this ANOPR, the regional transmission planning process would identify transmission facilities that support future scenarios, including anticipated future generation, and improve pricing and cost allocation for interconnection-related network upgrades. In that scenario, interconnection customers themselves could be considered beneficiaries of transmission facilities that facilitate their interconnection, even if those transmission facilities were built prior to the generators entering the interconnection queue. We seek comment on whether merely making interconnection customers the beneficiaries fails to capture all of the relevant types of benefits for purposes of cost allocation of a regional transmission facility built to accommodate anticipated future generation. We also seek comment on whether it may therefore be preferable to consider developing new regional transmission cost allocation methods that measure all of the benefits of regional transmission facilities that are being assessed for potential selection in the regional transmission plan for purposes of cost allocation and that accrue to both transmission and interconnection customers.

87. We cannot ignore, of course, that it may be difficult to precisely quantify some of the benefits of transmission facilities, which can be a barrier to more broadly allocating the costs of those facilities among transmission and interconnection customers. Unlike costs, which are clearly defined and easily quantified, the scope of which transmission benefits count for purposes of cost allocation, and how well they need to be documented in order to be allocated to customers, is a distinct

[99] *Id.* P 760.

[100] *Cal. Indep. Sys. Operator Corp.,* 119 FERC ¶ 61,061.

[101] *Cal. Indep. Sys. Operator Corp.,* 119 FERC ¶ 61,061, at P 6.

[102] Order No. 1000, 136 FERC ¶ 61,051 at P 501.

[103] Order No. 890, 118 FERC ¶ 61,119 at P 557.

[104] *See, e.g.,* PJM's State Agreement Approach. *PJM Interconnection, L.L.C.,* 142 FERC ¶ 61,214, at PP 142–143 (2013), *order on reh'g and compliance,* 147 FERC ¶ 61,128, at P 92 (2014);

[105] Order No. 1000 left planning and cost allocation for Public Policy Requirements largely to the discretion of transmission providers. *See supra* P 16. Moreover, under PJM's State Agreement Approach (see supra n.104), the costs of transmission facilities required to meet the public policy requirements of an individual state or group of states may not be shifted to customers in other, non-participating states.

challenge to achieving a fair allocation. Requiring transmission providers to produce overly detailed reports on benefits before the costs of a transmission facility can be allocated to transmission and interconnection customers could lead to cost allocations that undervalue the largest transmission expansions, no matter their efficiency. The task is in striking the right balance to ensure just and reasonable rates and the allocation of transmission costs roughly commensurate with benefits.

88. We also note that, with greater deployment of renewable resources, and in part to the extent that regions focus on a project-specific regional transmission cost allocation method, it is possible that benefits may be distributed unevenly across regions. For example, there are likely zones or sub-zones within a region that are rich in renewable resources and therefore have generation significantly in excess of the local load. These zones, and generators in these zones, may not be the only beneficiaries of regional transmission facilities built to access these resources as customers outside those zones may reap reliability or economic benefits that result from the expanded transmission system and access to low cost resources. We seek comment on whether current regional transmission cost allocation approaches may not adequately address these circumstances and may not provide workable frameworks for the identification of transmission beneficiaries and sharing of benefits.

89. We seek comment on whether there should be reforms to cost allocation in regional transmission planning and cost allocation processes, including considering potentially a portfolio approach to assessing regional transmission facilities and consideration of a minimum set of transmission benefits, while seeking additional information about cost allocation approaches that may inform such reforms. Commenters proposing specific changes to cost allocation should address how such proposals will result in costs being allocated in a manner roughly commensurate with benefits, and demonstrate that costs will not be disproportionately borne by any given class of customers in a manner inconsistent with the requirements of the FPA and precedent. Commenters should also address how such proposals impact customers of load serving entities and whether and how proposed new cost allocation formulae may shift costs to new categories of customers and whether such cost-shifting is just and reasonable and consistent with the requirements of the FPA.

c. Potential Reforms and Request for Comment

90. We seek comment on whether broader transmission benefits should be taken into account when planning the transmission system for anticipated future generation, and how such benefits should be identified and quantified. Some transmission providers, *e.g.,* SPP, MISO, CAISO, and recently the New York Independent System Operator, Inc. (NYISO), have used broader transmission benefits in selecting regional transmission facilities for purposes of cost allocation in their regional transmission planning processes.

91. In addition, under a portfolio approach to regional transmission cost allocation, multiple transmission facilities are considered together, and the collective benefits of the transmission facilities are measured. MISO's MVP and SPP's Balanced Portfolio method are examples of portfolio approaches to regional transmission cost allocation. We seek comment on whether a portfolio approach recognizes that a regional transmission planning process that considers a group of transmission facilities that collectively provide multiple benefits, including reliability, economic, and Public Policy Requirements benefits, among others, may be able to better identify more efficient or cost-effective transmission facilities when compared to a process that focuses only on individual transmission facilities or individual benefits. We seek comment on whether an approach that both estimates broader transmission benefits for regional transmission facilities beyond those that are currently considered and that also allocates the costs for a portfolio of those individual transmission facilities may provide a cost allocation method that better matches benefits to burdens over time.[106] We seek comment on whether such an approach may also be more accurate or less likely to lead to anomalous results.

92. At the same time, we seek comment on whether there are circumstances in which the use of criteria other than reliability and economic considerations may result in projects being selected in the regional transmission plan for purposes of cost allocation that do not represent the optimal solution to the reliability or congestion problems identified and thus may not represent the most efficient or cost-effective solution for customers of the load serving entities both inside an RTO/ISO and in non-RTO/ISO region. Any proposals for changes to planning criteria and cost allocation should consider whether such proposals result in unjustly and unreasonably shifting costs to customers. We seek comment on whether the use of planning criteria beyond reliability and economic considerations may place the burden for the costs driven by Public Policy Requirements of one state on customers of load serving entities in non-participating states.

93. We seek comment on the current approaches that transmission providers take in defining transmission benefits for purposes transmission planning and cost allocation. For example, we are interested in how transmission providers calculate adjusted production costs, the extent to which transmission providers go beyond adjusted production costs in identifying transmission benefits, the types of benefits, and the methods for estimating. We also seek comment on the extent to which it may be challenging, for certain types of benefits, to identify the beneficiaries for cost allocation purposes. We seek comment on the extent to which the same set of benefits is currently used in regional transmission planning processes and their associated cost allocation processes, or whether some benefits are identified but not factored into cost allocation. Should the same set of benefits be used in all processes? If not, would it be appropriate to consider different benefits during the transmission planning and cost allocation stages? If so, what would be the basis for doing so?

94. We seek comment on the types of benefits provided by transmission facilities needed to meet the transmission needs of anticipated future generation that are relevant for cost allocation purposes and the manner in which those benefits can be quantified, if at all. This includes consideration of whether there are transmission benefits beyond those that transmission providers already take into account in allocating costs that the Commission should require all transmission providers to consider for regional transmission facilities. In other words, should the Commission require transmission providers to establish a broader set of transmission benefits for purposes of cost allocation than currently in use and, likewise, should the Commission adopt a minimum set of transmission benefits that must be considered? Such benefits could encompass economic benefits (*e.g.,*

[106] *See BNP Paribas Energy,* 743 F.3d at 268–69 (framing the cost causation principle ''as a matter of making sure that burden is matched with benefit'').

congestion reduction); resource adequacy benefits (*e.g.,* allowing imports to replace more expensive local generation, lowering required planning targets through increased diversity benefits); and reliability benefits (*e.g.,* avoided or deferred reliability transmission facilities, improved reserves sharing, increased voltage support). And to what extent are there benefits that will differ from region-to-region?

95. If there are types of benefits that cannot be quantified, but which are real and relevant to allocating the costs of regional transmission facilities roughly commensurate with benefits, we seek comment on how transmission providers can document and account for those benefits in crafting a cost allocation method. Similarly, we seek comment on whether the inability to precisely quantify benefits of transmission facilities can be a barrier to the development of those facilities, particularly those with potentially broad transmission benefits. If so, we are interested in what types of transmission facilities are most impacted and what types of benefits are typically associated with those types of transmission facilities, and how those benefits can be justified and quantified.

96. To the extent that there are relevant benefits that are difficult to quantify, we seek comment on ways in which the Commission can consider whether those benefits are appropriately credited to a regional transmission facility and accounted for as part of allocating the costs to beneficiaries. This includes consideration of when benefits of a transmission facility are sufficiently certain to justify a commensurately broad cost allocation, especially where those benefits are not susceptible to precise quantification. We also seek comment on whether it is appropriate to credit benefits that cannot be credibly quantified and whether, and if so, how, it is appropriate to factor such benefits into regional cost allocation.

97. In addition to identifying benefits, we also seek comment on best practices for identifying the beneficiaries of a transmission facility. For example, some interconnection-related network upgrades for generator interconnection may benefit more than a single interconnecting generator, however the scope (temporal and geographic) of such beneficiaries may not be clear. We seek comment on the efficacy and desirability of a regional transmission planning and cost allocation process that seeks to plan for future scenarios, including planning for anticipated future generation. What methods for ascertaining beneficiaries are most effective in allocating the costs of such facilities roughly commensurate with benefits? Are there threshold transmission system conditions that would enable the Commission to reasonably conclude that regional (or some greater or lesser geographical scope) allocation of costs is appropriate (such as the amount of congestion or level of interconnectedness in a particular area)? This necessarily links to our earlier questions about how to quantify benefits and what level of precision is required.

98. Along the same lines of identifying beneficiaries, we seek comment on whether the costs of transmission facilities planned in the regional transmission planning process for which we seek comment in this ANOPR should be allocated to both transmission and interconnection customers. As explained earlier, we are concerned about potential free-rider problems associated with interconnection customers that later connect to transmission facilities planned for anticipated future generation. We are therefore interested in approaches to cost allocation to ensure that both transmission and interconnection customers that benefit from those facilities pay their fair share. While we propose to potentially reform participant funding by interconnection customers of interconnection-related network upgrades, we are also considering how best to allocate costs of regional transmission facilities to interconnection customers (*e.g.,* whether cost allocation methods for regional transmission facilities should allocate a portion of the costs of a regional transmission facility directly to interconnection customers based on, for example, the capacity of the interconnection customer's generating facility).

99. We seek comment on the cost effectiveness of the reforms discussed herein. If the regional transmission planning and cost allocation processes are to consider transmission needs driven by anticipated future generation, is there a tradeoff between facilitating the construction of transmission facilities that are needed to connect such anticipated future generation, and ensuring against building more transmission than is necessary? If so, how should the Commission approach that tradeoff?

3. Participant Funding and Crediting Policy for Funding Interconnection-Related Network Upgrades

100. Since the issuance of Order No. 2003, the composition of the generation fleet has rapidly shifted from predominately large, centralized resources to include a large proportion of smaller renewable generators that, due to their distance from load centers, often require extensive interconnection-related network upgrades to interconnect to the transmission system. The significant interconnection-related network upgrades necessary to accommodate geographically remote generation are a result that the Commission did not contemplate when it established the interconnection pricing policy for interconnection-related network upgrades. Because the large-scale changes since Order No. 2003 may have impacted the underlying rationale for the interconnection pricing policy, we seek comment on whether the Commission should modify the participant funding and crediting policies, as discussed in further detail below.

a. Background

i. Original Rationale for the Order No. 2003 Interconnection-Related Network Upgrade Funding Requirements

101. As discussed above, the Commission in Order No. 2003 described two general approaches for assigning the costs of interconnection-related network upgrades needed to interconnect a generating facility to the transmission system: (1) the crediting policy, whereby the interconnection customer initially funds the interconnection-related network upgrades and is reimbursed through transmission credits;[107] and (2) participant funding, where the costs of interconnection-related network upgrades in RTOs/ISOs are assigned directly to the interconnection customer. Central to discussions of the Commission's interconnection-related network upgrade funding requirements is Order No. 2003's continued prohibition of ''and'' pricing. This prohibition provides that, when ''a Transmission Provider must construct

[107] Order No. 2003–B states that ''the period for reimbursement may not be longer than the period that would be required if the Interconnection Customer paid for transmission service directly and received credits on a dollar-for-dollar basis, or 20 years [from the generating facility's commercial operation date], whichever is less.'' Order No. 2003–B, 109 FERC ¶ 61,287 at PP 3, 36. If credits have not fully reimbursed the upfront payment within 20 years, Order No. 2003 requires ''a balloon payment'' at the end of year 20. *Id.* P 36. The crediting policy also requires that affected system operators provide credits for transmission service taken on an affected system. *Id.* P 42. Even if the interconnection customer does not take transmission service over the affected system, however, the affected system operator must still provide the 20-year balloon payment to refund any remaining balance to the interconnection customer. Order No. 2003–C, 111 FERC ¶ 61,401 at P 13.

