DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM10–23–001; Order No. 1000–A]

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Order on rehearing and clarification.

SUMMARY: The Federal Energy Regulatory Commission affirms its basic determinations in Order No. 1000, amending the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. This order affirms the Order No. 1000 transmission planning reforms that: Require that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; provide that local and regional transmission planning processes must provide an opportunity to identify and evaluate transmission needs driven by public policy requirements established by state or federal laws or regulations; improve coordination between neighboring transmission planning regions for new interregional transmission facilities; and remove from Commission-approved tariffs and agreements a federal right of first refusal. This order also affirms the Order No. 1000 requirements that each public utility transmission provider must participate in a regional transmission planning process that has: A regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation and an interregional cost allocation method for the cost of new transmission facilities that are located in two neighboring transmission planning regions and are jointly evaluated by the two regions in the interregional transmission coordination process required by this Final Rule. Additionally, this order affirms the Order No. 1000 requirement that each cost allocation method must satisfy six cost allocation principles.

DATES: This order on rehearing and clarification will be effective on July 2, 2012.

FOR FURTHER INFORMATION CONTACT:

John Cohen, Federal Energy Regulatory Commission, Office of the General Counsel, 888 First Street NE., Washington, DC 20426, (202) 502–8705.

Shiv Mani, Federal Energy Regulatory Commission, Office of Energy Policy and Innovation, 888 First Street NE., Washington, DC 20426, (202) 502–8240.

SUPPLEMENTARY INFORMATION:

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

Order No. 1000–A

Order On Rehearing and Clarification

Issued May 17, 2012

Table of Contents

I. Introduction

1. In Order No. 1000, the Commission amended the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. Order No. 1000's transmission planning reforms require: (1) Each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan; (2) that local and regional transmission planning processes must provide an opportunity to identify and evaluate transmission needs driven by public policy requirements established by state or federal laws or regulations; (3) improved coordination between neighboring transmission planning regions for new interregional transmission facilities; and (4) the removal from Commission-approved tariffs and agreements of a federal right of first refusal.

2. Order No. 1000 also requires that each public utility transmission provider must participate in a regional transmission planning process that has: (1) A regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation and (2) an interregional cost allocation method for the cost of new transmission facilities that are located in two neighboring transmission planning regions and are jointly evaluated by the two regions in the interregional transmission coordination process required by this Final Rule. Order No. 1000 also requires that each cost allocation method must satisfy six cost allocation principles.

3. Taken together, the reforms adopted in Order No. 1000 will ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. The Commission therefore rejects requests to eliminate, or substantially modify, the various reforms adopted in Order No. 1000; however, we do make a number of clarifications.[1] We address each of the arguments made by petitioners in turn.[2]

[1] No changes are being made to the regulatory text previously adopted, because any reference to Order No. 1000 (as well as to Order Nos. 888 and 890) in the existing regulatory text is meant to include any clarifications or changes made in subsequent orders on rehearing or clarification (e.g., Order Nos. 888–A, 890–A, and the instant Order No. 1000–A, etc.). The Commission has chosen this convention to help promote readability of the regulatory text.

[2] A list of petitioners filing requests for rehearing and/or clarification is provided in Appendix A. An untimely request for rehearing was filed by the New Jersey Board of Public Utilities (New Jersey BPU). Pursuant to section 313(a) of the Federal Power Act (FPA), 16 U.S.C. 8251(a) (2006), an aggrieved party

II. The Need for Reform

A. Final Rule

4. In Order No. 1000, the Commission concluded that it was appropriate to adopt the package of reforms addressing transmission planning and cost allocation set forth in the order, stating that its review of the record, as well as recent studies, indicated that the transmission planning and cost allocation requirements of Order No. 890 [3] were an inadequate foundation for public utility transmission providers to address challenges they currently face or will face in the near future.[4] The Commission found that the record was adequate to support its conclusion that the existing requirements of Order No. 890 are too narrowly focused geographically and fail to provide for adequate analysis of the benefits associated with interregional transmission facilities traversing neighboring transmission planning regions.[5]

5. The Commission found that recent increases in transmission investment in fact support the need to ensure that transmission planning and cost allocation requirements are adequate to support more efficient and cost-effective investment decisions.[6] It noted that this increase appears to be only the beginning of a longer-term period of investment in new transmission facilities, which is being driven, in part, by changes in the generation mix. Specifically, the Commission explained that existing and potential environmental regulation and state renewable portfolio standards are driving significant changes in the mix of resources, resulting in the early retirement of some coal-fired generation, increased reliance on natural gas for electricity generation, and large-scale integration of renewable generation.[7] The Commission stated that these shifts in the generation fleet increase the need for new transmission and that the existing transmission grids were not built to accommodate them.[8] It stated that the increased focus on investment in new transmission projects makes it even more critical to implement the reforms to ensure that the more efficient or cost-effective projects come to fruition. In short, the Commission stated that the record in this proceeding and the cited reports confirm that additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new sources of generation. The Commission concluded that it was, therefore, critical that it act now to address deficiencies to ensure that more efficient or cost-effective investments are made as the industry addresses these challenges.

6. The Commission then stated that it would not wait for systemic problems to undermine transmission planning before action is taken. Rather, the Commission concluded that it must act promptly to establish the rules and processes necessary to allow public utility transmission providers to ensure planning of and investment in the right transmission facilities as the industry moves forward to address the many challenges it faces. The Commission noted that such planning is a complex process that requires consideration of a broad range of factors and an assessment of their significance over a period that can extend decades into the future, and that the development of transmission facilities can involve long lead times and complex problems related to design, siting, permitting, and financing.[9] Given the need to deal with these matters over a long time horizon, the Commission concluded that it is appropriate and prudent to act at this time rather than allowing the problems in transmission planning and cost allocation to continue or to increase.

7. The Commission concluded that its actions are consistent with the D.C. Circuit's opinions in *National Fuel* and *Associated Gas Distributors*.[10] Consistent with *National Fuel,* the Commission found that the problem it seeks to resolve, i.e., the narrow focus of current planning requirements and the shortcomings of current cost allocation practices, represents a significant ''theoretical threat'' that justifies Order No. 1000's requirements and is not one that the Commission can address adequately or efficiently through the adjudication of individual complaints.[11] The Commission explained that the actual experiences cited in the record provide additional support for action but are not necessary to justify the remedy, and that the remedy is justified by the theoretical threat identified therein.[12]

8. The Commission also explained that the facts and findings of *Associated Gas Distributors* are in no way comparable to the matters involved in this proceeding.[13] It disagreed that its reforms will have an impact on the industry that is comparable to the impact at issue in *Associated Gas Distributors.* The Commission pointed out that compliance with Order No. 1000 will involve the adoption and implementation of additional processes and procedures, and that many public utility transmission providers already engage in processes and procedures of this type, even if some public utility transmission providers may need to do more than others to comply.[14]

9. The Commission disagreed with assertions that it relied on unsubstantiated allegations of discriminatory conduct or that the current Order No. 890 processes have not been in place long enough to justify the reforms.[15] It stated that it need not make specific factual findings of discrimination to promulgate a generic rule to ensure just and reasonable rates or eliminate undue discrimination.

10. The Commission disagreed with claims that any concerns with current transmission planning and cost allocation processes are better dealt with on a case-specific basis rather than through a generic rule.[16] The Commission stated that while the concerns it has with existing planning and cost allocation processes may not affect each region of the country equally, it nonetheless remained concerned that the existing processes are inadequate to ensure the development of more efficient and cost-effective transmission. It noted that it is well-established that the choice between rulemaking and case-by-case adjudication lies primarily in the informed discretion of the administrative agency. It also noted that

must file a request for rehearing within thirty days after the issuance of the Commission's order. Because the 30-day rehearing deadline is statutory, it cannot be extended, and New Jersey BPU's request for rehearing must be rejected as untimely. Moreover, the courts have repeatedly recognized that the time period within which a party may file an application for rehearing of a Commission order is statutorily established at 30 days by section 313(a) of the FPA and that the Commission has no discretion to extend that deadline. *See, e.g., City of Campbell* v. *FERC,* 770 F.2d 1180, 1183 (D.C. Cir. 1985); *Boston Gas Co.* v. *FERC,* 575 F.2d 975, 977–79 (1st Cir. 1978).

[3] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 (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 (2009), *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[4] *Id.* P 42.

[5] *Id.* P 373.

[6] *Id.* P 44.

[7] *Id.* P 45.

[8] *Id.*

[9] *Id.* P 50.

[10] *Id.* P 51 (citing *National Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831 (D.C. Cir. 2006) (*National Fuel*); *Associated Gas Distrib.* v. *FERC,* 824 F.2d 981 (D.C. Cir. 1985) (*Associated Gas Distributors*)).

[11] *Id.* P 52.

[12] *Id.* P 53.

[13] *Id.* P 54–55.

[14] *Id.* P 56–57.

[15] *Id.* P 58.

[16] *Id.* P 60.

each transmission planning region has unique characteristics, and Order No. 1000 provided significant flexibility to transmission planning regions to accommodate regional differences.[17]

11. On the specific issue of nonincumbent transmission developers, the Commission found that there was sufficient justification in the record to implement the elimination of federal rights of first refusal contained in Commission-jurisdictional tariffs or agreements. It noted that although it previously accepted in some cases, and rejected in others, a federal right of first refusal, it found its reasoning in the cases rejecting the federal right of first refusal to be more persuasive. In particular, the Commission stated that it rejected a federal right of first refusal based on an expectation that ''[t]he presence of multiple transmission developers would lower costs to customers.'' [18] The Commission explained that it is not in the economic self-interest of incumbent transmission providers to permit new entrants to develop transmission facilities, even if proposals submitted by new entrants would result in a more efficient or cost-effective solution to a region's needs.[19] In addition, the Commission required all public utility transmission providers to adopt a framework that requires, among other things, the development of qualification criteria and protocols for the submission and evaluation of proposed transmission projects.[20]

12. Regarding its cost allocation reforms, the Commission concluded in Order No. 1000 that considering the changes within the industry and the implementation of other reforms in Order No. 1000, the requirements of Order No. 890 were no longer adequate to ensure rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential.[21] It found that the challenges associated with allocating the cost of transmission appear to have become more acute as the need for transmission infrastructure has grown.[22] The Commission explained that within RTO or ISO regions, particularly those that encompass several states, the allocation of transmission costs is often contentious and prone to litigation.[23] It also noted that in other regions, few rate structures are currently in place that reflect an analysis of the beneficiaries of a transmission facility and provide for the corresponding cost allocation of the transmission facility's cost.[24] Similarly, the Commission noted that there are few rate structures in place today that provide for the allocation of costs of interregional transmission facilities.[25] Finally, the Commission found that the lack of clear *ex ante* cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified during the transmission planning process.[26]

B. Requests for Rehearing and Clarification

1. Arguments Regarding Whether the Commission Provided Substantial Evidence for the Transmission Planning and Cost Allocation Reforms

13. While several petitioners seeking rehearing or clarification express general support for Order No. 1000,[27] others argue that the Commission failed to provide adequate justification under FPA section 206 for adopting its reforms.[28] Coalition for Fair Transmission Policy acknowledges that the circumstances against which the Commission must fulfill its statutory responsibilities change with developments in the electric industry, including changes with respect to demands on the transmission grid; however, it argues that Order No. 1000 takes the principle several steps beyond the Commission's existing statutory authority. Coalition for Fair Transmission Policy contends that the Commission makes a number of statements about problems facing the industry that are remarkable in their ambiguity, and the existence of problems does not empower the Commission to address every policy problem that arises from such developments or to commandeer regional transmission planning. Coalition for Fair Transmission Policy asserts that, if this was the case, section 216 of the FPA, which gives the Commission limited authority to site transmission facilities in national interest electric transmission corridors, would not have been necessary.

14. PPL Companies argue that the Commission failed to show that existing rates, terms and conditions are unjust and unreasonable or unduly discriminatory absent Order No. 1000.[29] They also contend that Order No. 1000 not only fails to identify who is being discriminated against and who is discriminating, but never addresses whether discrimination has actually materialized in the three years since the Commission's last major rulemaking in this area. PPL Companies assert that, although the Commission is empowered to act against undue discrimination before it occurs, it must at least identify the discrimination it seeks to remedy.[30] They also maintain that the Commission did not specify which rate it has found to be unjust and unreasonable or what substantial evidence it relies upon to draw that conclusion.

15. Similarly, California ISO asserts that the Commission failed to identify any instance in which an existing rate is unjust, unreasonable, or unduly discriminatory or preferential because it does not include provisions for interregional coordination. Instead, California ISO asserts that the Commission only offers an unsupported hypothesis that planning between or among regions will enhance the Commission's ability to perform its mission.

16. Oklahoma Gas and Electric Company argues that Order No. 1000 provides no evidence that existing tariff provisions that address the construction and ownership of transmission facilities in any way result in unjust and unreasonable rates, or in undue discrimination against any customers. It asserts that the evidence the Commission cited is far weaker than the evidence it relied upon to support its expansion of the Standards of Conduct in Order No. 2004, where the court stated that ''citing no evidence demonstrating that there is in fact an industry problem is not reasoned decision-making.'' [31]

[17] *Id.* P 61.

[18] *Cleco Power LLC,* 101 FERC ¶ 61,008 at P 117 (2002), *order terminating proceedings,* 112 FERC ¶ 61,069 (2005); *see also Carolina Power and Light Co.,* 94 FERC ¶ 61,273 at 62,010, *order on reh'g,* 95 FERC ¶ 61,282 at 61,995 (2001) (finding that a federal right of first refusal would unduly limit the planning authority and present the possibility of discrimination by self-interested transmission owners, potentially reduce reliability, and possibly precluding lower cost or superior transmission facilities or upgrades by third parties from being planned and constructed).

[19] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 256.

[20] *Id.* P 7.

[21] *Id.* P 497.

[22] *Id.* P 498.

[23] *Id.* P 498.

[24] *Id.* P 498.

[25] *Id.* P 498.

[26] *Id.* P 499.

[27] *See, e.g.,* AEP; WIRES; AWEA; and Energy Future Coalition Group.

[28] *See, e.g.,* Large Public Power Council; Alabama PSC; Xcel; Georgia PSC; Ad Hoc Coalition of Southeastern Utilities; and PPL Companies.

[29] PPL Companies at 6 (citing 16 U.S.C. 825l(b)).

[30] PPL Companies at 6 (citing *Associated Gas Distributors,* 824 F.2d 981 at 1008).

[31] Oklahoma Gas and Electric Company at 14 (citing *National Fuel,* 468 F.3d at 844).

17. Oklahoma Gas and Electric Company also claims that Order No. 1000 is devoid of support for the conclusion that existing tariff provisions interfere with transmission planning. It argues that there is no evidence, anecdotal or otherwise, that current RTO transmission planning processes generate an unreasonably limited range of options, and that there is no evidence that projects are delayed because they are being constructed by incumbent transmission owners. Specifically, Oklahoma Gas and Electric Company argues that the Commission cannot support a finding that the current transmission rules in SPP result in rates that are unjust and unreasonable.[32]

18. Georgia PSC argues that the Commission should recognize ongoing transmission processes that utilities are participating in and allow them to work before inserting another process that will strain resources.

19. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council assert that the Commission misread *National Fuel,* arguing that the court faulted the Commission for failing to support its decision with record evidence, and was non-committal on whether a decision might be supported by theory alone.[33] They state that it is incumbent on an agency to ''examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made.''[34] They further note that *National Fuel* commented that ''[p]rofessing that an order ameliorates a real industry problem but then citing no evidence demonstrating that there is in fact an industry problem is not reasoned decision-making.''[35]

20. Several petitioners take issue with the Commission's conclusion that it may act by citing to a ''theoretical threat'' rather than providing concrete evidence that the reforms are necessary.[36] For example, petitioners argue that the Commission failed to set forth substantial evidence, or any evidence, of undue discrimination to support its reforms.[37] Xcel adds that the Commission appears to concede that it lacks actual evidence of undue discrimination. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council argue that it is reasonable to conclude that the Commission has effectively conceded that there is no evidence justifying Order No. 1000 and that the Commission is relying on theory alone.[38]

21. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council, as well as North Carolina Agencies, argue that the flaw in the Commission's decision is that both the problem it aims to solve and the solution are theoretical. Ad Hoc Coalition of Southeastern Utilities contends that reasoned decision-making calls for substantially more than a hypothesis that existing planning and cost allocation mechanisms may be suboptimal, and speculation that the mechanisms discussed in the order will result in the development of more efficient transmission. Southern Companies also argue that the Commission's explanation of the need for the transmission planning and cost allocation reforms in Order No. 1000 is built entirely on speculation.[39] Given this, Southern Companies contend that Order No. 1000 fails to represent lawful, reasoned agency decision-making by depending on a speculative theoretical threat to support the required reforms rather than providing the required assessment.[40]

22. Southern Companies and Ad Hoc Coalition of Southeastern Utilities state that Order No. 1000's reliance on an alleged theoretical threat misinterprets precedent that agencies need to prove theories beyond mere hypothesis or conjecture.[41] They argue that courts have historically allowed agencies to support orders by theory alone when the theory itself is well supported and represents a highly developed prediction of what actually happens in the real world. Southern Companies, Ad Hoc Coalition of Southeastern Utilities, and Large Public Power Council cite to *Business Roundtable* v. *SEC,*[42] where the court concluded that the Securities and Exchange Commission (SEC) had not adequately considered the effects of a proposed rule on efficiency, competition and capital formation. They maintain that the case deals with matters that are similar to the present proceeding.

23. With respect to federal rights of first refusal, Sponsoring PJM Transmission Owners state that Order No. 1000's hypothetical discrimination stands in marked contrast to the concrete findings in Order No. 888 justifying the implementation of open transmission access and assert the Commission offers no evidentiary support for its findings. Baltimore Gas & Electric argues that the Commission is taking away a tariff-sanctioned right with nothing more than a ''concern'' that a right of first refusal may be leading towards rates that may become too high. It states that if the Commission believes that the problem is that rates will become too high, it should deal with the problem directly by lowering them, rather than by eliminating rights of first refusal.[43]

24. FirstEnergy Service Company takes issue with the Commission's reliance on *National Fuel* and asserts that a tenuous application of theory cannot support a rulemaking.[44]

[32] Oklahoma Gas & Electric Company also states that SPP's transmission planning process is robust and almost all of the projects are being completed within designated timeframes. It contends that where appropriate, the process permits nonincumbent developers to collaborate with incumbent transmission owners to address system needs. It also asserts that the 90-day time limit for incumbent transmission owners to agree to build a designated project prevents a transmission provider from blocking or delaying the construction of projects and ensures that the process is open and transparent.

[33] Ad Hoc Coalition of Southeastern Utilities at 16 (quoting *National Fuel,* 468 F.3d at 844 (''[W]e express no view here whether a theoretical threat alone would be sufficient to justify an order extending the Standards to non-marketing affiliates.'')).

[34] *Id.* at 16 (quoting *Motor Vehicles Mfrs. Ass'n of U.S.* v. *State Farm Mut. Auto Ins. Co.,* 463 U.S. 29, 43 (1983) (*State Farm*)).

[35] Ad Hoc Coalition of Southeastern Utilities at 16 (quoting *National Fuel,* 468 F.3d at 843).

[36] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; North Carolina Agencies; and Southern Companies.

[37] *See, e.g.,* FirstEnergy Service Company; PSEG Companies at 25–32 (citing the APA, as well as *National Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831, 838 (D.C. Cir. 2006) and *Florida Gas Transmission Co.* v. *FERC,* 604 F.3d 636, 645 (D.C. Cir. 2010)); Xcel; PSEG Companies; Sponsoring PJM Transmission Owners; Baltimore Gas & Electric at 15 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 229); Ad Hoc Coalition of Southeastern Utilities at 55 (quoting in part Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 253); Large Public Power Council; and MISO Transmission Owners Group 2.

[38] Large Public Power Council also claims that the D.C. Circuit has taken judicial notice of the efficiencies derived from vertical integration. According to Large Public Power Council, this means that the court is effectively insisting that the Commission offer evidence that decisions to disaggregate utility operations planning must overcome a presumption that the efficiencies derived from vertical integration are not in the public interest. Large Public Power Council at n.38 (citing *National Fuel,* 468 F.3d at 840 (citing *Tenneco Gas* v. *FERC,* 969 F.2d 1187, 1197 (D.C. Cir. 1992))).

[39] Southern Companies at 89–90 (citing *Algonquin Gas Transmission Co.* v. *FERC,* 948 F.2d 1305 (D.C. Cir. 1991)).

[40] Southern Companies at 91 (citing *State Farm,* 463 U.S. 29, 43 (1983)).

[41] Southern Companies at 14 (citing *National Fuel; Electricity Consumer Resource Council* v. *FERC,* 747 F.2d 1511, 1517 (D.C. Cir. 1984) (*ELCON*)); Ad Hoc Coalition of Southeastern Utilities at 22–23 (citing same).

[42] *Business Roundtable* v. *SEC,* 647 F.3d 1144 (D.C. Cir. 2011).

[43] Baltimore Gas & Electric at 18 (quoting *National Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831, 844 (D.C. Cir. 2006)).

[44] FirstEnergy Service Company at 15 (citing *National Fuel Supply Corp.* v. *FERC,* 468 F.3d 831 (D.C. Cir. 2006) (*National Fuel*)).

According to FirstEnergy Service Company, while the court in *National Fuel* acknowledged the possibility of an agency proceeding on theory alone to support a rulemaking, it also cautioned that such reliance required a substantial showing of the need in order to proceed.[45] California ISO makes a similar argument. Both FirstEnergy Service Company and California ISO assert that the Commission has not made any showing similar to that described in *National Fuel* to justify its sole reliance on theory.

25. On the issue of the Commission's nonincumbent transmission developer reforms, Southern Companies assert that they do not have a federal right of first refusal and that there are no restrictions on a nonincumbent developer's ability to pursue transmission projects in the SERTP planning process. Southern Companies argue the Commission has failed to articulate a legal basis for imposing its nonincumbent requirements upon Southern Companies, when it has no right of first refusal. Furthermore, Southern Companies argue that the reason for the lack of nonincumbents in the Southeast is because the incumbent transmission owners have developed a robust transmission grid and are adequately investing in transmission. Southern Companies also assert that there have been no significant merchant transmission projects within their footprint because there is no congestion and generation is not remotely located. Thus, Southern Companies argue that Order No. 1000's generic findings of undue discrimination against nonincumbents are counter to record evidence and that to date no nonincumbents have proposed alternative transmission projects in the SERTP. In addition, Southern Companies state that the Commission does not have the authority to impose nonincumbent-related development rights *sua sponte* generically upon the industry.

26. Petitioners also argue that the Commission failed to identify any established theoretical principles in support of its reforms.[46] Southern Companies maintain that the Commission's reasoning does not meet the scientific standards of a ''good theory,'' which it defines as satisfying two conditions: ''[i]t must accurately describe a large class of observations on the basis of a model that contains only a few arbitrary elements, and it must make definite predictions about the results of future observations.'' [47] Xcel argues that if the Commission intends to rely only on theoretical evidence, it must satisfy the requirements of *National Fuel* by explaining why the individual complaint procedure provided an insufficient remedy.[48] MISO Transmission Owners Group 2 asserts that *National Fuel* did not authorize the Commission to issue a rulemaking solely on the basis of a ''theoretical threat'' but indicated that if the Commission attempted to do so, it would be required to provide a substantial explanation. It argues that the Commission provides no such analysis, but rather summarily indicates that the threat of abuse ''is not one that can be addressed adequately or efficiently through the adjudication of individual complaints.'' [49] MISO Transmission Owners Group 2 contends that a case-by-case analysis would be particularly appropriate in this instance given the dearth of empirical evidence demonstrating harm, compared to the actual examples of nonincumbent transmission developer participation in transmission planning processes in MISO and elsewhere.

27. Other petitioners add that the reforms are unnecessary because there is evidence that transmission expansion has increased significantly over the past several years.[50] Large Public Power Council states that Order No. 1000 does not rely on any finding regarding the need to increase transmission development. Some petitioners also point to existing processes in the Southeast as undercutting the predicate for Order No. 1000.[51] North Carolina Agencies assert that there is error in the Commission's unwillingness to consider the highly developed planning processes in the region as a relevant factor in ascertaining the need for new rules. They also claim that although the anticipated demand for significant interregional transmission projects to transfer large amounts of remotely located renewable energy to fulfill public policy mandates is a major factual predicate for the proposals articulated, this is simply not present in the Southeast due to its resource base. They note that the Southeast already has a robust transmission system, as recognized in DOE's 2009 Transmission Congestion Study. North Carolina Agencies state that utilities in the Southeast remain vertically integrated and provide bundled retail service; the bulk of the resulting transmission cost is included in, and recovered through, state approved bundled retail rates. Thus, they argue that the evidence demonstrates that needed transmission investment is not lacking with respect to the utilities in the Southeast.

28. Southern Companies raise similar arguments with respect to existing regional transmission planning, interregional transmission coordination, and cost allocation processes in the Southeast, claiming that the new planning processes will not be associated with any previously unidentified new load growth, supply or demand side resource, or transmission service request because all of those elements are already addressed in the bottom-up planning processes. Southern Companies further argue that because Order No. 1000 lacks a process to identify new solutions, it will only serve to potentially optimize existing upgrades, which is already occurring due to extensive coordination with neighboring utilities in the Southeast. Ad Hoc Coalition of Southeastern Utilities raise similar arguments, and add that Order No. 1000's concern that some regional transmission planning processes permitted by Order No. 890 are only a forum to confirm simultaneous feasibility does not apply to planning processes in the Southeast.

29. Southern Companies explain that their Order No. 890 Attachment K compliance filing was accepted as of July 2010, and none of the changed circumstances cited in Order No. 1000 has occurred since then. Southern Companies assert that the Commission ignored evidence addressing their existing transmission planning processes and explaining how those processes assure consideration of better regional solutions and support just and reasonable rates. Southern Companies assert that unless detailed facts show existing cost allocation methods are impairing the proposal and consideration of better regional solutions, Order No. 1000 may not lawfully determine they are causing Southern Companies' rates, terms, and conditions for transmission service to be unjust and unreasonable. They also argue that, although the Commission is permitted in certain circumstances to make generic findings in support of its rulemaking, specific findings for specific entities are required when the

[45] FirstEnergy Service Company at 15 (quoting *National Fuel*, 468 F.3d 831 at 844–45).

[46] *See, e.g.,* FirstEnergy Service Company; Xcel; Sponsoring PJM Transmission Owners; PSEG Companies; and Xcel.

[47] Southern Companies at 15 (quoting Stephen Hawking & Leonard Mlodinow, A Briefer History of Time 13–14 (2005)).

[48] Xcel at 13–14 (citing *Nat'l Fuel,* 468 F.3d 831, 834, 844 (D.C. Cir. 2006)).

[49] MISO Transmission Owners Group 2 at 15 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 52).

[50] *See, e.g.,* PSEG Companies.

[51] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; North Carolina Agencies; and Southern Companies.

actual facts applicable to those entities run counter to generic principles.[52] They add that, on rehearing, the Commission must address substantial evidence that supports the justness and reasonableness of Southern Companies' existing processes in determining whether the reforms of Order No. 1000 should be applied to supplant such processes, or exclude Southern Companies from Order No. 1000's generic findings.

30. Ad Hoc Coalition of Southeastern Utilities add that there are no planning gaps that need to be filled in the Southeast by the Commission's interregional coordination requirements. Ad Hoc Coalition of Southeastern Utilities and Southern Companies assert that the Southeastern utilities already share on an interregional basis data containing all of the information needed to make informed and efficient planning decisions. Ad Hoc Coalition of Southeastern Utilities further argues that the implication that additional interregional coordination will identify whether interregional transmission facilities are more efficient or cost-effective than regional transmission facilities is unfounded, and involves integrated resource planning analysis and 'optimatization' analyses along the seams/interfaces that already occur in the Southeast. Ad Hoc Coalition of Southeastern Utilities concludes that the Commission's holdings regarding its interregional coordination requirements are unfounded and counter to the record evidence.

31. Moreover, Ad Hoc Coalition of Southeastern Utilities and Southern Companies assert that the factual record in this rulemaking demonstrates that the required interregional coordination reforms are likely to do more harm than good. For instance, Ad Hoc Coalition of Southeastern Utilities and Southern Companies state that it is costly to negotiate many coordination agreements and parallel OATT language with many different entities and to prospectively implement multiple bureaucratic requirements.

32. Sacramento Municipal Utility District argues that a generic rule is arbitrary and inappropriate to address a problem that exists, if at all, only in isolated pockets.[53] It also argues that the Commission cannot defend its actions on purely theoretical grounds unless it abandons its unsubstantiated claim that an actual problem exists.[54] Sacramento Municipal Utility District states that to the extent the Commission's rule was adopted to address a theoretical problem, it has failed to meet its burden of establishing that the burdens and costs imposed by the rule are justified by the threat to be addressed.[55] With respect to transmission planning in particular, Sacramento Municipal Utility District contends that the assertion that regional planning taking place under Order No. 890 is insufficient and producing unjust and unreasonable rates is premised on the existence of an actual, not theoretical, problem. It states that there is no evidence to support this assertion, and no evidence that the alleged problem affects more than a few isolated regions of the country. Sacramento Municipal Utility District adds that Order No. 1000 scarcely acknowledges comments documenting the success of various regional planning efforts, but instead refers to generalized statements of concern about potential problems in unidentified regions of the country involving unidentified utilities. It states that this is not the type of evidence upon which a rule purporting to address a national problem can be sustained and this is the same problem that resulted in the remand in *National Fuel*.[56] It argues that the Commission failed to establish that the burdens imposed by Order No. 1000 are justified by the threat addressed,[57] and that Order No. 1000 fails the test of reasoned decision-making, citing the fact that Order No. 1000 failed to take into account whether imposition of its mandatory cost allocation provisions will discourage rather than facilitate regional planning. Alabama PSC likewise contends that the speculative benefits identified in Order No. 1000 are not legally sufficient to justify the rule's burdens and disruptions and, as such, Order No. 1000 is not justified under the Commission's authority under section 206. Alabama PSC encourages the Commission to consider a regional or case-by-case approach if the Commission continues to believe that it should move forward with this initiative.

33. Similarly, Ad Hoc Coalition of Southeastern Utilities contends that Order No. 1000 violates the guidance provided by *National Fuel* regarding what may be permissible by an order solely based upon a theory, arguing that the record demonstrates that there will be little benefit, and possible harm, if the interregional transmission coordination requirements are implemented. Additionally, Ad Hoc Coalition of Southeastern Utilities contend that these reforms would be burdensome to implement, because public utility transmission providers would have to negotiate a number of coordination agreements and parallel OATT language with many different entities and then prospectively implement a number of bureaucratic requirements.[58] Southern Companies agree.

34. NARUC argues that Order No. 1000 does not identify actual concerns or problems or rely on any factual record, but relies entirely on the conclusory statement that planning and cost allocation may be impeding the development of beneficial transmission lines. It also argues that efforts to sort through the ambiguities and comply with Order No. 1000 may stall existing local, regional, and DOE-funded interconnectionwide planning processes, creating uncertainty and requiring limited resources to be reallocated to compliance filings rather than to finalizing plans. NARUC further asserts that Order No. 1000 is premature because the results of the interconnectionwide planning process may eliminate the need for reform or indicate a need for different reforms.

35. Some petitioners also take issue with the Commission's efforts to distinguish Order No. 1000 from *Associated Gas Distributors*.[59] Large Public Power Council argues that the Commission is in error in attempting to minimize the exacting evidentiary standard for generic rulemaking called for in *Associated Gas Distributors* on the ground that the impact of the decision here is not ''comparable.'' [60] It argues that while the Commission states in Order No. 1000 that compliance ''will involve implementation of additional processes and procedures'' and many public utility transmission providers

[52] Southern Companies at 92 (citing *National Fuel,* 468 F. 3d at 839).

[53] Sacramento Municipal Utility District at 4 (citing *Associated Gas Distributors,* 824 F.2d 981 at 1019).

[54] Sacramento Municipal Utility District at 5 (citing *National Fuel,* 468 F.3d at 839).

[55] Sacramento Municipal Utility District at 5 (citing *National Fuel,* 468 F.3d at 844).

[56] Sacramento Municipal Utility District at 32 (citing *Nat'l Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831, 844 (D.C. Cir. 2006)).

[57] Sacramento Municipal Utility District at 33 (citing *Nat'l Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831, 844 (D.C. Cir. 2006)).

[58] Ad Hoc Coalition of Southeastern Utilities at 66 (quoting *National Fuel,* 468 F.3d at 844 (arguing that the Commission must explain how the ''potential danger * * * unsupported by a record of abuse, justifies such costly prophylactic rules.'')).

[59] *See, e.g.,* Large Public Power Council; Ad Hoc Coalition of Southeastern Utilities; MISO Transmission Owners Group 2; Southern Companies; and Sacramento Municipal Utility District.

[60] Large Public Power Council at 17 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 56).

''already engage in processes and procedures of this type,'' the goal of Order No. 1000 is to remedy unjust and unreasonable rates on a national basis by implementing new planning and cost recovery procedures.[61] Large Public Power Council asserts that even if this is not the case, the implications of Order No. 1000 involve cost shifting for the recovery of potentially hundreds of billions of dollars in transmission investment. Ad Hoc Coalition of Southeastern Utilities raises similar concerns, explaining that the attempt to distinguish *Associated Gas Distributors* ''gives short shrift to the Commission's ambitions in promulgating Order No. 1000, which is to implement new planning and cost recovery procedures.''[62]

36. MISO Transmission Owners Group 2 maintains that, while the Commission argued that *Associated Gas Distributors* states that it need not provide empirical data for every proposition upon which it depends, the Commission has a duty to ''respond meaningfully'' to the objections raised by opponents of its proposal, which it failed to do.[63] Southern Companies argue that the Commission did not squarely address comments asserting that there was no need for an industrywide solution when the problem applies only to a limited portion of the industry.

37. Similarly, California ISO argues that the Commission cannot find support in *Associated Gas Distributors* for acting based on a theoretical threat.[64] In contrast to *Associated Gas Distributors,* California ISO asserts that the Commission is not relying on an economic theory to determine the means for achieving its goal, but rather is attempting to rely on theory to establish the statutory predicate for action.[65] Furthermore, California ISO argues that the Commission's hypothesis that, in a regulated market, the absence of an *ex ante* cost allocation method will cause rates to be unjust or unreasonable is not based on an established economic theory. California ISO asserts that there is no empirical evidence for this hypothesis, and that the Commission has not cited any peer-reviewed or other economic analysis supporting its conclusion. As such, California ISO concludes that such a hypothesis cannot support action under section 206.

38. In addition, California ISO argues that the Commission has not identified any evidence to support a causal connection between a cost allocation methodology and improved cost-effectiveness. California ISO acknowledges two commenters that provided concrete examples that uncertainty about cost allocation was preventing some projects from going forward, but argues that these examples do not support the Commission's finding.

39. MISO Transmission Owners Group 2 asserts that the Commission relies on general suppositions to support its mandate that all rights of first refusal be removed from Commission-jurisdictional tariffs and contracts. For example, it states that Order No. 1000 states that nonincumbent transmission developers seeking to invest in transmission can be discouraged from doing so, but the Commission never identifies a single instance of a nonincumbent transmission developer foregoing an opportunity to invest in a transmission facility because of any existing federal right of first refusal. MISO Transmission Owners Group 2 maintains that the Commission ignored examples it and others gave of nonincumbent transmission developer involvement in regional planning processes, such as the CapX2020 Transmission Capacity Expansion Initiative, in which eleven entities, including MISO Transmission Owners, nonincumbent transmission developers, and transmission dependent utilities are engaged in a collaborative effort to construct nearly 700 miles of new extra-high voltage transmission facilities from the Dakotas to Wisconsin.

40. Similarly, MISO argues that while its existing regional planning processes have resulted in significant transmission expansion in the past and will result in even greater transmission construction in the future, Order No. 1000 does not identify any evidence that transmission planning, expansion and/or cost allocation have been hindered or harmed by the Transmission Owners Agreement provisions relating to the obligation to build, including any associated rights whose nature and effects may resemble rights of first refusal. It asserts that the Commission cannot use any evidence that may involve other RTO, ISOs, or public utilities to draw conclusions about any unjustness and unreasonableness of provisions in MISO's Transmission Owners Agreement, and to require the removal or modification of such provisions.

41. Baltimore Gas & Electric states that the Commission's rationale for eliminating the right of first refusal has no applicability to it and other transmission owner members of PJM since they have all relinquished transmission planning decisions to PJM. According to Baltimore Gas & Electric, it does not matter that transmission owners have an economic incentive to be unduly discriminatory in transmission planning once they have transferred that role to an RTO. Baltimore Gas & Electric asserts that PJM's Order No. 890 compliance filing ensures an open, transparent, and stakeholder-participatory transmission planning process that no transmission owner member has the ability to manipulate for anticompetitive purposes. In any event, Baltimore Gas & Electric states that the opportunity for undue discrimination existed in the abstract when federal right of first refusal rights were initially approved by the Commission, and that nothing has changed to warrant their removal now. Baltimore Gas & Electric adds that there are opportunities for any lawfully sanctioned activity to be misused. Thus, Baltimore Gas & Electric concludes that speculation as to how some bad actors may misuse rights is not a rational basis for eliminating the rights for all actors.

42. Similarly, Sunflower, Mid-Kansas, and Western Farmers dispute Order No. 1000's conclusion that it is not in the economic self-interest of public utility transmission providers, at least in the SPP region, to expand the grid to permit access to competing sources of supply to serve their customers.[66] They note that no state in the SPP region has enacted retail competition and, consequently, those states would not stand for anticompetitive behavior by incumbent transmission owners that would result in higher rates to consumers.[67]

43. Petitioners also disagree with the Commission's conclusion that it can rely on the benefits of competition to support the rule without a ground for a reasonable expectation that competition may have some beneficial impact.[68] These petitioners disagree with the Commission's interpretation of, and

[61] Large Public Power Council at 17–18 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at 56).

[62] Ad Hoc Coalition of Southeastern Utilities at 18.

[63] MISO Transmission Owners Group 2 at 13.

[64] California ISO at 16 (citing *Associated Gas,* 824 F.2d 981 at 1008–09).

[65] California ISO at 17 (citing *Associated Gas,* 824 F.2d 981 at 1008–09).

[66] Sunflower, Mid-Kansas, and Western Farmers at 3 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 254).

[67] Sunflower, Mid-Kansas, and Western Farmers argue that this is borne out by activity in SPP of at least two independent transmission developers (ITC Great Plains, LLC and Prairie Wind Transmission, LLC).

[68] *See, e.g.,* PSEG Companies; Ad Hoc Coalition of Southeastern Utilities at 55 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 268); and Large Public Power Council.

citation to, *Wisconsin Gas*.[69] Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council argue that *Wisconsin Gas* dealt with the benefits of competition associated with promoting competitive sales of natural gas, which Congress made a national policy. In contrast, they argue that there is no indication that Congress has endorsed promoting competition for the development of transmission infrastructure. Large Public Power Council quotes the language from *Wisconsin Gas* where the court stated that ''unsupported or abstract allegations of benefits that will accrue from increased competition cannot substitute for a conscientious effort to take into account what is known as to past experience and what is reasonably predictable about the future.'' [70] Large Public Power Council asserts that here, the Commission not only lacks any legitimate basis for a presumption that competition in the transmission development business serves the public interest, but fails to amass any evidence for its view.

44. A number of petitioners question the Commission's assertion that adding more transmission developers may lead to the identification of more efficient alternatives.[71] Oklahoma Gas and Electric Company asserts that the Commission has not supported the assumption that competition between potential developers in the process of evaluating and selecting proposed projects will result in more cost-effective transmission service rates. Sponsoring PJM Transmission Owners argue that precedent does not support the Commission's conclusion that the mere invocation of general beneficial impacts of competition suffices to support modifying rates pursuant to section 206. Sponsoring PJM Transmission Owners also assert the real issue is not competition between transmission providers, but rather which entity will be the monopoly owner of a transmission line. Oklahoma Gas and Electric Company states that nothing in Order No. 1000 will result in head-to-head competition between service providers, or between competing lines. It elaborates that the market will not be choosing who constructs new projects, but rather the stakeholder process will be used to make a choice based on uncertain estimates and inputs.

45. Sponsoring PJM Transmission Owners argue the Commission has not explained or demonstrated how competition among transmission developers would reduce the cost of transmission construction and consequently transmission service. For instance, Sponsoring PJM Transmission Owners state that even if a nonincumbent submits a proposal that it projects will have the lowest cost, the Commission has produced no evidence that its actual costs of construction will be lower than the cost the incumbent would incur. Instead, they argue that the incumbent is far more likely to have existing rights of way and more experience with construction and logistical issues that may arise in its area, and thus is better positioned politically to overcome local objections to siting. Baltimore Gas & Electric notes that the Commission has recognized that incumbents have certain advantages, such as a unique knowledge of their own systems and other matters, and that the Commission has stated that such factors can be highlighted in the decisional process leading to project selection. Baltimore Gas & Electric states that it is thus unclear to why the Commission would require that the existing federal right of first refusal provision should be eliminated if the same result can be achieved in the decisional process by taking into account that the incumbent is better placed to construct and own a project.

46. Sponsoring PJM Transmission Owners argue the Commission has not explained how any reduction in construction costs—assuming it could be achieved—would translate into lower rates, after taking into account differing corporate structures, rates of return, and Commission-granted incentives. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council argue that the efficiencies that the Commission presumes will be associated with its decisions, and that it assumes will overcome added costs and risks, are not a matter that the Commission is entitled to presume. Xcel argues that the Commission's rationale to increase competition does not apply to reliability projects, which have the narrow function of ensuring reliable service to customers.[72]

47. Some petitioners argue that the mixed record does not justify the Commissions ruling.[73] For instance, petitioners argue that the Commission must, as a matter of law, take notice of efficiencies lost and reliability problems created by the Commission's decision.[74] Specifically, Large Public Power Council argues that planning engineers will spend time addressing stakeholder and competitors' concerns in Commission-sponsored planning forums rather than working to meet the needs of their native loads. Additionally, it states that countless hours will be needed to perform studies, reengineer systems, and coordinate third-party construction schedules and priorities. Ameren adds that MISO will have to expend considerable resources to re-assess years of transmission planning work to apply the new rule.

48. Sponsoring PJM Transmission Owners argue the Commission has ignored other potential costs associated with eliminating the right of first refusal, including expensive mitigation plans in the event that a nonincumbent abandons a reliability project. Similarly, Xcel asserts that Commission's statement in P 344 of Order No. 1000 indicates the Commission's belief that certain nonincumbent transmission developers will not be able to complete the projects assigned to them. Xcel adds that other risks will increase from the utility transmission providers' inability to guarantee reliable service, such as litigation arising from outages.

49. Ad Hoc Coalition of Southeastern Utilities asserts that Commission policy has persistently treated transmission as a natural monopoly, and therefore the court's decision in *Wisconsin Gas* should serve as a warning light rather than the license that the Commission assumes it to be. Southern Companies contend that Order No. 1000 assumes that vertical integration is unduly discriminatory because it requires nonincumbents to have a right to propose, own, build and operate integrated network elements. Southern Companies assert that they operate under the traditional regulatory compact, with efficiencies of vertical integration, economy of scale, duty to serve, and adequate return on investment, which ensures necessary transmission is constructed on schedule and is appropriately operated and maintained. Southern Companies state that by not recognizing and rationally explaining this change in precedent, the

[69] *See, e.g.,* PSEG Companies; Ad Hoc Coalition of Southeastern Utilities at 56 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 268, n.243); and Large Public Power Council.

[70] Large Public Power Council at 28 (quoting *Wisconsin Gas,* 770 F.2d 1144 at 1158).

[71] *See, e.g.,* Southern Companies; Sponsoring PJM Transmission Owners at 16, 20 (citing *Williston Basin Interstate Pipeline Co.* v. *FERC,* 358 F.3d 45, 50 (D.C. Cir. 2004)); Ad Hoc Coalition of Southeastern Utilities at 57 (quoting *Washington Gas,* 770 F.2d at 1158).

[72] Xcel at 12–13 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 284–85).

[73] *See, e.g.,* Baltimore Gas & Electric at 16–17 (citing *Central Iowa Power Cooperative* v. *FERC,* 606 F.2d 1156 (D.C. Cir. 1979)).

[74] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council at 27 (citing *National Fuel* and *Tenneco Gas*).

Commission has acted arbitrarily and capriciously.

C. Commission Determination

50. We deny the requests for rehearing that challenge the Commission's determination that the reforms instituted by Order No. 1000 are needed. As we noted in Order No. 1000, changes are at work in the electric utility industry that have created an additional, and potentially significant, need for new transmission infrastructure. Order No. 1000 cited studies conducted by the North American Electric Reliability Corporation (NERC) and Edison Electric Institute (EEI) that confirmed an increase in transmission development over the last several years, and the Commission cited to an EEI-commissioned Brattle Group study suggesting that approximately $298 billion in new transmission facilities will be required over the period 2010 to 2030.[75] Order No. 1000 explained that these changes are being driven in large part by the changes in the generation mix, and it cited NERC's 2009 Assessment, which stated that existing and potential environmental regulation and state renewable portfolio standards are driving significant changes in the generation mix, resulting in early retirements of coal-fired generation, an increasing reliance on natural gas, and large-scale integration of renewable generation.[76]

51. The Commission concluded in Order No. 1000 that current transmission planning and cost allocation requirements are inadequate to meet these challenges. Current requirements threaten to thwart identification of transmission solutions that are more efficient or cost-effective than would be the case without the reforms contained in Order No. 1000. As a result, the Commission concluded—and we affirm here—that it is necessary and appropriate that we take proactive steps to ensure that this threat does not result in such adverse consequences. The narrow focus of current transmission planning requirements, and the shortcomings of current cost allocation practices, represent a threat that justifies Order No. 1000's requirements, and it is not one that the Commission can address adequately or efficiently through the adjudication of individual complaints.[77] The Commission explained that the actual experiences cited in the record provide additional support for action but are not necessary to justify the remedy, and that the remedy is justified by the theoretical threat identified therein.

52. Order No. 1000 addresses the inadequacy of existing requirements by establishing minimum criteria that the transmission planning process must satisfy, including general principles that cost allocation practices must follow. These criteria are interrelated and were designed as a package to ensure that an effective transmission planning process is in place in each region.[78] Effective transmission planning requires coordination among transmission planning entities; is open and transparent, which is necessary for any process that involves multiple entities with a variety of needs or views regarding this process; considers all transmission needs of all transmission customers; results in an identifiable product reflecting regional determinations; and does not create unnecessary barriers to the consideration of good ideas or the selection of the most advantageous transmission solutions, regardless of whether the developer of a transmission solution is an incumbent transmission developer/provider or a nonincumbent transmission developer. Effective transmission planning should also recognize that there may be even more efficient or cost-effective solutions that are identified through interregional transmission coordination efforts than those solutions identified in a regional transmission planning process. Finally, effective transmission planning is performed with a clear *ex ante* understanding of who will pay for a facility selected in a regional transmission plan for purposes of cost allocation. Without that understanding, the likelihood that selected facilities will be implemented is diminished, undermining the entire purpose of the transmission planning process, namely, the development of efficient and cost-effective transmission solutions.

53. These basic principles encompass all the reforms found in Order No. 1000 and show how the reforms are interrelated to serve a common purpose. If any of the reforms are absent, the effectiveness of transmission planning and cost allocation processes would be undermined. We are not able to identify any argument raised on rehearing that demonstrates that any of these principles are invalid. Instead, the overriding objection raised by the petitioners to the Commission's discussion of the need for the reforms in Order No. 1000 is that the Commission either has not demonstrated the existence of a problem that requires correction through implementation of new requirements, or that it has not shown that the problems it has identified exist in all regions of the country, thus undermining the need for generic rules that apply to all public utility transmission providers. The petitioners that raise these objections maintain that the development of needed transmission facilities is proceeding apace, either nationally or in a specific region, and thus currently there is nothing amiss that requires correction. From this, petitioners conclude that the Commission has not presented substantial evidence of a current problem that shows the need for its reforms.

54. We disagree. As the Commission noted in Order No. 1000, the expansion of the transmission grid is the result of a complex and often contentious process that occurs over a long time horizon.[79] It is capital intensive and subject to numerous regulatory hurdles. It is further complicated by the problem of determining how costs for the expansion will be allocated in instances when multiple entities benefit. Given the fundamental importance of transmission infrastructure, and the many difficulties involved in its development, including the long lead times involved, we continue to believe that a proactive approach is necessary. As discussed in Order No. 1000 and reiterated below, such an approach is fully consistent with the applicable legal requirements.

55. Petitioners' specific arguments that the Commission has not adequately justified the need for the reforms in Order No. 1000 fall under six broad headings: (1) The Commission has failed to demonstrate that any existing rate, term or condition of or for transmission service is unjust and unreasonable or unduly discriminatory or preferential; (2) the Commission supports its need for reform based solely on the existence of a theoretical threat, and it is not clear in *National Fuel* whether such a decision can be supported on this basis alone: (3) the theoretical threat that the Commission uses to justify its reforms in Order No. 1000 amounts to hypothesis and speculation and ignores existing realities, especially in the Southeast; (4) the Commission has not identified a theoretical threat that justifies the removal of federal rights of first refusal from Commission-

[75] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 44–45.

[76] *Id.* P 45.

[77] *Id.* P 52.

[78] Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at 42; Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 47.

[79] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 50.

jurisdictional tariffs and agreements and that the Commission has not shown that there is a reasonable expectation that competition in transmission development may have some beneficial impact on rates; (5) the burdens imposed by the Commission's reforms outweigh the benefits; and (6) other issues that do not fall into a general category. We address each of these arguments in turn below.

Whether Is It Necessary That the Commission Demonstrate That Any Existing Rate, Term or Condition of or for Transmission Service Is Unjust and Unreasonable or Unduly Discriminatory or Preferential

56. California ISO, PPL Companies, Southern Companies, and Oklahoma Gas and Electric Company challenge the Commission on the grounds that it has failed to demonstrate that any existing rate, term or condition of or for transmission service is unjust and unreasonable or unduly discriminatory or preferential. However, the Commission is not required to make individual findings concerning the rates of individual public utility transmission providers when proceeding under FPA section 206 by means of a generic rule.[80] When the Commission proceeds by rule it can conclude that ''*any* tariff violating the rule would have such adverse effects * * * as to render it 'unjust and unreasonable' '' within the meaning of section 206 of the FPA.[81]

57. One circumstance that can justify the application of this principle is the existence of a threat that, in the absence of Commission action, would materialize and cause rates to be unjust and unreasonable, or unduly discriminatory or preferential. A threat that has not yet materialized is what the court in *National Fuel* described as a ''theoretical threat.'' The Commission justified the need for the reforms in Order No. 1000 based on such a threat created by the inadequacy of existing transmission planning and cost allocation requirements to meet the anticipated challenges facing the industry, a threat whose existence was illustrated by actual problems that the Commission noted in the order, but that are not necessary to justify its response to the threat.[82]

[80] *Associated Gas Distributors* v. *FERC,* 824 F.2d at 1008.

[81] *Id.* (emphasis in original).

[82] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 53.

Whether the Reforms in Order No. 1000 can be Supported on the Basis of a Theoretical Threat Alone

58. A number of petitioners call into question the use of a theoretical threat as the basis for the Commission's reforms.[83] For example, Ad Hoc Coalition of Southeastern Utilities maintains that, based on *National Fuel,* it is not clear whether a decision might be supported by theory alone. We disagree that the court in *National Fuel* was non-committal on this point. The court specifically stated that the Commission could choose ''to rely solely on a theoretical threat.'' [84] While it listed certain matters that the Commission would need to address on remand, it did not comment on the possibility of addressing them successfully, nor did it say anything to suggest that this approach might be defective in principle. FirstEnergy Service Company argues that the list of specific matters that the court listed defines the showing that must be made to rely on a theoretical threat in all cases. However, the court's list of matters to be addressed on remand was simply a reflection of the specific issues it saw in the case at hand, not what was required in all cases. Moreover, when the court stated in *National Fuel* that it expressed ''no view here whether a theoretical threat *alone* would justify an order * * *,'' [85] it was referring to the justification of an order in the matter at hand, not any and every possible proceeding. Additionally, we note that the same court subsequently reconfirmed the legitimacy of reliance on theoretical threats, and it based its conclusion directly on the ruling it made in *National Fuel.*[86]

Whether the Commission's Argument That the Reforms in Order No. 1000 Are Needed Amounts to Hypothesis and Speculation and Ignores Existing Realities, Especially in the Southeast

59. Several petitioners characterize the Commission's approach as based on hypothesis and speculation. For example, Southern Companies claim that the Commission is making ''little more than a guess—a speculative hypothesis,'' [87] and Ad Hoc Coalition of Southeastern Utilities and Alabama PSC also claim that the Commission is acting on mere conjecture. Southern Companies insist that the Commission must provide detailed facts showing that existing cost allocation methods are impairing better regional transmission solutions. NARUC states that the Commission does not identify actual concerns or problems or rely on any factual record and instead proceeds in a conclusory fashion. Some petitioners also maintain that the existing situation in the Southeast undercuts the Commission's position.

[83] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; and Large Public Power Council.

[84] *National Fuel,* 468 F.3d at 844.

[85] *Id.* at 844.

[86] *BNSF Railway Co.* v. *Surface Transportation Board,* 526 F.3d 770, 778 (D.C. Cir. 2008) (*BNSF Railway Co.*) (finding that the Surface Transportation Board could adopt a new method to correct excessive railroad rates arising through gaming behavior by the railroads even when there was no evidence of such behavior on their part).

[87] Southern Companies at 16.

60. As an initial matter, we note that, based on our expertise and knowledge of the industry, we do not consider it to be speculation or conjecture to conclude that regional transmission planning is more effective if it results in a transmission plan, is open and transparent, and considers all transmission needs. Nor do we consider it speculation or conjecture to state that barriers to the proposal and evaluation of alternative transmission solutions will inhibit more efficient or cost-effective transmission solutions, or that the implementation of transmission plans will be improved where there is a clear *ex ante* understanding of who will pay for the facilities selected in the regional transmission plan for purposes of cost allocation. As we explain in the following discussion, such propositions are fully consistent with the grounds for action that courts have accepted in the past.

61. To argue that drawing such conclusions amounts to speculation or conjecture also conflicts with the principle articulated above that the Commission is not required to make individual findings under section 206 when formulating generic rules. They also imply that a threat that can justify Commission action in a rulemaking must be actual, i.e., one whose consequences have been realized, not one whose consequences are anticipated or, as the court expressed it in *National Fuel,* a threat that is ''theoretical.''

62. These criticisms thus mischaracterize what the courts mean by proceeding on the basis of a theoretical threat. It means to proceed on the basis of a particular type of fact, ''generic'' facts that constitute the basis for ''generic factual predictions'' that can constitute a rational basis for an agency's decision.[88] The court in *Associated Gas Producers* gave the following as an example of an acceptable generic factual prediction: ''the increased incentive to compete

[88] *Associated Gas Distributors,* 824 F.2d 981 at1008.

vigorously in the market would eventually lead to lower prices for all consumers.'' [89] The court treated such predictions as based on behavioral assumptions that are not subject to serious dispute. Thus the court stated that ''[a]gencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall; nor need they do so for predictions that competition will normally lead to lower prices.'' [90] Indeed, the court acknowledged that such propositions can be accepted without record evidence when the prediction is viewed ''as at least likely enough to be within the Commission's authority.'' [91]

63. Other courts have recognized that when promulgating rules of general and prospective applicability, agencies can draw ''factual inferences * * * in the formulation of a basically legislative-type judgment, for prospective application only.'' [92] Such judgments are closely bound up to what are sometimes referred to as ''legislative facts,'' i.e., ''facts which help the tribunal determine the content of law and of policy and help the tribunal to exercise its judgment or discretion in determining what course of action to take.'' [93] The District of Columbia Circuit has stated that ''legislative facts are crucial to the prediction of future events and to the evaluation of certain risks, both of which are inherent in administrative policymaking.'' [94] The Supreme Court has ruled that when dealing with matters that are ''primarily of a judgmental or predictive nature * * * complete factual support in the record for [an agency's] judgment or prediction is not possible or required; 'a forecast of the direction in which future public interest lies necessarily involves deductions based on the expert knowledge of the agency.' '' [95] This is precisely what is involved in the Commission's reasoning in Order No. 1000.

64. We disagree with the arguments made by various petitioners that we have ignored evidence that disproves our reasoning. The evidence in question consists of a description of the current state of transmission planning and development in a specific region combined with an expression of satisfaction with the current situation. For example, North Carolina Agencies state that there is no evidence that transmission is lacking in the Southeast and that there is no need in this region for transmission projects that can transfer large amounts of renewable energy. North Carolina Agencies state that the transmission planning processes in the Southeast are already highly developed, and Southern Companies state that in the Southeast all transmission needs have already been planned for.

65. First, the Commission is authorized not simply to make generic findings but also to act on generic factual predictions.[96] To state that the facts in a particular region run counter to the Commission's assessment of the future course of events is to argue either that present circumstances can be expected to persist into the future or that certain basic principles, such as the proposition that transmission developers are more likely to invest if they have a mechanism by which their costs will be allocated, do not apply in the region. We do not find the latter sort of claim to be credible, and the former claim simply overlooks the fact that the present is not a prediction of the future. The Commission is authorized to make rules with prospective effect that will prevent situations that are inconsistent with the FPA from occurring, which means that it is authorized to consider how the future may be different from the present if the rules it proposes are not adopted. We thus also reject Sacramento Municipal Utility Districts' claim that the Commission cannot act unless it shows the existence of an ''actual problem'' in a particular region, a claim that lies at the root of all the arguments that petitioners make on this point. An ''actual problem'' is what one has when a theoretical threat comes to fruition. To insist that the Commission must identify the existence of an actual problem in the present before it can act is thus to deny that a theoretical threat that one reasonably concludes exists can be a basis for action. Such a conclusion is inconsistent with the cases we have cited on this point.[97]

66. In addition, these arguments overlook the fact that in Order No. 1000, the Commission identifies a minimum set of requirements that must be met to ensure that transmission planning processes and cost allocation mechanisms result in Commission-jurisdictional services being provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential. Given that the requirements are minimum requirements, it would not be surprising that some current practices in some regions may already satisfy many of them. If that is the case, the public utility transmission providers concerned need only show in their compliance filing how current practices in their regions satisfy the Commission's standards. This does not mean that the reforms are not needed, as all of these requirements are not satisfied in all regions. We thus do not consider Alabama PSC's proposal of a regional or case-by-case approach for applying these reforms to be appropriate or necessary. We also disagree with Southern Companies and others that assert that there is not an issue to be remedied in their respective regions. As we note above, if public utility transmission providers believe that they already satisfy the minimum requirements in Order No. 1000, they may seek to demonstrate this in their compliance filings.

67. The concept of minimum requirements supplies the answer to Southern Companies argument that there is no basis for requiring them to adopt the nonincumbent transmission developer reforms of Order No. 1000 because they do not have a federal right of first refusal and because there are no restrictions on nonincumbent transmission projects in the SERTP planning process. Southern Companies also note that to date no nonincumbents have proposed projects in SERTP. They attribute this to incumbents, who they argue have developed a robust transmission grid and are adequately investing in transmission. However, the purpose of the minimum requirements for nonincumbent transmission developers is to provide objective criteria that can help ensure that the lack of nonincumbent participation will not be attributable to lack of equal treatment or some other reason identified in Order No. 1000 as an impairment to the identification and evaluation of more efficient or cost-effective alternatives. Moreover, if the requirements of Order No. 1000 are in fact already met in SERTP, then Southern Companies need only show in their compliance filing how current practices satisfy the Commission's requirements. Finally, Southern Companies state the Commission has no

[89] *Id.* (citing *Wisconsin Gas,* 770 F2d at 1161).

[90] *Id.* at 1008–9.

[91] *Id.* at 1008.

[92] *United States* v. *Florida East Coast Ry.,* 410 U.S. 224, 246 (1973); *United Air Lines, Inc.* v. *Civil Aeronautics Board,* 766 F.2d 1107, 1119 (7th Cir 1985).

[93] *Association of National Advertisers, Inc.,* v. *FTC,* 627 F.2d 1151, 1161–62 (D.C. Cir. 1979) (*Ass'n of National Advertisers*) (*quoting* 2 K. Davis, Administrative Law Treatise, § 15.03, at 353 (1958)).

[94] *Id.* at 1162.

[95] *FCC* v. *National Citizens Committee for Broadcasting,* 436 U.S. 775, 814 (1978) (quoting *FPC* v. *Transcontinental Gas Pipe Line Corp.,* 365 U.S. 1, 29 (1961)); see also *Ass'n of National Advertisers, Inc.,* 627 F.2d at 1162.

[96] *Associated Gas Distributors,* 824 F.2d at 1008.

[97] *See, e.g., BNSF Railway Co.,* 526 F.3d at 778.

authority to impose nonincumbent development rights, but the Commission is not imposing any such rights in Order No. 1000. It is simply establishing minimum requirements for the treatment of nonincumbent transmission developers in the transmission planning process. These requirements do not confer any rights to develop a facility. They only confer a right to have a proposal considered.

68. Some petitioners confuse agency judgments based on legislative facts, i.e., factual inferences made in light of the policy underlying a statute, with formal academic theories. Southern Companies maintain that the theoretical basis of Order No. 1000 does not constitute good theory by scientific standards.[98] California ISO argues that the Commission's hypothesis that the absence of a regional cost allocation method will cause rates to be unjust or unreasonable is not based on an established economic theory and the Commission cites no peer-reviewed or other economic analysis that supports its conclusion.

69. The courts have specifically rejected such notions. The court in *Associated Gas Distributors* clearly distinguished between generic factual predictions that are commonly made in rulemakings and the practice of economics as an academic discipline.[99] The court criticized the use of another case, *Electricity Consumers Resource Council* v. *FERC,*[100] to invoke economic theory as a basis for decision making in a way that is similar to the way that Southern Companies and Ad Hoc Coalition of Southeastern Utilities invoke economic theory. For example, Southern Companies state that ''FERC has pointed to no * * * established theory (such as marginal pricing at issue in *Electricity Consumers*) upon which it may rely to support the application of Order No. 1000's requirements to the Southeast.'' [101] The court in *Associated Gas Distributors* stated that ''[c]learly nothing in *Electricity Consumer's* reference to 'economic theory' was intended to invalidate agency reliance on generic factual predictions merely because they are typically studied in the field called economics.'' [102]

70. This is the case because the court recognized that there was no reason that an agency must demonstrate the validity of well-established general principles such as ''that competition will normally lead to lower prices.'' [103] Southern Companies and Ad Hoc Coalition of Southeastern Utilities confuse a theoretical threat, a potential threat that has not yet materialized, with a theory used in an academic discipline, an area of activity that is not comparable to the tasks or responsibilities entrusted to a regulatory agency. The type of principles that the Commission has relied upon here are fully commensurate with those that the court in *Associated Gas Distributors* said the Commission could utilize when addressing matters that fall within its area of expertise. For these same reasons, we disagree with the argument of California ISO that the Commission's finding that the absence of a cost allocation method will cause rates to be unjust or unreasonable must be based on an established economic theory and that the Commission must cite a peer-reviewed or other economic analysis that supports its conclusion.

71. Moreover, we note that the substantial evidence standard does not require scientific certitude, a point which serves to dispel the confusion between theoretical threats and scientific theories. It only requires evidence that a ''reasonable mind might accept'' as ''adequate to support a conclusion.'' [104] In the context of rulemakings that involve legislative facts and generic factual predictions, the relevant criterion is whether the agency has provided a reasonable explanation of the problem presented and its solution to it.[105] A reasonable justification of a policy choice is not, and given the nature of the task involved cannot be, a scientific prediction.

72. This point is confirmed by the discussion of theoretical threats in *National Fuel.* While some petitioners argue that this case requires substantial empirical verification of the existence of a theoretical threat,[106] a careful examination of what the courts says shows that this is not correct. The court did not specify any requirements for demonstrating the existence of a theoretical threat other than a showing that the threat is ''plausible.'' [107] A specific theoretical threat that it found met this requirement is stated in its entirety in the following language:

> If a pipeline did not have an affiliated marketer, it would be in its interest to disseminate widely information relevant to operating constraints, capacity, and available receipt points, limited only by the cost of doing so. The affiliate relationship, however, creates an incentive for the pipeline to withhold information that otherwise would be made available to the affiliate's competitors. Withholding this information from non-affiliated shippers reduces their ability to arrange transactions efficiently.[108]

This description of a theoretical threat, which is drawn from an earlier decision cited by the court in *National Fuel,* corresponds precisely to the type of generic factual predictions discussed above that can justify agency action. It focuses on an incentive to withhold information that is created simply by the existence of an affiliate relationship. The court nowhere indicated that the plausibility of this theory depended on additional confirmation in the form of predictive economic models or extensive empirical data.

73. We thus disagree with Southern Companies that our use of words such as ''may'' and ''could'' in describing the anticipated effects of our reforms is evidence that these reforms are based on speculation or guesswork. When making a generic factual prediction, one is not predicting what will occur with certainty in every instance but rather what it is reasonable to conclude will occur with sufficient frequency and to a sufficient degree to conclude that the reforms are needed. Our use of words such as ''may'' and ''could'' in this context must be understood in this sense.

74. California ISO states that the Commission is not relying on economic theory to determine the means for achieving its goal but rather to establish a statutory predicate for action. However, a theoretical threat, which should not be confused with an economic theory, is precisely that, a predicate for agency action. The Commission's task is to assess current circumstances and to form a judgment on the steps necessary to avoid adverse effects on rates that it concludes are likely to arise if the present situation persists. We reject the idea that the only

[98] *See, e.g.,* Southern Companies.

[99] *Associated Gas Distributors,* 824 F.2d at 1008.

[100] 747 F.2d 1511 (D.C. Cir. 1984) (*Electricity Consumers*).

[101] Southern Companies at 16.

[102] *Associated Gas Distributors,* 824 F.2d at 1008; *accord Sacramento Municipal Utility District* v. *FERC,* 616 F.3d 520, 531 (D.C. Cir. 2010) (stating that ''[n]either [*Electricity*] *Consumers* nor any other case law prevents the Commission from making findings based on 'generic factual predictions' derived from economic research and theory.'').

[103] *Associated Gas Distributors,* 824 F.2d at 1009.

[104] *Dickenson* v. *Zurko,* 527 U.S. 150, 155 (1999).

[105] *See Federal Communications Commission* v. *Nat'l Citizens Comm. for Broadcasting,* 436 U.S. 775, 814 (1978) (stating that ''complete factual support in the record for the [agency's] judgment or prediction is not possible or required''); *Industrial Union* v. *Hodgson,* 499 F.2d 467 at 475–476 (1974). *Bradford Nat'l Clearing Corp.* v. *SEC,* 590 F.2d 1085, 1103–04 (D.C. Cir. 1978) (judicial deference to agency increases where agency decision rests primarily on predictions).

[106] *See, e.g.,* Sacramento Municipal Utility District.

[107] *National Fuel,* 468 F.3d at 840.

[108] *Tenneco Gas* v. *FERC,* 969 F.2d 1187, 1197 (1992) (*Tenneco Gas*).

appropriate predicates for our action in this area are current failures that are traceable to inadequate transmission planning and cost allocation. That would mean that the only predicate for action is a fully realized threat, which is contrary both to the clear position taken by the courts, and, given the special problems involved in transmission development, to the public interest.[109]

75. Finally, aside from *National Fuel* and *Associated Gas Distributors,* the only case that petitioners cite on rehearing dealing with evidentiary burdens in a rulemaking is *Business Roundtable* v. *SEC.* In that case, the court vacated a rule issued by the SEC on the grounds that it had not adequately considered the rule's effect upon efficiency, competition, and capital formation. A number of petitioners describe this case as involving matters that are ''remarkably'' or ''strikingly'' similar to the present proceeding.[110] However, *Business Roundtable* dealt with a failure by the SEC to comply with specific provisions of the Exchange Act and the Investment Company Act of 1940 that require it to assess the economic impacts of a new rule. The court described these requirements as being ''unique'' to the SEC.[111] Requirements that apply uniquely to the SEC under statutes that it administers do not address requirements that apply to this Commission under the FPA or its compliance with them. Moreover, the petitioners that rely on *Business Roundtable* point to no requirements in the FPA that are similar to those that applied to the SEC under its statutes and that might show how the case applies to this proceeding. We are, of course, required to consider the burdens that Order No. 1000 creates in relation to the benefits that we expect its requirements to produce.[112] However, we have done that and have concluded that, in light of the substantial investment in new transmission facilities that is generally expected to occur, the potential benefits from improved planning for new transmission facilities outweigh the burdens involved in complying with the requirements of Order No. 1000 to revise existing transmission tariffs and institute additional planning procedures.

Whether the Commission Has Identified a Theoretical Threat That Justifies the Removal of Federal Rights of First Refusal From Commission Jurisdictional Tariffs and Agreements and Has Shown That There Is a Reasonable Expectation That Competition in Transmission Development May Have Some Beneficial Impact on Rates

76. A number of petitioners contend that the Commission has not identified a theoretical threat that justifies the removal of federal rights of first refusal from Commission jurisdictional tariffs and agreements and that the Commission has not shown that there is a reasonable expectation that competition in transmission development may have some beneficial impact on rates. In fact, the record in this proceeding includes the type of evidence that courts have found appropriate in these circumstances. The Federal Trade Commission, one of the two federal agencies responsible for enforcement of the antitrust laws, supported the elimination of federal rights of first refusal as a means for promoting consumer benefit, support that it described as consistent with antitrust policy disfavoring regulatory barriers to entry in all but a limited number of instances.[113] While we possess our own expertise on barriers to entry when dealing specifically with the transmission grid, we note that the court in *Tenneco Gas* attributed considerable weight to analogous remarks by the Department of Justice that supported the identification of a theoretical threat.[114]

77. Large Public Power Council maintains that *Wisconsin Gas* contains strictures regarding agency action premised on the benefits of competition that the Commission has violated. This case requires only ''that there must be 'ground for reasonable expectation that competition may have some beneficial impact.' '' [115] We think that there is a reasonable expectation that removal of a barrier to entry in the area of transmission development will have benefits of the type that competition creates in most industries. When the court in *Wisconsin Gas* stated that ''unsupported or abstract allegations of the benefits that will accrue from increased competition'' [116] do not form an adequate basis for agency action, it did this in response to the Commission's position on a complex rate issue whose effects were difficult to discern. Order No. 1000 does not involve a comparable situation. In fact, the court's full argument was that such allegations ''cannot substitute for 'a conscientious effort to take into account what is known as to past experience and what is reasonably predictable about the future.' '' [117] In fact, we have made just such an effort, and on that basis we find it quite reasonable to expect benefits from removing barriers to transmission development. Moreover, as noted above, this analysis is consistent with that of the Federal Trade Commission.

78. We also see no significance in the fact that *Wisconsin Gas* involved competitive sales of natural gas in accordance with a policy established by Congress. Ad Hoc Committee of Southeastern Utilities and Large Public Power Council state that Congress has voiced no similar policy regarding competition in the development of transmission infrastructure, but it likewise has not objected to it. We thus do not see how this difference between *Wisconsin Gas* and this proceeding is controlling. Barriers to entry in this area can adversely affect rates, and our action to ensure that such barriers in the form of federal rights of first refusal do not adversely affect rates is well within the scope of actions that we are authorized to take under section 206 of the FPA. The fact that Congress expressed a policy regarding competitive sales of natural gas does not affect this conclusion. These points also address the objections by Oklahoma Gas and Electric Company and Sponsoring PJM Transmission Owners that the Commission has not supported the conclusion that competition between potential developers will result in more efficient or cost effective solutions or that this conclusion suffices to support Commission action under section 206.