[interconnection-related] Network Upgrades to provide new or expanded transmission service, the Commission generally allows the Transmission Provider to charge the higher of the embedded costs of the Transmission System with expansion costs rolled in, or incremental expansion costs, but not the sum of the two.'' [108] The Commission also explained that allowing the transmission provider to charge either the higher of an embedded cost rate for transmission service or an incremental rate designed to recover the cost of the interconnection-related network upgrades ''provides the Transmission Provider with a cost recovery mechanism that ensures that native load and other transmission customers will not subsidize service to the Interconnection Customer.'' [109]

(a) Crediting Policy

102. The Commission instituted the crediting policy to achieve multiple objectives. First, the Commission found that this policy would avoid prohibited ''and'' pricing for interconnection-related network upgrades because it ensures that the interconnection customer will not be charged twice for the use of the transmission system by paying both for the incremental cost of the upgrade and an embedded-cost rate (with the cost of that interconnection-related network upgrade rolled in) for use of the transmission system.[110] Also, the Commission stated that the crediting policy was intended to facilitate the efficient construction of interconnection-related network upgrades and enhance competition in bulk power markets by promoting the construction of new generation [111] Furthermore, the Commission found that the crediting policy would ensure comparable treatment for interconnection customers that are not affiliated with the transmission provider, as transmission providers traditionally roll the costs of interconnection-related network upgrades associated with their own generating facilities into their transmission rates.[112]

103. Additionally, in Order No. 2003–A, the Commission stated that it does ''not believe that the costs of [interconnection-related] Network Upgrades required to interconnect a Generating Facility to the Transmission System of a non-independent Transmission Provider are properly allocable to the Interconnection Customer through direct assignment because upgrades to the transmission grid benefit all customers.'' [113] The Commission also stated that the crediting policy has a two-fold purpose. First, by providing the transmission provider with a source of funds to construct the interconnection-related network upgrades, the upfront payment by the interconnection customer alleviates any delay that might result if the transmission provider were forced to secure funding elsewhere. Second, by placing the interconnection customer initially at risk for the full cost of the interconnection-related network upgrades, the upfront payment provides the interconnection customer with a strong incentive to make efficient siting decisions and, in general, to make good faith requests for interconnection service.[114]

104. In *NARUC* v. *FERC*,[115] multiple petitioners challenged the crediting policy established in Order No. 2003. The petitioners argued that the crediting policy was inconsistent with the cost causation principle because they disagreed with the Commission's conclusions that ''[interconnection-related] Network Upgrades benefit the entire network,'' [116] and therefore, all transmission customers should essentially pay for those interconnection-related network upgrades through the crediting policy.[117] The U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) agreed with the Commission's position and noted that the D.C. Circuit had previously ''endorsed the approach of 'assign[ing] the costs of system-wide benefits to all customers on an integrated transmission grid.' '' [118]

(b) *Participant Funding*

105. In Order No. 2003, the Commission stated that ''under the right circumstances, a well-designed and independently administered participant funding policy for [interconnection-related] Network Upgrades offers the potential to provide more efficient price signals and a more equitable allocation of costs than the crediting approach.'' [119] Therefore, the Commission stated that it would provide RTOs/ISOs with the flexibility to propose participant funding for interconnection-related network upgrades for a generator interconnection.[120] In accordance with this flexibility, the Commission did not prescribe specific policies for RTOs/ISOs but instead provided them with the flexibility to adopt policies of their own choosing, subject to Commission approval.[121] Over time, each RTO/ISO sought, and the Commission accepted, independent entity variations to adopt some form of participant funding rather than the crediting policy.

106. The Commission expressed its willingness to consider a well-designed participant funding approach in response to commenter concerns that the crediting policy ''mutes somewhat the Interconnection Customer's incentive to make an efficient siting decision that takes new transmission costs into account, and it provides the Interconnection Customer with what many view as an improper subsidy, particularly when the Interconnection Customer chooses to sell its output off-system.'' [122] Additionally, while the Commission mandated the crediting policy for non-independent transmission providers, Order No. 2003 acknowledged that the concerns that gave rise to the adoption of the crediting policy do not apply to RTOs/ISOs. For example, Order No. 2003 noted that ''a number of aspects of the 'but for' approach are subjective, and a Transmission Provider that is not an independent entity has the ability and the incentive to exploit this subjectivity to its own advantage'' by, for example, finding ''that a disproportionate share of the costs of expansions needed to serve its own power customers is attributable to competing Interconnection Customers.'' [123] In contrast, however, the Commission noted that RTOs and ISOs are independent, and neither own nor have affiliates that own generating facilities and thus do not have an incentive to discourage new generation by competitors.[124]

107. The Commission also explained that participant funding might speed up the development of new transmission infrastructure. In particular, Order No. 2003 postulated that ''participant

[108] Order No. 2003, 104 FERC ¶ 61,103 at n.111.

[109] Order No. 2003–A, 106 FERC ¶ 61,220 at P 613.

[110] Order No. 2003, 104 FERC ¶ 61,103 at P 694.

[111] *Id.* PP 612, 694.

[112] *Id.* P 694.

[113] Order No. 2003–A, 106 FERC ¶ 61,220 at P 212. As noted in the discussion below on participant funding, the Commission has allowed direct assignment of interconnection-related network upgrade costs to generators interconnecting to independent transmission providers such as RTOs/ISOs.

[114] *Id.* P 613.

[115] 475 F.3d 1277.

[116] *Id.*, 475 F.3d at 1285.

[117] *Id.* (citing *Pub. Serv. Co. of Colo.*, 62 FERC ¶ 61,013, at 61,061 (1993)).

[118] *Id.* (citing *W. Mass. Elec. Co.* v. *FERC*, 165 F.3d 922, 927 (DC Cir. 1999)).

[119] Order No. 2003, 104 FERC ¶ 61,103 at P 695.

[120] *Id.* P 28.

[121] Order No. 2003–A, 106 FERC ¶ 61,220 at P 696.

[122] Order No. 2003, 104 FERC ¶ 61,103 at P 695.

[123] *Id.* n.111.

[124] Order No. 2003–A, 106 FERC ¶ 61,220 at P 691.

funding of [interconnection-related network] upgrades may provide the pricing framework needed to overcome the reluctance of incumbent Transmission Owners in many parts of the country to build transmission, with the result that badly needed transmission infrastructure could be put in place quickly.'' [125]

108. RTOs/ISOs that have adopted a participant funding approach do not reimburse interconnection customers with transmission service credits for the cost of the interconnection-related network upgrades. Instead, the Commission allowed interconnection customers to receive well-defined capacity rights that are created by the interconnection-related network upgrades.[126] As an example, the Commission in Order No. 2003 pointed to PJM Firm Transmission Rights and Capacity Interconnection Rights, which, it stated, are ''created by the [interconnection-related] Network Upgrades for which the Interconnection Customer pays, and they are well-defined, long-term and tradeable.'' [127] The Commission stated that provision of such ''well-defined capacity rights'' in lieu of credits does not violate the prohibition of ''and'' pricing because the ''Interconnection Customer pays separate charges for separate services,'' namely ''an access charge for transmission service that may involve an obligation to pay congestion charges, and in exchange for its 'but for' payment, [the interconnection customer] receives these well-defined capacity rights, which provide some protection for having to actually pay the congestion charges.'' [128]

109. Commission precedent makes clear that the purpose of providing ''well-defined'' rights is not to provide full reimbursement for the costs of interconnection-related network upgrades. In fact, where an RTO/ISO adopts a participant funding approach for interconnection-related network upgrades required to interconnect an interconnection customer, there is no requirement that the capacity rights being awarded for interconnection-related network upgrades have equal value to the cost of the interconnection-related network upgrades because the costs would not exist ''but for'' the proposed interconnection and are simply part of a project's construction costs and business risk that the interconnection customer must consider.[129] Moreover, RTOs/ISOs are ''not required to provide transmission capacity rights where . . . the network upgrades create no additional transmission capability.'' [130] To this point, the Commission in *Old Dominion Electric Cooperative* v. *PJM Interconnection, L.L.C.* explained that, while Order No. 2003 ''stated that generation interconnection customers would receive capacity rights, those statements were based on the assumption that a network upgrade provided by an interconnection customer would create additional transmission capability beyond that needed to simply interconnect with the grid.'' [131]

110. Again, each RTO/ISO sought an independent entity variation to adopt a participant funding approach rather than adopt the crediting policy. In MISO, an interconnection customer is responsible for 100% of interconnection-related network upgrade costs, with a possible 10% reimbursement or ''crediting'' for interconnection-related network upgrades that are 345 kV and above.[132] In CAISO, the interconnection customer's cost responsibility for a particular interconnection-related network upgrade depends on how CAISO classified the interconnection-related network upgrade (*i.e.,* whether the interconnection-related network upgrade is considered area, local, or reliability) and the interconnection-related network upgrade's deliverability status (*e.g.,* full capacity, partial capacity, or energy-only).[133] In CAISO, full cash reimbursement is only available for the costs of certain categories of interconnection-related network upgrades, up to $60,000 per MW of installed generation capacity, and interconnecting generators receive congestion revenue rights in exchange for funding any upgrades that are not eligible for cash reimbursement. SPP, NYISO, PJM, and ISO-New England, Inc. use a participant funding approach where the transmission provider assigns 100% of the interconnection-related network upgrade costs to the interconnection customer and the interconnection customer may receive compensation through transmission capacity rights.[134]

b. Potential Need for Reform

i. Participant Funding

111. Since the issuance of Order No. 2003, changing circumstances have cast doubt on whether it continues to be just and reasonable to provide RTOs/ISOs with the flexibility to adopt participant funding approaches for interconnection-related network upgrades. We seek comment on whether these developments suggest that the allowance of participant funding for interconnection-related network upgrades, both as a concept and in its application, may no longer be just and reasonable. Moreover, it appears that the incentives created by participant funding in this context may produce outcomes that are counter to the Commission's intentions in allowing flexibility for RTOs/ISOs to adopt participant funding in Order No. 2003.

112. To begin with, participant funding may allocate the costs of extensive interconnection-related network upgrades entirely to interconnection customers without accounting for the significant benefits that these interconnection-related network upgrades may provide to transmission customers. As a result, there are circumstances where this allocation of interconnection-related network upgrade costs may not be roughly commensurate with the distribution of benefits. For instance, a large interconnection-related network upgrade built on a consistently congested portion of the transmission system may provide significant

[125] Order No. 2003, 104 FERC ¶ 61,103 at P 703.

[126] *Id.* P 700.

[127] *Id.*

[128] *Id.*

[129] *PJM Interconnection, L.L.C.,* 108 FERC ¶ 61,025, at P 20 (2004); *see also Midwest Indep. Transmission Sys. Operator, Inc.,* 114 FERC ¶ 61,106, at P 66 (2006).

[130] *Old Dominion Elec. Coop.* v. *PJM Interconnection, L.L.C.,* 119 FERC ¶ 61,052, at P 18 (2007) (*ODEC* v. *PJM*).

[131] *ODEC* v. *PJM,* 119 FERC ¶ 61,052 at P 18; *see also id.* P 16 (''Not every system upgrade required simply to interconnect a generating facility safely to the grid entitles the generator to capacity rights; however, a generation interconnection customer would be 'allowed to receive' capacity rights if a [interconnection-related] network upgrade creates additional transmission capability.'').

[132] *See, e.g., Midcontinent Indep. Sys. Operator, Inc.,* 164 FERC ¶ 61,158, at P 5 (2018) (''MISO's Interconnection Customer Funding Policy . . . requiring the interconnection customer to 'participant fund' 90–100 percent of its [interconnection-related] network upgrades . . . was accepted, under the Order No. 2003 independent entity variation standard in 2009.''); *Midwest Indep. Transmission Sys. Operator, Inc.,* 129 FERC ¶ 61,060, at P 8 (2009) (accepting MISO's ''proposed change [that] would result in the interconnection customer bearing 100 percent of the costs of [interconnection-related] network upgrades rated below 345 kV and bearing 90 percent of the costs of [interconnection-related] network upgrades rated at 345 kV and above (with the remaining 10 percent being recovered on a system-wide basis'')); *Midwest Indep. Trans. Sys. Operator, Inc.,* 114 FERC ¶ 61,106, at P 62 (2006).

[133] *Cal. Indep. Sys. Operator Corp.,* 140 FERC ¶ 61,070, at PP 24–27 (2012).

[134] *PJM Interconnection, L.L.C.,* 108 FERC ¶ 61,025 (2004); *Sw. Power Pool, Inc.,* 127 FERC ¶ 61,283 (2009); *Sw. Power Pool, Inc.,* 171 FERC ¶ 61,272 (2020); *N.Y. Indep. Sys. Operator, Inc.,* 108 FERC ¶ 61,159 (2004), *order on reh'g,* 111 FERC ¶ 61,347 (2005); *ISO New Eng. Inc.,* 133 FERC ¶ 61,229 (2010).

economic and reliability benefits to transmission customers. Also, transmission customers, in some instances, can make use of any excess transmission capacity created by a participant funded interconnection-related network upgrade without paying any of the capital costs that are paid for through a participant funding approach. Allowing transmission customers to receive the benefits of interconnection-related network upgrades without paying for a proportionate share of their costs is an example of the ''free rider'' problem that the Commission's ''beneficiary pays'' cost causation principle is supposed to avoid.[135]

113. Furthermore, while the interconnection customer may receive well-defined capacity rights associated with the increased transfer capability caused by the interconnection-related network upgrade, these well-defined capacity rights do not compensate the interconnection customer for the broad range of benefits that the interconnection-related network upgrades can provide to the transmission system and therefore do not solve the ''free rider'' problem. This is because the well-defined capacity rights do not capture reductions in congestion costs paid by transmission customers that were the result of the expansion of the transfer capability created by the interconnection-related network upgrade; nor do they capture transmission service charges for use of the excess capacity created by the interconnection-related network upgrade. Instead, well-defined capacity rights capture congestion costs paid by transmission customers on a going forward basis across the relevant transmission path on which the interconnection-related network upgrade increased transmission capacity. To the extent that the interconnection-related network upgrade may have eliminated most of the *ex ante* congestion on the relevant paths, the transmission customers that transact across such paths and have their congestion costs reduced as a result of the large interconnection-related network upgrade now in service will receive this benefit for free in most cases.

114. We seek comment on whether costs allocated to interconnection customers pursuant to participant funding approaches have increased over time, and if so, why. We seek comment on whether this increase in costs is evidence that regional transmission planning processes are not building adequate transmission system capacity. We seek comment on whether the Commission's policies on participant funding have impacted the interconnection queue, *e.g.,* through late-state withdrawals, and if so, how and to what degree. In the case that there are late-stage withdrawals from the interconnection queue, we seek comment on the ability of transmission providers to efficiently process interconnection requests from other interconnection customers affected by the withdrawal. Finally, we seek comment on whether uncertainty regarding interconnection costs drives up the cost of developing supply resources and thereby ultimately increases the cost of electricity supply for customers.

115. Participant funding also may create a separate incentive for the interconnection customer that may undermine the development of interconnection-related network upgrades that produce greater benefits. Specifically, the interconnection customer, knowing that it will be responsible for all interconnection-related network upgrade costs, is likely to strongly oppose any addition or modification to the transmission system beyond what is necessary to support its own interconnection, even if such additions and modifications may ultimately benefit it and others by providing improved reliability or economic outcomes.[136]

116. An additional rationale that the Commission provided in Order No. 2003 for allowing participant funding was the concern that the interconnection crediting policy would ''mute somewhat the Interconnection Customer's incentive to make an efficient siting decision that takes transmission costs into account.'' [137] The Commission in Order No. 2003 also found that participant funding in RTOs/ISOs is consistent with the policy of promoting competitive wholesale markets because it causes the interconnection customer to face the same marginal cost price signal that it would face in a competitive market.[138] We seek comment on whether to reconsider these findings in light of current circumstances.

117. We note, for instance, that the Commission's view of efficient siting of generation in Order No. 2003 was from a transmission costs perspective, *i.e.,* which points of interconnection would require the least expensive interconnection-related network upgrades. We seek comment on whether this perspective may be at odds with the primary siting considerations for renewable generation developers decades later. That is, interconnection at locations where renewable generation may experience higher efficiency factors (*e.g.,* because they have abundant wind or sun) may still be uneconomic where participant funding applies because the costs of interconnection-related network upgrades for that location may be significant and would not be allocated beyond the interconnection customer. We seek comment on whether interconnection at such locations may be considered economic, however, if the cost of the interconnection-related network upgrades were allocated more broadly among those that benefit. Thus, because the price signal participant funding sends does not account for the broader economic efficiencies from siting renewable generation in fuel-rich areas, it can instead encourage the development of renewable generation in less productive locations. Because increased renewable resource penetration in RTOs/ISOs is likely to continue, it may make less sense to retain a policy that encourages renewable developers to develop lower quality, less dependable renewable resources.

118. Further, given the uncertainty created by the RTO/ISO queue backlogs and cascading interconnection-related network upgrade cost allocations that move from withdrawing higher-queued interconnection customers to lower-queued interconnection customers, participant funding may no longer provide efficient price signals that allow generators to act freely to achieve the desirable level of entry of new cost-effective generating capacity. We understand that a contributing factor to the interconnection queue backlog is a tendency by interconnection customers to submit multiple interconnection requests at different points of interconnection, with the intention of discovering the lowest cost site for a

[135] *See, e.g.,* Order No. 1000–A, 139 FERC ¶ 61,132 at P 562 (''Given the nature of transmission operations, it is possible that an entity that uses part of the transmission grid will obtain benefits from transmission facility enlargements and improvements in another part of that grid regardless of whether they have a contract for service on that part of the grid and regardless of whether they pay for those benefits. This is the essence of the 'free rider' problem the Commission is seeking to address through its cost allocation reforms.'').

[136] *See Review of Generator Interconnection Agreements and Procedures,* Technical Conference Transcript, Docket No. RM16–12–000 at Tr: 193: 20–24 (Steve Naumann, Exelon) (filed Aug. 23, 2016) (''[Y]ou need to also deal with the [interconnection] customer who says, 'Okay, I will be perfectly willing to take the risk, but I don't want to pay for a single upgrade more than I have to [to] have a the reliability interconnection.'').

[137] Order No. 2003, 104 FERC ¶ 61,103 at P 695.

[138] *Id.* P 702.

project (from an interconnection perspective), and then withdrawing higher-cost projects from the queue later in the process. This tendency can require numerous restudies and reallocation of interconnection-related network upgrade costs, compounding the uncertainty surrounding the amount of interconnection-related network upgrade costs that will be attributable to viable projects as the queue progresses.

119. We seek comment on whether it is appropriate to eliminate or reduce participant funding for interconnection-related network upgrades in RTOs/ISOs and whether any specific proposed changes to interconnection funding mechanisms allocate costs in a manner roughly commensurate with benefits and are otherwise consistent with the Commission's authority under the FPA and do not unjustly or unreasonably shift costs to customers of load serving entities.

ii. Crediting Policy

120. We seek comments on whether we should revisit the crediting policy in all regions by requiring that transmission providers, instead of interconnection customers, fund upfront all or a portion of the interconnection-related network upgrade costs. We describe multiple variations of this proposal below. Some generation developers may find it difficult to provide upfront funding for the costs of network upgrades when the reimbursement period can be as long as 20 years. Accordingly, we seek comment on whether the current approach may unjustly and unreasonably allocate significant financing costs for interconnection-related network upgrades to interconnection customers when the benefits of the interconnection-related network upgrades accrue to the broader system. We seek comment on whether, if interconnection-related network upgrade costs are increasing on average, it is possible that these upfront funding costs may pose an unjust and unreasonable barrier to entry for generation developers. Given these considerations, below we seek comment on some potential reforms to the crediting policy.

c. Potential Reforms and Request for Comment

121. We seek comment on whether the Commission should eliminate the independent entity variations that allow RTOs/ISOs to use participant funding for interconnection-related network upgrades. We also seek comment on potential approaches for modifying or replacing the existing crediting policy for the costs of interconnection-related network upgrades in all regions. We seek comment on these options and invite alternative suggestions by commenters that take into consideration the concerns discussed above.

122. Additionally, for each of the reforms contemplated below, we seek comment on whether there are articulable and plausible reasons to believe that these reforms would allocate the costs of interconnection-related network upgrades in a manner that is at least roughly commensurate with the benefits of those interconnection-related network upgrades and that do not unjustly and unreasonably shift costs to customers of load serving entities or are otherwise inconsistent with the Commission's statutory authority.

i. Eliminate Participant Funding for Interconnection-Related Network Upgrades

123. We seek comment on whether participant funding of interconnection-related network upgrades may be unjust and unreasonable. We seek comment on whether RTOs/ISOs with previously approved independent entity variations that directly assign some or all the cost responsibility for interconnection-related network upgrades to interconnection customers should be required to revise their tariffs to remove the participant funding of interconnection-related network upgrade requirements and instead implement the crediting policy as prescribed in the *pro forma* LGIA.

124. The potential proposal to eliminate participant funding of interconnection-related network upgrades in RTOs/ISOs would recognize, however, that simply because an interconnection request makes an interconnection-related network upgrade necessary for interconnection (and in that sense, ''causes'' the need for interconnection-related network upgrades that would not be needed ''but for'' an interconnection request), an interconnection-related network upgrade may sufficiently benefit transmission customers that it is appropriate to allocate the interconnection-related network upgrade costs more broadly. Also, this potential proposal could address the free rider problem that is created by participant funding of interconnection-related network upgrades. We note, however, that the specific proposal is to eliminate participant funding and replace it with the crediting policy, a pricing approach that still requires interconnection customers to initially fund interconnection-related network upgrades.[139] Moreover, no potential reform presented here would modify the existing requirement that an interconnection customer bear cost responsibility for the interconnection facilities that would not be needed but for its interconnection request.

125. We seek comment on whether the removal of participant funding of interconnection-related network upgrades may also have the potential to increase integration of generation by removing the possibly prohibitive cost assignment that participant funding can place on some interconnection customers. Furthermore, it may reduce cost uncertainty to those resources in the interconnection queue, and by extension, increase the likelihood that an interconnection request will result in a developed generating facility.[140]

126. Additionally, we seek comment on whether eliminating participant funding may reduce the queue backlogs that plague many regions because interconnection customers would have less incentive to submit multiple interconnection requests in an attempt to lower their interconnection costs, and may no longer drop out of interconnection queues at late stages due to unforeseen interconnection-related network upgrade cost increases. To these points, we seek comment on the number of interconnection requests that have withdrawn from the queue because the direct assignment of significant interconnection-related network upgrade costs made otherwise viable interconnection requests uneconomic.

127. We seek comment on whether the independent entity variation granted to RTOs/ISOs in Order No. 2003 is no longer just and reasonable. In general, we seek comment on whether the incentives created by participant funding of interconnection-related network upgrades in RTOs/ISOs may produce outcomes that are counter to the Commission's transmission planning and cost allocation efforts.

[139] As noted below, however, we are exploring reforms to the existing crediting policy approach (that could be adopted alone or in combination with the elimination of participant funding) that could reduce the level of upfront funding to be provided by the interconnection customers.

[140] *See, e.g., Review of Generator Interconnection Agreements and Procedures,* Technical Conference Transcript, Docket No. RM16–12–000, at Tr. 25: 8–15 (May 13, 2016) (Dean Gosselin, NextEra) (filed Aug. 23, 2016) (''I'd like to just talk about what is optimal . . . as a developer . . . trying to advance [a project] to fruition . . . . I would say for the interconnection queue that the initial results closely match final results in a defined and reasonable timeline, that would be my definition.''); *id.* at 134:5–7 (Omar Martino, EDF Renewable Energy) (''[C]osts can change dramatically between [the] system impact and [the] facility study.'').