79. Xcel and MISO Transmission Owners Group 2 argue that the

[109] We reject for the same reasons the contention by Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council that it is somehow significant that the Commission has effectively conceded that there is no evidence justifying Order No. 1000 and it is relying on theory alone. The Commission is acting on the basis of a theoretical threat whose existence has been demonstrated through a reasonable explanation. The identification of this threat is based ''on an assessment of the relevant market conditions'' and involves ''a forecast of the direction in which future public interest lies'' which ''necessarily involves deductions based on the expert knowledge of the agency.'' *Ass'n of National Advertisers,* 627 F.2d at 1162 (internal citations omitted). Such judgments will satisfy evidentiary requirements in rulemakings such as this one. *Id.* at 1161–62.

[110] *See, e.g.,* Southern Companies; Ad Hoc Committee of Southeastern Utilities; and Large Public Power Council.

[111] *Business Roundtable* at 1148.

[112] *See, e.g., National Fuel,* 468 F.3d at 844; *Associated Gas Distributors,* 824 F.2d at 1019.

[113] Federal Trade Commission Comments on Proposed Rule at 2, 7.

[114] *Tenneco Gas,* 969 F.2d at 1202.

[115] *Wisconsin Gas,* 770 F.2d 1144, at 1158 (quoting *FCC* v. *RCA Communications, Inc.,* 346 U.S. 86, 96–7 (1953)).

[116] *Id.* at 1158.

[117] *Id.* (quoting *American Public Gas Association* v. *FPC,* 567 F.2d 1016, 1037 (D.C. Cir. 1977)).

Commission has not explained why problems created by federal rights of first refusal cannot be dealt with through individual complaints. Rights of first refusal create barriers to participation in the transmission development process. To require nonincumbent transmission developers to overcome those barriers solely through individual complaint proceedings, requiring litigation each time they seek to engage in the development process would create expense, delay, and uncertainty that would serve as a further disincentive to participation. That is, they would have to invest in project development and participate in an extensive regional transmission planning process, and if the project is then taken over by an incumbent transmission developer/provider who exercises a federal right of first refusal, they would have to invest still more time and resources in litigation. As long as the federal right of first refusal remains in a Commission-approved tariff or agreement, their chances of succeeding in litigation would be severely diminished. They would likely forego participating in that region in the first place and place their efforts elsewhere. The remedy suggested by Xcel and MISO Transmission Owners Group 2 would thus itself act as a form of barrier to entry.

80. MISO Transmission Owners 2, Xcel, and MISO argue that the Commission has not identified an instance where federal rights of first refusal have led to adverse effects on rates, discrimination against a nonincumbent transmission developer, or failure by a nonincumbent to invest in a transmission facility. While the Commission did receive evidence that nonincumbent transmission developers experience discriminatory treatment,[118] we think the more important point is that the practical effect of a federal right of first refusal is to discourage investment by nonincumbent transmission developers. We do not think it is surprising that there is limited evidence of exclusion of nonincumbent transmission developers in a situation that discourages them from proposing projects in the first place. While Sponsoring PJM Transmission Owners contrast the evidence of specific discrimination provided in Order No. 888 to support open access transmission with the number of specific examples of barriers to participation by nonincumbent transmission developers in this proceeding, they fail to acknowledge that Order No. 888 and Order No. 1000 involve different factual circumstances and bases for Commission action. Order No. 888 dealt with instances of undue discrimination in transmission access involving entities that were already connected to the transmission grid. Order No. 1000, by contrast, deals as much or more with the effect on rates of excluding entities whose ability even to become involved in the transmission planning process is being hindered from the outset.

81. MISO Transmission Owners 2 state that the Commission ignored the example of nonincumbent transmission developer participation in CapX2020, which they maintain shows that existing construction rights are not a disincentive to investment, at least with respect to the Midwest ISO.[119] However, MISO Transmission Owners 2 do not identify any nonincumbent transmission developer that independently proposed a transmission project and was able to develop it despite the existence of a federal right of first refusal, and initially referred only to certain transmission dependent utilities that had been ''renters'' of the transmission system'' [120] but that had chosen to invest in and own a portion of CapX2020.[121] While the Commission supports investment in transmission infrastructure by transmission dependent utilities, the existence of a single joint project like CapX2020 does not demonstrate that nonincumbent transmission developers are treated in a manner that is not unduly discriminatory or preferential.

82. We disagree with Baltimore Gas & Electric that if our concern is the effect of federal rights of first refusal on transmission rates, we should deal with rates directly rather than federal rights of first refusal. Barriers to entry affect markets in various ways. These include their ability to discourage innovation. Federal rules should not prevent consumers from being able to benefit from the full range of advantages that competition can provide, which the preservation of barriers to entry does not allow.

83. We also disagree with Baltimore Gas & Electric that our rationale for eliminating federal rights of first refusal has no applicability to the transmission owner members of PJM because they have relinquished all transmission planning decisions to PJM and thus have no economic incentive to discriminate against nonincumbents. Even if the transmission owner members of PJM have no economic reason to object to development by nonincumbent transmission developers, this does not mean that federal rights of first refusal cannot adversely affect transmission rates. In other words, the Commission's rationale for requiring the elimination of federal rights of first refusal is not based solely on the economic incentives of incumbent transmission developers/providers; it is also based on the belief that expanding the universe of transmission developers offering potential solutions can lead to the identification and evaluation of potential solutions to regional needs that are more efficient or cost-effective.

84. These points apply equally to the argument of Sunflower, Mid-Kansas, and Western Farmers that it is not in the economic self-interest of public utility transmission providers in the SPP region to inhibit projects proposed by nonincumbent transmission developers because no state in the SPP region has enacted retail competition. For example, the fact that no state in the SPP region would stand for anticompetitive behavior by incumbent transmission developers/providers does not ensure that the potentially more efficient or cost-effective solutions offered by nonincumbent transmission developers will be considered. To do that, it is necessary to have a requirement that they be considered without having to adjudicate complaints of anticompetitive behavior that discourage proposals of alternative solutions.

85. We disagree with Xcel that requiring the elimination of a federal right of first refusal for reliability projects constitutes an overly broad remedy. While Xcel may be correct that it is less likely that a nonincumbent transmission developer will propose a competing transmission project that satisfies only a specific reliability need, a nonincumbent transmission developer may decide to propose a transmission project that satisfies several regional needs, including a specific reliability need. In that instance, the Commission is concerned that if an incumbent transmission developer/provider has the ability to assert a federal right of first refusal for a transmission project because it addresses a reliability need, then the nonincumbent transmission developer may be discouraged from proposing the transmission project that satisfies several regional needs. In

[118] *See* LS Power Comments on Proposed Rule at 3.

[119] Midwest Transmission Owners 2 Petition for Rehearing at 12.

[120] Midwest Transmission Owners Reply Comments on Proposed Rule at 14.

[121] Midwest Transmission Owners Comments on the Proposed Rule at 37 and n.89. Midwest Transmission Owners 2 consists of all the entities that compose Midwest Transmission Owners, with the exception of American Transmission Company LLC.

addition, we note that nothing in Order No. 1000 prevents an incumbent transmission developer/provider from choosing to meet a reliability need or service obligation by building new transmission facilities that are located solely within its retail distribution service territory or footprint and that is not submitted for regional cost allocation.[122]

86. Ad Hoc Coalition of Southeastern Utilities asserts that the Commission's longstanding treatment of transmission as a natural monopoly undercuts its support for competition in the development of transmission infrastructure, but we see no contradiction here. In dealing with transmission as a natural monopoly, the Commission has explained that ''[t]he monopoly characteristic exists in part because entry into the transmission market is restricted or difficult. * * * In addition, as unit costs are less for larger lines and networks, transmission facilities still exhibit scale economies.'' [123] The Commission has never found that natural monopoly is antithetical to competition in all respects. Rather it has said ''it is often better for a single owner (or group of owners) to build a single large transmission line rather than for many transmission owners to build smaller parallel lines on a non-coordinated basis.'' [124] This is because ''effective competition among owners of parallel transmission lines is unlikely, and often impossible, with existing practices and technology.'' [125] This, however, does not mean that determining who will be the owner (or group of owners) of a particular line with natural monopoly characteristics cannot be done on a competitive basis or that competition in this connection would not promote benefits that are similar to the benefits that it produces elsewhere in our economy, in terms of improved facilities, enhanced technology, or better transmission solutions generally.

87. This point provides the answer to the Oklahoma Gas and Electric's statement that nothing Order No. 1000 will result in head-to-head competition between transmission service providers and PJM Transmission Owners' statement that the real issue is not competition between transmission service providers but rather which entity will be the monopoly owner of a transmission line. These statements overlook the fact that competitive forces can be harnessed in a number of ways. In this case, the Commission seeks to make it possible for nonincumbent transmission developers to compete in the proposal of more efficient or cost-effective transmission solutions. Oklahoma Gas and Electric Company states that the choice of new transmission projects will not be made in the market but rather in the stakeholder process, but this simply highlights the fact that competitive forces can be harnessed in various ways, including through the offering of competitive alternatives in a stakeholder process. Oklahoma Gas and Electric Company states that choices in the stakeholder process are based on uncertain estimates and inputs, but this is true of the transmission planning process whether or not it allows for competitive proposals.

88. The fact that incumbent transmission developers/providers may have certain advantages, such as rights of way and experience with the area in question, does not affect these conclusions. Incumbent transmission developers/providers may in some situations be well-equipped to prevail in a competitive process, but this is not an argument against competition. One cannot presume that an incumbent transmission developer/provider will always be better placed to construct and own a project and that the transmission planning process therefore will always reach the same result with or without a federal right of first refusal, as Baltimore & Electric Company maintains. The fact that an incumbent transmission developer/provider may possess certain capabilities does not imply that the incumbent transmission developer/provider is more capable than any possible nonincumbent transmission developer in all situations.

89. Nor do the effects of differing corporate structures, rates of return, or the other factors mentioned by Sponsoring PJM Transmission Owners affect our conclusion. These are all matters that can be considered in the transmission planning process, as can the issue of potential other costs and risks that Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council propose may arise. Such matters may be relevant to the identification of more efficient or cost effective solutions. We do not see how they require one to conclude that competition will not promote more efficient or cost-effective solutions.

90. Finally, the nonincumbent reforms of Order No. 1000 are not based on the assumption that vertical integration is unduly discriminatory. Southern Companies argues that vertical integration provides efficiencies and benefits to consumers, and we do not deny that this may be the case in some situations. However, if it is, we would expect that vertically-integrated public utilities will be well positioned to compete in a transmission development process that is open to nonincumbent transmission developers. Southern Companies argument against nonincumbent transmission developer participation confuses the concept of vertical integration with that of monopoly. The existence of vertical integration does not imply that the vertically integrated public utility must be a monopoly. The emergence of competitive generation markets makes it no longer possible to argue that vertically integrated utilities are natural monopolies in all aspects of electric service.[126] In short, vertical integration itself is not unduly discriminatory, but there is no basis for claiming that vertical integration requires the exclusion of nonincumbent transmission developers.

Whether the Burdens Imposed by the Commission's Reforms Outweigh the Benefits

91. Next, we address the question of the burdens imposed by the Commission's reforms. The court made clear in both *National Fuel* and *Associated Gas Distributors* that one metric for assessing whether a rule has been adequately justified is whether the costs the rule imposes are reasonable in

[122] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 262.

[123] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking,* 60 FR 17662 (April 7, 1995), FERC Stats. & Regs. ¶ 32,514, at 33,070 (1995).

[124] *Id.*

[125] *Id.*

[126] *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, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,642 (1996) (noting Congressional recognition of ''rising costs and decreasing efficiencies of utility-owned generating facilities'' and also describing the emergence of ''non-traditional power producers * * * [that following the enactment of the Public Utility Regulatory Policies Act of 1978] began to build new capacity to compete in bulk power markets''), *order on reh'g,* Order No. 888–A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *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). *See also, Morgan Stanley Capital Group, Inc.* v. *Public Utility District No. 1 of Snohomish County, Washington,* 554 U.S. 527, 535–36 (2008) (stating that ''[s]ince the 1970's * * * engineering innovations have lowered the cost of generating electricity and transmitting it over long distances, enabling new entrants to challenge the regional generating monopolies of traditional utilities'').

light of the threat identified.[127] The Commission acknowledged in Order No. 1000 that its new requirements would require adoption and implementation of additional processes and procedures, but it noted that in many cases public utility transmission providers already engage in processes and procedures of the type in question.[128] Large Public Power Council argues that the implications of Order No. 1000 in ''creating a mechanism for socializing the cost of new regional transmission developments are dramatic, and involve, by the Commission's own reckoning, cost shifting for the recovery of potentially hundreds of billions of dollars in transmission investment.'' [129] However, Order No. 1000 requires that the costs of facilities selected in a regional transmission plan for purposes of cost allocation be allocated in a way that is roughly commensurate with benefits, i.e, allocated in accordance with the requirements of cost causation. To the extent that Large Public Power Council's use of the term ''socializing'' costs is meant to refer to a method of cost allocation that does not conform with the principle of cost causation, we disagree with that characterization of Order No. 1000's cost allocation requirements. Consequently, we do not see how ensuring that the costs of facilities selected in a regional transmission plan for purposes of cost allocation are allocated to those who receive benefits from the facilities represents ''cost shifting'' or an undue burden. On the contrary, it is a clear benefit because it ensures that rates for those facilities will be just and reasonable and not unduly discriminatory or preferential, and it promotes the identification of more efficient or cost-effective transmission solutions. Moreover, it is a benefit that is achieved at minimal cost, i.e., the cost of adopting and implementing additional procedures, in comparison to the estimated billions of dollars of needed transmission investment that current transmission planning and cost allocation practices have been frustrating,[130] or the estimated $298 billion in investment in new transmission facilities that EEI suggests will be required over the period from 2010 to 2030.[131]

92. We likewise disagree with Ad Hoc Coalition of Southeastern Utilities' and Southern Companies' assertion that the interregional transmission coordination reforms are contrary to *National Fuel* because the burdens of such coordination outweigh any potential benefits. We note that Order No. 1000 provided a sufficient rationale for the need for specific reform of the interregional transmission coordination requirements. Order No. 1000 explained that ''[c]lear and transparent procedures that result in the sharing of information regarding common needs and potential solutions across the seams of neighboring transmission planning regions'' would help identify interregional transmission facilities that could more efficiently or cost-effectively meet the needs of each region.[132] The Commission further found that Order No. 890's transmission planning requirements ''are too narrowly focused geographically'' and do not provide for adequate analysis of the benefits of interregional transmission facilities in neighboring regions.[133] Accordingly, the Commission concluded that the interregional transmission coordination reforms should be adopted now and not delayed.

93. We continue to find that we have adequately justified the interregional transmission coordination requirements and that, in doing so, we have fully satisfied what is required by *National Fuel,* as that standard is discussed herein. We disagree with the contention that such requirements are overly burdensome as compared to the benefits. The interregional transmission coordination requirements are part of what goes into effective transmission planning. These requirements will help public utility transmission providers, in consultation with stakeholders, in one transmission planning region to work proactively with their counterparts in neighboring regions to identify what may be more efficient or cost-effective transmission facilities than the solutions identified in individual regional transmission plans. We do not believe these benefits are outweighed by the burdens involved, i.e., the cost of the adoption and implementation of procedures necessary for interregional transmission coordination, particularly when compared to the significant transmission investment expected in the future. Indeed, it may be the case that there will be little burden at all for the members of the Ad Hoc Coalition of Southeastern Utilities in implementing these requirements, given that they state that there is already an ''optimization'' analysis along the seams and interfaces in the Southeast.[134] Accordingly, we deny rehearing on this issue.

94. We also disagree with Large Public Power Council and Ameren that the transmission planning requirements of Order No. 1000 will place unnecessary burdens on planning engineers by requiring them to focus on matters other than meeting the needs of their native loads or will require a reassessment of prior planning. We see no contradiction between transmission planning for native loads and ensuring that transmission plans are consistent with regional or interregional transmission needs. Indeed, the native loads of individual entities ultimately benefit from improved regional transmission planning and interregional transmission coordination because they benefit from improvements to the transmission grid that extend beyond their own local facilities. We therefore do not think that any additional burden that Order No. 1000 may create for planning engineers outweighs the benefits that we expect Order No. 1000 to provide. In addition, the requirements of Order No. 1000 apply only to new transmission facilities, and we therefore do not see how they require a reassessment of past planning activities.

95. We have not, as Sponsoring PJM Transmission Owners contend, ignored costs associated with elimination of federal rights of first refusal, specially the need for expensive mitigation plans in the event a nonincumbent transmission developer abandons a reliability project. We see no reason to expect that the performance of incumbent and nonincumbent transmission developers/providers will differ, and as a result, the example that Sponsoring PJM Transmission Owners advances is based on conjecture. Moreover, selection criteria for project developers are an appropriate means of providing assurances that all project developers will be in a position to fulfill their commitments.

96. Sacramento Municipal Utility District states that Order No. 1000 does not satisfy the requirements of reasoned decision-making because it fails to take into account whether the cost allocation provisions will discourage rather than facilitate regional transmission planning. As we have noted already, the Commission continues to find that

[127] *National Fuel,* 468 F.3d at 844; *Associated Gas Distributors,* 824 F.2d at 1019.

[128] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 56.

[129] Large Public Power Council at 18.

[130] *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 38 (discussing Brattle Group study contending that a large portion of projects with an estimated total cost of over $180 billion will not be built due to overlaps and deficiencies in transmission planning and cost allocation processes).

[131] *See id.* P 44.

[132] *Id.* P 368.

[133] *Id.* P 369.

[134] Ad Hoc Coalition of Southeastern Utilities at 65.

transmission planning is more successful when it is understood upfront who will be allocated costs for the facilities in a transmission plan. Regional cost allocation methods accomplish this, among other things. The regional participants will decide which facilities in the regional transmission plan will have their costs allocated according to a method that they select, and which facilities will not. It is thus known how much each beneficiary will pay for the first set of facilities when the regional transmission plan is formed, and it is known that the latter set of facilities must be supported by the facility sponsors alone. Sacramento Municipal Utility District appears to take the position that the cost allocation requirements will discourage transmission planning because entities will be forced to pay for facilities from which they receive no benefit. We address and reject this argument elsewhere in this order.[135]

Other Issues

97. A number of petitioners raise objections to our demonstrations of the need for reform that do not fall under any of the general categories set forth above.

98. We are not, as Coalition for Fair Transmission Policy asserts, stepping beyond our statutory authority and seeking to address every policy problem that faces the industry. We have fully explained our statutory authority in Order No. 1000, and we are addressing only matters that can affect transmission rates in a way that could cause them to become unjust and unreasonable, or unduly discriminatory or preferential. We find nothing ambiguous about, for example, our reference to such things as the impacts of renewable portfolio policies, as Coalition for Fair Transmission Policy maintains. These policies affect transmission needs and thus transmission rates, and rather than being ambiguous, our reference to them provides a clear and concrete example of how transmission planning cannot be fully effective if it does not consider all transmission needs.

99. We also reject the characterization of our action in Order No. 1000 by Coalition for Fair Transmission Policy as commandeering regional transmission planning. The transmission planning and cost allocation requirements of Order No. 1000 are focused on the transmission planning process, not any substantive outcomes of this process.[136] Order No. 1000 establishes a set of minimum requirements that regional planning must meet and allows considerable flexibility in the implementation of these requirements. Establishing flexible minimum requirements for a process cannot be equated with commandeering that process.

100. Coalition for Fair Transmission Policy states that the Commission's authority under section 216 of the FPA to site transmission facilities in national interest corridors would not have been necessary if it had authority to address all policy problems and commandeer the transmission process. We do not see how the Commission's limited authority under this section is relevant to Order No. 1000. Since we are acting to address matters that can have an adverse effect on transmission rates and are not taking any control over the transmission planning process itself, we are not taking any actions that fall within the scope of the activities authorized in section 216.

101. In response to NARUC's concern that compliance with Order No. 1000 may stall existing local, regional, and DOE-funded interconnection-wide planning, the Commission stated in Order No. 1000 that the compliance filing deadlines it established are compatible with the interests of those that intend to develop transmission planning processes that take into account the lessons learned through the ARRA-funded transmission planning initiatives.[137] NARUC states that its reason for concern is the need to sort through ambiguities and comply with Order No. 1000. The Commission is committed to engaging in outreach and consultation to assist the compliance process. NARUC also maintains that the ARRA-funded transmission planning initiatives may eliminate the need for the Commission's reforms, but as we noted in Order No. 1000, those initiatives are complementary to, not substitutes for, the reforms in Order No. 1000. For example, they do not specifically provide for regional cost allocation or for ongoing coordination of planning for interregional transmission facilities, which we concluded is necessary to ensure that rates, terms, and conditions of jurisdictional services are just and reasonable and not unduly discriminatory or preferential.[138] NARUC has not challenged this conclusion regarding the ARRA-funded transmission planning initiatives in its petition for rehearing.

III. Transmission Planning

A. Regional Transmission Planning Process

102. Order No. 1000 built on the reforms adopted in Order No. 890 to improve regional transmission planning. First, Order No. 1000 required each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan and complies with existing Order No. 890 transmission planning principles.[139] Second, Order No. 1000 adopted reforms under which transmission needs driven by Public Policy Requirements are considered in local and regional transmission planning processes.[140] The Commission explained that these reforms work together to ensure that public utility transmission providers in every transmission planning region, in consultation with stakeholders, evaluate proposed alternative solutions at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers.[141] The Commission noted that, as in Order No. 890, the transmission planning requirements in Order No. 1000 do not address or dictate which transmission facilities should be either in the regional transmission plan or actually constructed, and that such decisions are left in the first instance to the judgment of public utility transmission providers, in consultation with stakeholders participating in the regional transmission planning process.[142]

1. Legal Authority for Order No. 1000's Transmission Planning Reforms

a. Final Rule

103. Order No. 1000 concluded that the Commission has the authority under section 206 of the FPA to adopt the transmission planning reforms. The Commission explained that the reforms build on those of Order No. 890, in which the Commission reformed the *pro forma* OATT to, among other things, require each public utility transmission provider to have a coordinated, open

[135] *See* discussion *infra* at section IV.

[136] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 12.

[137] *Id.* P 794.

[138] *Id.* P 371.

[139] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 68.

[140] *Id.* The Commission explained that Public Policy Requirements are those established by state or federal laws or regulations, meaning enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level. *Id.* at P 2.

[141] *Id.*

[142] *Id.* P 68 n.57.

and transparent regional transmission planning process.[143] The Commission concluded that the reforms adopted in Order No. 1000 are necessary to address remaining deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional transmission services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.[144]

104. Order No. 1000 rejected arguments that FPA section 202(a) [145] precluded the Commission from adopting the transmission planning reforms, explaining that this provision requires that the interconnection and coordination, i.e., coordinated operation (such as power pooling), of facilities be voluntary and the provision does not mention planning.[146] The Commission explained that transmission planning is a process that occurs prior to the interconnection and coordination of transmission facilities. The Commission explained that this is consistent with the *Central Iowa Power Coop.* v. *FERC* decision,[147] because the court in that case was presented with a request that the Commission require an enhanced level of, or tighter, power pooling, which the court found it could not do given ''the expressly voluntary nature of coordination under section 202(a).'' [148] Section 202(a) was therefore relevant to the problem at issue in *Central Iowa* because, unlike Order No. 1000, the operation of the system through power pooling was its central subject matter.[149] The Commission also found that because section 202(a) does not mention transmission planning, it was unnecessary to resort to the legislative history of the provision, which nevertheless discussed ''planned coordination'' of the operation of facilities, not the planning process for the identification of transmission facilities.[150]

105. The Commission also made clear that nothing in Order No. 1000 infringed on those matters traditionally reserved to the states, such as matters relevant to siting, permitting and construction, as the reforms in Order No. 1000 are associated with the processes used to identify and evaluate transmission system needs and potential solutions to those needs.[151] Further, the Commission disagreed with commenters suggesting that the transmission planning reforms in the Proposed Rule, which were similar to those adopted in Order No. 1000, were inconsistent or precluded by, or legally deficient for failing to rely on, FPA section 217(b)(4),[152] because Order No. 1000 supports the development of needed transmission facilities, which ultimately benefits load-serving entities.[153]

106. Next, the Commission concluded that it could require public utility transmission providers to amend their OATTs to provide for the consideration of transmission needs driven by Public Policy Requirements. The Commission explained that such requirements may modify the need for and configuration of prospective transmission facility development and construction, and therefore, the transmission planning process and the resulting transmission plans would be deficient if they do not provide an opportunity to consider transmission needs driven by Public Policy Requirements.[154] The Commission also rejected assertions that the transmission planning reforms were inconsistent with the Administrative Procedure Act, due process requirements, or Commission regulations governing incentive rates.[155] The Commission explained that it satisfied FPA section 206's burden, as its review of the record demonstrated that existing transmission planning processes are unjust and unreasonable or unduly discriminatory or preferential.[156] Finally, the Commission addressed concerns raised by non-jurisdictional entities regarding issues associated with public power participation in the regional transmission planning process.[157]

107. In the section above on Need for Reform, the Commission has already addressed legal arguments surrounding the Commission's determination that there is substantial evidence establishing a need for the package of reforms in Order No. 1000. A number of petitioners, however, also seek rehearing of the Commission's conclusions regarding its legal authority to specifically require Order No. 1000's regional transmission planning and interregional transmission coordination reforms. In general, these arguments, addressed below, concern: (1) The Commission's interpretation of FPA section 202(a); (2) the Commission's statements regarding section 217(b)(4); (3) Order No. 1000's alleged infringement on state regulatory jurisdiction; (4) Order No. 1000's requirement to consider transmission needs driven by Public Policy Requirements; (5) legal issues related to interregional transmission coordination; and (6) other legal issues.

b. Order No. 1000's Interpretation of FPA Section 202(a)

i. Requests for Rehearing and Clarification

108. Several petitioners argue that the Commission erred in concluding that FPA section 202(a) permitted the Commission to require public utility transmission providers to engage in mandatory regional transmission planning and interregional transmission coordination.[158] Generally, these petitioners assert that the Commission erred in interpreting both the language of the statute and the D.C. Circuit's *Central Iowa* decision that addressed the scope of section 202(a).[159] Petitioners also cite to the D.C. Circuit's *Atlantic City* decision for support for their proposition that transmission planning

[143] *Id.* P 99.

[144] *Id.*

[145] Section 202(a) reads, in relevant part, as follows:

For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy. * * *

16 U.S.C. 824a(a).

[146] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 100–06.

[147] 606 F.2d 1156 (D.C. Cir. 1979) (*Central Iowa*).

[148] *Id.* at 1168.

[149] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 102–03.

[150] *Id.* PP 104–05.

[151] *Id.* P 107.

[152] Section 217(b)(4) of the FPA specifies that:

The Commission shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.

16 U.S.C. 824q(b)(4).

[153] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 108.

[154] *Id.* PP 109–12.

[155] *Id.* PP 113–15.

[156] *Id.* P 116.

[157] *Id.* P 117.

[158] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; California ISO; FirstEnergy Service Company; Large Public Power Council; North Carolina Agencies; PPL Companies; Sacramento Municipal Utility District; Southern Companies; and Xcel.

[159] While most of the arguments regarding section 202(a) are opposed to the Commission's authority over transmission planning as a general matter, some parties raise this argument in the specific context of interregional transmission coordination. All of the rehearing requests regarding section 202(a) are addressed here.

is to be left to the voluntary action of public utilities under section 202(a).[160]

109. Many petitioners contend that Order No. 1000's interpretation of section 202(a) is contrary to the plain meaning of the provision. Ad Hoc Coalition of Southeastern Utilities argues that Order No. 1000 itself recognizes that transmission planning is an aspect of the ''coordination of facilities for * * * transmission'' because Order No. 1000 states that ''coordination of planning on a regional basis will also increase efficiency through the *coordination of transmission upgrades.''* [161] Ad Hoc Coalition of Southeastern Utilities also argues that Order No. 1000 states that its interregional coordination requirements involve ''*coordination* with regard to the identification and evaluation of interregional transmission facilities * * *.'' [162] FirstEnergy Service Company also cites to statements in Order No. 1000 itself, which it argues demonstrates that the Commission recognized that transmission planning is an aspect of coordination.[163]

110. Additionally, Ad Hoc Coalition of Southeastern Utilities disagrees that section 202(a) only applies to interconnection and operation because section 202(a) discusses ''interconnection and coordination'' but does not mention operation. It also argues that interconnection is discussed along with coordination rather than to the exclusion of coordination. Thus, it argues that language regarding the ''coordination of facilities for * * * transmission'' encompasses transmission planning. It also argues that the interconnection of transmission facilities encompasses transmission planning. FirstEnergy Service Company asserts that the natural reading of ''coordination'' is not limited to ''coordinated operation,'' but also includes ''coordinated planning.'' [164] FirstEnergy Service Company notes that, while the Commission points to the fact that section 202(a) does not mention planning in an effort to avoid this natural reading of ''coordination,'' the logic of the Commission's argument would mean that ''coordinated operations'' must also be excluded, because section 202(a) does not explicitly mention ''operations,'' a point echoed by California ISO.

111. Ad Hoc Coalition of Southeastern Utilities argues that good utility practice compels the conclusion that coordination and interconnection closely involve system planning, asserting that for transmission systems to be interconnected and operated in a reliable manner, they must be planned in a coordinated manner to avoid serious reliability consequences. FirstEnergy Service Company states that the Commission cites no authority for the proposition that section 202(a) focuses on power pooling, but asserts that, even if power pools were the focus of section 202(a), the fact that the first power pool was formed to realize the benefits and efficiencies possible by interconnecting to share generating resources involves at least a limited form of coordinated planning.

112. Sacramento Municipal Utility District argues that Congress left the issue of regional planning to the voluntary decision of the entities involved and only once they elect to do so would the Commission have authority to determine whether the terms of their arrangements are just and reasonable and not unduly discriminatory.[165] It also argues that if Congress intended that the Commission should encourage the coordination of transmission operations, there is no logical reason that it did not also intend that it encourage transmission planning, which further means that it did not intend that the Commission could mandate transmission planning. Moreover, PPL Companies assert that in all the revisions Congress made to the FPA in the Energy Policy Act of 2005,[166] it did not mandate regional planning and left section 202(a) in place without changes to that provision's voluntary nature.

113. Petitioners also argue that the Commission misinterpreted *Central Iowa,* asserting that the court in that case understood that coordination included transmission planning.[167] FirstEnergy Service Company states that *Central Iowa* described coordination as including planning and described various degrees and methods of regional coordination.[168] Similarly, North Carolina Agencies note that *Central Iowa* quoted the Commission's own statement that ''coordination is joint planning and operation of bulk power facilities by two or more electric systems for improved reliability and increased efficiency * * *.'' They also argue that *Central Iowa's* statement that the Commission could not have mandated the power pooling agreement means that the Commission could not have mandated the adoption of coordinated transmission planning.[169]

114. Large Public Power Council also asserts that the court in *Central Iowa* found that the Commission's involvement in transmission planning rests on the voluntary cooperation of utilities subject to the statute. Sacramento Municipal Utility District contends that the Commission's assertion that *Central Iowa* meant only to refer to the operation of transmission facilities when it said ''voluntary power pooling'' rather than planning of their construction is not credible, noting that the court explicitly stated that one type of pooling arrangement is designed to achieve certain goals, ''plus the economies of joint planning and construction of generation and transmission facilities.'' Ad Hoc Coalition of Southeastern Utilities points to legislative history cited in *Central Iowa* stating that Congress ''is confident that enlightened self-interest will lead the utilities to cooperate * * * in bringing about the economies which can alone be secured through planned coordination.'' [170] It also states that *Central Iowa* noted that non-generating distribution systems ''could attend MAPP meetings at which long-range plans are discussed'' and it points to *Central Iowa*'s rejection of calls to enlarge the scope of the power pooling agreement because it ''would be inconsistent with Congress' intent to

[160] *Atlantic City Elec. Co.* v. *FERC,* 295 F.3d 1, 12 (D.C. Cir. 2002) (*Atlantic City*).

[161] Ad Hoc Coalition of Southeastern Utilities at 35 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 254 (emphasis added)). *See also* PPL Companies.

[162] Ad Hoc Coalition of Southeastern Utilities at 35 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 345 n.310 (emphasis added)). PPL Companies also point out that Order No. 890 states that ''the coordination requirements imposed [therein] are intended to address transmission planning issues.'' Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 453.

[163] FirstEnergy Service Company at 9 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (stating that Order No. 1000 ''improves coordination between neighboring transmission planning regions'')). FirstEnergy Service Company further argues that Order No. 1000 elsewhere uses ''coordination'' to refer to coordinated planning between regions.

[164] FirstEnergy Service Company at 9 (quoting *Wolverine Power Co.* v. *FERC,* 963 F.2d 446, 454 (D.C. Cir. 1992); *U.S.* v. *Wells,* 519 U.S. 482, 483 (1997)).

[165] Sacramento Municipal Utility District at 23 (citing *Central Iowa,* 606 F.2d at 1167–68).

[166] Energy Policy Act of 2005, Public Law 109–58, §§ 1261 *et seq.,* 119 Stat. 594 (2005) (EPAct 2005).

[167] *See, e.g.,* FirstEnergy Service Company; North Carolina Agencies; Large Public Power Council; Sacramento Municipal Utility District; Ad Hoc Coalition of Southeastern Utilities; and Southern Companies.

[168] FirstEnergy Service Company at 11 (citing *Central Iowa,* 606 F.2d at 1168, n.36).

[169] North Carolina Agencies at 7–8 (citing *Central Iowa,* 606 F.2d at 1168, n.36).

[170] Ad Hoc Coalition of Southeastern Utilities at 30 (citing *Central Iowa,* 606 F.2d at 1162 (quoting S. Rep. No. 74–62)).

promote planned coordination of electric systems.'' [171]

115. Other petitioners also assert that the legislative history of section 202(a), as well as the Commission's own precedent, undermine Order No. 1000's interpretation of that provision.[172] North Carolina Agencies emphasize that Congress rejected arguments by the Federal Power Commission that it should be empowered to mandate such coordination when it adopted section 202(a)'s requirements. They argue that section 202(b) [173] also reveals that Congress purposefully limited the Commission's authority to require coordination by enabling it only to order the interconnection of facilities and the sale/exchange of electricity. Ad Hoc Coalition of Southeastern Utilities and Southern Companies point out that the solicitor of the Federal Power Commission testified before Congress that the express intent in drafting section 202(a) was to facilitate regional planning. Petitioners also cite to Federal Power Commission policy statements regarding data collection that make statements such as ''[l]ong-range planning is an indispensable element to the accomplishment of the objectives of [s]ection 202(a)'' and that achieving the goals of section 202(a) ''requires coordinated efforts on an industry[-]wide basis, at both the regional and national levels, to enhance reliability and adequacy of service.'' [174]

116. Ad Hoc Coalition of Southeastern Utilities points to the *1970 National Power Survey,* which stated that ''coordination is joint planning and operation of bulk power facilities by two or more electric systems for improved reliability and increased efficiency which would not be attainable if each system acted independently.'' [175] Sacramento Municipal Utility District argues that the notion that section 202(a) does not include transmission planning, or that transmission planning is not considered part of the coordination of electric systems, would surprise those who recall the Federal Power Commission's work with regional reliability councils in the decades following the Northeast blackout of 1965. It also asserts that the Commission's interpretation cannot be squared with the 1993 *Policy Statement Regarding Regional Transmission Groups,* where the Commission recognized it lacked authority to mandate the formation of regional transmission organizations.[176]

117. Some petitioners also cite to the D.C. Circuit's *Atlantic City* decision. FirstEnergy Service Company quotes *Atlantic City*'s conclusion that the Commission's ''expansive reading of its section 203 jurisdiction could not be reconciled with section 202, which has been definitively interpreted to make clear that Congress intended coordination and interconnection arrangements be left to the voluntary action of the utilities.'' [177] Ad Hoc Coalition of Southeastern Utilities claims that *Atlantic City* reinforces that section 202(a) encompasses transmission planning, noting that the court held that section 202(a) applied to an ISO arrangement, which encompassed transmission planning, and therefore its voluntary nature precluded the Commission from requiring transmission owners to make a filing under section 203 before they could leave the ISO.[178] Southern Companies state Order No. 1000 conceded that the interregional coordination required constitutes the ''coordination of facilities * * * for transmission.'' [179] Thus, Southern Companies argue that Order No. 1000, by specifying that public utility transmission providers adopt identical terms and conditions in their respective OATTs, requires the functional equivalent of mandatory coordination agreements despite the court's decision in *Atlantic City* that the Commission cannot require adoption of coordination agreements.[180]

118. Southern Companies also assert that the design of the FPA is one of specifically conferred powers, not broad sweeping authority.[181] They add that regional transmission planning is voluntary under section 202(a) and note the Commission did not invoke its limited authority under section 216. Southern Companies also assert that the Commission's broader plenary authority over interstate transmission facilities set forth in FPA section 201 cannot be construed to allow the Commission to indirectly regulate matters incident to primary state jurisdiction over transmission facility necessity, siting, and construction.[182]

119. In addition, Large Public Power Council disagrees with the Commission's statement in Order No. 1000 that Order No. 890 serves as precedent for the exercise of mandatory authority over transmission planning because jurisdictional and non-jurisdictional utilities voluntarily complied with the Order No. 890 reforms, leaving no opportunity for judicial review. Accordingly, Large Public Power Council argues the question of whether the Commission has acted outside of its authority may always be raised.[183]

120. Finally, Ad Hoc Coalition of Southeastern Utilities asserts that even if section 202(a) does not encompass transmission planning, nothing in the FPA provides the Commission with any authority in this area. It reiterates that section 217(b)(4) is clear that the Commission is charged with facilitating transmission planning to meet native load, and it adds that nothing else in the statute suggests that the Commission has authority over this area.