128. We are aware that there could be complications associated with implementing the crediting policy in RTOs/ISOs with zonal transmission rates that do not occur outside RTOs/ISOs. Outside RTOs/ISOs, a single transmission provider owns and operates its transmission system and generally charges a single rate for the entire system, regardless of the specific transmission customer's location. In contrast, an RTO/ISO operates the combined transmission assets of multiple transmission owners within its footprint at non-pancaked transmission rates, and generally has separate transmission pricing zones. The transmission rates for each zone are generally designed to recover the costs of transmission facilities *located* within each zone. As a result, we seek comment on whether simply applying the crediting policy currently used outside RTOs/ISOs in RTOs/ISOs may disproportionately increase the burden to the native load of transmission zones where large amounts of interconnection-related network upgrades are constructed to facilitate the interconnection of location-constrained resources, which ultimately may benefit the entire RTO/ISO footprint.

129. Under a crediting policy in an RTO/ISO, there may be a need for an appropriate mechanism to reimburse the interconnection customers, including a mechanism for determining which transmission owner(s) or zonal transmission rates will include the interconnection-related network upgrade costs. For example, there is a question of whether it would be just and reasonable to allocate the costs only within the transmission zone where the interconnection-related network upgrade is located or more broadly to multiple transmission zones.[141] We therefore seek comment on how to implement the crediting policy in RTOs/ISOs and what principles should be used to guide the application of the crediting policy in RTOs/ISOs.

130. Finally, given the concerns about the free-rider problem and whether the ''well-defined capacity rights'' received by interconnection customers capture the benefits the interconnection-related network upgrades provide to the system, we seek comment on: (1) The value of the ''well-defined capacity rights'' that interconnection customers have received for funding interconnection-related network upgrades; and (2) the value of the benefits that interconnection-related network upgrades have provided to the system, such as the value of congestion relieved by interconnection-related network upgrades. We are also interested in any other concerns related to the ''well-defined capacity rights'' that interconnection customers receive and the ability of these ''well-defined capacity rights'' to reflect the value of the full incremental capacity and congestion benefits added to the transmission system by the interconnection-related network upgrades.

[141] *See, e.g., Interstate Power & Light Co.* v. *ITC Midwest, LLC,* 144 FERC ¶ 61,052, at P 40 (2013), *order on reh'g, clarification and compliance,* 146 FERC ¶ 61,113 (2014). *See also Sw. Power Pool, Inc.,* 127 FERC ¶ 61,283, at P 5 (2009).

ii. Revisions to the Existing Crediting Policy

131. We seek comment on possible revisions to the Order No. 2003 interconnection crediting policy, which requires that interconnection customers provide upfront funding for interconnection-related network upgrades and receive reimbursement through transmission service credits or a balloon payment after 20 years. We enumerate multiple proposals below. Not all of these proposals are mutually exclusive, and some could be implemented in tandem.

(a) Transmission Providers Provide Upfront Funding for All Interconnection-Related Network Upgrades

132. Pursuant to this potential proposal, each transmission provider would provide upfront funding for all the interconnection-related network upgrades on its transmission system. Then, once such an interconnection-related network upgrade is in service, the transmission provider would be able to include the cost of that interconnection-related network upgrade in its transmission service rate base and recover a return on, and of, the network upgrade capital costs through the cost-of-service transmission rates in its OATT. Thus, interconnection customers that take transmission service on a transmission system would still pay for a portion of interconnection-related network upgrades through transmission rates. We seek comment on (1) this approach and (2) how this approach could be implemented in a just and reasonable manner.

133. This option would reduce the initial financing burden that interconnection customers currently may encounter when significant interconnection-related network upgrades are required for their interconnection request. Furthermore, this option may increase generator competition by lowering barriers to entry, which in turn will benefit customers by creating a more competitive market for energy.

134. There may also be additional efficiency benefits to removing the crediting policy because the financing of interconnection-related network upgrades would follow the same financing process that the transmission owners apply to the other transmission infrastructure that they fund and build on their system. That is, there could be an efficiency gain from using one financing process for all transmission system facilities instead of the existing two: one for interconnection-related network upgrades and another for other transmission system facilities. In addition to that particular inefficiency, under the current crediting approach applied in non-RTO/ISO regions, each interconnection-related network upgrade is financed twice—initially by the interconnection customer and then again by the transmission provider when the interconnection customer receives credits as it takes transmission service or receives a balloon payment after 20 years. Without the initial funding by the interconnection customer, interconnection-related network upgrades would only need to be financed once.

(b) Interconnection Customers Contribute to the Upfront Funding of Interconnection-Related Network Upgrades Through a Fee

135. Another possible reform to the current crediting policy is to consider the establishment of a non-refundable fee to be charged for submitting an interconnection request and that is not reimbursable through transmission service credits. Under this approach, an appropriate fee should not be so large that it creates barriers to entry for smaller developers. Potential benefits of this type of fee could include: (1) Defraying some of the cost to transmission customers for interconnection-related network upgrades and therefore decreasing the overall impact on transmission customers of the related potential reform to eliminate participant funding of interconnection-related network upgrades in RTOs/ISOs; (2) discouraging the submission of speculative interconnection requests; and (3) for some variable fees, providing a price signal to interconnection customers that could incent efficient siting decisions where possible. We seek comment on (1) whether to impose a non-refundable, non-reimbursable fee on each submitted interconnection request and (2) how this approach could be implemented in a just and reasonable manner.

136. We seek comment on two specific versions of this approach. First, we seek comment on the potential establishment of a fixed fee applied to each interconnection request, which would be the same for all interconnection requests, irrespective of the generating facility's capacity or project location. We seek comment on whether establishing a fixed fee would be appropriate and, if so, the appropriate amount of such a fee.

137. Second, we seek comment on the potential establishment of a variable fee applied to each interconnection request. The amount of the variable fee could depend upon the generating facility capacity associated with the interconnection request and/or the identified interconnection-related network upgrades. For example, the fee could be based on a percentage of the estimated interconnection-related network upgrade costs or be calculated based on the generating facility capacity and/or the voltage rating of the interconnection-related network upgrade. We seek comment on the appropriate size of this fee and the structure of the fee, if the Commission were to require one. We also seek comment on whether it is possible to use a percentage of interconnection-related network upgrade cost estimates for this fee, and if so, at which point in the generator interconnection process a transmission provider would calculate that cost.

138. Finally, we seek comment on whether such a fee should be established at the outset of the generator interconnection process, or whether an escalating fee should be imposed as the interconnection request moves through the study process. For example, a smaller fee could be required for entry into the feasibility study phase, with a larger fee for the system impact study phase and the largest fee required to enter the facilities study.[142] In this manner, speculative projects could be discouraged from entering the later stages of the generator interconnection process, while still allowing interconnection customers to use the feasibility study process as it was designed, to determine project feasibility for a broader range of project sizes and locations.

(c) Transmission Providers Provide Upfront Funding for Only Higher Voltage Interconnection-Related Network Upgrades

139. We seek comment on whether it would be appropriate to require transmission providers to fund upfront the costs of any interconnection-related network upgrade that is rated at or above a certain voltage threshold. Interconnection customers would be responsible for upfront funding the cost of interconnection-related network upgrades below that threshold and be reimbursed through transmission service credits pursuant to the crediting policy.

140. Because higher voltage transmission facilities tend to produce greater and broader benefits to transmission systems than lower voltage transmission facilities, this option may better satisfy the requirement that the allocation of costs be at least roughly commensurate with the distribution of benefits.[143] Thus, where an interconnection-related network upgrade's voltage exceeds a defined threshold and is likely to produce system-wide benefits, it may be appropriate to require that transmission providers fund the costs of such interconnection-related network upgrades upfront.

141. The Commission could also adopt a modified version of this approach by requiring transmission providers to upfront fund the portion of the costs of higher voltage interconnection-related network upgrades that exceeds a pre-determined cost threshold. For example, the Commission could require transmission providers to upfront fund the costs of a 345 kV interconnection-related network upgrade that exceed $10 million. Pursuant to this modified version, in this example of a 345 kV interconnection-related network upgrade, the Commission would require the interconnection customer to fund all network upgrade costs up to $10 million and require the transmission provider to provide upfront funding for all interconnection-related network upgrade costs above the $10 million threshold. Even in this situation, however, the transmission provider would still have to provide transmission service credits to reimburse the interconnection customer for its $10 million subject to the crediting policy.

142. We note that the Commission has approved a version of this cost sharing approach in MISO, albeit in the context of responsibility for payment of interconnection-related network upgrade costs themselves and not just the upfront funding of them as discussed here. MISO's tariff provides for some cost sharing for interconnection-related network upgrades under which transmission providers recover the costs of 10% of interconnection-related network upgrades rated 345 kV and above on a system-wide basis while directly assigning through participant funding 90% of the costs of such upgrades to the interconnection customer whose interconnection required the network upgrade.[144] Furthermore, on multiple occasions, the Commission has permitted RTOs/ISOs to define different transmission facility categories and adopt different cost allocation methods for transmission facilities based on the transmission facility's voltage threshold.[145]

143. If the Commission were to split the upfront funding responsibility for interconnection-related network upgrades between the transmission provider and the interconnection customer, it may be useful to create a split based on voltage. For example, adopting an interconnection-related network upgrade voltage threshold to be funded upfront by the transmission provider has the potential to significantly reduce interconnection-related network upgrade financing costs by eliminating interconnection customers' need to fund upfront the likely more expensive higher voltage interconnection-related network upgrades. It could be appropriate to require the transmission provider to fund upfront the cost of higher voltage interconnection-related network upgrades because higher voltage transmission facilities are likely to produce greater region-wide benefits than lower voltage ones.

144. Whatever the selected voltage threshold might be, interconnection customers would still be required to upfront fund the costs of interconnection-related network upgrades (subject to the crediting policy) that do not meet that threshold. Thus, the selection of a voltage threshold would necessarily exclude from transmission provider upfront funding some interconnection-related network upgrades that produce regional

[142] These non-refundable fees would be in addition to, and distinct from, the initial deposit submitted with an interconnection request and study deposits that are applied toward an interconnection customer's interconnection study costs.

[143] *See, e.g., Old Dominion Elec. Coop.* v. *FERC*, 898 F.3d 1254, 1260 (D.C. Cir. 2018) (adopting Commission finding that ''high-voltage power lines produce significant regional benefits'').

[144] MISO Tariff, Attach. FF (Transmission Expansion Planning Protocol), Section III.A2.d (81.0.0).

[145] *See Midcontinent Indep. Sys. Operator, Inc.*, 172 FERC ¶ 61,095 (2020) (accepting MISO's proposal to change the qualifying voltage threshold for a certain class of project from 345 kV to 230 kV).

transmission benefits. We think it important to ensure that, if the Commission requires that transmission providers establish a voltage threshold for sharing the responsibility to fund upfront the cost of interconnection-related network upgrades, then the voltage threshold should be based upon the likelihood that interconnection-related network upgrades that meet that threshold produce more transmission benefits than interconnection-related network upgrades below that threshold. Furthermore, we recognize that there is some tension between such an approach, which would eliminate the requirement that interconnection customers upfront fund some interconnection-related network upgrades based on voltage, thus reducing the interconnection customers' financing costs only on larger interconnection-related network upgrades, and Order No. 2003's general acknowledgement that interconnection-related network upgrades, regardless of voltage or size, ''benefit all users.'' [146] Additionally, if the Commission adopted this option, in order to avoid the responsibility to upfront fund, transmission providers will have an incentive to identify a lower voltage interconnection-related network upgrade rather than identifying a higher voltage project that may be more efficient or cost-effective.

145. We seek comment on: (1) This approach; (2) the appropriate voltage threshold and any pre-determined cost threshold; and (3) how this approach could be implemented in a just and reasonable manner.

(d) Allocate the Upfront Cost of Interconnection-Related Network Upgrades on a Percentage Basis

146. We seek comment on whether to reduce the allowable percentage of interconnection-related network upgrade costs that interconnection customers must fund upfront (*i.e.,* from 100% to a lower percentage). The crediting policy would apply to the portion of the interconnection-related network upgrade costs that the interconnection customer upfront funds. To allow flexibility, we seek comment on whether an interconnection customer should have the option to elect to upfront fund 100% of the interconnection-related network upgrade if it chooses.

147. This method could benefit both the interconnection customer and the transmission provider. With the ability to provide partial to full upfront funding for interconnection-related network upgrades, interconnection customers will have the ability to retain some control over the speed of interconnection-related network upgrade construction because they will be able to provide initial funding in cases where the transmission owner does not have the funding readily on hand to pay for certain construction milestones. Transmission providers will benefit because this construct will retain the price signal to interconnection customers regarding siting decisions, as interconnection customers would still have to upfront fund (*i.e.,* finance) the costs of more expensive larger interconnection-related network upgrades associated with their interconnection requests and the costs related to financing interconnection-related network upgrades (*e.g.,* interest payments due on the loan) should increase as the costs of the interconnection-related network upgrades increase.