[171] Ad Hoc Coalition of Southeastern Utilities at 39 (quoting *Central Iowa,* 660 F.2d at 1165, 1170).

[172] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; Sacramento Municipal Utility District; and Southern Companies.

[173] FPA section 202(b) provides, in part:

Whenever the Commission, upon application * * * and after notice * * * and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility * * * to establish physical connection of its transmission facilities with the facilities of one or more other persons engaged in the transmission or sale of electric energy, to sell energy to or exchange energy with such persons: *Provided,* That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel such public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers.

16 U.S.C. 824a(b).

[174] Ad Hoc Coalition of Southeastern Utilities at 40 (quoting *Reliability and Adequacy of Electric Service—Reporting of Data,* Order No. 838–4, 56 FPC 3547, 3548 (1976); *Reliability and Adequacy of Electric Service—Reporting of Data,* Order No. 383, 41 FPC 846 (1969)); Southern Companies at 39–40; Large Public Power Council at 19–20.

[175] Ad Hoc Coalition of Southeastern Utilities at 37. Ad Hoc Coalition of Southeastern Utilities also states that the Commission's interpretation of *Central Iowa* is at odds with former Commissioner Vicky A. Bailey's statement that ''Congress * * * was motivated by the desire to leave the coordination and joint planning of utility systems to be to the voluntary judgment of individual utilities.'' Ad Hoc Coalition of Southeastern Utilities at 40 (quoting *Regional Transmission Organizations,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (Bailey, Comm'r. concurring)).

[176] Sacramento Municipal Utility District at 25 (citing *Policy Statement Regarding Regional Transmission Groups,* FERC Stats. & Regs. ¶ 30,967 at 30,870 & 30,872 (1993) (*RTG Policy Statement*)).

[177] First Energy Companies at 7 (citing *Atlantic City,* 295 F.3d at 12).

[178] Ad Hoc Coalition of Southeastern Utilities at n.117 (citing *Atlantic City,* 295 F.3d at 11–14).

[179] Southern Companies at 85 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 345 n.310; 16 U.S.C. 824a(a)).

[180] Southern Companies at 85 (citing *Atlantic City,* 295 F.3d at 12 (D.C. Cir. 2002)).

[181] Southern Companies at 101 (citing *Otter Tail Power Co.* v. *U.S.,* 410 U.S. 366, 374 (1973) (stating that Part II of the FPA does not involve pervasive regulatory scheme over any or all activities that could have an effect on transmission rates or services)).

[182] Southern Companies at 102 (citing 16 U.S.C. 824(b)).

[183] Large Public Power Council at 21 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 99).

ii. Commission Determination

121. We deny rehearing. The arguments provided in the various requests for rehearing on the Commission's interpretation of FPA section 202(a) do not persuade us that the Commission's interpretation is at odds with existing precedent or that it does not represent a reasonable interpretation of the statute. The arguments raised on rehearing largely repeat or further elaborate upon points that the Commission rejected in Order No. 1000. For ease of reference in the following discussion, we restate here our interpretation of section 202(a).

122. Section 202(a) reads, in relevant part, as follows:

> For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy. * * * [184]

123. As the Commission explained in Order No. 1000, section 202(a) requires that the interconnection and coordination, i.e., the coordinated operation, of facilities be voluntary. It neither mentions planning nor implicitly establishes limits on the Commission's jurisdiction with respect to transmission planning. The Commission explained that transmission planning is a process that occurs prior to the interconnection and coordination of transmission facilities. The transmission planning process itself does not create any obligations to interconnect or operate in a certain way. Thus, the Commission found that when establishing transmission planning process requirements, it is in no way mandating or otherwise impinging upon matters that section 202(a) leaves to the voluntary action of public utility transmission providers.[185] As explained below, this point is reinforced by the way that section 202(a) presents the matters that it does address in a specific sequence.

124. First, section 202(a) empowers the Commission to divide the country into regional districts. If the Commission takes that step, the statute then envisions voluntary interconnection of facilities within those districts, after which occurs the voluntary coordination of those facilities, something which can occur only after the facilities are interconnected. This sequence leads to the inference that the ''coordination of facilities'' refers to their operational coordination, the only relevant form of coordination once facilities are interconnected.

125. The planning of new transmission facilities occurs before they can be interconnected, and for this reason any transmission planning relevant to these facilities occurs prior to those matters that the statute mandates be voluntary. The requirements of Order No. 1000 explicitly pertain only to the coordination of transmission planning, not the coordination of operations of generation and transmission facilities. In short, Order No. 1000 deals with the coordination of a process that is separate and distinct from, and that is completed prior to, the coordination of facilities that is the concern in section 202(a). For this reason, the transmission planning requirements of Order No. 1000 fall outside the scope of section 202(a) because they apply to matters that occur prior to any actions that fall within its scope.

126. Our task here is to provide a reasonable interpretation of section 202(a),[186] and we have done that. Our reading of the statute follows the direct flow of the statutory language, and in that way, it conforms with ''the cardinal rule that '[s]tatutory language must be read in context [since] a phrase 'gathers meaning from the words around it.' ' '' [187] It draws the most reasonable inference from the absence of any mention of planning, i.e., that Congress did not intend section 202(a) to apply to the planning of new transmission facilities. It also is consistent with the intent of Congress, which was the promotion of the economic use of resources through power pooling, as we discuss herein.[188]

127. The arguments that have been raised on rehearing against this interpretation of section 202(a) fall into two broad categories. The first involves claims concerning the nature of planning. The argument that petitioners advance is that planning by its nature is inherently inseparable from the interconnection and coordination of facilities mentioned in the statute. These arguments assert that the nature of planning is such that the requirement that it be voluntary either is found directly in the plain meaning of the language of the statute or is clearly implied by that language. The second class of arguments involves the claim that a number of court cases involving section 202(a), in particular *Central Iowa,* demonstrate that the transmission planning requirements of Order No. 1000 violate the statute. Many petitioners also point to Commission orders and studies that they claim support the same conclusion.

128. The first class of arguments can be summarized as follows: planning is necessary to interconnect and coordinate facilities; section 202(a) prohibits the Commission from requiring the interconnection and coordination of facilities; therefore, section 202(a) prohibits the Commission from requiring anything pertaining to new transmission facility planning. For example, Ad Hoc Coalition of Southeastern Utilities argues that transmission planning is an aspect of the coordination of facilities, and therefore, if the interconnection and coordination of transmission facilities must be voluntary, transmission planning alone also must be coordinated voluntarily. A number of other petitioners make similar arguments.[189]

129. While it is true that facilities must be planned before they can be interconnected and coordinated, we find that this fact proves nothing regarding the scope of section 202(a). The fact that many significant undertakings require planning does not mean that the planning process is indistinct and inseparable from the implementation of plans and subsequent operations. For instance, there is a significant difference between planning a trip and taking it. Likewise, the act of planning the transmission grid and the act of coordinating facilities in their operations are two quite different things. In the case of transmission facilities, planning involves the consideration of various alternatives using economic and engineering analysis, whereas the operation of interconnected facilities involves operational cooperation, such as coordinated dispatch, among other things. We thus disagree with the various petitioners who argue that the ''coordination of facilities * * * for transmission'' necessarily encompasses transmission planning. The latter must be completed before the former can occur. Moreover, planning is an extremely general concept, which means that in practice there are many different types of planning. A plan for

[184] 16 U.S.C. 824(a) (2006).

[185] *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 100–01.

[186] *Chevron U.S.A.* v. *Natural Resources Defense Council,* 467 U.S. 837, 842–45 (1984) (*Chevron*).

[187] *General Dynamics Land Sys., Inc.* v. *Cline,* 540 U.S. 581, 596 (2004). (quoting *Jones* v. *United States,* 527 U.S. 373, 389, (1999) (quoting *Jarecki* v. *G. D. Searle & Co.,* 367 U.S. 303, 307 (1961))).

[188] *See* discussion *infra* at P 0.

[189] *See, e.g.,* PPL Companies; and Southern Companies.

the coordination of facilities for the generation, transmission, and sale of electric energy is an operational plan for facilities already in existence. Such a plan differs from a plan for the development of new transmission facilities, which is all that is at issue under Order No. 1000.

130. In addition, to plan is not to mandate some action that occurs beyond the planning process. Between planning and the implementation of a plan stands a decision to proceed or not to proceed with some or all of the planning proposals. We thus disagree with North Carolina Agencies that the transmission planning process itself creates obligations regarding interconnection or operation.

131. FirstEnergy Service Company states that one must begin with the literal terms of the statute and maintains that when one does, one finds that the natural reading of ''coordination'' includes both coordinated planning and coordinated operation. While we agree with FirstEnergy Service Company on the starting point of statutory interpretation, one cannot stop there. It is a ''fundamental principle of statutory construction (and, indeed, of language itself) that the meaning of a word cannot be determined in isolation, but must be drawn from the context in which it is used.'' [190] Section 202(a) does not use the term ''coordination'' in isolation but rather in the phrase ''coordination of facilities.'' The language found in section 202(a) does not include any terms such as plan or planning or any synonyms for such terms. We disagree that the ''natural reading'' of ''coordination'' in the phrase ''coordination of facilities'' requires one to conclude that the phrase means both ''coordination of facilities'' and ''coordination of planning.''

132. FirstEnergy Service Company defends its ''natural'' reading of the term ''coordination'' in section 202(a) by pointing to the various uses that the Commission has made of the term in Order No. 1000, including statements on how the planning requirements of Order No. 1000 promote coordination among planning regions. Ad Hoc Coalition of Southeastern Utilities and PPL Companies make similar arguments. We reject these arguments because, as used by the Commission in those instances, ''coordination'' simply means ''joint cooperation,'' not coordination as petitioners argue. The word ''coordination,'' like ''planning,'' is extremely general in its scope. Its meaning in one context, such as section 202(a), does not suggest or imply that it has the same meaning in every other context, such as Commission references to the coordination of new transmission planning. As noted above, ''the meaning of a word cannot be determined in isolation, but must be drawn from the context in which it is used.'' [191] In the case of Order No. 1000, the use of the term ''coordination'' in connection with new requirements is restricted to interregional transmission coordination. We see no connection between the coordination between regions and the coordination of facilities referred to in section 202(a).

133. Additionally, Ad Hoc Coalition of Southeastern Utilities overlooks this point when it argues that Order No. 1000 found that its interregional transmission coordination requirements involve ''*coordination* with regard to the identification and evaluation of interregional transmission facilities * * *.'' [192] The quoted language is taken out of context as the footnote in Order No. 1000 from which it is drawn is intended to make clear that the Commission draws a distinction between the interregional transmission coordination it is requiring in Order No. 1000 and the type of coordination at issue in section 202(a). The full footnote is as follows: ''[w]e note that our use of the term 'coordination' with regard to the identification and evaluation of interregional transmission facilities *is distinct from the type of coordination of system operations discussed in connection with section 202(a) of the FPA.*'' [193] FirstEnergy Service Company also claims support for its argument in the statement in Order No. 1000 that its interregional planning reforms would ''improve coordination among public utility transmission planners with respect to the coordination of interregional transmission facilities.'' [194] This argument, however, fails for the same reason. The language from Order No. 1000 cited immediately above makes clear that the Commission distinguished its use of the word ''coordination'' with regard to interregional coordination of new transmission planning in Order No. 1000 from the meaning of the word ''coordination'' in section 202(a).

134. We also disagree with FirstEnergy Service Company that the Commission cites no authority for the proposition that power pools and operational activities were the focus of section 202(a). *Central Iowa* supports the Commission's view.[195] Moreover, the standard that the Commission must satisfy in advancing an interpretation of section 202(a) is that it be a reasonable interpretation.[196] The Commission's interpretation is a reasonable one, given that the provision seeks the promotion of the ''interconnection and coordination of facilities for the generation, transmission, and sale of electric energy,'' i.e., existing resources of public utility systems, for the purpose of promoting ''the greatest possible economy and with regard to the proper utilization and conservation of natural resources.'' [197] Such economizing of resources is the purpose of a power pool. This is precisely the point made in the secondary literature that the court quoted in *Central Iowa,* which reinforces the point that the case supports the Commission's interpretation.[198]

135. Sacramento Municipal Utility District argues that if Congress intended that the Commission should encourage the coordination of transmission operations, there is no logical reason that it did not also intend that the Commission encourage transmission planning, which further means that it did not intend that the Commission could mandate transmission planning. On the contrary, there is no logical basis for this conclusion. Section 202(a) deals with the coordination of facilities, i.e., facilities already in existence, whereas Order No. 1000 deals with the planning of new transmission facilities. While facilities must be planned before they can be built, and built before they can be coordinated, it does not logically follow that encouragement of the coordination of existing facilities entails encouraging the planning of new facilities, which, if built, could be coordinated. There is thus no logical basis for concluding that Congress intended anything at all with regard to planning of new transmission facilities.

136. Similar considerations apply to the argument that the plain meaning of section 202(a) requires one to conclude that joint planning must be voluntary. The basic principle underlying the plain meaning rule is that in interpreting a statute, ''we start—and if it is 'sufficiently clear in its context,' end—

[190] *Deal* v. *United States,* 508 U.S. 129, at 132 (1993).

[191] *Deal* v. *United States,* 508 U.S. at 132.

[192] Ad Hoc Coalition of Southeastern Utilities at 35 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 345 n.310 (emphasis added)).

[193] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 345 n.310 (emphasis added).

[194] *Id.* P 345.

[195] *See, e.g., Central Iowa,* 606 F.2d at 1160–62 (stating that the agreement at issue is designed to promote reliable and economical operation of the interconnected electric network in the mid-continent area).

[196] *Chevron U.S.A.* v. *Natural Resources Defense Council,* 467 U.S. 837, 842–45 (1984) (*Chevron*).

[197] 16 U.S.C. 824a(a).

[198] *Central Iowa,* 606 F.2d at n.16.

with the plain language of the statute.'' [199] To end with the plain language of the statute means that:

* * * when words are free from doubt they must be taken as the final expression of the legislative intent, and are not to be added to or subtracted from by considerations drawn from titles or designating names or reports accompanying their introduction, or from any extraneous source. In other words, the language being plain, and not leading to absurd or wholly impracticable consequences, it is the sole evidence of the ultimate legislative intent.[200]

Section 202(a) makes no mention of transmission plans, planning new transmission, or any planning at all. Therefore, the plain meaning rule does not support petitioners' argument. Petitioners' reading of section 202(a) is not a required interpretation of the statute.

137. For instance, Ad Hoc Coalition of Southeastern Utilities argues that the coordination of facilities for transmission encompasses transmission planning. This is an argument based on inference, not plain meaning, and ''[i]nterpreting the intent of Congress from the inferential meaning of its statutes is a far different exercise * * * from looking at the plain meaning of a statute for an express provision. * * *'' [201] To argue that a statute requires a particular result based on an inference, the inference must be a necessary one, not simply one that is possible.[202] That the interpretation proposed by petitioners is not a necessary one is demonstrated by the existence of other, and in our view, more reasonable interpretations such as the one advanced in Order No. 1000. We are required only to present a reasonable interpretation,[203] and we believe that we have done so.

138. Nevertheless, Ad Hoc Coalition of Southeastern Utilities and Southern Companies further maintain that the Federal Power Commission assisted Congress in drafting the FPA with the express intent of facilitating regional planning. They argue that the legislative history of the statute demonstrates this and undercuts the Commission's position that the ''planned coordination'' mentioned in the legislative history refers only to the coordination of facility operations. However, the evidence on which Ad Hoc Coalition of Southeastern Utilities and Southern Companies base their argument—statements made in Congressional hearings by the Federal Power Commission's solicitor and drafting representative, Dozier A. DeVane—does not support their conclusion and is, at best, irrelevant to the point they seek to make.

139. It is important to note that Mr. DeVane was commenting on an early draft of the FPA that differs in fundamental respects from the version that eventually became law. Specifically, the draft in question created an obligation for all public utilities ''to furnish energy to, exchange energy with, and transmit energy for any person upon reasonable request therefore. * * *'' [204] The draft also required public utilities to receive a certificate of public convenience and necessity before constructing or operating new jurisdictional facilities or abandoning facilities other than through retirement in the normal course of business.[205] In short, the draft statute was to require sales and exchanges of energy that are central to pooling operations, and the Commission was to have direct oversight over the development of the transmission grid through the approval of new facilities prior to construction. As Ad Hoc Coalition of Southeastern Utilities and Southern Companies note, Mr. DeVane considered these sections to be among those that were ''absolutely necessary to effectively carry out regional planning.'' [206] Thus, even if Ad Hoc Coalition of Southeastern Utilities and Southern Companies are correct that the Federal Power Commission draft of the FPA expressed an intent to facilitate planning, that intent is not expressed in the statute itself since provisions that the Federal Power Commission representative considered to be essential to the goal were not included in the statute. Moreover, given the fact that the Commission would have had oversight over the transmission development process through the power to issue certificates of public convenience and necessity, we think that Mr. DeVane meant by ''planning'' the planning and promotion of enhanced power pooling under active Commission supervision, something very different from the matters at issue in this proceeding. We thus do not agree with Ad Hoc Coalition of Southeastern Utilities and Southern Companies that the legislative history of the FPA contradicts the Commission's interpretation of section 202(a) of the statute.

140. This brings us to the second class of arguments advanced by petitioners, those that rely on sources such as court cases dealing with section 202(a), as well as Commission orders and reports. Petitioners who advance such arguments on rehearing focus on *Central Iowa.* As the Commission noted in Order No. 1000, *Central Iowa* dealt with a claim that the Commission should have used its authority under section 206 of the FPA to compel greater integration of the utilities within the Mid-Continent Area Power Pool (MAPP) than was specified in the MAPP agreement. Those who took this position in the Commission proceeding at issue in *Central Iowa* sought to have the Commission require MAPP participants ''to construct larger generation units and engage in single system planning with central dispatch.'' [207] The court held that given ''the expressly voluntary nature of coordination under section 202(a),'' the Commission was not authorized to grant that request.[208]

141. The court in *Central Iowa* was thus presented with a request that the Commission require an enhanced level of, or tighter, power pooling. Section 202(a) was relevant to the problem at issue in *Central Iowa* because the operation of the system through power pooling is its central subject matter. Order No. 1000, however, is focused on the process of planning new transmission, which is distinct from any specific system operations. Nothing in Order No. 1000 is tied to the characteristics of any specific form of system operations, and nothing in it requires any changes in the way existing operations are conducted. Order No. 1000 requires compliance with certain general principles within the

[199] *Lutheran Hosp. of Indiana, Inc.* v. *Business Men's Assur. Co.,* 51 F.3d 1308, 1312 (7th Cir. 1995) (quoting *Ernst & Ernst* v. *Hochfelder,* 425 U.S. 185, 201 (1976)).

[200] *Caminetti* v. *United States,* 242 U.S. 470, 490 (1917).

[201] *Breuer* v. *Jim's Concrete of Brevard, Inc.,* 292 F.3d 1308, 1309 (11th Cir. 2002), *aff'd,* 538 U.S. 691 (2003).

[202] *Kirkhuff* v. *Nimmo,* 683 F.2d 544, 549 (D.C. Cir. 1982); *Safarik* v. *Udall,* 304 F.2d 944, 948 (D.C. Cir. 1962); 2B Sutherland Statutory Construction § 55:3 (7th ed.).

[203] *Chevron,* 467 U.S. at 842–45.

[204] Hearing on H.R. 5423 Before the House Interstate & Foreign Commerce Comm. 74th Cong. 32 (1935).

[205] *Id.* The language on certificates of public convenience and necessity is found in section 204(a) of the draft statute, which provided that:

No public utility shall undertake the construction or extension of any facilities subject to the jurisdiction of the Commission, or acquire or operate any such facilities, or extension thereof, or engage in production or transmission by means of any such new or additional facilities or receive energy from any new source, unless and until there shall first have been obtained from the Commission a certificate that the present or future public convenience and necessity require or will require such new construction, or operation or additional supply of electric energy. * * *

[206] Ad Hoc Coalition of Southeastern Utilities at 41 (quoting Hearing on H.R. 5423 Before the House Interstate & Foreign Commerce Comm. 74th Cong. 560 (1935)); Southern Companies at 40 (quoting the same text).

[207] *Central Iowa,* 606 F.2d at 1166.

[208] *Id.* at 1168.

transmission planning process regardless of the nature of the operations to which that process is attached. The court's interpretation of section 202(a) with respect to system operations is therefore not applicable.[209]

142. Many of the arguments that petitioners make based on their reading of *Central Iowa* attempt to demonstrate that regional transmission planning must be voluntary because the court in various ways noted the importance of planning for the interconnection and coordination of facilities. Large Public Power Council maintains that the court in *Central Iowa* believed that planning was an intimate part of the authority addressed in section 202(a) based on the court's reference to a passage in the legislative history discussing ''the economies which alone can be secured through * * * planned coordination.'' [210] Several petitioners also point to the court's use of the definition of ''coordination'' set forth in the Commission's *1970 National Power Survey*. This definition states that ''coordination is joint planning and operation of bulk power facilities by two or more electric systems for improved reliability and increased efficiency which would not be attainable if each system acted independently.'' Large Public Power Council also cites the court's reference to a passage from the *1970 National Power Survey* that states that the ''[r]eduction of installed reserve capacity is made possible by mutual emergency assistance arrangements and associated coordinated transmission planning.'' [211]

143. As explained in Order No. 1000, section 202(a) does not mention ''planning,'' and we have determined that section 202(a) was not intended to address the process of planning new transmission facilities that is the subject of this proceeding. Moreover, the cited legislative history does not refer to the new transmission planning process that is the subject of Order No. 1000. Instead, the legislative history refers to ''planned coordination,'' i.e., to the pooling arrangements and other aspects of system operation that are the underlying focus of section 202(a). It is in this sense that *Central Iowa* must be understood when it refers to engaging ''voluntarily in power planning arrangements.'' The ''planned coordination'' mentioned in the legislative history cited in *Central Iowa* means ''planned coordination'' of the operation of existing facilities, not the planning process for the identification of new transmission facilities. In short, neither *Central Iowa* nor the legislative history cited in that case involves or applies to the planning process for new transmission facilities. Rather, they deal with the coordinated, i.e., shared or pooled, operation of facilities after those facilities are identified and developed. By contrast, Order No. 1000 deals with the process for planning new transmission facilities, a separate and distinct set of activities that occur before new transmission facility construction and before the generation and transmission operational activities that are the subject of section 202(a).[212]

144. Additionally, we note that in referring to ''the economies which alone can be secured through * * * planned coordination,'' the legislative history is referring to the economies that arise through the coordination of facilities in power pool operations. The legislative history states that Part II of the FPA ''seeks to bring about the regional coordination of the operating facilities of the interstate utilities.'' [213] Planned coordination in facility operations generally involves utilizing the lowest cost generation facilities available at any particular time and reducing installed reserve capacity. The new transmission planning required by Order No. 1000 is intended to ensure that transmission planning processes consider and evaluate possible transmission alternatives and produce transmission plans that can meet transmission needs more efficiently and cost-effectively. Nothing in the coordinated new transmission planning process envisioned by Order No. 1000 requires or inevitably leads to the coordinated operation of existing generation and transmission facilities and coordinated sales of electric energy in pooling operations envisioned in the legislative history of section 202(a).

145. Moreover, the fact that the legislative history describes the coordination of facilities that Congress had in mind as ''planned'' does not make the planning requirements in Order No. 1000 part of what was under discussion in the legislative history. As noted above, planning is an extremely general concept. The broad range of activities that involve planning cannot be deemed to be intrinsically related to each other simply by virtue of having a characteristic in common that virtually all business, commercial, and industrial activities share.

146. Additionally, nothing anyone cites to in the *1970 National Power Survey* suggests that its definition of the term ''coordination'' is intended as an interpretation of the term ''coordination'' for purposes of section 202(a). Moreover, if ''coordination'' means, as the *1970 National Power Survey* defines it to mean, ''joint planning *and* operation of bulk power facilities'' (emphasis supplied), then joint planning alone, which is only one element of the definition, is not coordination under this definition. Therefore, Order No. 1000 does not require coordination under this definition because it does not require one of the essential elements of the definition (i.e., it does not require joint operation). We thus see no basis to conclude that the definition of ''coordination'' in the *1970 National Power Survey* or use of the definition by the court in *Central Iowa* demonstrates that the phrase ''coordination of facilities'' in section 202(a) also means ''coordination of planning.''

147. The language from the *1970 National Power Survey* that Large Public Power Council cites also does not demonstrate that planning is necessarily part of the authority addressed in section 202(a). This language simply points out that coordinated transmission planning can play a role in reducing the amount of installed reserve capacity needed. The coordination of plans for new transmission can have many beneficial effects, but the argument that one of these effects brings it within the function addressed in section 202(a) because it is something that the section requires to be voluntary is another example of a failure to distinguish between new transmission planning and the implementation of plans for other purposes. The statement from the *1970 National Power Survey* does not show that planning is an integral part of the authority addressed in section 202(a) because nothing in it shows how the planning requirements of Order No. 1000 have the effect of requiring either the interconnection or the coordination of facilities.

148. Additionally, Sacramento Municipal Utility District argues that the court in *Central Iowa* did not mean to refer only to facility operations when referring to voluntary power pooling because it noted that some forms of pooling are designed to achieve certain goals, plus economies of joint planning and construction of generation and transmission facilities. This fact does not make joint planning by itself, which is the subject of Order No. 1000, a form

[209] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at 103.

[210] Large Public Power Council at 20 (quoting S Rep. No. 74–621 at 49 (1935), as cited by *Central Iowa,* 606 F.2d at 1162).

[211] Large Public Power Council at 21 (quoting 1970 National Power Survey, p. I–17–1, as cited by *Central Iowa,* 606 F. 2d at n.23).

[212] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 105.

[213] S. Rep. No. 621, 74th Cong., 1st Sess. 4 (1935).

of power pooling or demonstrate that something falls within the scope of section 202(a) simply because it is something that some power pools have decided to do.

149. Sacramento Municipal Utility District also cites *Central Iowa* as support for the argument that the Commission's authority is limited to determining whether the terms of any voluntary agreements to plan together are just and reasonable and not unduly discriminatory or preferential. In fact, however, *Central Iowa* does not support Sacramento Municipal Utility District's argument. In that case, the court approved Commission action requiring joint planning where one group of public utilities refused to agree to plan together with another group. Specifically, the MAPP agreement separated MAPP members into different classes based on the size of their systems and allowed members of the class with larger, but not those with smaller, systems to have access to the planning function. Those not admitted objected, and the Commission found the size criterion irrelevant and unduly discriminatory and required the admission of the previously excluded systems.[214]

150. In other words, *Central Iowa* involved a situation where a power pool voluntarily agreed to joint planning and operation, but allowed only some members to participate in planning. The Commission found that it was unduly discriminatory to allow only some members to participate in planning, directed MAPP to allow all members to participate in planning, and the Court affirmed that decision.[215] While Sacramento Municipal Utility District contends *Central Iowa* limits the Commission's ability to create planning requirements to the circumstances there, nothing in the Court's opinion supports this. Rather the opinion shows that the Court focused on and affirmed the Commission on the specific facts before it. Whether the Commission can mandate planning in other circumstances, such as those here, was neither considered by nor ruled on by the Court. For these reasons, we also disagree with North Carolina Agencies that the court's statement in *Central Iowa* that the Commission could not have mandated the adoption of the MAPP agreement means that the Commission could not have mandated coordinated transmission planning. The court specifically approved a Commission mandate of joint planning.

151. We also disagree with Sacramento Municipal Utility District that the Commission's action in the order underlying *Central Iowa* was proper only because the planning provisions of the MAPP agreement were ''the voluntary decision of the entities involved,'' [216] i.e., the voluntary decision of those MAPP members that had agreed to engage in planning with some MAPP members but not with others. Rather, the Commission imposed the requirement in the absence of any substantive agreement to the requirement among the parties affected, because the practices at issue were matters that were subject to the Commission's jurisdiction under sections 205 and 206 of the FPA.[217] That is, the Commission's authority arises from the fact that planning is a practice that affects rates, and the Commission has a duty under sections 205 and 206 of the FPA to ensure that such practices are just and reasonable and not unduly discriminatory or preferential. Indeed, this is the very same authority upon which the Commission relies in adopting the transmission planning reforms in Order No. 1000. This point also supplies our response to Ad Hoc Coalition of Southeastern Utilities' claim that even if section 202(a) does not encompass transmission planning, nothing in the FPA gives the Commission any authority in this area.

152. Regarding Ad Hoc Coalition of Southeastern Utilities' argument that the Commission's interpretation of *Central Iowa* is at odds with former Commissioner Vicky A. Bailey's statement that ''Congress * * * was motivated by the desire to leave the coordination and joint planning of utility systems to be to the voluntary judgment of individual utilities,'' [218] we note that she made this statement in an opinion in which she concurred in part and dissented in part. Neither concurring opinions nor dissenting opinions constitute binding precedent,[219] and Commissioner Bailey's statement thus does not call into question the validity of our actions here.

153. We also find nothing in *Atlantic City* that is relevant to the issue of the Commission's authority to establish transmission planning requirements. In *Atlantic City,* the court held that the Commission could not require a transmission-owing public utility to obtain authorization under section 203 of the FPA before withdrawing from an ISO. The court reasoned that section 203 applies only to situations where a public utility sells, leases, or otherwise disposes of jurisdictional assets, and the transfers of control over such facilities that occurred when a public utility joined or departed from an ISO did not rise to the level of such a transaction. The court also concluded that the Commission's position that approval under section 203 is required could not be reconciled with the requirement of section 202(a) that arrangements for the interconnection and coordination of facilities be voluntary. The court nowhere stated or implied that these voluntary arrangements also covered planning matters. Indeed, the court's main point was that section 202(a) ''does not provide [the Commission] with any substantive powers 'to compel any particular interconnection or technique of coordination.' '' [220] Nothing in Order No. 1000 compels ''any particular interconnection or technique of coordination'' or indeed any interconnection or coordination of facilities at all.

154. Some petitioners maintain that *Atlantic City* demonstrates that the Commission cannot impose planning requirements because the ISO agreement at issue in that case encompassed transmission planning. However, the fact that section 202(a) has applicability to some aspects of an agreement does not mean that it has applicability to all aspects. The claim to the contrary is based on the idea that every kind of transmission planning is inseparable from the interconnection and coordination of facilities, a claim that we reject. In addition, it is clear from the context in which the court raised section 202(a) in *Atlantic City* that it was not making any statements that are relevant to transmission planning.

155. As noted above, the issue before the *Atlantic City* court was whether the transfer of control over jurisdictional facilities that occurred when a public utility entered or left an ISO was a jurisdictional transfer for purposes of section 203 of the FPA. For purposes of section 202(a), such a transfer constitutes a decision either to

[214] *Mid-Continent Area Power Pool Agreement,* Opinion No. 806, 58 F.P.C. 2622, 2631–36 (1977) (*MAPP Agreement Order*).

[215] *Central Iowa,* 606 F.2d at 1170–72.

[216] Sacramento Municipal Utility District at 23.

[217] *Central Iowa* at 1170; *MAPP Agreement Order,* 58 F.P.C. at 2636–37.

[218] Ad Hoc Coalition of Southeastern Utilities at 40 (quoting *Regional Transmission Organizations,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (Bailey, Comm'r. concurring in part and dissenting in part)).

[219] *Maryland* v. *Wilson,* 519 U.S. 408, 412–13 (1997) (acknowledging that a concurring opinion does not constitute binding precedent).

[220] *Atlantic City,* 295 F.3d at 12 (quoting *Duke Power Co.* v. *Federal Power Comm'n,* 401 F.2d 930, 943 (D.C. Cir. 1968)).

coordinate facilities through the ISO or to withdraw from such a coordination arrangement, i.e., to turn operational authority over to an ISO or to reclaim that authority from the ISO. Neither joint nor coordinated new transmission planning involves any transfer of control over any facilities, which makes clear that the court in *Atlantic City* was not addressing issues pertinent to transmission planning. We thus disagree with Southern Companies that the transmission planning requirements of Order No. 1000 constitute the functional equivalent of a coordination agreement that the court in *Atlantic City* found must be voluntary.

156. We also disagree with PPL Companies that the lack of a mandate on regional transmission planning in the Energy Policy Act of 2005 and the fact that Congress made no changes to section 202(a) has any significance for Order No. 1000. Section 202(a) does not mention transmission planning. With respect to the Energy Policy Act of 2005, which does not address regional transmission planning, we note that the Supreme Court has observed that ''[t]he search for significance in the silence of Congress is too often the pursuit of a mirage.'' [221]

157. Sacramento Municipal Utility District maintains that the Commission's work with regional reliability councils in the decades following the Northeast blackout of 1965 contradicts its interpretation of section 202(a). To demonstrate this point, Sacramento Municipal Utility District quotes a long passage from a 1993 proposed rule dealing with information to be filed by transmitting utilities providing information on potentially available transmission capacity and known constraints.[222] The passage in question includes a number of statements that point out the importance of planning for the development of coordinated systems. However, this passage does not mention section 202(a) or the Commission's jurisdiction, and nothing in the document from which it is drawn states anything, either explicitly or implicitly, that allows one to conclude that transmission planning either is or is not something that can be subject to Commission requirements.

158. Finally, the same conclusion applies to the Commission policy statements on data collection that petitioners cite. None of these policy statements includes any analysis of the scope of section 202(a). They do mention the importance of planning for achieving the goals of section 202(a), but such statements do not speak to what the Commission can require with respect to planning. Indeed, since they require reporting of information relevant to planning, one can just as easily infer that they pertain to matters where the Commission can establish requirements.

c. Role of FPA Section 217(b)(4)

i. Requests for Rehearing and Clarification

159. Some petitioners contend that the transmission planning reforms in Order No. 1000 ignore or run counter to the requirements of FPA section 217(b)(4).[223] Similarly, several petitioners raise concerns that Order No. 1000's requirement that public utility transmission providers, in consultation with stakeholders, consider transmission needs driven by Public Policy Requirements is prohibited by section 217(b)(4).[224] Finally, some petitioners argue that the Commission erred in not finding that section 217(b)(4) is a Public Policy Requirement for purposes of Order No. 1000.[225]

160. With respect to whether Order No. 1000's transmission planning reforms are inconsistent with section 217(b)(4), PPL Companies argue that Order No. 1000 undermines the intent of section 217 by stating that all planning improvements will assist load-serving entities.

161. Transmission Dependent Utility Systems ask the Commission to clarify that regional and interregional transmission planning processes will abide by section 217(b)(4) by optimizing solutions for transmission to allow long-term firm access to economically-priced long-term energy supplies by all load-serving entities to best satisfy their service obligations. Transmission Dependent Utility Systems therefore seek clarification or rehearing that coordination of reliability and economic planning includes identifying optimal solutions to congestion, to ensure that load-serving entities' reasonable needs are met under FPA section 217(b)(4). They argue that once a transmission customer identifies an interregional transmission need, the interregional coordination process should consider this even if no developer has proposed an interregional solution and the public utility transmission providers themselves have not identified a potential interregional solution.