148. We note that adoption of the transmission planning and cost allocation reforms discussed above is likely to result in the development of regional transmission facilities intended to accommodate significant amounts of generation, and thus, has the potential to reduce the need for more extensive and costly interconnection-related network upgrades relative to those identified in the generator interconnection process at present. Thus, the adoption of this generator interconnection reform, in conjunction with the regional transmission planning and cost allocation reforms discussed above, could result in a significant reduction in interconnection customer financing costs while still maintaining a price signal for siting decisions.

149. We seek comment on: (1) This approach; (2) the appropriate percentage for the interconnection customer's upfront funding; and (3) how this approach could be implemented in a just and reasonable manner. As part of this inquiry, we are interested in hearing perspectives on the extent to which partial upfront funding by an interconnection customer may preserve or reduce the incentive for that customer to efficiently site a project. We seek comment on whether there are there other mechanisms, beyond customer upfront funding, that may incent a customer to site efficiently, and that could be adopted in conjunction with the elimination of participant funding.

iii. Additional Considerations

(a) Interconnection-Related Network Upgrade Cost Sharing

150. If the Commission does not eliminate participant funding of interconnection-related network upgrades, we seek comment regarding potential cost-sharing measures to account for the fact that later-in-time interconnection customers may accrue benefits from interconnection-related network upgrades built to accommodate a prior interconnection request. That is, if a later-in-time interconnection customer benefits from the interconnection-related network upgrades required to interconnect an earlier-in-time interconnection customer, the later-in-time interconnection customers may also be assigned a portion of those costs. The transmission provider could require the allocation of costs in proportion to the benefits that the later-in-time interconnection customers receive from network upgrades or be based on a different method, such as a percent share based on usage. To make this approach workable, the transmission provider could also dictate a point after which a later-in-time interconnection customer would be insulated from bearing the costs of a specific interconnection-related network upgrade, *e.g.,* prohibiting allocation of interconnection-related network upgrade costs to interconnection customers that enter the queue five years or more after the interconnection-related network upgrade's energization.[147] As we noted above, the Commission has previously approved tariff provisions pursuant to which earlier-in-time interconnection customers receive a form of reimbursement for the network upgrade costs from later-in-time customers.[148] We note that the sharing of costs between earlier-in-time and later-in-time interconnection customers would only apply in situations where the earlier-in-time interconnection customer was assigned any of the costs of the interconnection-related network upgrade under the participant funding framework. We seek comment on a just and reasonable method to calculate cost sharing for shared network upgrades. We also seek comment on whether to require, and the appropriate duration of, a time after which a later-in-time interconnection customer would not be

[146] Order No. 2003, 104 FERC ¶ 61,103 at P 65.

[147] For the purpose of this order, we will refer to this time period as the sunset period.

[148] *See* NYISO Tariff, attach S (Rules to Allocate Responsibility for the Cost of New Interconnection Facilities), Section 25.7.2; *see also* MISO Tariff, Attach. FF Section III.A.2.d.2 (81.0.0).

allocated the costs of an interconnection-related network upgrade.

(b) Option To Build

151. Order No. 2003 established, and Order No. 845 expanded, the interconnection customer's option to build transmission provider's interconnection facilities [149] and stand alone network upgrades.[150] In a non-RTO/ISO, if an interconnection customer elects to exercise the option to build, the interconnection customer assumes the responsibility to design, procure, and construct the transmission provider's interconnection facilities and stand alone network upgrades and is repaid by the transmission provider pursuant to the crediting policy.

152. Importantly, the option to build allows interconnection customers to have some control over their own timelines and construction schedules and potentially achieve cost savings associated with the design, procurement, and construction of the transmission provider's interconnection facilities and stand alone network upgrades. If the Commission revises the requirement that interconnection customers upfront fund all or some of the costs all of interconnection-related network upgrades, corresponding changes may be necessary to the option to build provisions as they apply to stand alone network upgrades to recognize that an interconnection customer that wants to exercise the option to build would no longer be responsible to upfront fund the full cost of those network upgrades. Therefore, we seek comment on what changes may be necessary to ensure that the option to build provisions remain just and reasonable and to retain flexibility for interconnection customers in light of the potential change to the funding policy.

(c) Interconnection Request Limit

153. We understand that a contributing factor to the interconnection queue backlog is a tendency by interconnection customers to submit multiple interconnection requests at different points of interconnection, with the intention of discovering the lowest cost location to site the generating facility (from an interconnection perspective), and then withdrawing higher-cost interconnection requests from the queue later in the process. We also understand that, absent an appropriately-sized penalty (or reasonable restriction) associated with submitting an interconnection request and then subsequently withdrawing such an interconnection request, there still may be an incentive to submit speculative interconnection requests under any of the potential interconnection reforms discussed above. Therefore, we seek comment on whether there should penalties for submitting speculative requests, how such should be defined, and whether there should be a limit on the number of interconnection requests that a developer can submit in an interconnection queue study year and how narrowly such a limit should apply (*e.g.,* by transmission provider or by transmission pricing zone). We also seek comment on how to determine a just and reasonable limit to the number of interconnection requests. Finally, we seek comment on how to address interconnection requests made by affiliated companies and whether those interconnection requests should count against the limit to the number of interconnection requests if one is imposed.

(d) Fast-Track for Interconnection of Generating Facilities Committed to Regional Transmission Facilities

154. As discussed above, we seek comment on the model established by ERCOT to construct the CREZ transmission projects. For those transmission projects to be approved, ERCOT required a certain percentage of capacity to be reserved by generation developers with existing projects, projects under construction, projects with signed interconnection agreements, or posted collateral. In the case that this model may improve the coordination between transmission planning and the development of future generation, it may become important to streamline the generator interconnection process for generating facilities that are committed to interconnecting to these transmission facilities.

155. Therefore, we seek comment on whether a fast-track generator interconnection process should be developed to facilitate interconnection of generating facilities that have firmly committed to connecting to new regional transmission facilities. An example of such a fast-track option may be to allow the transmission provider to perform a limited system impact study for only the cluster of generating facilities committed under the regional transmission planning process and to move to the facilities study without waiting for earlier studies to complete. We recognize that the timeline for transmission facility permitting and construction often far exceeds that of the generator interconnection and construction process but seek comment nonetheless on whether a faster generator interconnection process in this scenario would be beneficial.

156. We seek comment on whether such a process would constitute inappropriate ''queue jumping,'' or instead would be more appropriately viewed as an extension of the previously approved first-ready, first-served queueing practice. In this case, are generating facilities that have put up financial collateral to ensure that a regional transmission facility is constructed to serve them appropriately considered ''ready'' projects? We seek comment on the feasibility of establishing such a proposal, as well as the implications on the rest of the generator interconnection queue and on any legal challenges related to a potential ''queue jumping'' concern.

(e) Fast-Track for Interconnection of ''Ready'' Generating Facilities

157. In addition to considering a fast-track generator interconnection process for interconnection customers that have committed financially to new regional transmission facilities, we are considering whether allowing a fast-track for ''ready'' interconnection requests would remove barriers to entry for interconnection requests that have met certain readiness criteria. For example, interconnection requests for which the developer has already executed a power purchase agreement or that have been chosen in a state or utility request for proposals may be appropriately deemed more ''ready'' than projects that enter the interconnection queue without either contractual arrangement. Another

[149] Order No. 2003 defined two categories of interconnection facility: (1) Transmission provider's interconnection facilities, which refer to all facilities and equipment owned, controlled or operated by the transmission provider from the point of change of ownership to the point of interconnection, including any modifications, additions or upgrades to such facilities and equipment;'' and (2) interconnection customer's interconnection facilities, which are located between the generating facility and the point of change of ownership and which the interconnection customer must design, procure, construct, and own. *See pro forma* LGIA art. 1 (Definitions); *pro forma* LGIA art. 5.10.

[150] Order No. 2003, 104 FERC ¶ 61,103 at P 353; *Reform of Generator Interconnection Procedures and Agreements,* Order No. 845, 163 FERC ¶ 61,043, at P 85 (2018), *order on reh'g,* Order No. 845–A, 166 FERC ¶ 61,137, *order on reh'g,* Order No. 845–B, 168 FERC ¶ 61,092 (2019). Stand alone network upgrades refer to interconnection-related 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.'' *See pro forma* LGIP Section 1 (Definitions).

example of an interconnection request that demonstrates a higher degree of readiness could be one sited at a previously developed point of interconnection that can make use of existing interconnection facilities. Such interconnection requests may be considered more ready because they have more ready access to the transmission system. Both of these examples could be considered more ready than interconnection requests proposed at points of interconnection where the interconnection customer or the transmission provider must acquire new rights-of-way, permits, and agreements with landowners, or that face other obstacles to rapid development. We seek comment on which types of interconnection requests could be considered more ''ready'' and able to advance through the interconnection queue more quickly, as well as comments on the just and reasonable structure for such a fast-track option. We also seek comment on how to implement such a proposal in a manner that is not unduly discriminatory. As in the prior proposed reform, we seek comment on how to address possible concerns related to what some may consider ''queue jumping'' or whether appropriate factors may justify such measures.

(f) Grid-Enhancing Technologies

158. We seek comment on whether there is the potential for Grid-Enhancing Technologies not only to increase the capacity, efficiency, and reliability of transmission facilities, but, in so doing, also to reduce the cost of interconnection-related network upgrades.[151] In light of the potential of Grid-Enhancing Technologies, we seek comment on whether the Commission should require that transmission providers consider Grid-Enhancing Technologies in interconnection studies to assess whether their deployment can more cost-effectively facilitate interconnections. To the extent transmission providers currently consider Grid-Enhancing Technologies in the generator interconnection process, what, if any, shortcomings exist in that consideration? If the Commission were to require greater consideration of Grid-Enhancing Technologies, how should it do so? What, if any, challenges exist in establishing such a requirement and how might these challenges be addressed?

[151] Commission staff led a workshop in 2019 to explore the role, benefits, and challenges of Grid-Enhancing Technologies. FERC, *Grid-Enhancing Technologies,* Notice of Workshop, Docket No. AD19–19–000 (Sept. 9, 2019).

C. Enhanced Transmission Oversight

159. The potential for a significant investment in the transmission system in the coming years underscores the importance of ensuring that ratepayers are not saddled with costs for transmission facilities that are unneeded or imprudent. As part of this package of potential reforms, we are considering whether reforms may be needed to enhance oversight of transmission planning and transmission providers' spending on transmission facilities to ensure that transmission rates remain just and reasonable.

1. Potential Need for Reform

160. As discussed above, the electricity sector is in the midst of a fundamental transition as the generation mix shifts rapidly from largely centralized resources located close to population centers towards renewable resources located far from customers. Potential reforms to regional transmission planning and cost allocation and generator interconnection should help protect customers throughout this transition by directing planning toward the more efficient or cost-effective transmission facilities. Nevertheless, particularly in light of potential costs of new transmission infrastructure that may be needed to meet the needs of the changing resource mix, we seek comment on whether additional measures may be necessary to ensure that the planning processes for the development of new transmission facilities, and the costs of the facilities, do not impose excessive costs on consumers.

161. We seek comment on whether the relatively large investment in transmission facilities resulting from the regional transmission planning and cost allocation processes reflects the more efficient or cost-effective solutions for meeting transmission needs, including those associated with a changing resource mix. The transparency with which transmission needs are identified and transmission facilities approved is an important element in ensuring that excessive costs are not being imposed on consumers. Although Order No. 890 requires that transmission planning processes comply with the transmission planning principles, including transparency and openness, transmission providers comply with those requirements in various ways.

162. We seek comment on whether the current transmission planning processes provide sufficient transparency for stakeholders to understand how best to obtain information and fully participate in the various processes. For example, we seek comment whether 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. We seek comment on whether this may result in material costs being imposed on consumers with limited visibility into the actual need for a local transmission facility or support for a specific local transmission solution. We also seek comment on whether, in light of the significant potential costs of transmission and this potential deficit in transparency, customers and other stakeholders might benefit from enhanced oversight over identification and costs of transmission facilities.