162. APPA and National Rural Electric Coops argue that Order No. 1000 incorrectly concludes that section 217(b)(4) does not provide a preference to load-serving entities, explaining that in Order No. 681, the Commission stated that section 217(b)(4) provided such a preference.[226] Meanwhile, Coalition for Fair Transmission Policy states that, rather than seeking a preference, entities are requesting a reasonable safeguard against planning process results that breach an unambiguous statutory prescription. It adds that Order No. 1000's dismissal of requests for section 217(b)(4) protection in the regional transmission process is insufficient in light of Congress' directive to enable load-serving entities to fully implement their resource decisions made under state authority.

163. NARUC argues that the planning process should require integrated resource plans or enacted state energy policies to be properly incorporated in the regional and interregional plans. NARUC states that while Order No. 1000 purports to respect integrated resource planning, it denies requests to have the planning process follow the requirement in FPA section 217(b)(4) for bottom-up transmission planning based on the needs of load-serving entities. It contends that this leaves the process open to potential top-down planning that might abrogate state integrated resource plans or other electricity policies enacted by state legislatures or regulators. Finally, NARUC seeks clarification that the Commission does not intend to leverage regional and interregional transmission plans that emerge from Order No. 1000 or the forthcoming compliance processes to infringe upon state siting authority or exceed the Commission's backstop siting authority under FPA section 216.

[221] *Sampson* v. *Murray,* 415 U.S. 61, 78 (1974) (quoting *Scripps-Howard Radio* v. *F.C.C.,* 316 U.S. 4, 11 (1942)).

[222] *New Reporting Requirement Under the Federal Power Act and Changes to Form No. FERC–714,* FERC Stats. & Regs, Proposed Regulations ¶ 32,685 at 32,688 (1993).

[223] *See, e.g.,* PPL Companies; Southern Companies; Ad Hoc Coalition of Southeastern Utilities; and North Carolina Agencies. Ad Hoc Coalition of Southeastern Utilities and Southern Companies argue that Congress added section 217 in response to the Commission's Standard Market Design (SMD) proposal in Docket No. RM01–12–000. They assert that many considered this proposal as an intrusion on utilities' ability plan to meet their native load.

[224] *See, e.g.,* Large Public Power Council; Southern Companies; Ad Hoc Coalition of Southeastern Utilities.

[225] *See,* e.*g.,* Ad Hoc Coalition of Southeastern Utilities; APPA; Large Public Power Council; National Rural Electric Coops; and Transmission Access Policy Study Group.

[226] APPA at 10–11 (citing *Long-Term Firm Transmission Rights in Organized Electricity Markets,* Order No. 681, FERC Stats. & Regs. ¶ 31,226, at P 319, 320 (2006) (stating that ''a broader preference for load-serving entities in general vis-à-vis non-load-serving entities is fully supported by the statute'' and that ''we believe section 217 of the FPA provides a general 'due' preference for load-serving entities'')); National Rural Electric Coops at 9–10 (citing same).

164. Other petitioners raise concerns about the relationship between section 217(b)(4) and Order No. 1000's requirement that public utility transmission providers consider transmission needs driven by Public Policy Requirements. Large Public Power Council argues that the requirement that public utility transmission providers consider transmission needs driven by Public Policy Requirements runs counter to FPA section 217(b)(4). It argues that imposing such a requirement would result in reconsideration by regional planners of the same matters that resulted in the transmission demand projections by load-serving entities, and is likely to lead to skewed decision-making, reflecting political value judgments and stakeholder business plans. Southern Companies also assert that these requirements violate section 217(b)(4) by hampering their ability to expand the transmission system to meet the needs of their native load by making the transmission planning process more bureaucratic and inefficient.

165. Several petitioners assert that the Commission erred in not stating specifically that FPA section 217(b)(4) is a Public Policy Requirement that must be considered in the transmission planning process.[227] APPA states that this provision is a specific legal directive regarding transmission planning enacted by Congress and imposed on the Commission. Transmission Access Policy Study Group explains that the intent of section 217(b)(4) is to protect all load-serving entities, including transmission dependent utilities, and therefore, failure to include it as a public policy that must be considered in planning sends the message that planning to meet the reasonable needs of transmission dependent load-serving entities is optional in the planning process. Transmission Access Policy Study Group asserts that treating such entities as simply stakeholders whose needs may or may not be considered in the planning process violates section 217(b)(4)'s directive to the Commission to help meet load-serving entities' needs. Ad Hoc Coalition of Southeastern Utilities states that section 217, as the only passage in the FPA that explicitly addresses planning, imposes on the Commission an obligation of a higher order than furthering other public policies not mentioned in the Commission's organic statute. Ad Hoc Coalition of Southeastern Utilities contends that Order No. 1000 fails to facilitate planning to meet native load because it compels load-serving entities to participate in planning processes in which their obligations to serve native load are considered as just one among many public policies goals that may be advanced by stakeholders. Large Public Power Council agrees.

166. Other petitioners argue that the Commission's nonincumbent reforms violate section 217(b)(4) by making it more difficult for them to meet their obligations to serve native load.[228] Southern Companies assert that not only does the Commission lack authority to impose Order No. 1000's nonincumbent transmission developer requirements, but, to the extent it makes it more difficult for Southern Companies to expand their transmission system to meet their native load service obligations, those requirements are prohibited by section 217(b)(4).

167. As for the regional planning process, MISO Transmission Owners Group 2 argues that eliminating the federal rights of first refusal will discourage robust participation in regional transmission planning. It asserts that eliminating the federal right of first refusal provides an incentive for incumbent public utilities with state-imposed retail service obligations that have local transmission planning processes to rely on their local process rather than the regional process to expand their transmission systems to serve their customers and comply with state mandates. It argues the same is true for incumbent public utility transmission providers that are NERC-registered entities that must construct transmission facilities to satisfy reliability standards or avoid NERC penalties. According to MISO Transmission Owners Group 2, this will result in the type of divided, inefficient, and potentially duplicative transmission expansion process that Order No. 1000 purports to discourage, and will create an unreasonable incentive for utilities with local planning processes to favor local projects when a regional solution is warranted.

ii. Commission Determination

168. We deny rehearing. We continue to find that the transmission planning reforms required by Order No. 1000 are consistent with the Commission's obligations under FPA section 217(b)(4). Section 217(b)(4) directs the Commission to exercise its authority under the FPA:

> in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.[229]

We believe that the regional transmission planning reforms required by Order No. 1000 are consistent with this mandate because they will enhance the transmission planning process for all interested entities, including load-serving entities. We expect that load-serving entities and their customers, like other interested parties, will benefit from a regional planning process that identifies transmission solutions that are more efficient or cost-effective than what may be identified in the local transmission plans of individual public utility transmission providers. For example, we expect that the planning process required by Order No. 1000 will help identify efficient or cost-effective transmission projects that address the transmission needs of load-serving entities and their customers, whether they are driven by reliability, economics, or public policy requirements.

169. The Commission's discussion of the relationship between section 217(b)(4) and the transmission planning reforms undertaken in Order Nos. 890 and 890–A further demonstrate that the Order No. 1000 regional transmission planning reforms are consistent with, and not prohibited by, section 217(b)(4).[230] In Order No. 890–A, the Commission explained that ''[t]ransmission planning activities are within our jurisdiction and, therefore, we have a duty under FPA section 206 to remedy undue discrimination in this area and a further obligation under FPA section 217 to act in a way that facilitates the planning and expansion of facilities to meet the reasonable needs of LSEs [load-serving entities].'' [231] We believe that the discussions in Order Nos. 890 and 890–A apply with equal force here.[232] Contrary to some

[227] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; APPA; Large Public Power Council; National Rural Electric Coops; and Transmission Access Policy Study Group.

[228] *See, e.g.,* Baltimore Gas & Electric; and Southern Companies.

[229] 16 U.S.C. 824q(b)(4) (2006).

[230] In Order No. 890, the Commission explained that section 217(b)(4) supported the transmission planning reforms therein. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 436. Order No. 1000's regional transmission planning reforms require public utility transmission providers to, among other things, adopt Order No. 890 transmission planning principles as part of their regional transmission planning process. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 150–52.

[231] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 172.

[232] The Commission discusses its jurisdiction with respect to transmission planning in this rule.

petitioners' arguments, section 217(b)(4) does not limit or prohibit the transmission planning reforms required by Order No. 1000; rather, it directs the Commission to take action to facilitate the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities. While each transmission planning region may conclude that different approaches are best suited to accommodate those needs, we find that the framework we set forth in Order No. 1000 will assist in accomplishing the requirements of section 217(b)(4).

170. As the Commission explained in Order No. 1000, the reforms adopted therein build on the requirements of Order No. 890 and further facilitate open and transparent transmission planning to, a goal that does not conflict with FPA section 217. Indeed, the Commission explained that Order No. 1000 is consistent with section 217, because it supports the development of needed transmission facilities that benefit load-serving entities. The Commission pointed out that the fact that the Order No. 1000 transmission planning reforms serve the interests of other stakeholders as well does not place the Commission's action in conflict with section 217.[233] Nothing in Order No. 1000 is intended to prevent or restrict a load-serving entity from fully implementing resource decisions made under state authority. Rather, the Commission's expectation is that Order No. 1000 will facilitate the evaluation of potential transmission facilities needed to accommodate such resource decisions.

171. We find that assertions made by APPA and National Rural Electric Coops that section 217(b)(4) establishes a preference for load-serving entities are too broad. APPA and National Rural Electric Coops state that Order No. 681, in which the Commission promulgated regulations under section 217(b)(4) regarding long-term firm transmission rights, expressly noted such a preference. However, Order No. 681 made this point in the context of securing long-term firm transmission rights supported by *existing* transmission capacity, which was the subject of that rulemaking proceeding, but not in the broader context of planning new transmission capacity. Specifically, Order No. 681 established a guideline that provided:

> Load-serving entities must have priority over non-load-serving entities in the allocation of long-term firm transmission rights that are supported by existing transmission capacity. The transmission organization may propose reasonable limits on the amount of existing transmission capacity used to support long-term firm transmission rights.[234]

172. We do not find this statement inconsistent with the reforms in Order No. 1000, which address the planning and cost allocation for *new* transmission.[235] In any event, as discussed above, we find that Order No. 1000's transmission planning reforms will aid, not hinder, load-serving entities in meeting their reasonable transmission needs. Thus, nothing in Order No. 1000's transmission planning reforms conflicts with the existing requirements of Order No. 681 regarding the availability of long-term firm transmission rights in organized electricity markets.

173. In addition, by requiring that transmission needs driven by Public Policy Requirements be considered in local and regional transmission planning processes, our expectation is that such a requirement will assist load-serving entities and others in better meeting their transmission needs. For this same reason, we allow but do not require that the coordination of reliability and economic transmission planning include identifying optimal solutions to congestion to ensure that load-serving entities' needs are met under section 217(b)(4), as suggested by Transmission Dependent Utility Systems.

174. We also disagree with Coalition for Fair Transmission Policy's contention that Order No. 1000 may not allow load-serving entities to implement their states' resource decisions. As discussed in the following section, nothing in Order No. 1000 conflicts or interferes with the states' integrated resource planning processes. Accordingly, and for the reasons discussed above, we do not believe that Order No. 1000's requirements conflict with section 217, as some petitioners maintain.

175. We also disagree with petitioners such as Large Public Power Council that the consideration of transmission needs driven by Public Policy Requirements runs counter to section 217(b)(4). First, as we stated above, we find that Order No. 1000 will enhance, not impede, meeting the needs of load-serving entities. We also believe that these specific reforms may assist load-serving entities in meeting their transmission needs, especially because many, if not all, of the Public Policy Requirements will likely impose legal obligations on load-serving entities. Therefore, we see nothing inconsistent between these reforms and section 217(b)(4).

176. We affirm Order No. 1000's conclusion that we will not prescribe any statutes and regulations as Public Policy Requirements for purposes of Order No. 1000, including section 217(b)(4). We explained that we would not pick and choose any federal or state law or regulation as a Public Policy Requirement. Rather, it will be up to public utility transmission providers, in consultation with stakeholders, to develop a process that considers transmission needs driven by Public Policy Requirements.

177. Further, we disagree with NARUC's assertion that, while Order No. 1000 purports to support integrated resource planning, its requirements are contrary to section 217(b)(4)'s requirement of a bottom-up transmission planning process. First, by its terms, section 217(b)(4) does not require a bottom-up transmission planning process, as NARUC claims. Rather, section 217(b)(4) requires the Commission to exercise its authority to facilitate the planning and expansion of transmission facilities to assist load-serving entities in meeting their reasonable transmission needs and to secure long-term firm transmission rights. It does not speak at all to how transmission planning processes should be established. Second, regardless of whether a regional transmission planning process is termed bottom-up or top-down, we emphasize that nothing in any of Order No. 1000's requirements interferes with states' authority to require integrated resource planning or utilities' obligation to comply with such requirements, as discussed herein.

178. We disagree with petitioners that argue that Order No. 1000's nonincumbent transmission developer reforms are prohibited by, or inconsistent with, section 217(b)(4).[236] Contrary to Southern Companies' contention, these reforms do not make it more difficult for incumbent

See Order No. 1000, Stats. & Regs. ¶ 31,323 at section III.A.2; *see also* discussion *supra* at section III.A.1.

[233] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 108.

[234] Order No. 681, FERC Stats. & Regs. ¶ 31,226 at P 325.

[235] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 65 (the requirements of Order No. 1000 are ''intended to apply to new transmission facilities, which are those transmission facilities that are subject to evaluation, or reevaluation as the case may be, within a public utility transmission provider's local or regional transmission planning process after the effective date of the public utility transmission provider's filing adopting the relevant requirements'' in Order No. 1000).

[236] Other issues regarding Order No. 1000's nonincumbent reforms are discussed in section III.B, *infra.*

transmission providers to serve native load. Indeed, we believe just the opposite to be the case, for as found in Order No. 1000, the Commission believes that greater participation by transmission developers in the transmission planning process may lower the cost of new transmission facilities, enabling more efficient or cost-effective deliveries by load-serving entities and increased access to resources.[237] Accordingly, we expect that incumbent transmission providers will ultimately benefit from these reforms because they support the identification of more efficient or cost-effective transmission solutions, thereby improving their ability to meet the reasonable needs of load-serving entities to satisfy their load serving obligations.

179. We also disagree with MISO Transmission Owners Group 2 that these reforms will necessarily encourage incumbent transmission providers to favor local transmission planning and local transmission projects over regional transmission planning and regional transmission solutions. While nothing in Order No. 1000 prohibits an incumbent transmission provider from proposing a local transmission solution to satisfy a reliability need or service obligation, we are not persuaded that allowing incumbent transmission providers to choose among these options will lead to less robust regional transmission planning. There are a variety of factors that incumbent transmission providers must consider when deciding whether to propose a local transmission facility instead of relying on a transmission facility selected in the regional transmission plan for purposes of cost allocation. We also believe, as discussed in Order No. 1000 and herein, that the nonincumbent transmission developer reforms will lead to more competition among developers, which in turn will lead to the identification of more efficient and cost-effective transmission facilities. Accordingly, we are not persuaded that the elimination of a federal right of first refusal will necessarily will lead to inefficient or duplicative transmission planning processes.

d. Effect on Integrated Resource Planning and State Authority Over Transmission Siting, Permitting, and Construction

i. Requests for Rehearing and Clarification

180. Several state regulators and others claim that Order No. 1000 improperly intrudes on authority over matters traditionally reserved to the states, such as integrated resource planning and the construction and siting of transmission facilities.[238] North Carolina Agencies and Southern Companies argue that, in contrast to the extensive jurisdiction over transmission planning historically exercised by the states, the FPA grants the Commission little, if any, authority in this area. Florida PSC and Georgia PSC also state that FPA section 201(a) limits the Commission's authority to regulate interstate transmission and wholesale power sales to only those matters that are not subject to state regulation, and that the Commission provided no evidence of discrimination to support preempting state authority over transmission planning.[239]

181. Several petitioners argue that Order No. 1000's planning reforms will disrupt, and potentially preempt, a state's integrated resource planning.[240] For example, Georgia PSC states that if regional and interregional transmission planning and coordination requirements result in a previously unidentified transmission project being included in a Commission-regulated process, that result will disrupt and skew existing state-regulated transmission and integrated resource planning processes, and will undermine its ability to effectively regulate bundled retail service.

182. Similarly, Alabama PSC contends that least-cost, reliable solutions identified for its ratepayers through integrated resource planning will be subordinated to the solutions identified for the region under the Commission-administered process, with no assurance that this regional solution will hold local ratepayers harmless. NV Energy also asserts that inclusion of alternative transmission and non-transmission proposals in the regional or interregional plan could trump a transmission facility in a local plan, rendering the state's integrated resource planning process meaningless.[241] NV Energy contends that this could lead to ''forum shopping,'' particularly in the case of considering Public Policy Requirements, and that states may be reluctant to approve the siting of facilities that are the result of a process of exclusion or substitution of facilities that they deem necessary and appropriate in their integrated resource planning processes.[242] NV Energy thus seeks clarification that for any facilities included in a ''local'' plan, those facilities are not subject to ''de novo'' review at the regional or interregional level unless the transmission provider voluntarily subjects the facilities to an alternative review or the facilities are proposed by the transmission provider for regional cost allocation and they are so chosen.[243] Coalition for Fair Transmission Policy seeks clarification that regional transmission planning processes and interregional transmission coordination do not have the ability or authority to affect or change resource decisions made by entities with responsibility to meet public policy requirements and the transmission needs that they have identified associated with those resource decisions, except with the voluntary agreement of those responsible entities.

183. Kentucky PSC argues that Order No. 1000 infringes on state jurisdiction over integrated resource planning through its failure to require transmission planning and cost allocation processes to allow for the unique role of state regulators in determining which projects will be constructed and who will pay for them. Kentucky PSC notes that in Kentucky, only the state legislature can decide if in-state utilities must use certain proportions of various types of energy resources. It maintains that a decision to develop a transmission facility might *de facto* make decisions about types and locations of generation resources. Kentucky PSC also argues that Order No. 1000 erred regarding the consideration of non-transmission alternatives, asserting that such matters are within the exclusive province of state-regulated integrated resource planning.[244]

184. Some petitioners, such as Ad Hoc Coalition of Southeastern Utilities, argue that regional cost allocation determinations under Order No. 1000 will have a preemptive effect on decisions made at the state level. Ad Hoc Coalition of Southeastern Utilities asserts that if ratepayers must pay for a nonincumbent's transmission line

[237] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 291.

[238] *See, e.g.,* NARUC; Florida PSC; Alabama PSC; Georgia PSC; Kentucky PSC; North Carolina Agencies; Large Public Power Council; Ad Hoc Coalition of Southeastern Utilities; Southern Companies; and Coalition for Fair Transmission Policy.

[239] In relevant part, FPA section 201(a) provides that federal regulation over the interstate transmission and wholesale sale of electric energy only ''extend[s] to those matters which are not subject to regulation by the States.'' 16 U.S.C. 824(a).

[240] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Alabama PSC; Georgia PSC; and Southern Companies.

[241] *See also* Coalition for Fair Transmission Policy at 27 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 154).

[242] NV Energy at 7–8.

[243] NV Energy at 9.

[244] *See also* Alabama PSC at 3–4.

chosen in the regional planning process, it would be difficult for the incumbent owner to pursue an alternate project, resulting in the indirect regulation of actual transmission planning decisions, including siting, construction, permitting, and resource planning decisions. It states that the Commission is prohibited from doing indirectly what it is prohibited from doing directly.[245] Ad Hoc Coalition of Southeastern Utilities also states that if the Commission states on rehearing that it does not regulate substantive planning, then it should explain the ramifications of a transmission provider not implementing the regional transmission plan. Southern Companies raise the same argument, emphasizing that the decision to fund transmission projects determines the projects to be pursued.

185. Ad Hoc Coalition of Southeastern Utilities assert that Order No. 1000's regional and interregional processes will likely result in more long distance transmission lines, which could prove to be disruptive to a bottom-up integrated resource planning process due to its significant impacts on bulk power flows.

ii. Commission Determination

186. As we stated in Order No. 1000, nothing therein is intended to preempt or otherwise conflict with state authority over the siting, permitting, and construction of transmission facilities or over integrated resource planning and similar processes. Order No. 1000 explained that ''nothing in this Final Rule involves an exercise of siting, permitting, and construction authority. The transmission planning and cost allocation requirements of this Final Rule, like those of Order No. 890, are associated with the processes used to identify and evaluate transmission system needs and potential solutions to those needs.'' Order No. 1000 concluded that ''[t]his in no way involves an exercise of authority over those specific substantive matters traditionally reserved to the states, including integrated resource planning, or authority over such transmission facilities.''[246]

187. We affirm that conclusion here. In so finding, we recognize, as we did in Order No. 1000, that the states have a significant jurisdictional role in the siting, permitting, and construction of transmission facilities, and that many states require public utility transmission providers to undertake and implement integrated resource plans. However, as we explain below, the Commission may undertake Order No. 1000's reforms without intruding on state jurisdiction.

188. At the outset, it is important to recognize that Order No. 1000's transmission planning reforms are concerned with process; these reforms are not intended to dictate substantive outcomes, such as what transmission facilities will be built and where.[247] We recognize that such decisions are normally made at the state level.[248] Rather, Order No. 1000's transmission planning reforms are intended to ensure that there is an open and transparent regional transmission planning process that produces a regional transmission plan. If public utility transmission providers' regional transmission processes satisfy these requirements, then they will be in compliance with Order No. 1000's regional transmission planning requirements. Thus, contrary to arguments raised by some state regulators and others, Order No. 1000's transmission planning reforms respect the jurisdictional authority of the states regarding the siting, permitting, and construction of transmission facilities.

189. In support of their contention that Order No. 1000 infringes on state authority, North Carolina Agencies claim that the *SMD White Paper* expressly acknowledged that the planning aspects of the SMD proposal infringed on state jurisdiction over transmission planning. The content of the *SMD White Paper* is not relevant to this proceeding.[249] There is nothing in Order No. 1000 that preempts state authority regarding transmission planning, including authority over the siting, permitting, and construction of transmission facilities.

190. By requiring public utility transmission providers to participate in an open and transparent regional transmission planning process that leads to the development of a regional transmission plan, the Commission has facilitated the identification and evaluation of transmission solutions that may be more efficient or cost-effective than those identified and evaluated in the local transmission plans of individual public utility transmission providers.[250] This will provide more information and more options for consideration by public utility transmission providers and state regulators and, therefore, can hardly be seen as detrimental to state-sanctioned integrated resource planning. Of course, we recognize that a regional transmission planning process may not identify any such transmission facilities and, even where more efficient or cost-effective transmission solutions are identified and selected in the regional transmission plan for purposes of cost allocation, such solutions may not ultimately be constructed should the developer not secure the necessary approvals from the relevant state regulators. Consistent with this, we also clarify that we do not require that the transmission facilities in a public utility transmission provider's local transmission plan be subject to approval at the regional or interregional level, unless that public utility transmission provider seeks to have any of those facilities selected in the regional transmission plan for purposes of cost allocation.

191. Accordingly, in response to Ad Hoc Coalition of Southeastern Utilities, we disagree that we are effectively making decisions about which transmission facilities will be sited and constructed, that we are effectively preempting state decisions in that regard, or that we are doing anything indirectly that we cannot do directly. As discussed above, we conclude that we possess ample legal authority under the FPA to implement Order No. 1000's transmission planning reforms. As we also explain immediately above, nothing in Order No. 1000 explicitly or implicitly requires that any transmission facilities be sited, permitted, or constructed. We do not see that decisions made in the regional transmission planning process would interfere with these state-jurisdictional processes. Further, in response to Ad Hoc Coalition of Southeastern Utilities' question regarding the implications of not implementing the regional transmission plan, we reiterate that Order No. 1000 requires a regional transmission plan be developed

[245] Ad Hoc Coalition of Southeastern Utilities at 43–44 (citing generally *Towns of Concord, Norwood, and Wellesley, Mass.* v. *FERC,* 955 F.2d 67, 71 n.2 (D.C. Cir. 1992)).

[246] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 107.

[247] *Id.* P 113 (''This Final Rule is focused on ensuring that there is a fair regional transmission planning *process,* not substantive outcomes of that process.'') (emphasis in original).

[248] The Commission has limited backstop transmission siting authority under section 216 of the FPA. However, that limited authority is not at issue in this proceeding. In response to NARUC, we clarify that nothing in Order No. 1000 is intended to leverage the regional transmission planning or interregional transmission coordination reforms to exceed the Commission's section 216 backstop authority.

[249] In addition, what North Carolina Agencies actually cite to is a brief summary of arguments that the *SMD White Paper* proceeds to address.

[250] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 146 (''We determine that such [regional] transmission planning will expand opportunities for more efficient and cost-effective transmission solutions for public utility transmission providers and stakeholders. This will, in turn, help ensure that the rates, terms and conditions of Commission-jurisdictional services are just and reasonable and not unduly discriminatory or preferential.'').

pursuant to a Commission-approved process, the Commission is not requiring that such a plan be filed for Commission approval or be implemented. Rather, as was made clear in Order No. 1000, the designation of a transmission project as a ''transmission facility in a regional transmission plan'' or a ''transmission facility selected in a regional transmission plan for purposes of cost allocation'' only establishes how the developer may allocate the costs of such a facility in Commission-approved rates if it is built.[251] Order No. 1000, however, does not require that such facilities be built, give any entity permission to build a facility, or relieve a developer from obtaining any necessary state regulatory approvals.[252]

192. We disagree with Ad Hoc Coalition of Southeastern Utilities that the Order No. 1000 transmission planning reforms will be disruptive to integrated resource planning due to the impact of long-distance transmission lines on bulk power flows. Some public utility transmission providers may be concerned that Order No. 1000, because it provides for transmission facilities being selected in the regional transmission plan for purposes of cost allocation, establishes an incentive for other entities to propose larger regional transmission projects that may disrupt or interfere with state-level integrated resource planning efforts. Even if such an incentive were present, we note that unless a long-distance transmission solution identified in the regional transmission planning process is a more efficient or cost-effective solution than what is identified in the local transmission plans of individual public utility transmission providers, it would not be selected in the regional transmission plan for purposes of cost allocation.

193. We also disagree with Kentucky PSC that Order No. 1000's direction that public utility transmission providers, in consultation with stakeholders, consider non-transmission alternatives is outside of the Commission's jurisdiction. We do not require anything more than considering non-transmission alternatives as compared to potential transmission solutions, similar to what was developed in Order No. 890, Order No. 890–A, and resulting compliance filings.[253] The evaluation of non-transmission alternatives as part of the regional transmission planning process does not convert that process into integrated resource planning. Order No. 1000 requires that there be a regional transmission plan that includes transmission facilities selected in the regional transmission plan for purposes of cost allocation.[254]

194. In further response to those petitioners who claim that Order No. 1000 will disrupt state integrated resource planning, we note that the identification of more efficient or cost-effective transmission facilities through a regional transmission planning process should not disrupt state integrated resource planning. In any event, we find that such concerns are speculative and, should they arise, it will be in the context of a specific factual circumstance. If any issues arise in such a context, affected parties are free to raise these issues before the Commission in the appropriate proceeding.

e. Legal Authority Related to Consideration of Transmission Needs Driven by Public Policy Requirements

i. Requests for Rehearing and Clarification

195. Several petitioners express concerns about the Commission's legal authority to require public utility transmission providers to consider transmission needs driven by Public Policy Requirements, arguing that the Commission failed to meet its burden, and that the requirements raise federalism issues and go beyond the Commission's statutory authority.

196. PPL Companies assert that while the Commission may permit public utility transmission providers to consider Public Policy Requirements on a voluntary basis, it erred in mandating such consideration without first finding that existing rates are unjust, unreasonable, or unduly discriminatory. They assert that the Commission has not met its FPA section 206 burden to explain why consideration of transmission needs driven by Public Policy Requirements will remedy unjust and unreasonable rates or undue discrimination. They argue that having to plan for and construct such public policy-driven transmission projects could unduly burden utilities and their customers with additional unjust and unreasonable costs that would not likely have been incurred but for the Public Policy Requirements.

197. ELCON, AF&PA, and the Associated Industrial Groups argue that, by allowing one state's public policy agenda to adversely affect electricity prices in other states that do not share that agenda, Order No. 1000 raises significant federalism issues. They claim that this obscures political accountability because ISOs/RTOs will have discretion to determine which public policy to follow, and that this approach permits the federal government to burden state taxpayers with onerous, unpopular policies or force them to subsidize the public policy decisions of neighboring states without facing the political accountability that federalism demands. They state that the federal government cannot commandeer state legislatures and state executives in the name of federal interests.[255] Alabama PSC raises similar concerns.

198. PPL Companies argue that the FPA does not permit utilities, or the Commission, to pursue public policy objectives broadly, and such a departure from the FPA requires an amendment to the statute itself and cannot be undertaken by the Commission via rulemaking.[256] PSEG Companies contend that the Commission acted outside the scope of its authority, arguing that there is no statute authorizing the Commission to require that transmission providers build public policy projects or even consider Public Policy Requirements. They also argue that, in the absence of specific findings of undue discrimination in a particular region, the Commission should leave it to transmission providers to determine if there is a problem that needs to be

[251] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 66.

[252] *Id.*

[253] *Id.* P 155 n. 149 (citing to Commission orders addressing Order No. 890 compliance filings that require the evaluation of transmission, generation, and demand response on a comparable basis in the public utility transmission providers' transmission planning process).

[254] It may be the case that non-transmission alternatives may result in a regional transmission planning process deciding that a proposed transmission facility is not a more efficient or cost-effective solution and, accordingly, that facility may not be selected in the regional transmission plan for purposes of cost allocation. Such a decision by the regional transmission planning process does not interfere with integrated resource planning.

[255] ELCON, AF&PA, and the Associated Industrial Groups at 10 (quoting *New York* v. *United States,* 505 U.S. 144 (1992)); *see also* PSEG Companies at 45.

[256] PPL Companies at 10–11 (citing *NAACP* v. *FPC,* 425 U.S. 662, 669–70 (1976) (explaining why Congress' direction for the Commission to act in furtherance of the public interest under the FPA ''is not a broad license to promote the general welfare''); *Atlantic City,* 295 F.3d at 8 (explaining that, as a federal agency, the Commission is a ''creature of statute,'' having ''no constitutional or common law existence or authority, but only those authorities conferred upon it by Congress.'' (quoting *Michigan* v. *EPA,* 268 F.3d 1075, 1081 (D.C. Cir. 2001) (emphasis added)); *Louisiana Pub. Serv. Comm'n* v. *FCC,* 476 U.S. 355, 374 (1986) (recognizing that ''an agency literally has no power to act * * * unless and until Congress confers power upon it''); *American Petroleum Inst.* v. *EPA,* 52 F.3d 1113, 1119–20 (D.C. Cir. 1995) (stating that in the absence of statutory authorization for its act, an agency's ''action is plainly contrary to law and cannot stand''); *Ethyl Corp.* v. *EPA,* 51 F.3d 1053, 1060 (D.C. Cir. 1995)).

addressed through revisions to the planning process and, if necessary, develop solutions that do not get ahead of states' efforts to implement their own public policies. They argue that the requirement that transmission providers prognosticate public policy outcomes and plan the system based on those predictions is not proportional to the alleged problem and is thus impermissible.[257] They also allege that the Commission did not explain how and why the existing construct focusing on the planning of reliability and economic projects has not served the needs of load-serving entities.

199. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council assert that the Commission exceeded its authority under the FPA, as delineated in *NAACP* v. *FPC,* by directing transmission providers to consider Public Policy Requirements in the planning process. Ad Hoc Coalition of Southeastern Utilities argues that although Congress directs the Commission to act in furtherance of the public interest, it is not a broad license to promote the general public welfare.[258] Instead, it asserts that public interest must be understood in the context of the broad goals of the FPA itself—to ensure the provision of reliable transmission service on a non-discriminatory basis, at just and reasonable rates. Thus, it argues that the Commission lacks authority to consider broad concepts of public policy in implementing its duties under the FPA, and may not promulgate rules advancing environmental goals. It notes that the Commission has recognized that its NEPA-related responsibilities to consider environmental policy objectives do not extend to section 205 rate filings.[259]

200. Southern Companies argue that the Commission lacks authority under the FPA to enforce and implement state and federal policies, which violates *Comcast* v. *FCC.*[260] They add that Order No. 1000's regulation of specific evaluative practices violates precedent establishing that the Commission cannot regulate a matter just because the Commission is able to articulate some relationship between that matter and the Commission-regulated, wholesale electric and transmission services.[261] They assert that the Commission's reading of the holding of *CAISO* v. *FERC,* which it interprets as giving it authority to control anything that affects the need for interstate transmission facilities, is too broad since all aspects of our modern, electricity-consuming lives drive the need for interstate transmission facilities.[262]

201. Southern Companies asserts that Public Policy Requirements are merely components that drive load growth and resource decisions that are the major aspects of integrated resource planning, which demonstrates that addressing Public Policy Requirements is an issue for state-regulated integrated resource planning. In addition, they state that even though it already incorporates public policies into its transmission planning process, Order No. 1000's Public Policy Requirement appears to add nothing but costs and burdens by mandating nothing more than compliance activities. Therefore, Southern Companies argue that Order No. 1000's Public Policy Requirements are arbitrary and capricious,[263] and violate *National Fuel.*[264]

202. Bonneville Power seeks clarification that the Public Policy Requirement reforms to its local planning process must be consistent with its statutory authorities related to providing regional and interregional transmission facilities.[265] Bonneville Power states that its statutory authorities for planning and building transmission facilities are not constrained by the FPA's just and reasonable and not unduly discriminatory standard. It also explains that while its Administrator may consider policies at play under those standards, he must also factor in other considerations.[266] If the Commission declines to grant this clarification, Bonneville Power seeks rehearing, arguing that the Commission failed to provide reasonable notice of the requirement and failed to consider Bonneville Power's comments and statutory requirements.

ii. Commission Determination

203. We deny rehearing. Many of the arguments raised on rehearing simply repeat assertions made by commenters in response to the Proposed Rule in this proceeding, namely, that the Commission is not permitted to require public utility transmission providers to consider transmission needs driven by public policy under the FPA or that the direction to public utility transmission providers to consider transmission needs driven by Public Policy Requirements is not a practice affecting rates.

204. At the outset, it is important to emphasize exactly what these reforms are intended to do and what they clearly are not intended to do. As explained in Order No. 1000, in requiring the consideration of transmission needs driven by Public Policy Requirements, the Commission is not mandating fulfillment of those requirements or that public utility transmission providers consider the Public Policy Requirements themselves. We address this issue in more detail below,[267] but we clarify here the basic components of Order No. 1000's requirements in this regard, as it appears there are misconceptions about precisely what Order No. 1000 requires. To be clear, we are not requiring that any federal or state laws or regulations themselves be considered as part of the transmission planning process. That distinction is critical, and we want to be clear that this is not what Order No. 1000 requires.[268]

205. Instead, the Commission is acknowledging that the requirements in question are facts that may affect the need for transmission services and these facts must be considered for that reason. Our intent is that public utility transmission providers consider such transmission needs just as they consider transmission needs driven by reliability or economic concerns.[269] We are not

[257] PSEG Companies at 47 (citing *California Indep. Sys. Operator Corp.* v. *FERC,* 372 F.3d 395 (D.C. Cir. 2004) (*CAISO* v. *FERC*)).

[258] Ad Hoc Coalition of Southeastern Utilities at 53 (citing *NAACP* v. *FPC,* 425 U.S. 662, 665 (1976)).

[259] Ad Hoc Coalition of Southeastern Utilities at 54 (citing, e.g., *Monongahela Power Co.,* 39 FERC ¶ 61,350, at 62,097, *reh'g denied,* 40 FERC ¶ 61,256 (1987) (*Monongahela*); 18 CFR 380.4(a)(15) (2011)). *See also* Large Public Power Council.