2. Potential Reforms and Request for Comment

a. Independent Transmission Monitor

163. We seek comment on which potential measures the Commission could take to ensure that there is appropriate oversight over how new regional transmission facilities are identified and paid for. For example, we seek comment on whether, to improve oversight of transmission facility costs, it would be appropriate for the Commission to require that transmission providers in each RTO/ISO, or more broadly, in non-RTO/ISO transmission planning regions, establish an independent entity to monitor the planning and cost of transmission facilities in the region.

164. We seek comment on the Commission's authority to require an independent entity to monitor transmission spending in each transmission planning region, as well as the role that such monitor(s) would play. For example, this independent transmission monitor might potentially review transmission planning processes, planning criteria that lead to the identification of particular transmission needs and facilities, as well as the rules and regulations governing such processes. Additionally, the independent transmission monitor could review transmission provider spending on transmission facilities and identify instances of potentially excessive transmission facility costs, including through inefficiencies between local and regional transmission planning processes. Further, the independent transmission monitor could identify instances in which transmission facilities were selected in the regional transmission plan for cost allocation when it may not be clear that such projects were the more efficient or

cost-effective transmission solutions, or were approved for regional cost allocation when credible less-costly alternatives were available. If the independent transmission monitor identifies such examples, it could make a referral to the Commission. The Commission could then conduct a review of the relevant transmission planning processes and/or transmission facility costs under section 206 of the FPA. We seek comment on the proposal outlined in this paragraph.

165. We seek comment on whether the independent transmission monitor's review could potentially focus on the transmission planning process and costs of transmission facilities before construction starts.[152] We seek comment on whether and how the Commission might modify the regional transmission planning and cost allocation processes or rate recovery rules and procedures so as to facilitate such up-front review.

166. We also seek comment on how an independent transmission monitor could approach cost oversight. One possible method would be to scrutinize the relevant regional transmission plan(s) to determine whether a different portfolio of local and regional transmission facilities would lead to higher net benefits. With regard to individual transmission facilities selected via the regional transmission planning processes or chosen through the local transmission planning processes, the independent entity could provide information to assist the Commission in determining whether the selection of a given transmission facility warrants additional Commission review. Such assistance may include the development of independent cost estimates for transmission facilities. Given the challenges of reviewing all transmission facilities, we seek comment on whether it would be useful for the Commission or the independent entity to develop criteria (such as a minimum spending threshold) to determine which transmission facilities should be subject to review.

167. We seek comment on tools that could be developed to assist such a transmission monitor or the Commission in reviewing transmission-related spending. For example, such a monitor might develop benchmark cost estimates that would be independent of cost estimates developed by a transmission provider, which could serve as a mechanism to assess performance for each transmission provider for the applicable transmission facilities. The independent transmission monitor could create separate estimates for regional versus local transmission facilities and classify facility costs by criteria (such as voltage level), with estimates based on well-established methods using the best information available just prior to the start of construction to minimize the error in cost estimation. The Commission could then review the costs for transmission facilities that significantly exceed the cost estimates, either sua sponte or on the recommendation of the independent transmission monitor or a third party. An independent transmission monitor could also seek information from transmission providers regarding the variances between actual and estimated costs for selected regional transmission facilities and use this information in its assessment of whether further Commission review is recommended.

168. We seek comment on whether an independent transmission monitor should provide advice on the design and implementation of the regional transmission planning and cost allocation processes in addition to oversight of the regional transmission planning process and the costs of the development of individual transmission facilities. The independent transmission monitor could review the design of the regional transmission planning and cost allocation processes on an ongoing basis and highlight areas where improvements could be made (for example, optimization between local and regional transmission planning). The independent transmission monitor could also review mechanisms used in transmission planning processes, such as adjusted production cost modeling tools, and assess the extent to which modifications to such mechanisms might yield more efficient transmission spending decisions.

169. The independent transmission monitor could also identify and report on situations in which non-wires alternatives could more cost-effectively address transmission system needs. We seek comment on the value of such reporting and whether such information could improve the ability for states to participate in the regional transmission planning process and provide a greater opportunity for input. Similarly, we seek comment on whether an independent transmission monitor or other oversight mechanism should evaluate and report on transmission providers' consideration of Grid-Enhancing Technologies in the transmission planning process. If so, how should that evaluation be conducted and what information should be reported?

170. Additionally, we seek comment on whether oversight of the planning and approval of local transmission facilities is necessary to ensure that transmission rates are just and reasonable. We seek comment on whether an independent transmission monitor should evaluate whether the transmission needs identified in the local transmission planning processes could be better considered during regional transmission planning processes to allow for the identification of more efficient or cost-effective transmission solutions. In addition, we seek comment on whether oversight should consider the development and application of transmission planning criteria. Finally, we encourage commenters to identify any other factors that they believe the Commission should consider for oversight within the local transmission planning process. At the same time, we seek comment on whether such a role for a federally-regulated regional transmission monitor would improperly or inappropriately expand the role of federal regulation over local utility regulation and/or potentially increase administrative and legal costs of local transmission planning with no commensurate benefits for customers. More broadly, we seek comment on whether there is a need to delineate more clearly the oversight roles of federal and state regulators over local transmission planning.

171. In addition, we seek comment on whether there is sufficient clarity on the roles and responsibilities between state and federal regulators regarding the local transmission planning criteria and the development of local transmission facilities (*e.g.,* ''Supplemental Projects'' in PJM). We seek comment on whether such transmission facilities require additional oversight and whether

[152] This is different than the safeguards provided under the transmission formula rate protocols that have been implemented for formula rates in transmission providers' OATTs. The transmission formula rate protocols are generally designed to provide interested parties sufficient opportunity to obtain and review information necessary to evaluate the implementation of the formula rate, which allows public utilities to recover the cost for transmission facilities that are already constructed and placed in service, except in limited circumstances (*e.g.,* a transmission provider may recover a return on costs of plant that is in the process of construction by receiving regulatory approval to include such costs of construction work in progress in rate base under its formula rate). The protocols outline the process for the annual formula rate informational filing at the Commission, transparency around the transmission formula rate information exchange, the scope of participation, and the ability of customers to challenge transmission providers' implementation of the formula rate. *See Midwest Indep. Transmission Sys. Operator, Inc.,* 139 FERC ¶ 61,127 (2012); *Midwest Indep. Transmission Sys. Operator, Inc.,* 143 FERC ¶ 61,149 (2013); *Midcontinent Indep. Sys. Operator, Inc.,* 146 FERC ¶ 61,212 (2014); *Midcontinent Indep. Sys. Operator, Inc.,* 150 FERC ¶ 61,025 (2015).

additional coordination among state and federal regulators would be beneficial. Similarly, we seek comment on whether and how greater oversight may improve coordination between individual transmission provider's planning processes and regional transmission planning processes. Order No. 1000 requires the evaluation of ''alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers.'' [153] We seek comment on whether current rules and processes are adequately aligned with and facilitate such consideration or evaluation, and if not, whether there are oversight measures or other mechanisms, including via an independent transmission monitor, that could better facilitate the consideration of more efficient or cost-effective alternatives. For example, we seek comment on whether individual transmission provider practices regarding retirement and replacement of 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. We also seek comment on whether sufficient transparency exists in retirement decisions to allow for such regional assessment. We seek comment on what role can or should an independent transmission monitor play in facilitating enhanced coordination.

172. Furthermore, we seek comment on whether additional transparency measures are appropriate or should be in place for transmission providers, including those outside of RTO/ISO regions. If so, we seek comment on whether the Commission should apply transparency measures, some of which are currently utilized within RTO/ISO regions (*e.g.,* dedicated transmission planning web pages, requirements to publish and detail full transmission plan at end of each transmission planning cycle, scorecards), or consider different or new transparency measures for transmission providers outside of RTO/ISO regions. We seek comment on whether new or different transparency measures are needed within the RTO/ISO regions.

173. An independent transmission monitor would not replace the Commission's rate jurisdiction but instead could provide the Commission with an additional means of ensuring that rates are just and reasonable. With respect to other aspects of prudence, or transmission facility selection against alternatives, the independent transmission monitor would not supplant the Commission's authority with respect to prudence, but could inform the Commission as to whether a further review is warranted; the final determination on whether costs are prudently incurred remains with the Commission. Similarly, the record created by the independent transmission monitor could help the Commission in ensuring that the design of the regional transmission planning and cost allocation processes remain just and reasonable and not unduly discriminatory or preferential.

174. We seek comment on (1) the independent transmission monitor proposal, and (2) any alternative options for improving oversight of transmission costs or the effectiveness of transmission planning processes. Additionally, we seek comment on whether the concerns regarding transmission oversight are best addressed by an independent entity similar to the role of an independent market monitor, or whether the concerns can be adequately addressed by the RTO/ISO or transmission providers in non-RTO/ISO regions, or through another approach.

175. We also seek comment on (1) how an independent transmission monitor (or set of regional monitors) would be created or authorized; (2) whether a single monitor should be appointed for each transmission region, or instead a given monitor might review transmission across several regions; (3) the Commission's authority to require an independent transmission monitor in all transmission planning regions; (4) how this entity would work in practice, in both the RTO/ISO and non-RTO/ISO regions; and (5) the scope of review such monitor(s) should be charged with carrying out, including whether such monitoring should extend to oversight of the generator interconnection process.

b. State Oversight

176. Another way to add oversight to the transmission planning and cost allocation processes could be to involve state commissions in those processes. By way of example, SPP has a 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.'' [154]

177. We seek 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: Provide insight into regional transmission facility costs and cost allocation methods; evaluate whether the transmission needs identified in the local transmission planning processes could be better considered during regional transmission planning processes; inform the Commission as to whether a further review is warranted of whether incurred costs are prudent; or provide the Commission with an additional means of ensuring that rates are just and reasonable. We also seek comment on how such a model may be combined with other oversight tools or mechanisms explored herein. For example, given state regulatory authority over the approval of non-wires solutions, can or should a regional state committee play a role in identifying circumstances under which a non-wires solution would be the more efficient or cost-effective solution to solving an identified regional transmission need, and facilitating a process by which the relevant state regulator could be given an opportunity to approve such a solution?

c. Limitation on Recovery of Costs for Abandoned Projects

178. There is always a risk that once approved, a regional project may be abandoned before going into service for a variety of reasons including a failure to obtain all necessary state and federal approvals, including, for example, state certificates of public convenience and necessity. The Commission's general policy for recovery of the costs of abandoned plant under section 205 of the FPA allows recovery of and return on 50% of the prudently incurred investment costs incurred in connection with the abandoned plant.[155] In

[153] Order No. 1000, 136 FERC ¶ 61,050 at P 148.

[154] SPP, Governing Documents Tariff, Bylaws, Section 7.2 (Regional State Committee) (1.0.0).

[155] *New Eng. Power Co.,* Opinion No. 295, 42 FERC ¶ 61,016, at 61,081–82, *order on reh'g,* Opinion No. 295–A, 43 FERC ¶ 61,285 (1988). The Commission also allows recovery under section 205 of return on 50% of investment costs incurred to construct transmission facilities (and other non-pollution control plant) through the inclusion of Construction Work in Progress (CWIP) in rate base during the construction period, provided certain conditions are met. *Construction Work In Progress*

Continued

addition, the Commission may grant as an incentive under section 219 of the FPA for transmission facilities meeting the qualifications for the incentive, recovery of 100% of prudently-incurred costs related to such facilities if they are abandoned for reasons beyond the control of the transmission owner.[156] In light of potential costs of new regional transmission infrastructure and the corresponding risk that some of those projects may be abandoned, we seek comment on whether the Commission should revisit its policies regarding abandoned plant to better protect consumers from increased costs due to never-built transmission facilities.

179. For example, one proposal to protect consumers would be to limit the recovery of costs through abandonment by allowing only the recovery of some portion of actual development or pre-commercial costs, and/or no recovery of a return on equity on such costs prior to the project receiving all necessary regulatory approvals. We therefore seek comment on this or other proposals to limit the amount that can be recovered for regional transmission facilities that are abandoned prior to going into service. Commenters are, of course, welcome to address all issues and concerns pertinent to such proposals.

d. Additional Oversight Approaches

180. Finally, we seek comment on additional oversight approaches the Commission might take to ensure that wholesale transmission spending is cost effective. For example, performance-based regulation. We ask how performance-based regulation may be designed to ensure that rates are just and reasonable, ensure reliability of the transmission system, promote regional expansion of transmission facilities for a sufficiently wide range of future scenarios, including anticipated future generation, and encourage transmission provider participation.