[260] Southern Companies at 51 (citing *Comcast Corp.* v. *FCC,* 600 F.3d 642, 659 (D.C. Cir. 2010)).

[261] Southern Companies at 51 (quoting *State of Missouri* v. *Southwestern Bell Tel. Co.,* 262 U.S. 276, 289 (1923) (stating that a regulatory agency with general oversight and rate authority ''is not the owner of the property of public utility companies, and is not clothed with the general power of management incident to ownership'') (*Southwestern Bell*)).

[262] Southern Companies at 52 (citing *CAISO* v. *FERC,* 372 F.3d 395).

[263] Southern Companies at 50 (citing *Motor Vehicles Mfrs. Ass'n of the U.S.* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 43 (1983)).

[264] Southern Companies at 50 (citing *National Fuel,* 468 F.3d at 844).

[265] Bonneville Power at 21. Bonneville Power states that it is only requesting clarification with respect to its local planning process rather than with respect to the regional planning process in which it voluntarily participates. Bonneville Power at 22.

[266] Bonneville Power states that Congress recognized this in section 1232 of EPAct 2005, which provides that if Bonneville Power enters into a contract, agreement, or arrangement for participation in a transmission organization, then it must assure, among other things, ''consistency with the statutory authorities, obligations, and limitations of the federal utility.'' Bonneville Power at 22 (quoting 42 U.S.C. § 16431(c)(1)(C)).

[267] *See* discussion *infra* at section III.A.2.

[268] *See* discussion *infra* at section III.A.2.

[269] We note that this is consistent with the approach taken in Order No. 888, and reiterated in Order No. 890, that public utility transmission providers are obligated to plan for the needs of their

Continued

requiring that public utility transmission providers do any more than that. Such requirements may modify the need for and configuration of prospective transmission facilities. Accordingly, the transmission planning process and the resulting transmission plans would be deficient if they do not provide an opportunity to consider transmission needs driven by Public Policy Requirements.[270] As a result, in Order No. 1000 we acted pursuant to our section 206 authority to ensure that this deficiency is remedied in the OATTs of public utility transmission providers.

206. We thus disagree with PSEG Companies that Order No. 1000's requirements in this regard are impermissible because the remedy is disproportionate to the identified problem. Again, we are requiring only that there be a process in place for public utility transmission providers, in consultation with stakeholders, to consider transmission needs driven by Public Policy Requirements. We believe that these reforms are necessary, because the record shows that there are, and there will continue to be, federal and state laws and regulations that will have a direct impact on transmission needs, just as reliability and economic concerns have a direct impact on transmission needs. By setting forth this process, our expectation is that public utility transmission providers, in consultation with stakeholders, will identify more efficient or cost-effective solutions to such transmission needs than may be the case without these requirements.

207. Given the parameters described above, and discussed in more detail below,[271] we do not see how these reforms are comparable to the matters at issue in *NAACP* v. *FPC.* As discussed in Order No. 1000, the Court in *NAACP* v. *FPC* found that the Commission did not have the power under the FPA or the Natural Gas Act (NGA) to construe its obligation to promote the public interest under those statutes as creating a ''broad license to promote general public welfare.'' [272] The Court also found that the Commission's duty to promote the public interest under the FPA and NGA ''is not a directive to the Commission to seek to eradicate discrimination,'' and it thus did not authorize the Commission to promulgate rules prohibiting the companies it regulates from engaging in discriminatory employment practices merely because the statutes pertain to matters affected with a public interest.[273] We reiterate here that the consideration of transmission needs driven by Public Policy Requirements ''cannot be construed as pursuing broad general welfare goals that extend beyond matters subject to our authority under the FPA.'' [274]

208. The planning necessary to consider transmission needs driven by Public Policy Requirements is not different in substance from the planning required to address reliability or economic needs. Such planning requires an open and transparent process that provides interested stakeholders with access to studies, models and data used to make decisions. This transparency and coordination helps to ensure no undue discrimination on the part of the public utility transmission provider in planning for its own needs vis-à-vis the needs of customers to which it is obligated to provide open access transmission service. Thus, we disagree with petitioners that suggest that Order No. 1000's requirements in this regard are analogous to promoting broad notions of public policy, as contemplated in *NAACP* v. *FPC.*

209. Similarly, we find that references to the Commission's order in *Monongahela* are not relevant here. In that case, the Commission explained that we ''have consistently recognized that [our] review of electric rate filings is not subject to NEPA,'' [275] and we then rejected arguments by an environmental advocacy group that the Commission curtail the operation of existing but unused capacity within a transmission provider's system. We stated that ''[b]ecause the Commission does not possess such curtailment authority by virtue of section 201(b) of the FPA, it could not accomplish indirectly through NEPA that which it is prohibited from doing directly under section 201(b) of the FPA.'' [276] Nothing in Order No. 1000 contradicts these statements. Similar to our discussion above that we are not promoting broad notions of public policy, we emphasize that we are not advocating for any particular environmental or other public policy and we are not requiring electric rate filings under section 205 to be subjected to NEPA. We are requiring only that transmission needs driven by Public Policy Requirements be considered in transmission planning processes, just as public utility transmission providers consider reliability- and economic-based transmission needs.

210. Further, we disagree with Southern Companies that our actions in this regard are akin to what was at issue in *CAISO* v. *FERC.* As explained in Order No. 1000, in that case, the court found that the Commission did not have the authority under section 206 of the FPA to direct the California ISO to alter the structure of its corporate governance, concluding that the choosing and appointment of corporate directors is not a ''practice * * * affecting [a] rate'' within the meaning of the statute.[277] The court explained that the Commission is empowered under section 206 to assess practices that directly affect or are closely related to a public utility's rates and ''not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so.'' [278] As we explained in Order No. 1000, the transmission planning activities that are the subject of the rule have a direct and discernable effect on rates.[279] These reforms are intended to help create a path to allow public utility transmission providers, in consultation with stakeholders, in each transmission planning region to assess what transmission needs are being driven by Public Policy Requirements, just as they currently look to whether transmission needs are driven by reliability or economic considerations.

211. Similarly, our actions in this regard are not contrary to the Supreme Court's opinion in *Southwestern Bell,* which was cited by Southern Companies. We are ''not the owner of the property of public utility companies'' and we are ''not clothed with the general power of management incident to ownership,'' and nothing in these rules provide the Commission with such authority.[280] We are, as we discuss herein, providing for the consideration of transmission needs driven by Public Policy Requirements, just as public utility transmission providers consider transmission needs driven by reliability or economics. That direction is not tantamount to directing public utility transmission providers how to manage their property.

212. Because, as discussed herein, we have statutory authority to implement these reforms, we disagree with Southern Companies' that Order No. 1000 is contrary to *Comcast* v. *FCC,* where the court concluded that the

transmission customers. *See, e.g.,* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at PP 418–19.

[270] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 109.

[271] *See* discussion *infra* at section III.A.3.

[272] *NAACP* v. *FERC,* 425 U.S. 662 at 668.

[273] *Id.* at 670.

[274] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 111.

[275] *Monongahela,* 39 FERC ¶ 61,350 at 62,097

[276] *Id.*

[277] *CAISO* v. *FERC,* 372 F.3d at 403.

[278] *Id.*

[279] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 112.

[280] *Southwestern Bell,* 262 U.S. at 289.

Federal Communications Commission (FCC) lacked requisite statutory authority to regulate an Internet service provider's network management practices. The court explained that the FCC could not rely on policy statements in the Communications Act of 1934 by themselves as the basis for the FCC to exercise ancillary authority to regulate Internet service, noting that policy statements are not delegations of regulatory authority.[281] The court also found that the FCC's reliance on other statutory provisions failed because the agency was using its ancillary authority to pursue standalone policy objectives rather than to support its exercise of a delegated power.[282] By contrast, the Commission's transmission planning reforms, including those related to Public Policy Requirements, fall within the Commission's statutorily mandated duties under the FPA, as discussed above. Thus, the Commission is not relying on ancillary authority to pursue standalone policy objectives, much less basing its actions on broad statements of Congressional policy.

213. We disagree with ELCON, AF&PA, and Associated Industrial Groups that Order No. 1000's requirements regarding Public Policy Requirements raise significant federalism issues. As a factual matter, there are significant differences between what we are requiring in Order No. 1000 and the decision in *New York* v. *U.S.,* which petitioners cite in support of their federalism argument. In that case, the Supreme Court held that the federal government could not compel states to implement a federal regulatory program.[283] That is not what is at issue here. Instead, Order No. 1000 requires that local and regional transmission planning processes consider transmission needs driven by Public Policy Requirements. This requirement is directed to public utility transmission providers, which are subject to the Commission's FPA jurisdiction, and not states. States are not required to implement any action.

214. Petitioners' federalism argument focuses more on the allocation of costs associated with transmission facilities developed in response to Public Policy Requirements that are selected in the regional transmission plan for purposes of cost allocation. But it is unclear how petitioners can reasonably make the leap from the federal commandeering of state legislatures at issue in *New York* v. *U.S.* to the requirement that costs for transmission needs driven by Public Policy Requirements be allocated pursuant to an Order No. 1000-compliant cost allocation method. As discussed below, it may or may not be the case that entities in one state benefit from a new transmission facility built in response to another state's Public Policy Requirement, in accordance with a transmission planning region's regional cost allocation method. For example, a transmission facility selected in a regional transmission plan for purposes of cost allocation that was in the first instance advanced to meet the transmission needs driven by a particular state's Public Policy Requirement may also provide reliability or economic benefits to entities located outside of that state. We do not see how a regional cost allocation method making such a finding equates with the commandeering of states by the federal government or that this is tantamount to requiring the states to implement a federal regulatory program. Rather, this simply ensures that costs are allocated to all those entities that benefit from any given transmission facility that is selected in a regional transmission plan for purposes of cost allocation, regardless of whether those benefits are reliability, economic, or related transmission needs driven by Public Policy Requirements.

215. Next, we disagree with Southern Companies that the consideration of transmission needs driven by Public Policy Requirements interferes with integrated resource planning. First, as we explain above, Order No. 1000 does not infringe on integrated resource planning. States can continue to require utilities under their jurisdiction to engage in integrated resource planning, and nothing in Order No. 1000 changes that or otherwise negates those state-level resource decisions. Second, with respect to these specific reforms, we note that this requirement is a tool for public utility transmission providers to consider transmission needs that may not be captured under existing transmission planning processes, which are focused on reliability and economic needs. If the transmission planning process does consider additional transmission needs, i.e., those driven by Public Policy Requirements, that does not mean this interferes with state-level integrated resource planning, just as those existing transmission planning processes do not interfere today.

216. We clarify that, for entities such as Bonneville Power, which may be subject to their own organic statutes and regulations, nothing in Order No. 1000's reforms regarding the consideration of transmission needs driven by Public Policy Requirements is intended to preempt those organic statutes or regulations. We believe that this should address Bonneville Power's concern.

f. Legal Issues Related to Order No. 1000's Interregional Transmission Coordination Reforms

i. Requests for Rehearing and Clarification

217. While most rehearing requests address legal issues associated with transmission planning in general, some petitioners raise legal issues specifically related to Order No. 1000's interregional transmission coordination reforms.

218. Some petitioners argue that the Commission lacks authority to require transmission providers to engage in interregional coordination.[284] Xcel, for example, argues that the Commission has not adequately explained how interregional transmission planning activities of public utilities directly affect jurisdictional rates. It asserts that under a planning process no rate is charged and no transmission customer is in privity to the transmission owner. California ISO asserts that it is not precluded from arguing that the Commission's interregional planning requirements in Order No. 1000 are beyond its authority based on the fact that it did not seek judicial review of the transmission planning provisions of Order No. 890.

219. Ad Hoc Coalition of Southeastern Utilities and Southern Companies assert that the Commission has not historically required transmission planning and coordination agreements to be filed, and argues that it is arbitrary and capricious for the Commission to determine now that such agreements are jurisdictional under section 205. They state that the Commission did not include transmission planning and coordination agreements among the type of agreements that are listed as jurisdictional in the Commission's *Prior Notice* order.[285] Ad Hoc Coalition of Southeastern Utilities adds that this is logical because the penalty for untimely filings of jurisdictional agreements, i.e., the payment of a refund to the affected customer in the form of interest on the payments received over the period that the jurisdictional agreement was not on file, would not apply to a transmission

[281] *Comcast* v. *FCC,* 600 F.3d at 654–55.

[282] *Id.* at 658–61.

[283] *New York* v. *U.S.,* 505 U.S. at 151.

[284] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; California ISO; Southern Companies; and Xcel.

[285] Ad Hoc Coalition of Southeastern Utilities at 63–64; Southern Companies at 85 (citing *Prior Notice and Filing Req'ts Under Part II of the Fed. Power Act,* 64 FERC ¶ 61,139 (1993) (*Prior Notice Order*)).

coordination planning agreement.[286] For example, because there are no rates or payments in a transmission planning or coordination agreement, it asserts that there would be no penalty, which reinforces its claim that the Commission has no jurisdiction over such agreements for purposes of section 206.

220. WIRES states that section 206 requires the Commission to indicate what measures will cure the practical and legal deficiencies in interregional planning and to order industry to make curative filings, not to ask industry to spend months in effect deciding what will satisfy the FPA. Moreover, it states that ordering regulated entities to make filings under section 205 is impermissible. It therefore contends that Order No. 1000 lacks substantial evidence for this approach and is not the result of reasoned decision-making.

221. Bonneville Power seeks clarification that the formal procedure required by Order No. 1000 to identify and jointly evaluate transmission facilities that are proposed to be located within adjacent transmission planning regions may be established in a manner that allows Bonneville Power to identify and evaluate the interregional facility in an open and transparent process in accordance with its statutory authority.[287] Alternatively, it requests rehearing of the Commission's rejection of Bonneville Power's concerns on the grounds that the Commission's decision is arbitrary and capricious and violates the Administrative Procedure Act. Bonneville Power argues that, if the requirement for a formal procedure to identify and jointly evaluate proposed interregional facilities includes details about how the facilities will be planned and developed, then the Commission effectively ignored Bonneville Power's comment without explanation. Bonneville Power asserts that the Commission's requirement, in effect, impermissibly requires non-public utilities to adhere to the FPA requirements applicable to public utilities, which it believes will have a chilling effect on non-public utility participation in regional planning process, contrary to the Commission's goal of broad-based participation. Bonneville Power also argues that the Commission lacks authority to require it to accept regulations under sections 205 and 206 as a condition of its participation in regional or interregional transmission planning.

ii. Commission Determination

222. We affirm our legal authority to undertake Order No. 1000's reforms regarding interregional transmission coordination. We disagree with Xcel that we have not explained how interregional transmission coordination is a practice affecting jurisdictional rates. Similar to our regional transmission planning reforms, the Commission found that the interregional transmission coordination reforms will help to identify transmission facilities that may be more efficient or cost-effective than what individual transmission planning regions may identify, thereby helping to ensure that jurisdictional rates for transmission service are just and reasonable and not unduly discriminatory or preferential.

223. Further, we disagree with WIRES that we cannot undertake the interregional transmission coordination reforms as set forth in Order No. 1000. Order No. 1000 requires that the public utility transmission providers in each pair of neighboring transmission planning regions, working through their regional transmission planning processes, must develop the same language to be included in each public utility transmission provider's OATT that describes the interregional transmission coordination procedures for that particular pair of regions, or alternatively, to enter into interregional coordination agreements.[288] In doing so, the Commission is allowing public utility transmission providers in the first instance to negotiate the terms of the common OATT language or agreements, so long as they meet the minimum requirements set forth in Order No. 1000. This approach is consistent with the regional flexibility provided elsewhere in Order No. 1000. WIRES offers no compelling reason that we should depart from that approach here. The Commission has taken appropriate action under FPA section 206 to undertake the interregional transmission coordination reforms. While we provide flexibility and, therefore, allow public utility transmission providers the ability to craft agreements that take into account their needs and the needs of their stakeholders, it is important to note that the Commission will review each compliance filing to ensure that they are just and reasonable and not unduly discriminatory or preferential.

224. We also disagree with Ad Hoc Coalition of Southeastern Utilities and Southern Companies that it is arbitrary and capricious to require public utility transmission providers to file interregional transmission coordination agreements. As an initial matter, as noted above, the Commission does not require that public utility transmission providers enter into interregional transmission coordination agreements to comply with Order No. 1000, though they may do so. Rather, public utility transmission providers must develop common OATT language that implements Order No. 1000's interregional transmission coordination reforms. As noted above, we find that these reforms are necessary to identify more efficient or cost-effective transmission facilities than what individual transmission planning regions may identify, thereby helping to ensure that jurisdictional rates for transmission service are just and reasonable and not unduly discriminatory or preferential. Accordingly, it follows that such common OATT language must be filed with the Commission. Furthermore, we fail to see how this is changed by the Commission allowing, as an alternative, public utility transmission providers to reflect the interregional transmission coordination procedures in an agreement filed with the Commission.

225. Moreover, whether or not such agreements were contemplated in the *Prior Notice Order,* we find that the *Prior Notice Order* does not prescribe the entire universe of filings that the Commission will require to be filed. To so limit the universe of such agreements would impede the Commission's statutory duty to ensure that the rates, terms, and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. In the *Prior Notice Order,* the Commission made an effort to bring certainty to a number of jurisdictional issues surrounding certain agreements. Among other things, the *Prior Notice Order* stated that ''the utility industry remains unclear as to whether various types of agreements need to be filed for Commission review because of the uncertain jurisdictional status of particular types of agreements.'' [289] It should be noted that the Commission did not represent that the agreements it addressed in the *Prior Notice Order* were, or would be, the only agreements that are subject to the Commission's jurisdiction.[290]

[286] Ad Hoc Coalition of Southeastern Utilities at 63 (citing generally *Prior Notice Order,* 64 FERC ¶ 61,139, App. at 11.)

[287] Bonneville Power at 32–34 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 478, 481).

[288] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 475.

[289] *Prior Notice Order,* 64 FERC ¶ 61,139 at 61,977.

[290] In the appendix to the *Prior Notice Order,* the Commission provided ''a brief analysis of the various types of agreements identified by the participants in this proceeding * * *. [T]his analysis is general in nature and is intended to be illustrative of the Commission's current thinking on

226. Ad Hoc Coalition of Southeastern Utilities overstates the *Prior Notice Order's* discussion when it contends that the *Prior Notice Order's* remedy for late-filed agreements (i.e., time-value refunds) shows the questionable jurisdictional nature of interregional transmission coordination agreements because the remedy would not apply. We stated: ''If a utility files an otherwise just and reasonable cost-based rate after the new service has commenced, we will require the utility to refund to its customers the time value of the revenues collected * * * for the entire period that the rate was collected without Commission authorization * * *. We will implement a similar remedy for the unauthorized late filing of market-based rates.'' [291] We note that this discussion focuses on rate filings (whether market-based or cost-based). However, there are other types of documents that the Commission requires to be filed that govern the terms and conditions of jurisdictional transmission service. For example, many *pro forma* OATT provisions deal with terms and conditions rather than strictly with rates. And, as discussed herein, we find that interregional transmission coordination issues have a direct and concrete impact on jurisdictional rates and, consequently, interregional transmission coordination agreements must also be filed.

227. We clarify for Bonneville Power that Order No. 1000's interregional transmission coordination reforms are not intended to preempt the statutes governing Bonneville Power. However, to the extent that any of the interregional transmission coordination efforts in which Bonneville Power participates does have the effect of interfering with Bonneville Power's statutory duties, it may bring those concerns to the Commission's attention.

g. Other Legal Issues Related to Regional Transmission Planning Requirements

i. Requests for Rehearing and Clarification

228. APPA asserts that public power systems will likely be unable to participate in regional transmission planning processes without specific assurances that their legal obligations and concerns will be accommodated in regional transmission planning processes. In particular, APPA is concerned that public power systems may lose their tax-exempt status if transmission facilities are found to be used for private activity rather than public activity. APPA argues that Order Nos. 888 and 890 acknowledged the importance of this issue by limiting a jurisdictional public utility's transmission obligations regarding facilities funded with local furnishing bonds, and that Congress limited the Commission authority to require non-jurisdictional transmission providers to provide comparable transmission service. APPA states that the Commission's expectation that non-public utility transmission providers will participate in regional transmission planning processes is at odds with the Commission's declining to provide assurance in Order No. 1000 of accommodations for their unique limitations, choosing instead to advise public power systems to advocate such accommodation on their own in these regional processes. APPA encourages the Commission to reaffirm the specific assurances provided to public power transmission providers in the past regarding the protection of their tax-exempt financing.

229. Arizona Cooperative and Southwest Transmission seek clarification that nothing in Order No. 1000 alters the rights of entities to submit section 206 complaints charging that a transmission plan submitted, accepted, or approved under Order No. 1000, or a subsequent cost allocation or cost recovery made under such a plan, establishes or contributes to a rate, charge, classification, rule, regulation, practice, or contract that is not just and reasonable or that is unduly discriminatory or preferential. Otherwise, they seek rehearing because the right to file a complaint and the applicable standard for such complaints and for a rate, charge, classification, rule, regulation, practice or contract is established by sections 205 and 206 of the FPA and cannot be abrogated by the Commission by rule or practice.

ii. Commission Determination

230. We recognize that Order No. 1000 may have been unclear as to whether public power entities, such as those represented by APPA, would be provided with the same assurances that they received in Order Nos. 888 and 890 as to whether the requirements of the rule would abrogate their tax-exempt status or cause them to violate a private activity bond rule. Order No. 1000 had focused on the consistency of reciprocity obligations in the three orders but did not specifically address the tax-exempt status of public power entities. To be clear, the assurances provided in Order Nos. 888 and 890 remain unchanged in Order No. 1000. Consistent with Order Nos. 888 and 890, nothing in Order No. 1000 is intended to abrogate the tax-exempt status of public power entities or otherwise cause such entities to violate a private activity bond rule for purposes of section 141 of title 26 of the Internal Revenue Code.

231. In response to Arizona Cooperative and Southwest Transmission, we clarify that nothing in Order No. 1000 modifies any right to file a section 206 complaint. In so clarifying, we make the following observations. We note that Order No. 1000 does not require the filing of a regional transmission plan for Commission approval. Nonetheless, entities may file a complaint regarding the implementation of the process itself. We have entertained such complaints in similar circumstances.[292] For example, a party might argue in a section 206 complaint that the public utility transmission providers in a given region did not follow their Commission-approved Order No. 1000-compliant regional transmission process in selecting facilities in their regional transmission plan for purposes of cost allocation. Of course, under section 206, the complainant bears the burden of proof to demonstrate that the process was unjust and unreasonable and that its proposed remedy is just and reasonable. We also note that a primary purpose of Order No. 1000 is to establish a Commission-approved open and transparent regional transmission planning process that includes cost allocation determinations based on a cost allocation method that is also Commission-approved.[293]

2. Regional Transmission Planning Requirements

a. Final Rule

232. Order No. 1000 required each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan that complies with seven of the nine transmission planning principles of

these subjects.'' *Prior Notice Order,* 64 FERC ¶ 61,139 at 61,989. The specific types of agreements discussed in the appendix to the *Prior Notice Order* include: (1) Contribution in aid of construction agreements; (2) Qualifying Facility agreements; (3) exchanges; (4) borderline agreements; and (5) *de minimis* agreements. *Id.* at 61,989–96.

[291] *Id.* at 61,979–80.

[292] *See, e.g., Transmission Technology Solutions, LLC and Western Grid Development, LLC* v. *California Indep. Sys. Operator Corp.,* 135 FERC ¶ 61,077 (2011) (*Transmission Technology Solutions*).

[293] *See, e.g., Transmission Technology Solutions,* 135 FERC ¶ 61,077 at P 122 (''Contrary to Complainants' arguments, CAISO submitted evidence to demonstrate that its decision-making process reflected objective analysis; was consistent with the CAISO Tariff; and was based on approving the most prudent and cost-effective long-term projects that maintain reliability for the region.'').

Order No. 890.[294] Order No. 1000 required public utility transmission providers to evaluate, through this 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 public utility transmission providers in their local transmission planning process. This could include transmission facilities needed to meet reliability requirements, address economic considerations, or meet transmission needs driven by Public Policy Requirements.[295] When evaluating the merits of such alternative transmission solutions, the Commission also directed public utility transmission providers in the transmission planning region to consider proposed non-transmission alternatives on a comparable basis.[296] In addition, Order No. 1000 provided public utility transmission providers in each transmission planning region the flexibility to develop, in consultation with stakeholders, procedures by which the public utility transmission providers in the region identify and evaluate the set of potential solutions that may meet the region's needs more efficiently or cost-effectively.

233. The Commission clarified that for purposes of Order No. 1000, a transmission planning region is one in which public utility transmission providers, in consultation with stakeholders and affected states, have joined for purposes of satisfying the requirements of Order No. 1000, including among other purposes to develop a regional transmission plan.[297] The Commission explained that the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions.[298] While the Commission declined to prescribe the geographic scope of any transmission planning region, the Commission nevertheless clarified that an individual public utility transmission provider cannot, by itself, satisfy the regional transmission planning requirements of either Order No. 890 or Order No. 1000.[299] The Commission also noted that every public utility transmission provider has already included itself in a region for purposes of complying with Order No. 890's regional participation principle, and encouraged public utility transmission providers to look to existing regional processes for guidance on compliance in formulating transmission planning regions.[300]

234. Further, Order No. 1000 declined to require merchant transmission developers to participate in a regional transmission planning process, because they assume all financial risk for developing and constructing their transmission facilities, and therefore, it is unnecessary to require such developers to participate in a regional transmission planning process for purposes of identifying the beneficiaries of their transmission facilities so that they can avail themselves of regional cost allocation.[301] However, Order No. 1000 acknowledged that a transmission facility proposed or developed by a merchant transmission developer has broader impacts than simply cost recovery. Therefore, Order No. 1000 concluded that it is necessary for a merchant transmission developer to provide adequate information and data to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region.[302]

b. Requests for Rehearing and Clarification

235. Petitioners raise a number of arguments with respect to the regional transmission planning process, which address such topics as whether public utility transmission providers were given too much flexibility, the definition of a ''transmission planning region,'' the participation of non-public utility transmission providers in regional transmission planning processes, compliance with Order No. 890 transmission planning principles, whether there needs to be a post-plan process, the role of state regulators in the regional transmission planning process, Order No. 1000's treatment of merchant transmission projects, what constitutes ''new'' transmission facilities for purposes of Order No. 1000, and other issues.

236. Some petitioners are concerned that the Order No. 1000 does not set out the regional transmission planning requirements in sufficient detail. Illinois Commerce Commission contends that the Commission erred in providing too much flexibility in the regional planning process, and that now is the time for the Commission to provide guidance to the industry that will reduce business uncertainty and increase process efficiency. WIRES urges the Commission to assist the industry with new standard procedures for regional planning, including criteria for evaluating both major backbone projects and transmission upgrades that have a relatively short planning and construction cycle and that can be adapted to fill economic or reliability needs as they arise in the ordinary course of system operations. Regarding Order No. 1000's statement that ''public utility transmission providers *explain* in their compliance filings how they will determine which facilities evaluated in their local and regional planning processes will be subject to the requirements of this Final Rule'' (emphasis added), Western Independent Transmission Group requests that transmission providers should not only simply ''explain'' how they will determine which facilities to evaluate, but also should be required to justify those determinations in their compliance filings.

237. PPL Companies are concerned with Order No. 1000's mandate to participate in a regional transmission planning process, arguing that such a mandate forces utilities in non-RTO regions to join an RTO or RTO-like process. PPL Companies claim that because this mandate may put certain entities at odds with their state commissions, the Commission should clarify that RTO membership remains voluntary, as does participation in regional transmission planning.

238. Others are concerned that Order No. 1000's regional transmission planning reforms may allow public utility transmission providers to discriminate against other entities. Transmission Access Policy Study Group claims that Order No. 1000 enhances the ability of public utility transmission providers in non-RTO regions to benefit their generation function by giving them the right to make decisions as to which upgrades go into the regional transmission plan for purposes of cost allocation, while transmission dependent utilities and non-jurisdictional entities are only offered the opportunity to provide input into the planning process. It points to the *RTG Policy Statement,* which it

[294] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 146, 151 & n.141 (the regional participation and cost allocation principles were not included because they are the subject of specific reforms in Order No. 1000).

[295] *Id.* P 148.

[296] *Id.*

[297] *Id.* P 160.

[298] *Id.* (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 527).

[299] *Id.*

[300] *Id.*

[301] *Id.* P 163.

[302] *Id.* P 164.

states provides for fair and nondiscriminatory governance and decision-making procedures and which states that transmission dependent utilities must be protected.[303] If a non-RTO region does not provide balanced decision-making, Transmission Access Policy Study Group argues that there should be consequences, such as more scrutiny with respect to transmission rates and regional cost allocation methods. PPL Companies seek clarification that the Commission will review the voting rules and structures of regional and interregional groups to ensure that the effect of such structures on small utilities is not unjust, unreasonable or unduly discriminatory.

239. Transmission Dependent Utility Systems further argue the Commission should clarify that more efficient and cost-effective solutions to the effects of loop flow are among the things to be considered in regional planning and interregional coordination processes. Transmission Dependent Utility Systems state that although Order No. 1000 discusses loop flows in the context of cost allocation, it does not address the issue in the context of regional planning or interregional coordination.

240. Several petitioners seek clarity as to what the Commission means by a ''transmission planning region.''[304] Energy Future Coalition Group asserts that the Commission must set minimum standards for defining transmission planning regions; otherwise, such regions may be defined in a way that is irrational and unworkable, thus hindering the transmission development that Order No. 1000 is meant to promote. It suggests the following: All transmission providers in the region must be within the same interconnection; participants in the region must be electrically contiguous; the region must have sufficient existing internal electricity generation and consumption to justify the planning of high voltage transmission facilities within it; and the region must be an integrated electric system for which transmission planning within the region can be accomplished consistent with engineering principles and common sense. It also suggests that the Commission specify that use of the regions approved for purposes of Attachment K coordination of transmission plans would be presumptively acceptable.

241. Ad Hoc Coalition of Southeastern Utilities commends the Commission for what it characterizes as a reaffirmation of existing regions. However, it asserts that if the Commission changes course and finds that planning regions in the Southeast are different from current regions, such a finding would be counter to Order No. 890 precedent. It also asserts that it would violate FPA section 202(a) because affected transmission owners and providers have not agreed to engage in transmission coordination based on a different configuration of a region. Southern Companies raise similar arguments, noting that it is commencing its compliance requirements with the understanding that the SERTP is an appropriate region under Order No. 1000.

242. PPL Companies state that the geographic scope requirement poses difficulties outside of an RTO. For example, they state that if Louisville Gas & Electric and Kentucky Utilities prefer to have a Kentucky-only planning group, it is unclear from Order No. 1000 whether such a region would be sufficient for regional planning purposes. PPL Companies further claim that regional transmission planning requirements raise practical concerns for entities outside of RTOs, particularly those in regions with non-public utility transmission providers, which have the discretion, not a mandate, to comply. PPL Companies thus seek clarification that a region can be comprised of a single system or single state where a broader scope is either difficult or impossible to attain.

243. MISO Northeast seeks clarification that an RTO/ISO may have more than one transmission planning region for purposes of developing regional transmission plans, noting that there are three distinct subregions in MISO. MISO Northeast states that while the Commission does not require any changes to existing regions, limiting the number of transmission planning regions in an RTO/ISO to one would have the effect of prescribing the geographic scope of a transmission planning region, which the Commission said it would not do in Order No. 1000.

244. Several petitioners take issue with Commission's statement in Order No. 1000 that, ''if a non-public utility transmission provider makes the choice to become part of the transmission planning region and it is determined by the transmission planning process to be a beneficiary of certain transmission facilities selected in the regional transmission plan for purposes of cost allocation, that non-public utility transmission provider is responsible for the costs associated with such benefits.''[305]

245. Large Public Power Council contends that unless non-public utility transmission providers vote on which proposed transmission projects should be selected in the regional transmission plan for purposes of cost allocation, the Commission should allow non-public utility transmission providers to participate in all aspects of regional transmission planning without being allocated costs pursuant to the regional cost allocation method. Large Public Power Council argues that to do otherwise will substantially disrupt existing planning processes by discouraging non-public utility transmission providers from participating out of concern that they will be allocated costs, detrimentally affecting system efficiency, cost, and reliability.

246. MEAG Power contends that it would be problematic for it to enter into an open-ended commitment to pay costs that are allocated per a regional plan before the regional planning and cost allocation protocols have been developed and determined. Moreover, MEAG Power states that this will deter it from continuing to participate in the current SERTP planning effort on a voluntary basis if in doing so it would be bound to an unknown amount of allocated transmission costs. MEAG Power requests clarification that its choice to continue to participate in SERTP does not bind it to a cost allocation result under Order No. 1000 Otherwise, it states it will be compelled by its Board's policy to withdraw from SERTP as well as SIRPP before the provisions of Order No. 1000 take full effect.

247. Transmission Dependent Utility Systems request that the Commission clarify or grant rehearing to specify that those stakeholders who have not meaningfully participated in the regional planning or interregional coordination, the development of regional and interregional cost allocation methods, or in the determination of beneficiaries, will have no costs for such projects allocated to them. Transmission Dependent Utility Systems argue this clarification will ensure participation of load-serving customers and is consistent with Cost Allocation Principle 2.

248. Sacramento Municipal Utility District states that it participates in both

[303] Transmission Access Policy Study Group at 9 (citing *RTG Policy Statement,* 58 Fed. Reg. 41,626 (Aug. 5, 1993), FERC Stats. & Regs. ¶ 30,976 (1993); *Southwest Regional Transmission Ass'n,* 69 FERC ¶ 61,100, at 61,400–02 (1994); *PacifiCorp,* 69 FERC ¶ 61,099, at 61,382, n.70 (1994)).

[304] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Energy Future Coalition Group; MISO Northeast; PPL Companies; and Southern Companies.

[305] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 629.

the California Transmission Planning Group and the WestConnect planning processes, but would have little incentive to participate in either if doing so would expose it to costs for transmission over which it does not take any service and could result in duplicative charges.

249. Bonneville Power seeks clarification that it may independently decide, using an open and transparent process consistent with its statutory authorities, whether it will receive the benefits of, and pay for, a transmission project. It requests clarification that the regional planning process determination would not be binding on it, but that, instead, it and transmission developers could use the cost allocation analysis as input to their negotiations and other required statutory processes. Bonneville Power argues that this clarification is appropriate because its governing statutes do not permit it to participate in mandatory cost allocation, explaining that its Administrator must determine its cost allocation responsibilities and cannot delegate them to the regional planning process.[306] Bonneville Power argues that it also must retain the right to determine whether or not to commit funds to a project until conclusion of a review of a project under the National Environmental Policy Act. In the alternative, Bonneville Power requests rehearing, arguing that the Commission failed to adequately consider and address its comments addressing Bonneville Power's statutory authorities related to mandatory cost allocation.

250. With respect to Order No. 1000's discussion of compliance with Order No. 890 transmission planning principles and related issues, Ad Hoc Coalition of Southeastern Utilities argues that the Southeast transmission planning regions already comply with Order No. 890's planning principles. Ad Hoc Coalition of Southeastern Utilities asserts that Order No. 890 and the subsequent compliance orders make it clear that the nine planning principles apply to regional planning processes. However, it asserts that certain statements in Order No. 1000, such as the statement that some regions are not exchanging sufficient data, imply that all or some of the nine planning principles do not apply under Order No. 890 to the existing regional planning processes.[307] If the Commission assumes or concludes that utilities in the Southeast are not exchanging sufficient information, then Ad Hoc Coalition of Southeastern Utilities contends that such an assumption or conclusion would be in error and not supported by substantial evidence.

251. With regard to the openness and transparency transmission planning principles, Transmission Dependent Utility Systems want the Commission to clarify that information cannot be withheld from load-serving entities based on common rationales offered by transmission owners, such as claims of discrimination against non-load-serving entity customers, violation of tariff confidentiality provisions, or violation of the Commission's Standards of Conduct. They argue that if these concerns are legitimate, they can be adequately addressed by confidentiality agreements or through other appropriate means. Transmission Dependent Utility Systems also want the Commission to confirm that such disclosure will not be deemed a violation of the Standards of Conduct.

252. With respect to the requirement that public utility transmission providers develop a regional transmission plan, Illinois Commerce Commission argues that the Commission erred in not requiring each transmission provider to file its regional transmission plan (as well as associated cost allocations), contending that the regional and interregional stakeholder processes that Order No. 1000 requires are not sufficient to ensure notice to the public and an opportunity to be heard. Illinois Commerce Commission states that the failure to establish a process for Commission review of regional transmission plans and associated cost allocations burdens ratepayers and exacerbates the problem associated with delegating authority to transmission providers.[308]

253. Transmission Access Policy Study Group argues that Order No. 1000 should have required a timely post-plan process to ensure that the plan is acted upon, and argues that if a transmission developer has made a commitment to construct facilities, then it should not have the option to abandon the project, thus leaving others that counted on the upgrade responsible for the costs. It contends that the steps Order No. 1000 did take, such as Web site posting requirements and the reliability protections addressed in the context of Order No. 1000's nonincumbent reforms, are inadequate. Additionally, Transmission Access Policy Study Group argues that Order No. 1000 should have made clear that the Web site posting requirement it did require must be made on a timely basis, such as a specified time after the regional transmission plan is posted.

254. Some state regulators raise concerns about the role they are intended to play in the regional transmission planning process.[309] NARUC argues that, while prior Commission orders and the DOE-funded interconnectionwide planning processes properly recognize the essential role of state regulators, Order No. 1000 improperly lumps state regulators with all other stakeholders. Illinois Commerce Commission also points out that Order No. 1000 does not require transmission providers to establish any unique role or provide any special weight in the process for state regulators. Wisconsin PSC asserts that there is no rational basis for the casual and undefined potential role that Order No. 1000 implies that states would have in the regional and interregional transmission planning processes. It asserts that states and state commissions are different from other stakeholders in materially important ways, such as their authority to authorize utilities to build and the ability to collect an allocated share of the cost of transmission facilities. It also claims that this treatment of the states is at odds with Order No. 890's express emphasis that ''planning must be coordinated with state regulators * * *''.[310] Given this, Wisconsin PSC suggests the following changes to help enhance state participation: (1) More focus on reducing planning delays in a project's preconstruction phase by coordinating with state regulators; (2) minimizing overlap between state and regional transmission planning procedures relative to evaluation of project need or sponsor qualification; and (3) where feasible, required compliance with applicable state laws by a transmission developer before any transmission line is selected for eligibility for regional cost sharing. North Carolina Agencies state that the Commission should recognize the unique and indispensible role that state regulatory authorities play, rather than demoting them to one of many stakeholders, as suggested in Order No. 1000.

255. Further, Illinois Commerce Commission contends that the

[306] Bonneville Power at 13–15 (citing Northwest Power Act, 16 U.S.C. § 839f(b) (2006); Transmission System Act, 16 U.S.C. § 838b (2006); *Pacific Northwest Generating Coop.* v. *DOE, Bonneville Power Admin.*, 580 F.3d 792, 823 (9th Cir. 2009)).

[307] Ad Hoc Coalition of Southeastern Utilities at 48 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 151–52).

[308] As noted above, Illinois Commerce Commission also believes that Order No. 1000 provides too much flexibility to transmission providers.

[309] *See, e.g.*, NARUC; Florida PSC; Illinois Commerce Commission; and Wisconsin PSC.

[310] Wisconsin PSC at 9 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574 (2007)).

Commission failed to recognize that state regulators may be limited in their ability to actively engage in transmission planning processes given the prohibition against pre-judging cases that may subsequently come before them for siting, certification, or rate recovery. Illinois Commerce Commission suggests that Commission attendance in a meeting of the states to discuss this issue may be useful to reconcile the Commission's expectations and the practical realities borne by state regulators in this regard.

256. Florida PSC states that it is unclear how the Order No. 1000 transmission planning process overlay will interact and coexist with existing planning processes. Florida PSC also asserts that participating in the planning processes and monitoring neighboring interregional agreements would require additional state commission resources during a time of constrained state budgets. Illinois Commerce Commission likewise contends that the level of participation the Commission is encouraging is beyond most states' current capabilities. It states that the Commission must go beyond Order No. 890 initiatives to facilitate enhanced participation by state authorities in regional and interregional planning processes. Illinois Commerce Commission also seeks clarification that, where regional state committees have been formed, it will be that committee (with Commission review) that decides on its budget for participation in the planning process, and such budget shall not be subject to veto by the transmission provider or any stakeholder group.

257. Some petitioners seek rehearing or clarification of Order No. 1000's discussion of the role of merchant transmission developers in the regional transmission planning process.[311] APPA asks that the Commission reconsider its decision to allow merchant developers merely to provide information to transmission planners and instead require merchant transmission developers to participate fully in regional and interregional transmission planning processes. APPA argues that requiring such developers to participate in regional and interregional planning processes will give transmission planners the opportunity to evaluate all projects side-by-side and then develop the set of projects that will best serve the needs of all loads in a region, while presenting the best economics and minimizing adverse impacts on the environment.

258. National Rural Electric Coops seek clarification that Order No. 1000 does not create a special class of public utilities, i.e., merchant transmission developers, who are excused from obligations imposed on other public utility transmission providers. National Rural Electric Coops argue that the creation of a preferred class distinguished solely by their method of cost recovery does not square with the purpose of Order No. 1000 to ensure that all public utility transmission providers be treated comparably in the transmission planning process. They contend that the method of cost recovery is not a valid reason for excusing public utility merchant developers from the regional planning requirements generally applicable to public utility transmission providers.

259. Transmission Dependent Utility Systems seek rehearing of the determination that merchant transmission developers may opt out of participation in regional transmission planning processes if they assume all financial risk. Transmission Dependent Utility Systems argue that financial arrangements have no bearing on the ability of affected load-serving entities to reliably and economically serve their native loads, that the failure to mandate merchant participation in regional transmission planning therefore conflicts with FPA section 217(b)(4), and that the internalization of risk by a merchant developer cannot justify excusing it from compliance with other planning obligations. They add that requiring merchant developers only to share information with public utility transmission providers fails to ensure that load-serving transmission customers will be able to obtain information about proposed merchant projects, evaluate their effects, and provide input regarding their development. Transmission Dependent Utility Systems seek clarification that if a merchant developer does not fully participate in a regional transmission planning process, it should be obligated to internalize the costs of any adverse reliability effects on the grid posed by its project or any need for upgrades caused by a change in flows, adding that the failure to require merchant developers to internalize all related costs of their transmission projects would violate cost causation principles by forcing transmission customers to pay for the costs of upgrades caused, but not paid for, by merchant transmission developers.

260. Petitioners raise concerns about Order No. 1000's conclusion that public utility transmission providers could apply flexible criteria when determining which transmission projects are in the regional transmission plan. PSEG Companies argue that the Commission introduced vague criteria into the planning process that will result in an opaque and confusing, rather than a formulaic, approach.[312] They claim that an opaque approach will allow transmission providers to unofficially represent policymaking bodies and impose their costs on customers, who must pay for unneeded projects.

261. Finally, some petitioners request guidance on what constitutes a ''new'' transmission facility for purposes of Order No. 1000. Western Independent Transmission Group seeks clarification of the Commission's statement that Order No. 1000 applies to new transmission facilities. It states that Order No. 1000 does not provide sufficient guidance as to how transmission providers should define evaluation and reevaluation for purposes of determining what facilities are subject to Order No. 1000. It contends that, in the absence of Commission guidance, transmission providers will have excessive discretion to determine which facilities are subject to Order No. 1000. Western Independent Transmission Group seeks clarification regarding the extent of transmission planning entities' discretion and Commission guidance as to how such discretion should be exercised without restricting independent developers' access to the grid.

262. LS Power requests that the Commission clarify that all projects that are approved on or after the compliance date shall be subject to Order No. 1000, regardless of the status of the planning cycle. It explains that such a requirement would not burden the regional planning process as the transmission planning entity has ample warning regarding the requirement and can tailor its planning process to incorporate Order No. 1000 for all projects not yet approved as of the compliance date.

c. Commission Determination

263. Order No. 1000's regional transmission planning reforms are intended to ensure that there is an open and transparent regional transmission planning process that complies with Order No. 890's transmission planning principles and produces a regional transmission plan. There, we stated that

[311] *See, e.g.,* APPA; National Rural Electric Coops; and Transmission Dependent Utility Systems.

[312] PSEG Companies at 50 (citing *PJM Interconnection, L.L.C.,* 119 FERC ¶ 61,265 at P 24 (2007) (directing PJM to file a formulaic approach with respect to planning for economic transmission projects)).

such transmission planning will expand opportunities for more efficient and cost-effective transmission solutions for public utility transmission providers and stakeholders, which, in turn, will help ensure that the rates, terms, and conditions of Commission-jurisdictional services are just and reasonable and not unduly discriminatory or preferential.[313]

264. For the most part, petitioners do not argue against the soundness of Order No. 1000's basic regional transmission planning requirements although, as discussed above, some petitioners question the need for these reforms as applied to their specific regions of the country,[314] while some assert that the Commission lacks the legal authority to undertake these reforms, as discussed earlier in this section.[315] However, most of the petitioners' requests as to the actual regional transmission planning requirements go to specific issues, such as the flexibility afforded in Order No. 1000 to public utility transmission providers, the definition of a transmission planning region, the participation of non-public utilities and the role of state regulators in the regional transmission planning process, compliance with certain transmission planning principles, the treatment of merchant transmission developers, and the definition of ''new'' transmission facilities under Order No. 1000.

265. In this section, we affirm Order No. 1000's regional transmission planning reforms. We also provide clarifications on many of the issues raised by petitioners, including an issue that generated a number of requests for rehearing and clarification, namely, the participation of non-public utility transmission providers in the regional transmission planning process. We believe the discussion herein will assist public utility transmission providers, in consultation with stakeholders, in developing their Order No. 1000 compliance filings by providing more clarity as to what the Commission's requirements are with respect to Order No. 1000's regional transmission planning reforms.

266. Some petitioners, such as Illinois Commerce Commission, assert that Order No. 1000's regional transmission planning reforms provide too much flexibility to public utility transmission providers. We disagree. Rather, we believe that Order No. 1000 sets forth an approach that balances the need to ensure that specified regional transmission planning requirements are satisfied with our belief that the various regions of the country differ significantly in resources, industry organization, market design, and other ways so that a one-size-fits-all approach to regional transmission planning would not be appropriate. Specifically, Order No. 1000 requires public utility transmission providers to develop a regional transmission planning process that complies with the Order No. 890 transmission planning principles and that produces a regional transmission plan. Within these parameters, public utility transmission providers, in consultation with stakeholders, have the flexibility to ensure that their respective regional transmission planning process is designed to accommodate the unique needs of that particular region. We will then evaluate each of the Order No. 1000 compliance filings to ensure that they satisfy these requirements.

267. For the same reasons, we decline to adopt standard procedures in the regional transmission planning process for evaluating backbone transmission facilities or for addressing transmission upgrades that have a short planning and construction cycle and that can be adapted to fill economic or reliability needs as they arise in the ordinary course of system operations, as suggested by WIRES. As the Commission found in Order No. 1000, each public utility transmission provider is required to amend its OATT to describe 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. This process must comply with the Order No. 890 transmission planning principles, ensuring transparency and the opportunity for meaningful stakeholder input. The evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected in the regional transmission plan for purposes of cost allocation.[316] Accordingly, we do not find that standardized procedures such as those suggested by WIRES are necessary or appropriate. Moreover, by requiring an open and transparent transmission planning process that produces a regional transmission plan, Order No. 1000 will provide the Commission and interested parties with a record that we believe will be able to highlight whether public utility transmission providers are engaging in undue discrimination against others, such as transmission-dependent utilities and non-jurisdictional entities.

268. As discussed in greater detail in the section of Order No. 1000 addressing nonincumbent reforms,[317] we agree with Western Independent Transmission Group that public utility transmission providers should both explain and justify the nondiscriminatory evaluation process proposed in their compliance filings. Additionally, Commission review and approval of a not unduly discriminatory evaluation process will address Transmission Access Policy Study Group's concern that Order No. 1000's regional transmission planning reforms may empower public utility transmission providers at the expense of other stakeholders, as well as its concern that the regional transmission planning governance process should be fair and not unduly discriminatory for all participants, including transmission dependent utilities.

269. PPL Companies assumes that a region will have formal voting rules and structures to carry out these evaluations and decide which proposed new transmission facilities are in the regional transmission plan and selected for cost allocation, and it requests that we review the voting rules and structures of each region's transmission planning process to ensure that they do not disadvantage smaller utilities. While Order No. 1000 does not necessarily require formal voting rules, we will review any rules submitted to ensure that they are fair to all participants. More important, we believe that adherence to the seven Order No. 890 transmission planning principles, as adopted in Order No. 1000, will ensure fair treatment of all regional planning participants, and we will review the process in every compliance filing, whether or not it has formal voting rules and stakeholder governance structure, for compliance with the transmission planning principles for (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, and (7) economic planning. If public utility transmission providers in a transmission planning region, in consultation with stakeholders, decide to establish formal stakeholder governance procedures, such as voting measures, they should include these in their Order No. 1000 compliance filings.

270. We agree with PPL Companies that RTO membership is and remains voluntary. However, regional

[313] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 146.

[314] *See* discussion *supra* at section II.B.

[315] *See* discussion *supra* at section III.A.

[316] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 328.

[317] *See id.* at section III.B.3.

transmission planning under Order No. 1000 is not voluntary for public utility transmission providers.[318] We disagree that by mandating a regional transmission planning process we are forcing utilities in non-RTO areas to join an RTO-like organization. The transmission planning function of Order No. 1000 is but one of nine essential characteristics and functions of an RTO under Order No. 2000, which include having an independent grid operator for the entire region, among other operating functions. Here, Order No. 1000's transmission planning requirements involve the consideration of whether more efficient or cost-effective alternatives to solutions identified in individual local transmission plans exist and whether they will be selected in a regional transmission plan for purposes of cost allocation. As discussed in Order No. 1000 and here, we find that such transmission planning activities are wholly within the Commission's statutory authority, and that such reforms are necessary to implement at this time.

271. In response to Transmission Dependent Utility Systems, we do not believe that it is necessary that we require that the regional transmission planning process and interregional transmission coordination procedures specifically address loop flows. We believe that such concerns will necessarily be evaluated by the public utility transmission providers in the regional transmission planning process as they plan for the region's reliability and economic needs, as well as the transmission needs driven by Public Policy Requirements. Likewise, if loop flow affects more than one transmission planning region, these issues may be addressed as part of Order No. 1000's interregional transmission coordination.

272. With respect to questions from some petitioners concerning transmission planning regions,[319] we affirm Order No. 1000's determination that ''the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions.'' [320] We also affirm Order No. 1000's determination that the Commission will not prescribe the size or scope of a transmission planning region in a generic proceeding except to provide that a single public utility transmission provider by itself may not be a transmission planning region, consistent with Order No. 890.[321] We find that Order No. 1000 appropriately provided flexibility in this regard, and that this flexibility will permit public utility transmission providers and others the opportunity to form or join a transmission planning region that best meets their needs and the needs of their transmission customers.

273. In response to Southern Companies and Ad Hoc Coalition of Southeastern Utilities, we reiterate that public utility transmission providers may look to the transmission planning regions that were accepted by the Commission in the Order No. 890 compliance phase in forming a transmission planning region for purposes of Order No. 1000.

274. We appreciate petitioners' concerns about Order No. 1000's expectations regarding the participation of non-public utility transmission providers in the regional transmission planning process. After reviewing the requests for rehearing and clarification on this topic, we provide additional clarifications to the discussion in Order No. 1000 regarding the participation of non-public utility transmission providers in the regional transmission planning process.

275. As discussed more fully below, public utility transmission providers in each transmission planning region must have a clear enrollment process that defines how entities, including non-public utility transmission providers, make the choice to become part of the transmission planning region.[322] In addition, each public utility transmission provider (or regional transmission planning entity acting for all of the public utility transmission providers in its transmission planning region) must include in its OATT a list of all the public utility and non-public utility transmission providers that have enrolled as transmission providers in its transmission planning region. A non-public utility transmission provider that makes the choice to become part of a transmission planning region by enrolling in that region would be subject to the regional and interregional cost allocation methods for that region.[323] Any non-public utility transmission providers that do not make the choice to become part of the transmission planning region will nevertheless be permitted to act as stakeholders in the regional transmission planning process.[324] In sum, we believe that the requirement to have a clear enrollment process for transmission providers in a transmission planning region, including non-public utility transmission providers that make the choice to join that region, along with the maintenance of a list of such enrollees, provides certainty regarding who is enrolled in a region and therefore who is a potential beneficiary that may be allocated costs.

276. In response to petitioners such as MEAG Power, we clarify that participation in the development of the regional transmission planning process and regional cost allocation method that a public utility transmission provider will submit to the Commission to comply with Order No. 1000 does not obligate a non-public utility transmission provider to choose to join the transmission planning region by enrolling and thus be eligible to be allocated costs under its regional cost allocation method. As such, a non-public utility transmission provider will not be considered to have made the choice to join a transmission planning region and thus eligible for cost allocation until it has enrolled in the transmission planning region. However, the regional transmission planning process is not required to plan for the transmission needs of such a non-public utility transmission provider that has not made the choice to join a transmission planning region. If the non-public utility transmission provider is a customer of a public utility transmission provider in the region, that public utility transmission provider must plan for that customer's needs as it would for the needs of any customer. That non-public utility transmission provider's ability to participate as a stakeholder in the regional transmission planning process should be the same as

[318] We address PPL Companies' legal arguments regarding mandatory transmission planning requirements above. *See* discussion *supra* at section III.A.1.

[319] *See, e.g.,* PPL Companies; MISO Northeast; and Energy Future Coalition Group.

[320] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 160 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 527).

[321] *Id.*

[322] While Order No. 1000 did not address issues relating to stakeholder procedures, we note that those that make the choice to become part of a transmission planning region could be provided with voting rights upon enrollment if the regional transmission planning process has a voting mechanism for selecting transmission projects in the regional transmission plan for purposes of cost allocation. *See, e.g.,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 252 (stating that ''[w]ithin an RTO or ISO, stakeholder processes can be used to determine whether to pursue either economic or reliability upgrades and, thus, voting mechanisms such as those suggested by PSEG could be adopted if stakeholders desire.'').

[323] We note that many of the issues raised by petitioners that are addressed in this part of the order also implicate reciprocity issues. Requests for rehearing and clarification regarding Order No. 1000's conclusions regarding reciprocity are addressed in section V.B, *infra.*

[324] The term ''stakeholder'' is intended to include any party interested in the regional transmission planning process. *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at n.143.

for any other similarly situated stakeholder customer.

277. While we acknowledge concerns raised by petitioners such as MEAG Power and Large Public Power Council about how non-public utility transmission providers make the choice to join a transmission planning region, we conclude that these concerns are best addressed in the first instance through participation in the development of the regional transmission planning process and cost allocation method that its neighboring public utility transmission provider(s) will rely on to comply with Order No. 1000. Each non-public utility transmission provider may decide whether or not to enroll in the region as a transmission provider as such development nears completion. Participation in the development of regional processes will not in itself make the participant subject to regional cost, absent enrollment. We encourage MEAG Power and other non-public utility transmission providers to raise their concerns with all participants in the development of the regional transmission planning process and cost allocation method as they are developing the compliance filings.[325] If non-public utility transmission providers believe that their concerns have not been adequately addressed, they may raise their concerns when the neighboring public utility transmission providers in the region submit their compliance filing to the Commission.

278. We decline to adopt Large Public Power Council's suggestion that there either be voting mechanisms in place or allow non-public utility transmission providers to participate in all aspects of regional transmission planning without being allocated costs pursuant to the regional cost allocation method. The enrollment process that we are requiring here should address these concerns in part. Additionally, as noted above, non-public utilities—including non-public utility transmission providers that also are load-serving entities or have other stakeholder interest in the regional transmission system—can still participate as stakeholders in the regional transmission planning process, even if they do not enroll in the regional transmission planning process. As stakeholders, non-public utility transmission providers will have an opportunity to express their views and concerns as part of the process.

279. We clarify for Bonneville Power that the Commission in Order No. 1000 did not require it, or any other non-public utility transmission provider, to enroll or otherwise participate in a regional transmission planning process. As discussed above, it will be Bonneville Power's decision whether or not to enroll as a transmission provider in a transmission planning region and become subject to that region's cost allocation method. Additionally, with respect to Bonneville Power's concerns regarding its perceived conflict between its statutory authorities and Order No. 1000's cost allocation requirements, we believe that any such perceived conflict is best addressed in the first instance through participation in the development of the regional transmission planning process and cost allocation method that its neighboring public utilities will rely on to comply with Order No. 1000.

280. We reaffirm Order No. 1000's statement that many public utility transmission providers may need to make only modest changes to their regional transmission planning processes to comply with Order No. 1000.[326] Thus, if public utility transmission providers believe that the regional transmission planning process in which they participate already complies with the Order No. 890 transmission planning principles, such as Ad Hoc Coalition of Southeastern Utilities' statement that existing regional processes in the Southeast are in compliance with the data exchange transmission planning principle, they should make the case for such assertions in their Order No. 1000 compliance filings.

281. In response to Transmission Dependent Utility Systems, we reiterate our determination in Order No. 890 that public utility transmission providers should provide sufficient information to ''enable customers, other stakeholders, or an independent third party to replicate the results of planning studies and thereby reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion.'' [327] Thus, as we stated in Order No. 890 and subsequent orders on compliance, public utility transmission providers should provide the basic methodology, criteria, and processes used to develop transmission plans sufficient for stakeholders to be able to replicate its transmission plans, and describe the methods it will use to disclose the criteria, data, and assumptions that underlie its transmission system plans. The information should be of sufficient detail to allow a customer to replicate the results of the planning studies.[328] Additionally, in discussing the openness principle in Order No. 890, the Commission required that ''transmission providers, in consultation with affected parties, develop mechanisms, such as confidentiality agreements and password-protected access to information, in order to manage confidentiality and CEII concerns.'' [329] Subject to our review of public utility transmission providers' compliance filings, we believe that these basic requirements should permit stakeholders to access and review information that is relevant to transmission planning, while at the same time protecting information that is commercially sensitive or that is otherwise considered confidential under Commission regulations.[330]

282. Regarding Transmission Dependent Utility Systems' request that the Commission confirm that information disclosure will not be deemed a violation of the Standards of Conduct, we reiterate our determinations on the transparency principle in Order No. 890, where we addressed similar concerns about the Standards of Conduct. There, we stated that the ''simultaneous disclosure of transmission planning information can alleviate * * * Standards of Conduct

[325] *See, e.g.,* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 117 (''[N]on-jurisdictional entities, unlike public utilities, may choose to join a regional transmission planning process and, to the extent they choose to do so, they may advocate for those processes to accommodate their unique limitations and requirements.'').

[326] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at n.142 (''[E]xisting regional transmission planning processes that many utilities relied upon to comply with the requirements of Order No. 890 may require only modest changes to fully comply with these Final Rule requirements.'').

[327] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 471.

[328] *Id.*

[329] *Id.* P 460.

[330] The Commission has addressed the issue of access to confidential material in Order No. 890 compliance proceedings. In *Entergy Services, Inc.,* 130 FERC ¶ 61,264, at PP 55–57 (2010), for example, the Commission accepted compliance revisions proposed by the Entergy Services, Inc. (Entergy) that would permit stakeholders to be certified to obtain CEII material by following certain procedures located on Entergy's Web site and the SIRPP Web site. Further, the Commission accepted revisions that allowed stakeholders to have access to resource-specific information if it was provided in the SIRPP and was needed to participate in the SIRPP or to replicate interregional studies. The Commission also found acceptable provisions regarding processing requests for CEII data. The Commission found that while Entergy and transmission owners had broad discretion over this process, as some protestors argued, that discretion was not unbounded because Entergy, its Independent Coordinator of Transmission, and transmission owners would develop procedures to review requests for access to CEII data, and protestors could thus raise concerns during that development process. The Commission noted that any party denied access to information could raise objections through the dispute resolution process.

concerns.'' [331] Further, Order No. 890 stated that ''transmission providers should make as much transmission planning information publicly available as possible, consistent with protecting the confidentiality of customer information,'' noting that it will be necessary for market participants ''to have access to basic transmission planning information'' to consider future resource options.[332] These principles apply to the Order No. 1000 regional transmission planning process. To the extent that an interested party believes that necessary information is being unreasonably withheld for unduly discriminatory purposes, we will review on a case-by-case basis.

283. With respect to questions about Order No. 1000's discussion as to whether public utility transmission providers can use flexible criteria or bright-line metrics when determining which transmission facilities are in the regional transmission plan, we affirm that public utility transmission providers, in consultation with stakeholders, may apply either flexible criteria or bright-line metrics. As we explained in Order No. 1000, the comments in the record indicated that flexible criteria may be more appropriate than the bright-line metrics we had previously required in one earlier decision.[333] We leave it to public utility transmission providers, in consultation with stakeholders, in each transmission planning region to determine what type of criteria they will use, consistent with Order No. 1000's overarching goal of providing flexibility to meet regional needs. Thus, we clarify that we were not necessarily endorsing flexible criteria over bright-line criteria.

284. However, we reject PSEG Companies' argument that, by making this decision, the Commission will introduce opaqueness and confusion into the transmission planning process and that it will allow public utility transmission providers to unofficially represent policymaking bodies. We continue to find that there is merit in using a flexible approach because it may capture certain transmission projects that might be unnecessarily excluded with a bright-line approach. We believe that this approach is reasonable, particularly in light of the many comments that were supportive of a flexible approach. And, again, we are not mandating such an approach, and proponents of bright-line metrics can advocate for use of those metrics during the compliance process. We also find PSEG Companies' argument that this approach would allow public utility transmission providers to unofficially represent policymaking bodies to be speculative and unsupported. We therefore reject that argument. However, if PSEG Companies believe that, in a specific case, that is the case, it may file a complaint under section 206.

285. In response to Illinois Commerce Commission, we decline to establish a generic requirement in Order No. 1000 for the filing of regional transmission plans with the Commission. We believe doing so is unnecessary given the requirements of Order No. 1000, which requires public utility transmission providers to participate in a regional transmission planning process that produces a regional transmission plan and complies with Order No. 890 transmission planning principles.[334] We will evaluate compliance filings to ensure that public utility transmission providers satisfy these requirements, but we do not see a need to mandate the additional requirement of filing regional transmission plans that result from the regional transmission planning process. Our concern is with ensuring that there is an open and transparent regional transmission planning process. We are not dictating substantive outcomes of that process.[335]

286. Similarly, we do not require under Order No. 1000 that public utility transmission providers file with the Commission associated cost allocation determinations. Again, we believe that this is unnecessary under Order No. 1000. There, the Commission required public utility transmission providers to have an *ex ante* cost allocation method on file with and approved by the Commission.[336] This cost allocation method is required to explain how the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation are to be allocated, consistent with the cost allocation principles set forth in Order No. 1000. Customers, stakeholders, and others have ''notice'' at the time the compliance filings are made, when the Commission acts on those filings, and as the open and transparent regional transmission planning process results in the selection of a transmission facility in the regional transmission plan for purposes of cost allocation. However, consistent with the regional flexibility provided in Order No. 1000, public utility transmission providers, in consultation with stakeholders, may propose OATT revisions requiring the submission of cost allocations in their Order No. 1000 compliance filings.

287. Moreover, we disagree with Illinois Commerce Commission that the Commission is delegating authority to public utility transmission providers. As discussed above, the Commission will evaluate compliance filings to ensure that they comply with Order No. 1000 and both stakeholders and the Commission have the right to initiate actions under section 206 of the FPA if they believe that, for example, a Commission-approved regional transmission planning process was not followed or if a cost allocation method was not followed or produced unjust and unreasonable results for a particular new transmission facility or class of new transmission facilities.

288. We deny Transmission Access Policy Study Group's request for a post-plan process to ensure transmission facilities are actually constructed. As we explained in Order No. 1000, the package of transmission planning and cost allocation reforms adopted is designed to increase the likelihood that transmission facilities in regional transmission plans will move from the planning stage to construction. Additionally, as acknowledged by Transmission Access Policy Study Group, a public utility transmission provider already is required to make available information regarding the status of transmission upgrades identified in transmission plans, including posting appropriate status information on its Web site.[337] To the extent that an entity has undertaken a commitment to build a transmission facility in a regional transmission plan, that information should be included in such a posting.[338] We continue to believe that this obligation, together with the other reforms found in Order No. 1000, is adequate without placing further obligations on public utility transmission providers.

289. Moreover, we are providing public utility transmission providers, in consultation with stakeholders, the flexibility to design a regional transmission planning process that meets regional needs. As part of the stakeholder process to develop the regional transmission planning processes in compliance with Order No. 1000, concerned stakeholders have the ability to participate and seek changes to those individual processes, subject to Commission review on compliance.

[331] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 476 & n.270.

[332] *Id.* P 476.

[333] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 223 (citing *PJM Interconnection, L.L.C.,* 119 FERC ¶ 61,265 (2007)).

[334] *Id.* P 146.

[335] *Id.* P 113.

[336] *Id.* PP 499–500.

[337] *Id.* P 159 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 472).

[338] *Id.* P 159 & n.155.

Additionally, we decline to prescribe specific timing parameters for the Web site posting requirement that we directed in Order No. 1000.[339] Again, if stakeholders would like to see such timing requirements as part of the Web site postings, they may seek to do so as part of the compliance process. However, the Web site postings should provide the information we require in a complete and transparent manner so that it will be fully accessible and useful to interested stakeholders such that they can see the status of various transmission facilities included in the regional transmission plan.

290. Regarding concerns about the role of state utility regulators in the regional transmission planning process, we support states' efforts to take an active role in the regional transmission planning process and encourage proposals that seek to establish a formal role for state commissions in the regional transmission planning process as well as proposals to establish cost recovery for state regulators' participation. However, for the reasons noted below, we will not require one formal method for how states will participate in the process.

291. We recognize that state utility regulators play an important and unique role in transmission planning processes, given that the states often have authority over transmission, permitting, siting, and construction, and that many state regulatory commissions require utilities to engage in integrated resource planning. We also expect that state utility regulators will play an active role in working with public utility transmission providers and other stakeholders in the Order No. 1000 compliant regional transmission planning processes.

292. That being said, the Commission finds that it would be premature in a generic proceeding to mandate any particular role for state regulators in regional transmission planning processes. Instead, we believe the best place for a state to determine the role it is to play is in the Order No. 1000 compliance process that will develop a regional transmission planning process that will be filed for Commission review. This is appropriate because individual states can be the best advocates for the role they wish to take in that process. For example, in large, multistate regions, states may seek to join a committee of state regulators that, in their view, may be a more effective vehicle for collective action than any single state could do individually. On the other hand, some states may feel that its best to have a more independent role if, for example, they believe that joining a formalized committee of state regulators may dilute their ability to participate in the regional transmission planning process. Some states may have a stronger interest in transmission planning issues than others.

293. We understand and appreciate the concerns expressed by NARUC and others that Order No. 1000 may appear to lump state utility regulators with all other stakeholders. That was not the Commission's intent. We understand that state regulators play a crucial role in transmission planning and that the role of state regulators is unique and distinctly different from the roles played by other stakeholders in transmission planning. We agree with Wisconsin PSC that the differences between state utility regulators and other stakeholders may well lead to a regional transmission planning process to treat state utility regulators differently than other stakeholders. However, for the reasons discussed next, we decline to adopt the various suggestions made by Wisconsin PSC and others to establish the same formal state commission role in every transmission planning region through a generic rulemaking proceeding, although all the regions are free to use the same formal process for state participation if they choose to do so. With respect to Illinois Commerce Commission's specific concerns about the roles state regulators might be allowed to play consistent with state law, we encourage it and other state regulators to raise such concerns during the compliance process.

294. We are aware of the wide range of views expressed by state utility commissions and others, both in rehearing petitions and previously in comments on the Proposed Rule, regarding the appropriate role of the states in regional transmission planning. Some state commissions argue for a strong role in shaping regional transmission plans, while others are concerned that their states' laws limit their ability to participate in forming plans that may come before them in regulatory proceedings. Respecting this range of views the Commission believes that each state commission, or the state commissions collectively in a region, is in the best position, in the first instance and in consultation with the transmission providers subject to their jurisdiction, to define the appropriate role for the state commissions in a particular region. This role will take into account the authorities and restrictions conferred by their own states' statutes and their own policy preferences. Thus, the Commission believes it would be inappropriate for us to define the role of all state commissions in every regional transmission planning process in a single generic proceeding, both because a state commission's authority and responsibility is established by its own state's laws—not by this Commission—and because a one-size-fits-all state role would not accommodate the wide range of views expressed by state commissions.

295. Instead, we believe the best place to determine the role any state commission plays is through the development of each region's transmission planning process. This is appropriate because individual state commissions can be the best advocates for the role they wish and are able to play in that process. We believe that, in a multistate region, the state commissions may want to establish a committee of state regulators, which may be more effective by acting collectively rather than individually. On numerous occasions, the Commission has expressed strong support for such regional state committees, and we continue to do so here. But we have not prescribed that states act though regional state committees. Some state commissions may want an independent role in regional transmission planning. Others may believe they lack authority under their states' laws to engage in planning facilities that are outside the state's borders. Finally, some states may have a stronger interest in regional transmission planning issues than others that simply have little interest in participating actively.

296. In response to Illinois Commerce Commission and Florida PSC's concerns regarding funding for state regulator participation in the regional transmission planning process, we affirm the approach taken in Order No. 1000. This approach adopted Order No. 890's requirement that public utility transmission providers propose a mechanism for recovery of planning costs in their compliance filings, including relevant cost recovery for state regulators, to the extent requested.[340] Accordingly, we encourage public utility transmission providers to engage respective state regulators regarding such provisions in their compliance filings.

297. With respect to arguments raised by petitioners concerning Order No. 1000's discussion of the role of merchant transmission developers in the regional transmission planning

[339] *Id.* P 159.

[340] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 162 (quoting Order No. 890, FERC Stats. & Regs. ¶ 31,241 at n.339 & P 586).

process, we deny rehearing. As the Commission found in Order No. 1000, because a merchant transmission developer assumes all financial risk for developing and constructing its transmission facility, it is unnecessary to require such a developer to participate in a regional transmission planning process for purposes of identifying the beneficiaries of its transmission facility that would otherwise be the basis for securing eligibility to use a regional cost allocation method or methods. However, because a merchant developer's transmission facility may nevertheless have an impact on a region's transmission network, we will continue to require a merchant transmission developer to provide adequate information and data, as explained in more detail in Order No. 1000, to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region. We will allow public utility transmission providers in each transmission planning region, in consultation with stakeholders, in the first instance to propose what information would be required. Public utility transmission providers should include these requirements in their filings to comply with Order No. 1000.[341]

298. In response to APPA and Transmission Dependent Utility Systems, we believe that by requiring merchant transmission developers to provide information regarding their projects, including information regarding reliability and operational impacts, public utility transmission providers and stakeholders will have sufficient information to analyze how a merchant transmission facility may impact the transmission planning region. In short, we believe that Order No. 1000's information sharing requirement balances the need for public utility transmission providers and stakeholders in transmission planning regions to know about the impacts of potential merchant transmission facilities in their regions with our view that it is unnecessary to require a specific degree of participation by merchant transmission developers in the regional transmission planning process when they are not establishing a cost-based rate base to be allocated to other beneficiaries of that facility.

299. We disagree with National Rural Electric Coops that we are establishing a ''special'' class of public utilities by requiring merchant transmission developers to comply only with an informational requirement, rather than being subject to the full panoply of requirements that will be applicable to all other public utility transmission providers. However, it should be noted that merchant transmission developers are those for which the costs of constructing the proposed transmission facilities will be recovered through negotiated rates instead of cost-based rates, so that this fact alone serves to distinguish them from other developers.[342] As noted above, merchant transmission developers are not seeking to allocate the costs associated with their merchant transmission facilities to other entities. Thus, we affirm our decision in Order No. 1000.