D. Transition

181. To implement any of the proposals outlined above, transmission providers must transition to new interconnection pricing paradigms and new regional transmission planning and cost allocation processes. Therefore, we seek comment on appropriate transition plans, including treatment of interconnection customers in the various stages of the generator interconnection process and those that have already interconnected as well as when the more holistic regional transmission planning and cost allocation processes would begin (including when the broader category of regional transmission facilities would be established).

182. The Commission also seeks input as to the length of time that might be necessary to implement any reforms that result from this process. Specifically, the Commission requests input as to how much time transmission providers might need to develop compliance filings related to all of the proposals in this ANOPR.

V. Comment Procedures

183. The Commission invites interested persons to submit comments on these matters and any related matters or alternative proposals that commenters may wish to discuss. Comments are October 12, 2021 and Reply Comments are due November 9, 2021. 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

184. 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.

185. 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.

VI. Document Availability

186. 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).

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

188. 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. Chairman Glick and Commissioner Clements are concurring with a joint separate statement attached. Commissioner Chatterjee is not participating. Commissioner Danly is concurring with a separate statement. Commissioner Christie is concurring with a separate statement.

Issued: July 15, 2021.

Debbie-Anne A. Reese,

Deputy Secretary.

Department of Energy

Federal Energy Regulatory Commission

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

Docket No. RM21–17–000

GLICK, Chairman, CLEMENTS, Commissioner, *concurring:*

1. The generation resource mix is changing rapidly. Due to a myriad of factors—including improving economics, customer and corporate demand for clean energy, public utility commitments and integrated resource plans, as well as federal, state, and local public policies—renewable resources in particular are coming online at an

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for Public Utilities; Inclusion of Costs in Rate Base, Order No. 298, 48 FR 24,323 (June 1, 1983), FERC Stats. & Regs. ¶ 30,455, *order on reh'g,* Order No. 298–A, 48 FR 46,012 (Oct. 11, 1983), FERC Stats. & Regs., ¶ 30,500 (1983), *order on reh'g,* Order No. 298–B, 48 FR 55,281 (Dec. 12, 1983), FERC Stats. & Regs. ¶ 30,524 (1983) (Order No. 298).

[156] *Promoting Transmission Investment 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).

unprecedented rate.[1] As a result, the transmission needs of the electricity grid of the future are going to look very different than those of the electricity grid of the past.

2. We are concerned that the current approach to transmission planning and cost allocation cannot meet those future transmission needs in a manner that is just and reasonable and not unduly discriminatory or preferential. In particular, we believe that the *status quo* approach to planning and allocating the costs of transmission facilities may lead to an inefficient, piecemeal expansion of the transmission grid that would ultimately be far more expensive for customers than a more forward-looking, holistic approach that proactively plans for the transmission needs of the changing resource mix. A myopic transmission development process that leaves customers paying more than necessary to meet their transmission needs is not just and reasonable.

3. In that regard, we are pleased to see the Commission taking a consensus first step toward updating its rules and regulations to ensure that we are meeting the nation's evolving transmission needs in a cost-effective and efficient fashion. Today's action complements our recently established joint federal-state task force with the National Association of Regulatory Utility Commissioners,[2] which we expect to produce a robust dialogue on many of the issues addressed herein. In our view, this advance notice of proposed rulemaking (ANOPR) is just the first step. Ensuring that transmission rates remain just and reasonable will require further action, including reforms to interregional transmission planning and cost allocation, as well as other reforms to our regional transmission planning and cost allocation and generator interconnection processes beyond those contemplated herein. Nevertheless, we believe that today's unanimous Commission action represents a solid foundation for an expeditious inquiry into how we can regulate to achieve the transmission needs of our changing electricity system in a manner consistent with our statutory obligations under the Federal Power Act.

* * * * *

4. The generation mix is shifting rapidly from large resources located close to population centers toward renewable resources, often combined with onsite storage, that tend to be located where their fuel source is best—*i.e.,* where the wind blows hardest or the sun shines brightest. According to the National Renewable Energy Laboratory (NREL), total renewable generation capacity nearly doubled from 2009 to 2018, increasing from 11.7% of total generation capacity to 20.5%.[3] And that is just the beginning: Of the roughly 750 GW of generation in interconnection queues around the country, nearly 700 GW are renewable resources,[4] providing every reason to believe that the dramatic shift toward renewable generation will only accelerate in the years ahead.

5. That shift is the result of many factors. First and foremost, the cost of renewable resources is plummeting. For example, in its annual report on the levelized cost of energy, Lazard found that between 2009 to 2020, the levelized cost of energy from unsubsidized wind generation and unsubsidized utility-scale solar generation decreased by 71% and 90%, respectively[5]—enough to make utility-scale solar and wind generation cost-competitive with central station fossil generation sources in many parts of the country.[6] Moreover, customers—both residential and commercial—are increasingly demanding clean energy, particularly energy from renewable resources—which is itself causing utilities and independent power producers to attempt to send large quantities of renewable energy onto the grid.[7] In addition, dozens of the biggest utilities in the country have established their own decarbonization goals, the achievement of which will require their

[1] *See, e.g.,* Joseph Rand et al., *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2020,* Lawrence Berkeley National Laboratory, May 2021, *https://eta-publications.lbl.gov/sites/default/files/queued_up_may_2021.pdf; Electric Power Monthly,* Table 6.1 Electric Generating Summer Capacity Changes (MW), U.S. Energy Information Administration, (Mar. 2021 to Apr. 2021), *https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_01.*

[2] *Joint Federal-State Task Force on Electric Transmission,* 175 FERC ¶ 61,224 (2021).

[3] *2018 Renewable Energy Data Book* at 26, NREL, *https://www.nrel.gov/docs/fy20osti/75284.pdf.* Wind and solar resources, in particular, have grown at a disproportionate rate, with solar generation capacity increasing roughly 5,000% from 1,054 MW to 51,899 MW nationwide, and wind generation capacity more than tripling from 31,155 MW to 96,442 MW.

[4] *See* Joseph Rand, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2020,* Lawrence Berkeley National Laboratory, May 2021, *https://eta-publications.lbl.gov/sites/default/files/queued_up_may_2021.pdf.* Equally important, this shift is taking place across the country, not just in a few areas. For example, as of the issuance of this ANOPR, in Midcontinent Independent System Operator, Inc. (MISO), solar and wind projects comprise 80% of all active projects in the current interconnection queue, or about 73 GW of total capacity. MISO, *Generator Interconnection Queue—Active Projects Map, https://giqueue.misoenergy.org/PublicGiQueueMap/index.html.* Similarly, in PJM Interconnection, L.L.C. (PJM), solar and wind projects with a total capacity of 62 GW comprise 79% of all active projects in the current interconnection queue as of the issuance of this ANOPR. PJM, *New Services Queue, https://www.pjm.com/planning/services-requests/interconnection-queues.aspx.* In California Independent System Operator Corporation (CAISO), renewable and storage capacity of 23 GW comprise 78% of all active projects in the current interconnection queue as of the issuance of this ANOPR. CAISO, *Generator Interconnection Queue, https://www.caiso.com/Documents/ISOGeneratorInterconnectionQueueExcel.xls.*

[5] *See, e.g., Lazard's Levelized Cost of Energy Analysis—Version 14.0,* at 9 (Oct. 19, 2020), *https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2020/#:~:text=Lazard's%20latest%20annual%20Levelized% 20Cost,build%20basis%2C%20continue%20to%20maintain*; Ryan Wiser et al., *Expert elicitation survey predicts 37% to 49% declines in wind energy costs by 2050,* Lawrence Berkeley National Laboratory (Apr. 2021), *https://eta-publications.lbl.gov/sites/default/files/wind_lcoe_elicitation_ne_pre-print_april2021.pdf* (finding that the decrease in levelized cost of energy for wind power from 2015–2020 outpaced the decrease predicted by experts, and that experts continue to predict significant declines in levelized cost of energy).

[6] *See Lazard's Levelized Cost of Energy Analysis—Version 14.0,* at 3, 7 (Oct. 19, 2020), *https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2020/#:~:text=Lazard's%20latest%20annual%20Levelized%20Cost,build%20basis%2C%20continue%20to%20maintain.*

[7] *See, e.g.,* Deloitte Resources 2020 Study at 22, *https://www2.deloitte.com/content/dam/insights/us/articles/6655_Resources-study-2020/DI_Resources-study-2020.pdf* (showing that U.S. corporate renewable generation purchase power agreements increased from 0.3 GW in 2009 to 13.6 GW in 2019); Kevin O'Rourke & Charles Harper, *Corporate Renewable Procurement and Transmission Planning: Communicating Demand to RTOs Necessary to Secure Future Procurement Options,* A Renewable America (October 2018), *https://acore.org/wp-content/uploads/2020/04/Corporates-Renewable-Procurement-and-Transmission-Report.pdf* (indicating that a group of corporations, forming the Renewable Energy Buyers Alliance, has set a goal to purchase 60 GW of new renewable energy capacity in the U.S. by 2025); Stanley Porter et al., *Utility Decarbonization Strategies, Renew, Reshape, and Refuel to Zero,* Deloitte Insights (Sept. 2021), *https://www2.deloitte.com/us/en/insights/industry/power-and-utilities/utility-decarbonization-strategies.html* (indicating that 43 of 55 utilities surveyed have emissions reductions targets and 22 have net-zero or carbon-free electricity goals); Esther Whieldon, *Path to net zero: 70% of biggest US utilities have deep decarbonization targets,* S&P Global Market Intelligence (Dec. 9, 2020) at 3–6, *https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/path-to-net-zero-70-of-biggest-us-utilities-have-deep-decarbonization-targets-61622651* (indicating that review of utilities' climate goals decarbonization plans, as of December 2020, shows that 70% of the 30 largest utilities have net-zero carbon targets or are moving to comply with similarly aggressive state mandates); *see also* Rich Glick and Matthew Christiansen, *FERC and Climate Change,* 40 Energy L.J. 1, 7–12 (2019) ("The growth of renewable resources is also a function of consumers' desire for clean energy. Customers—including residential, commercial, and even industrial consumers—are increasingly demanding that their energy come from renewable or zero-emissions sources").

own significant investment in renewable generation.[8]

6. Finally, federal, state, and local policymakers have adopted a range of public policies that are driving the changing resource mix. For example, 30 states and the District of Columbia have adopted renewable portfolio standards,[9] with those standards contributing to roughly 50% of the total growth in renewable generation over the last two decades.[10] In addition, several states have doubled down on the clean energy transition by enacting measures that require that most or all of their electricity come from zero emissions resources.[11] All told, ''states and utilities that have committed to transitioning to 100 percent clean power serve nearly 83 million households and businesses, representing around 50 percent of all U.S. electricity demand in 2019.'' [12]

7. Dramatic changes in the resource mix inevitably come with similarly dramatic changes in transmission needs. As noted, the increasingly cost-competitive renewable resources that customers and public policies demand tend to be developed farther away from customers where their fuel sources are strong and development costs are low rather than in close proximity to their ultimate customers. As a result, the future resource mix will likely present new transmission needs, different from those of the large resources located close to population centers that have dominated electricity generation in the past. Meeting those transmission needs will likely require both the infrastructure necessary to interconnect new resources to the transmission system efficiently and the infrastructure necessary to reliably move the electricity produced by those resources to where it is needed. This could make it considerably more expensive than necessary to bring in the low-cost generation demanded by customers and meet federal, state, and local public policies.

8. This Commission cannot sit idly by. Our role is to ensure just and reasonable rates and support reliability in light of changes in the market, not to pretend those changes are not happening. We are concerned that, in light of evolving transmission needs, the current regional transmission planning and cost allocation and generator interconnection processes may no longer ensure just and reasonable rates for transmission service.[13] In particular, we are concerned that existing regional transmission planning processes may be siloed, fragmented, and not sufficiently forward-looking, such that transmission facilities are being developed through a piecemeal approach that is unlikely to produce the type of transmission solutions that could more efficiently and cost-effectively meet the needs of the changing resource mix. Regional transmission planning processes generally do little to proactively plan for the resource mix of the future, including both commercially established resources, such as onshore wind and solar, as well as emerging ones, such as offshore wind. We are also concerned that current regional transmission planning processes are not sufficiently integrated with the generator interconnection processes, and are overwhelmingly focused on relatively near-term transmission needs, and that attempting to meet the needs of the changing resource mix through such a short-term lens will lead to inefficient transmission investments. As a result, under the *status quo,* customers could end up paying far more to meet their transmission needs than they would under a more forward-looking approach that identifies the more efficient or cost-effective investments in light of the changing resource mix.[14]

9. Relatedly, we are also concerned that the current approach to transmission planning and cost allocation is failing to adequately identify the benefits and allocate the costs of new transmission infrastructure. Although the regional transmission planning process considers transmission needs driven by reliability, economics, and Public Policy Requirements,[15] those transmission needs are often viewed in isolation from one another and the cost allocation methods for projects selected to meet those needs are similarly siloed. As a result, the *status quo* may be disproportionately producing transmission facilities that address a narrow set of needs, providing comparatively modest benefits, but at a still-substantial total cost instead of developing the type of transmission infrastructure that could provide the most significant benefits for customers. In the same vein, we are also concerned that many customers who share in the diverse array of benefits that transmission infrastructure can offer may not be paying their fair share, as required by the cost causation principle.[16]

10. In addition, we are concerned that, largely due to the potential shortcomings with the current regional transmission planning and cost allocation processes, transmission infrastructure is increasingly being

[8] *See, e.g., Corporate Renewable Procurement and Transmission Planning: Communicating Demand to RTOs Necessary to Secure Future Procurement Options,* A Renewable America, October 2018, *https://acore.org/wp-content/uploads/2020/04/Corporates-Renewable-Procurement-and-Transmission-Report.pdf;* Esther Whieldon, *Path to net zero: 70% of biggest US utilities have deep decarbonization targets,* S&P Global Market Intelligence, Dec. 9, 2020, at 3–6, *https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/path-to-net-zero-70-of-biggest-us-utilities-have-deep-decarbonization-targets-61622651.*

[9] Nat'l Conference of State Legislatures, *State Renewable Portfolio Standards and Goals* (Nov. 7, 2021), *https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx#:~:text=Thirty%20states%2C%20Washington%2C%20DC%2C,have%20set%20renewable%20energy%20goals.* Renewable portfolio standards are policies that are designed to increase the amount of renewable energy sources used for electricity generation.

[10] *See, e.g.,* Berkeley Lab, *U.S. Renewables Portfolio Standards: 2019 Annual Status Update* (Aug. 2019), *https://emp.lbl.gov/publications/us-renewables-portfolio-standards-2.*

[11] *Carbon Pricing in Organized Wholesale Elec. Markets,* 175 FERC ¶ 61,036, at P 2 (2021) (''Thirteen states—California, Hawaii, Maine, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, New York, Oregon, Vermont, Virginia, and Washington—and the District of Columbia have adopted clean energy or renewable portfolio standards of 50% or greater.''). In addition, ''a number of states—including Colorado, Connecticut, Nevada, Rhode Island, and Wisconsin—have established 100% clean electricity goals or targets by executive order or other non-binding commitment.'' *See id.* At the local level, cities and counties are also accelerating clean energy commitments. Kelly Trumbull *et al., Progress Toward 100% Clean Energy in Cities and States Across the U.S.,* University of California—Los Angeles Luskin Center for Innovation (November 2019) at 10, *https://innovation.luskin.ucla.edu/wp-content/uploads/2019/11/100-Clean-Energy-Progress-Report-UCLA-2.pdf* (finding over 200 cities and counties across 37 U.S. states have 100 percent clean energy commitments).

[12] National Resources Defense Council (NRDC), *NRDC's 8th Annual Energy Report: Slow and Steady Will Not Win the Climate Race* (Dec. 2, 2020), *https://www.nrdc.org/resources/nrdcs-8th-annual-energy-report-slow-and-steady-will-not-win-race?nrdcpreviewlink=rmmB6NM6zpiOTruhuObZJdH92bCOvmZTY1hx72xCSzQ#renewables.*

[13] 16 U.S.C. 824e.

[14] *See generally* Eric Larson *et al., Net-Zero America: Potential Pathways, Infrastructure, and Impact* (2020), *Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf* (discussing different pathways for meeting decarbonization goals, including differing approaches to transmission investment).

[15] *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, 136 FERC ¶ 61,051, at P 11 (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).

[16] *Cf. BNP Paribas Energy Trading GP* v. *FERC,* 743 F.3d 264, 268–269 (D.C. Cir. 2014) (''[T]he cost causation principle itself manifests a kind of equity. This is most obvious when we frame the principle (as we and the Commission often do) as a matter of making sure that burden is matched with benefit.'' (*citing Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d 1361, 1368 (D.C. Cir. 2004) *and Se. Michigan Gas Co.* v. *FERC,* 133 F.3d 34, 41 (D.C. Cir. 1998))).

developed through the generator interconnection process. That means that infrastructure with potentially significant benefits for a broad range of entities may be developed through a process that focuses exclusively on the needs of a comparatively small number of interconnection customers—a dynamic that is almost sure to result in comparatively inefficient investment decisions. The participant funding approach to financing interconnection-related network upgrades will often mean that the interconnection customer(s) alone must pay for all—or the vast majority—of the costs of that transmission infrastructure, even where it provides significant benefits to other entities. That, in turn, may cause those interconnection customers to withdraw projects from the queue, causing considerable uncertainty and delay, and may mean that net beneficial transmission infrastructure is never developed due to a misalignment in how that infrastructure would be paid for.

11. Finally, we are also concerned that the Commission's current approach to overseeing transmission investment may not adequately protect consumers. While transmission infrastructure can provide a broad spectrum of benefits, it is itself a significant investment that represents a major component of customers' electric bills. The Commission must vigorously oversee the rules governing how transmission projects are planned and paid for if we are to satisfy our responsibility to protect customers from excessive rates and charges.[17] The potential bases for invigorating our oversight of transmission spending contemplated in today's order have the potential to go a long way toward ensuring that we fulfill that function.

12. Today's action plants the seeds for addressing the concerns outlined above. A forward-looking, holistic approach to transmission planning has the potential to identify the more efficient or cost-effective solutions for meeting the transmission needs of the changing resource mix, including those resources that are not yet under development. Such an approach would allow transmission planners to proactively identify the areas of the transmission grid that will have significant transmission needs and select the more efficient or cost-effective solution to meet those needs, including needs driven by resources that are not yet in operation or even under development. Doing so has the potential to address the transmission needs of the future generation mix while costing customers considerably less than they would pay to meet those same needs under the *status quo.* That, in our view, is what is necessary to ensure that the rates for transmission service remain just and reasonable as the resource mix changes.

13. We anticipate that this effort will be the Commission's principal focus in the months to come. In addition to reviewing the record assembled in response to today's order, we intend to explore technical conferences and other avenues for augmenting that record—including through the joint federal-state task force[18]—before proceeding to reform our rules and regulations. We recognize that the issues addressed herein are highly technical, complex problems that do not lend themselves to easy solutions. That being said, we also recognize the urgent need to address the transmission needs of the changing resource mix and appreciate that we do not have the luxury of sitting back and debating these issues *ad nauseum.*

* * * * *

14. The electricity sector is at a pivotal moment. With the clean energy transition gaining steam, we can either continue with the *status quo,* trying to meet the transmission needs of the future by building out the grid in a myopic, piecemeal fashion, or we can start holistically and proactively planning for those future transmission needs. We believe that today's advance notice of proposed rulemaking represents an important and essential first step in the right direction and toward the type of transmission planning and cost allocation paradigm that is necessary to protect customers, support reliability, and ensure just and reasonable rates.

For these reasons, we respectfully concur.

Richard Glick,
Chairman.

Allison Clements,
Commissioner.

[17] *Cf., e.g., California ex rel. Lockyer* v. *FERC,* 383 F.3d 1006, 1017 (9th Cir. 2004) (rejecting ''an interpretation [that] comports neither with the statutory text nor with the Act's 'primary purpose' of protecting consumers''); *City of Chicago* v. *FPC,* 458 F.2d 731, 751 (D.C. Cir. 1971) (''[T]he primary purpose of the Natural Gas Act is to protect consumers.'' (citing, *inter alia, City of Detroit* v. *FPC,* 230 F.2d 810, 815 (D.C. Cir. 1955)).

[18] *See supra* n.2.

Department of Energy

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 July 15, 2021)

DANLY, Commissioner, *concurring:*

1. I concur with the issuance of this Advance Notice of Proposed Rulemaking (ANOPR) because the Commission is always entitled to solicit comments on possible changes to existing rules and a number of the questions raised here are worthy of consideration.

2. I write separately to highlight one overarching concern. The ANOPR poses several questions where the answer is ''no.'' Many of the contemplated proposals would exceed or cede our jurisdictional authority, violate cost causation principles, create stifling layers of oversight and ''coordination,'' trample transmission owners' rights, force neighboring states' ratepayers to shoulder the costs of other states' public policy choices, treat renewables as a new favored class of generation with line-jumping privileges, and perhaps inadvertently lead to much less transmission being built and at much greater all-in cost to ratepayers.

3. There are obviously problems with the existing transmission regime. I, for example, have long been troubled by interconnection logjams and have wondered whether we are needlessly propping up fantasy projects while viable projects get lost in the crowd.[1] This is but one example; there are any number of other critical transmission planning reforms that bear investigation.

4. My hope therefore is that commenters will supply us with a full record on each issue raised in the ANOPR: Whether and why the existing rule works or not, and whether and why the possible reform may work or not. With every proposed change, I specifically solicit comments on two subjects. *First:* Is the contemplated reform a proper exercise of the Commission's authority, *i.e.,* is it within our jurisdiction? That is always the threshold question before we turn to policy. *Second:* what will be the ultimate effect on ratepayers? I fear that in the enthusiasm to build transmission, many may tout the benefits of new transmission while overlooking the costs that will eventually be borne by ratepayers. No proposed policy,

[1] *See, e.g., PacifiCorp,* 171 FERC ¶ 61,112 (2020) (Danly, Comm'r, concurring).

however worthy, can evade our statutory duty to ensure that rates are just and reasonable.

5. I encourage everyone with an interest to file. I look forward to learning from the parties that submit comments and to engaging with my colleagues to consider whether there are legally durable, economically sound reforms that we might consider to improve the reliability of the transmission system at just and reasonable rates.

For these reasons, I respectfully concur.

James P. Danly,
Commissioner.

Department of Energy

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 July 15, 2021)

CHRISTIE, Commissioner, *concurring:*

1. I concur with today's ANOPR because approximately ten years after the Commission issued Order No. 1000, it is appropriate to review the implementation of that order, assess the successes and problems that have become evident over the past decade, and consider reforms and revisions to existing regulations governing regional transmission planning and cost allocation. This consideration of potential reforms is especially timely as the transmission system faces the challenge of maintaining reliability through the changing generation mix and efforts to reduce carbon emissions.

2. The broad goal of the Commission's regulation of our nation's power grid under the Federal Power Act (FPA) is to ensure a reliable power supply to consumers, which includes residential customers as well as the businesses providing jobs for tens of millions of Americans, at just and reasonable rates. Transmission is one of the three essential elements of a reliable power system, along with generation and distribution, so continually working to make America's transmission system more reliable, more efficient, and more cost-effective is our job at FERC.

3. As with Order No. 1000, the statutory framework governing our potential actions in this proceeding remains section 206 of the FPA, which requires us to ensure that all transmission planning processes and cost allocation mechanisms subject to our jurisdiction result in jurisdictional services being provided at rates, terms and conditions that are just, reasonable, and not unduly discriminatory or preferential. Any proposals ultimately adopted by this Commission for reforms or revisions to existing regulations must be consistent with this authority.

4. As Paragraph 4 of the ANOPR makes clear,[1] we have not predetermined that any specific proposal in this ANOPR has already been or will ultimately be approved. Rather, we seek comment from all interested persons and organizations on the wide range of proposals contained herein, as well as the submission of alternative proposals. Today is the beginning of a long process and I look forward to hearing from all concerned.

5. Similarly, my concurrence to issue today's ANOPR does not represent an endorsement at this point in the process of any one or more of the proposals included in the order. 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. Given the early stage of this process, however, I agree it is worthwhile to submit a broad range of proposals to the public for comment in the hope that the final result will be a more reliable, more efficient, and more cost-effective transmission system.

For these reasons, I respectfully concur.

Mark C. Christie,
Commissioner.

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[1] ANOPR at P 4 (''We note that the Commission has not predetermined that any specific proposal discussed herein shall or should be made or in what final form; rather, we seek comment from the public on those proposals and welcome commenters to offer additional or alternative proposals for consideration.'').