300. We also decline Transmission Dependent Utility Systems' request that we clarify that merchant transmission developers not participating in the regional transmission planning process should be obligated to internalize the costs of any adverse reliability effects on the grid posed by its transmission facility or any need for upgrades caused by a change in power flows. Every new facility affects the facilities around it, whether it is a merchant facility or a cost-based facility, just as the actions of one region may have positive or negative affects on neighboring regions. A generic proceeding on internalizing the costs of all new facilities, whether merchant or otherwise, is beyond the scope of Order No. 1000, and may not be suited for a blanket determination in any generic proceeding as such a determination would likely require an evaluation of the specific facts and circumstances of each particular new facility. The Commission reiterates, however, that Order No. 1000 provides that a merchant transmission developer has to pay for upgrades on neighboring systems.[343]

301. Finally, in response to those petitioners seeking clarification of what constitutes a ''new'' transmission facility, we will affirm the Commission's approach taken in Order No. 1000.[344] Order No. 1000 purposely does not define what type of evaluation or reevaluation of transmission facilities needs to occur to determine whether a previously approved facility may be subject to Order No. 1000. That is because we understand that different transmission planning regions may use different processes based on their unique needs and characteristics. We intentionally did not prescribe what such an evaluation or reevaluation must look like, and we leave it to public utility transmission providers, in consultation with stakeholders, to develop proposals addressing this issue as part of their Order No. 1000 compliance filings. If a stakeholder believes that these proposals are unduly discriminatory or preferential (e.g., they favor incumbent transmission owners to the detriment of nonincumbent transmission developers), it should raise these concerns during the development of the Order No. 1000 compliance filing and, if it is not successful at that stage, it may raise the issue before the Commission after the compliance filing is submitted. For these reasons, we decline to provide the clarifications requested by Western Independent Transmission Group and LS Power.

3. Consideration of Transmission Needs Driven by Public Policy Requirements

a. Final Rule

302. Order No. 1000 directed public utility transmission providers, in consultation with stakeholders, to amend their OATTs to describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes.[345] By considering transmission needs driven by Public Policy Requirements, the Commission explained that it meant: (1) The identification, with stakeholders, of transmission needs driven by Public Policy Requirements; and (2) the evaluation of potential solutions, including those proposed by stakeholders, to meet those needs.[346] The Commission emphasized that it would allow local and regional flexibility in designing these procedures.[347] Additionally, to ensure that requests to include transmission needs are reviewed in a fair and non-discriminatory manner, Order No. 1000 required public utility transmission providers to post on their Web sites an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local or regional transmission planning process, as well as an explanation of why other suggested transmission needs will not

[341] *Id.* P 163.

[342] *Id.* P 119.

[343] *Id.* P 165.

[344] *Id.* P 65.

[345] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 203.

[346] *Id.* PP 205–11.

[347] *Id.* P 208.

be evaluated.[348] The Commission further explained that Order No. 1000 did not establish an independent requirement to satisfy such Public Policy Requirements such that the failure of a public utility transmission provider to comply with a Public Policy Requirement established under state law would constitute a violation of its OATT.[349]

303. The Commission did not require public utility transmission providers to consider in the local and regional transmission planning processes any transmission needs that go beyond those driven by state or federal laws or regulations or to specify additional public policy principles or public policy objectives.[350] However, the Commission reiterated and clarified that Order No. 1000 does not preclude any public utility transmission provider from considering in its transmission planning process transmission needs driven by additional public policy objectives not specifically required by state or federal laws or regulations.[351]

b. Requests for Rehearing and Clarification

304. Several petitioners filed requests for rehearing and clarification regarding Order No. 1000's requirement that public utility transmission providers include in their OATTs language providing for the consideration of transmission needs driven by Public Policy Requirements. Some petitioners assert that the Commission has not spelled out with sufficient detail what is required of public utility transmission providers.[352] ELCON, AF&PA, and the Associated Industrial Groups, as well as PSEG Companies, contend that Order No. 1000 provides virtually no practical guidance as to how disparate state policies are to be reconciled. PSEG Companies also contend that the Commission's reforms may undermine competitive wholesale energy markets by driving market outcomes, explaining that predictions about generation additions and retirements that will occur in a competitive market are too speculative for a transmission provider to rely upon and, if a transmission provider were to make such judgments, then it would be a market maker or market influencer.

305. Ad Hoc Coalition of Southeastern Utilities is concerned that Order No. 1000's public policy planning requirements will be confusing and counterproductive and are likely to result in skewed decision-making. Coalition for Fair Transmission Policy argues that any construct of benefits associated with public policy-driven transmission projects would require speculation and deviate from industry norms that use models to project system conditions and dynamics for planning purposes. Long Island Power Authority argues that the process for identifying transmission needs driven by Public Policy Requirements is incomplete because it is necessary to identify what parties are subject to the Public Policy Requirements and whether such parties have a need for a transmission solution to meet those requirements.

306. Sacramento Municipal Utility District explains that current transmission planning processes take into account state renewable energy goals, adding that, to the extent that Public Policy Requirements spur development of new projects that create demand for new transmission, such projects would be incorporated into existing planning processes, even if those processes do not expressly reference the Public Policy Requirement that created the demand. Ad Hoc Coalition of Southeastern Utilities argue that Order No. 1000 fails to account for the fact that, at least in the Southeast, existing practices take into account Public Policy Requirements.

307. A number of petitioners seek rehearing or clarification on several other issues related to Order No. 1000's requirement that local and regional transmission planning processes consider transmission needs driven by Public Policy Requirements. APPA, for example, seeks clarification that the term ''Public Policy Requirements'' is intended to include duly enacted laws, ordinances, and regulations passed by units of state and local government regulating public power systems, such as city councils, utility district boards, and other governing bodies. MISO Northeast argues that the Commission should limit the definition of ''Public Policy Requirements'' to those requirements that create transmission-related benefits.

308. AEP seeks clarification that transmission providers are required to include specific, evaluated solutions to all transmission needs in the transmission plan, explaining that it is concerned that transmission providers may simply identify possible solutions to needs driven by Public Policy Requirements without including solutions that address such needs in an actionable transmission plan. As an example, AEP states that PJM is considering the ''FYI to Market'' approach, where PJM identifies projects that might respond to certain public policy needs and lets the market determine, without any PJM involvement, which projects are built.

309. Southern Companies contend that Order No. 1000's requirement that transmission needs driven by Public Policy Requirements must be considered in transmission planning processes is vague. Specifically, they claim that Order No. 1000's directive that public utility transmission providers post on their Web sites an explanation of which public policy considerations are and are not considered in the transmission planning process is impermissibly vague and overbroad. In support, Southern Companies explain that their native load has numerous federal and state legal requirements driving their load projections.

310. American Transmission seeks clarification on issues related to Order No. 1000's direction that the consideration of transmission needs driven by Public Policy Requirements applies to local, as well as regional, transmission planning processes. American Transmission seeks clarification that it is necessary and appropriate for it to amend its local planning process to include provisions for public policy-driven transmission projects.[353] It explains that it is a transmission-owning member of MISO, which has a Commission-approved regional planning process, but that it also has a Commission-approved local planning process, through which transmission projects are identified and included in the Midwest ISO MTEP process.

311. While others raise concerns about the reach of Order No. 1000 on this issue, AWEA argues that transmission planners should be required to do more than ''consider'' state and federal requirements, stating that the Commission recognized that when a transmission provider focuses only on the needs of its franchised or contract-load customers, it creates opportunities for undue discrimination. It suggests that the Commission require transmission providers to undertake scenario studies to plan and direct the build-out of the transmission system for those entities with signed interconnection agreements. It also suggests that the Commission require that scenarios account for transmission that may be necessary to accommodate

[348] *Id.* P 209.

[349] *Id.* P 213.

[350] *Id.* P 214.

[351] *Id.* P 216.

[352] *See, e.g.,* Coalition for Fair Transmission Policy; ELCON, AF&PA, and the Associated Industrial Groups; and PSEG Companies.

[353] American Transmission at 8–9 (citing what it terms as an inconsistency between paragraph 203 and footnote 185 of Order No. 1000).

individual or multiple RPS requirements or other state and federal requirements, and that transmission providers then would present these analyses to stakeholders and include recommended projects and anticipated costs under each scenario. Otherwise, it seeks clarification regarding the following: (1) That transmission providers must actively address public policy considerations within their local and regional planning processes; (2) the requirements imposed on transmission providers in meeting the requirement to consider public policy goals; and (3) that a transmission provider has an independent duty to identify needs, rather than being passive if no participant raises any concerns or needs.

312. Some petitioners raise concerns that the requirements will put transmission planners into the role of policymakers. Coalition for Fair Transmission Policy argues that, under the top-down planning permitted in Order No. 1000, the regional planning group would be placed in the position of making decisions that affect how utilities and other entities with the responsibility to meet Public Policy Requirements would meet those requirements. Coalition for Fair Transmission Policy asserts that Order No. 1000 thus authorizes submission of regional transmission planning processes that would reduce those with public policy obligations and state regulators to mere stakeholders in the regional transmission planning process. It argues that, with respect to transmission needs driven by Public Policy Requirements, regional transmission plans can be developed only through a bottom-up process. PPL Companies argue that requiring Public Policy Requirements in the transmission planning process could become a justification to unduly discriminate against ''non-renewable'' generation, which would violate the Commission's open access policies. They also assert that, to the extent public utility transmission providers are mandated to consider transmission needs driven by Public Policy Requirements in local and regional transmission planning processes, the Commission should clarify that such considerations need not, and cannot, trump the FPA's requirement that rates be just and reasonable.

313. Transmission Access Policy Study Group raises a similar concern, pointing to Order No. 1000's statement regarding the consideration of public policy goals not codified in laws and regulations. Florida PSC argues that provisions allowing transmission providers to consider additional public policy objectives not specifically required by state or federal laws or regulations should be struck. Instead, Florida PSC argues that transmission planning decisions should be based on meeting the policy requirements of state and federal law. It also states that it is unclear whether there will be enough flexibility to adjust planning decisions to respond to changes in uncodified public policies. Transmission Access Policy Study Group believes that allowing public utility transmission providers to consider such goals would allow them to substitute their own agenda for that of state and federal legislatures and regulators.

314. Transmission Access Policy Study Group raises the example that a public utility transmission provider's definition of a ''public policy'' may be influenced by the potential for incentive rate recovery or that it may define ''public policy'' to advance its own generation interests. It claims that, despite Order No. 1000's statement that public utility transmission providers always had the ability to plan for any transmission system needs that it foresees, public utility transmission providers in non-RTO regions have never before been authorized to allocate costs for transmission projects aimed at policy objectives not grounded in law or regulation.[354] It argues that planning for these goals should be grounded in terms of satisfying needs identified by load-serving entities, and requests that the Commission at least provide guidance that any plans developed based on public utility transmission providers' own public policy vision should be structured to ensure their usefulness by supporting multiple likely power supply scenarios should the original vision prove faulty. It believes this approach is more rational for integrating public policies into the planning process and will help focus planning on constructing broadly supported upgrades needed under multiple potential power supply and public policy scenarios.[355]

315. Some state electric regulatory agencies are concerned about the role they will play in the process to identify and evaluate transmission needs driven by Public Policy Requirements.[356] Illinois Commerce Commission asserts that the Commission should have clarified that, when state commissions in a region, either acting individually or via committee, decide that a unique role or special weight should be given to state authorities in the regional planning process regarding the consideration of transmission needs driven by Public Policy Requirements, then the transmission provider should be required by the Commission to defer to that decision. It maintains that by leaving the role of state authorities in the regional planning process up to the transmission providers, the Commission allows for the possibility that transmission providers can thwart the will of regionally organized state authorities. It also seeks clarification that the ''committee of regulators'' envisioned for the purpose of identifying transmission needs driven by Public Policy Requirements would not need to consist solely of personnel employed by state regulatory commissions, but could include other state authorities as well. It further seeks clarification that the engagement of such a committee will be at the discretion of the regional state committee, not at the transmission provider's discretion. It asks that the Commission clarify how its statement that authorizes use of ''a committee of state regulators'' to ''identify those transmission needs for which potential solutions will be evaluated in the transmission planning processes'' fits with the requirement that public utility transmission providers ''have in place processes that provide all stakeholders the opportunity to provide input into what they believe are transmission needs driven by Public Policy Requirements.''

316. Similarly, New York PSC requests clarification that when state regulators play a formal role in the planning process, their determinations regarding transmission needs driven by state public policies will be entitled to deference.

c. Commission Determination

317. We affirm Order No. 1000's reforms regarding the consideration of transmission needs driven by Public Policy Requirements. We recognize that Order No. 1000 could have been more clear regarding what the Commission intended, as evidenced by many of the petitioners' arguments suggesting that Order No. 1000 requires the

[354] Transmission Access Policy Study Group also cites to Order No. 1000's reference to PJM's inability to go beyond specific interconnection requests in its planning mechanism as a reason for requiring the consideration of transmission needs driven by Public Policy Requirements, claiming that this shows that the authorization to go beyond public policies embodied in state or federal laws or regulations may not be the *status quo* in some RTO regions.

[355] Transmission Access Policy Study Group at 18–19 (citing the CapX 2020 project, planning processes in MISO and New England, and California ISO's ''least regrets'' planning criteria).

[356] *See, e.g.,* Illinois Commerce Commission; and New York PSC.

consideration of Public Policy Requirements themselves, which is not the case. In this section, we clarify what the Commission intended by these reforms. We believe that these clarifications will be helpful in dispelling some of the misconceptions about this requirement that appear in many of the petitioners' requests for rehearing and clarification.

318. Order No. 1000 requires that public utility transmission providers amend their OATTs to provide for the consideration of transmission needs driven by Public Policy Requirements. Order No. 1000 did not require that Public Policy Requirements themselves be considered. This is a critical distinction. As discussed more fully below in response to requests for rehearing on this issue, we are not placing public utility transmission providers in the position of being policymakers or allowing them to substitute their public policy judgments in the place of legislators and regulators. Transmission needs driven by Public Policy Requirements, and not the Public Policy Requirements themselves, are what must be considered under Order No. 1000.

319. First, we discuss the elements of Order No. 1000's requirement regarding the consideration of transmission needs driven by Public Policy Requirements. Order No. 1000 defined ''Public Policy Requirements'' as public policy requirements established by state or federal laws and regulations.[357] Order No. 1000 explained that ''state or federal laws and regulations'' means ''enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level.'' [358] We grant APPA's clarification that Public Policy Requirements established by state or federal laws or regulations includes duly enacted laws or regulations passed by a local governmental entity, such as a municipal or county government. This is the intent of the word ''within'' in Order No. 1000's explanation that ''state or federal laws or regulations,'' meant ''enacted statutes * * * and regulations promulgated by a relevant jurisdiction, whether *within* a state or at the federal level.'' [359] In response to MISO Northeast, we will not revise the definition of Public Policy Requirements to limit it to those that provide transmission-related benefits. Order No. 1000 does not require the consideration of Public Policy Requirements: Rather, it requires the consideration of transmission needs driven by Public Policy Requirements. We also will not exclude any particular state or federal law or regulation from the definition of Public Policy Requirements.

320. Next, we discuss another key component of Order No. 1000's requirement, namely, the term ''consideration'' in reference to the requirement that public utility transmission providers amend their OATTs to provide for the consideration of transmission needs driven by Public Policy Requirements. By ''consideration,'' Order No. 1000 explained that this included: (1) The identification of transmission needs driven by Public Policy Requirements; and (2) the evaluation of potential solutions to meet those identified needs.[360] Order No. 1000 further explained that, with respect to the identification of transmission needs driven by Public Policy Requirements, the process must permit stakeholders with an opportunity to provide input and offer proposals regarding the transmission needs that they believe should be so identified.[361] Order No. 1000 also stated that not every suggested need will be identified such that solutions for the need will be evaluated.[362] In response to AEP, we reiterate that Order No. 1000 provides only that public utility transmission providers must *consider* transmission needs driven by Public Policy Requirements. Order No. 1000 does not require that every potential transmission need proposed by stakeholders must be selected for further evaluation. We find that this approach is a fair balance that allows interested stakeholders to submit their views on what is driving their transmission needs while allowing the process itself determine what transmission needs are identified for which solutions must be evaluated.

321. Similarly, in response to AWEA, we are not requiring anything more than what we directed in Order No. 1000, namely, the two-part identification and evaluation process. As with other Order No. 1000 transmission planning reforms, our concern is that the process allows for stakeholders to submit their views and proposals for transmission needs driven by Public Policy Requirements in a process that is open and transparent and satisfies all of the transmission planning principles set out in Order Nos. 890 and 1000, and that there is a record for the Commission and stakeholders to review to help ensure that the identification and evaluation decisions are open and fair, and not unduly discriminatory or preferential. However, we reiterate that not every proposal by stakeholders during the identification stage will necessarily be identified for further evaluation. The OATT revisions that public utility transmission providers submit as part of their Order No. 1000 compliance filings will set forth the process for permitting stakeholders to provide input and for determining which proposed transmission needs will be identified for evaluation.

322. We are also not prescribing how active a public utility transmission provider should itself be in identifying transmission needs driven by Public Policy Requirements, although it certainly may take a more proactive approach if it, in consultation with its stakeholders, so chooses. Even if a public utility transmission provider takes a less active approach on this issue, our expectation is that interested stakeholders will participate and suggest transmission needs driven by Public Policy Requirements.[363] An open and transparent transmission planning process will identify those transmission needs that should be evaluated, regardless of whether they are suggested by the public utility transmission provider or by an interested stakeholder.

323. In response to Coalition for Fair Transmission Policy, we recognize that consideration of transmission needs driven by Public Policy Requirements could create challenges in defining beneficiaries, but we fail to see how these challenges are appreciably different from those involved in determining beneficiaries of reliability or economic projects. In those cases as well, the determination of beneficiaries will often turn on informed forecasts or predictions regarding future needs and demands to be placed on the transmission system. In fact, given that the Commission is only requiring the consideration of transmission needs driven by Public Policy Requirements that are established by state or federal laws or regulations,[364] it may very well be the case that the determination of beneficiaries of transmission facilities to

[357] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 2.

[358] *Id.*

[359] *Id.* (emphasis added).

[360] *Id.* P 205.

[361] *Id.* P 209.

[362] *Id.*

[363] We emphasize that, although a public utility transmission provider is not obligated to proactively identify transmission needs driven by Public Policy Requirements, it still must consider the transmission needs driven by Public Policy Requirements raised by other stakeholders in the transmission planning process.

[364] As discussed above, the Commission clarifies that this requirement was meant to include local laws or regulations as well.

address transmission needs driven by Public Policy Requirements is easier to define than for other types of transmission facilities. In any event, we want public utility transmission providers, in consultation with stakeholders, to make those determinations in the first instance. We also disagree with Coalition for Fair Transmission Policy's argument that these reforms can only be implemented through bottom-up transmission planning. Coalition for Fair Transmission Policy has not persuaded us that these reforms cannot be implemented through either a ''top-down'' or ''bottom up'' process, particularly given the significant flexibility we are providing to public utility transmission providers to comply with these requirements.

324. Regarding American Transmission's request for clarification, we note that in Order No. 1000, footnote 185, we stated that ''[t]o the extent public utility transmission providers within a region do not engage in local transmission planning, such as in some ISO/RTO regions, the requirements of this Final Rule with regard to Public Policy Requirements apply only to the regional transmission planning process.'' [365] That statement only applies to public utility transmission providers that do not engage in local transmission planning. If a public utility transmission provider does engage in local transmission planning, regardless of whether or not it is in an ISO/RTO region, then the requirements of Order No. 1000 regarding Public Policy Requirements apply to both the local and regional transmission planning processes. Therefore, if American Transmission engages in local and regional transmission planning, then it must revise its local transmission planning process to reflect this aspect of Order No. 1000.

325. Southern Companies find the requirement that public utility transmission providers post on their Web sites an explanation of which transmission needs have been identified for evaluation and an explanation of why other suggested transmission needs will not be evaluated to be vague and overbroad. We clarify as follows. Public utility transmission providers are not required to research and post on their Web sites what they perceive to be every transmission need that is conceivably driven by a Public Policy Requirement and then explain why it will not evaluate each one. Public utility transmission providers are only obligated to (a) post an explanation of those transmission needs driven by Public Policy Requirements that have been identified for evaluation and (b) post an explanation of how other transmission needs driven by Public Policy Requirements introduced by stakeholders were considered during the identification stage and why they were not selected for further evaluation. For example, if public utility transmission providers or stakeholders in a transmission planning region submit what they believe are ten transmission needs driven by Public Policy Requirements, and five of those ten are identified for evaluation, then the public utility transmission providers must (a) post an explanation of why the five were evaluated and (b) post an explanation of why the other five were not evaluated.

326. Having provided additional clarifications and information as to what Order No. 1000 does require, i.e., the consideration of transmission needs driven by Public Policy Requirements, we now turn to discussing what Order No. 1000 does not require, i.e., the consideration of Public Policy Requirements themselves, as well as otherwise allowing public utility transmission providers to become policymakers, as some petitioners appear to believe. Order No. 1000 does not require public utility transmission providers to amend their OATTs to provide for the consideration of Public Policy Requirements. Nor do we believe that anything in Order No. 1000's reforms on this issue will lead to that outcome.

327. It is not the function of the transmission planning process to reconcile state policies. If the utilities in one state are required, for example, to procure wind resources and the utilities in another state are required to shut down old fossil units and construct new fossil units, it is not the transmission providers' function to decide on the merits of these federal or state requirements or to decide between wind and coal resources. It is their function to help both sets of utilities comply with the laws they each face by considering in the transmission planning process, but not necessarily including in the regional transmission plan, the new transmission facilities needed by both sets of utilities to meet their obligations, and also to determine if these diverse objectives can be met more efficiently or cost-effectively through regional transmission planning than through individual utility planning.

328. Additionally, in establishing this process, we are not requiring public utility transmission providers to make any substantive determinations as to what Public Policy Requirements may qualify under these reforms or to identify them in their OATTs. If they choose to do so, then such proposals must be vetted through the local and regional transmission planning process, as discussed in Order No. 1000.

329. For these reasons, we reject assertions that we are allowing public utility transmission providers to assume the role of policymaker in their transmission planning processes with respect to considering transmission needs driven by Public Policy Requirements. We also disagree with Ad Hoc Coalition of Southeastern Utilities that these reforms may lead to skewed decision-making. Our intent is to help develop a path to allow public utility transmission providers to consider transmission needs driven by Public Policy Requirements, just as they consider reliability-driven and economic-driven transmission needs, but we are not mandating that any particular transmission facility identified to address identified transmission solutions be built.

330. Further, we disagree with PSEG Companies' argument that, by requiring the development of a process, we are somehow getting ahead of the states' own public policy efforts. Nothing in the development of this process preempts or conflicts with state-level public policy efforts. Indeed, Order No. 1000 and state-level Public Policy Requirements should be complementary—Order No. 1000's intent is to establish a space in the transmission planning process to identify transmission needs driven by Public Policy Requirements and to evaluate potential solutions to identified needs.

331. We also decline to require that regional transmission plans support multiple likely power supply scenarios should a region's public policy vision not come to fruition, as requested by Transmission Access Policy Study Group. It may well be the case that evaluating different power supply scenarios will be an effective way of identifying more efficient or cost-effective transmission solutions; however, we will not prescribe any such requirements here, consistent with our preference for regional flexibility in designing regional transmission planning processes. Stakeholders may advocate for such a requirement in the development of Order No. 1000 compliance filings and, to the extent such language is included in the

[365] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at n.185.

compliance filing, the Commission will consider that language.[366]

332. Just as Order No. 1000 did not intend for public utility transmission providers to consider Public Policy Requirements, Order No. 1000 also does not convert public utility transmission providers into policymakers with respect to the consideration of public policy objectives that are not codified in federal or state laws or regulation. On this matter, Order No. 1000 stated: ''[T]he Final Rule does not preclude any public utility transmission provider from considering in its transmission planning process transmission needs driven by additional public policy objectives not specifically required by state or federal regulations.'' [367] Some petitioners expressed alarm that we are permitting public utility transmission providers to become policymakers and substitute their policy judgments in place of legislators and regulators. This was not our intent, and we take this opportunity to provide some clarifications on this matter.

333. We reiterate the observations we made in Order No. 1000. A public utility transmission provider ''has, and always had, the ability to plan for any transmission system needs that it foresees. Our recognition of this ability is not intended to limit *or expand* in any way the option that a public utility transmission provider has always had to plan for facilities that it believes are needed if it chooses to do so.'' [368] All this statement was intended to convey was that, even absent the requirements in Order No. 1000, public utility transmission providers take a number of different factors into account in developing their transmission plans. While Order No. 1000 established a requirement for certain factors that must be considered in transmission planning, as the quoted sentence states, it does not expand what public utility transmission providers have always been entitled to do. If, for example, a state law that has been identified as a Public Policy Requirement requires utilities to meet a 10 percent renewable portfolio standard and that state's governor urges them to meet a 20 percent standard, Order No. 1000 requires consideration of transmission needed to meet the 10 percent but neither requires utilities to, nor prohibits them from, considering a 20 percent standard, as some petitioners apparently urge us to do.

334. Order No. 1000 concluded that it is appropriate to require public utility transmission providers, in consultation with stakeholders, to design the appropriate procedures for identifying and evaluating the transmission needs that are driven by Public Policy Requirements in their area, subject to guidance the Commission provided in Order No. 1000 and our review on compliance.[369] Additionally, in response to Long Island Power Authority, we anticipate that the process for identifying transmission needs driven by Public Policy Requirements can identify what parties are subject to the Public Policy Requirements and whether such parties have a need for a transmission solution to meet those requirements.

335. With respect to the contention raised by Sacramento Municipal Utility District, Ad Hoc Coalition of Southeastern Utilities, and others that existing transmission planning processes already account for state renewable energy goals, we note that we are not endorsing, nor does the Public Policy Requirement include, any particular state or federal law or regulation as special or ''preferred.'' Further, as we have noted elsewhere, we understand that some regions may already be in compliance with many of the requirements of Order No. 1000 and thus may need to make only modest changes to comply. Compliance filers must explain how their process gives all stakeholders a meaningful opportunity to submit what they believe are transmission needs driven by Public Policy Requirements, and allow an open and transparent transmission planning process to determine whether to move forward regarding those needs.

336. Further, we disagree that we have not justified this reform generically, as suggested by Ad Hoc Coalition of Southeastern Utilities, which argues that there is no need for this reform in the Southeast. As discussed above and in Order No. 1000, we concluded that there was a need for the Commission to act under FPA section 206 to remedy a deficiency that we found in existing transmission planning processes. There was no formal requirement for public utility transmission providers to consider transmission needs driven by Public Policy Requirements, despite the fact that the record indicates that in recent years there has been significant activity at the federal and state levels in enacting laws and regulations that will potentially impact transmission needs.[370] The lack of a formal requirement in public utility transmission providers' OATTs to address this issue is, in our view, unjust, unreasonable, and unduly discriminatory.[371] We affirm our conclusion that these reforms are necessary on a nationwide basis.

337. Finally, some state regulators question their role in this process. We agree with petitioners that state regulators play an important and unique role in the transmission planning process, given their oversight over transmission siting, permitting, and construction, as well as integrated resource planning and similar processes. Additionally, they may be in the best position of determining how state-level public policy requirements are satisfied. Nonetheless, for the reasons discussed fully above, the Commission will not require as part of this generic rulemaking proceeding a particular status for state regulators in the transmission planning process.[372] To do so would ignore the wide range of roles that state regulators themselves tell us that they are permitted to take under their various state laws.

338. However, as we also explained in Order No. 1000 and above, our expectation is that state regulators should play a strong role and that public utility transmission providers will consult closely with state regulators to ensure that their respective transmission planning processes are consistent with state requirements. We believe this will be particularly true in the case of state-level Public Policy Requirements, where state regulators are likely to have unique insights as to how transmission needs driven by those state-level Public Policy Requirements should be satisfied. Thus, we leave it to state regulators and public utility transmission providers, in consultation with stakeholders, in each transmission planning region to determine the appropriate role of state regulators in the transmission planning process generally and in the consideration of transmission needs driven by Public Policy Requirements in particular.

339. In response to Illinois Commerce Commission, we are not prescribing how any committee of state regulators should be comprised. We note that existing committees of state regulators have been effective representatives of

[366] Similarly, we will not require the adoption of a ''least regrets'' process or processes that resulted in the development of transmission projects such as the CapX2020 project; however, the public utility transmission providers in each region are free to develop such processes and submit them in their compliance filing for Commission consideration.

[367] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 216.

[368] *Id.* (emphasis added).

[369] *Id.* P 208.

[370] *See, e.g.,* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 45–47.

[371] *Id.* PP 82–83. *See also* discussion *supra* at section II.C (explaining need for Order No. 1000's reforms).

[372] *See* discussion *supra* at section III.A.2.

state regulators, and any region that wants to form such a committee may want to look to these and other similar organizations in other regions of the country as possible models for organizing its own similar committees for purposes of regional transmission planning under Order No. 1000.

B. Nonincumbent Transmission Developers

340. This section of Order No. 1000 addressed the removal from Commission-jurisdictional tariffs and agreements of provisions that contain a federal right of first refusal [373] to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. The Commission also adopted a framework that requires the development of qualification criteria and protocols to govern the submission and evaluation of proposals for transmission facilities to be evaluated by public utility transmission providers in the regional transmission planning process. The Commission further required that the developer of any transmission facility selected in the regional transmission plan have a comparable opportunity to allocate the cost of such transmission facility through a regional cost allocation method or methods.[374]

1. Legal Authority

a. Final Rule [375]

341. In Order No. 1000, the Commission found that a federal right of first refusal is, in the language of FPA section 206, a ''rule, regulation, practice, or contract'' affecting the rates for jurisdictional transmission service. The Commission further stated that under section 206 when the Commission finds that such rules, regulations, practices, or contracts are unjust, unreasonable, unduly discriminatory, or preferential, it must determine by order the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force. The Commission concluded that because federal rights of first refusal in favor of incumbent transmission providers deprive customers of the benefits of competition in transmission development, and associated potential savings, these federal rights of first refusal affect the rates for jurisdictional transmission service, and so the Commission was compelled under FPA section 206(a) to take corrective action. The Commission also stated that federal rights of first refusal create opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes, and noted that it has a responsibility to consider anticompetitive practices and eliminate barriers to competition.[376]

342. The Commission noted that nothing in Order No. 1000 is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including, but not limited, to authority over siting or permitting of transmission facilities. The Commission therefore determined that its reforms regarding elimination of federal rights of first refusal from Commission-jurisdictional tariffs and agreements are not prevented or otherwise limited by the FPA. The Commission also explained that in directing the removal of a federal right of first refusal from Commission-jurisdictional tariffs and agreements, it is not ordering public utility transmission providers to enlarge their transmission facilities under sections 210 or 211 of the FPA, nor making findings related to its authorities under section 215 or 216.

343. The Commission also stated that, while a public utility transmission provider may have accepted an obligation to build in relation to its membership in an RTO/ISO, the Commission did not believe that obligation is necessarily dependent on the incumbent transmission provider having a corresponding federal right of first refusal to prevent others from constructing and owning new transmission facilities in that region.[377] The Commission stated that, while implementing these reforms may change the package of benefits and burdens in place for transmission owning members of RTOs/ISOs, such changes are necessary to correct practices that may be leading to unjust and unreasonable rates.[378]

344. Finally, the Commission declined to address the merits of comments arguing that section 3.09 of the ISO New England Transmission Operating Agreement establishes a federal right of first refusal that can be modified only if the Commission meets the *Mobile-Sierra* public interest standard, explaining that it was more appropriate to address this issue as part of the proceeding on ISO New England's compliance filing.[379]

b. Requests for Rehearing and Clarification

i. Arguments That the Commission Does Not Have the Authority To Eliminate a Federal Right of First Refusal

345. Several petitioners argue that the Commission acted outside of its authority by requiring the removal of the federal right of first refusal from Commission-jurisdictional tariffs and agreements.[380] Some petitioners assert that section 206 only extends to behavior that directly affects rates or the provision of jurisdictional service rather than to any term in a jurisdictional tariff or agreement.[381] They argue the federal right of first refusal is not a practice within the meaning of section 206, and therefore is not a behavior that the Commission can address under that section.[382] Similarly, Oklahoma Gas and Electric Company states that the Commission must show a direct and significant effect on jurisdictional rates before it can regulate actions indirectly affecting activity falling under state jurisdiction.

346. Petitioners also analogize the Commission's action in Order No. 1000 with its failed attempt to regulate corporate governance and structure, which was at issue in *CAISO* v. *FERC*.[383] Petitioners argue that the federal right of first refusal affects a transmission provider's financial relationship with its customers no more than the DC Circuit found governance to in *CAISO* v. *FERC*.[384] According to Baltimore Gas & Electric, the court in *CAISO* v. *FERC* explained that the

[373] We continue to use the phrase ''federal right of first refusal'' to refer only to rights of first refusal that are created by provisions in Commission-jurisdictional tariffs or agreements. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 253 n.231.

[374] *Id.* P 225.

[375] We address legal arguments related to the need for our nonincumbent transmission developer reforms in the ''Need for Reform'' discussion. *See* discussion *supra* at section 0.

[376] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 286.

[377] *Id.* P 261.

[378] *Id.*

[379] *Id.* P 292.

[380] *See, e.g.,* FirstEnergy Service Company; Baltimore Gas & Electric; Southern Companies; Ad Hoc Coalition of Southeastern Utilities; and Sponsoring PJM Transmission Owners.

[381] *See, e.g.,* FirstEnergy Service Company; Sponsoring PJM Transmission Owners; Baltimore Gas & Electric; and Oklahoma Gas and Electric Company.

[382] *See, e.g.,* Southern Companies; Sponsoring PJM Transmission Owners; Baltimore Gas & Electric; and Oklahoma Gas and Electric Company.

[383] Sponsoring PJM Transmission Owners at 5–6 (citing *California Indep. Sys. Operator Corp.* v. *FERC,* 372 F.3d 403 (D.C. Cir. 2004) (*CAISO* v. *FERC*)); Southern Companies at 60–61 (citing *CAISO* v. *FERC,* 372 F.3d 395); PSEG Companies; Baltimore Gas & Electric (citing *CAISO* v. *FERC,* 372 F.3d at 403; *City of Cleveland* v. *FERC,* 773 F.2d 1368 (DC Cir. 1985)); Oklahoma Gas and Electric Company at 9–10 (*CAISO* v. *FERC,* 372 F.3d at 403).

[384] Southern Companies at 60–61 (citing *CAISO* v. *FERC,* 372 F.3d 395); Sponsoring PJM Transmission Owners at 7 (citing *CAISO* v. *FERC,* 372 F.3d at 403 (quoting *Mich. Wisc. Pipeline Co.,* 34 FPC ¶ 621,626 (1965))).

Commission cannot regulate ''practices'' using its section 206 ratemaking authority unless the practices ''affect rates and services significantly * * * are realistically susceptible of specification, and * * * are not so generally understood in any contractual arrangement as to render recitations superfluous.'' [385] Sponsoring PJM Transmission Owners also note that the *CAISO* court explained that a more expansive interpretation of ''practice'' would allow the Commission to regulate a range of subjects that the court considered to be plainly beyond the Commission's proper authority. Sponsoring PJM Transmission Owners add that, while the costs the transmission provider incurs to construct or procure an upgrade will be reflected in its rates, the same could be said of a myriad of other decisions the transmission provider makes, ranging from its hiring of staff to the procurement of outside services and materials. Southern Companies also analogize Order No. 1000 to *CAISO* v. *FERC,* arguing that the Commission, without evidence or a record of systemic abuse or actual discrimination or unreasonable decision making, is using sections 205 and 206 and a theoretical threat of unjust and unreasonable rates or discrimination in the provision of transmission service to replace the existing business investment decision process with its own.[386]

347. Sponsoring PJM Transmission Owners also point out that the court in *CAISO* v. *FERC* found that section 305 of the FPA, giving the Commission authority over interlocking directorates, would not have been necessary if it intended that the Commission could regulate corporate governance as a practice affecting rates under sections 205 and 206 of the FPA. They contend that this same reasoning leads to the conclusion that section 206 does not encompass the assignment of construction responsibility. Sponsoring PJM Transmission Owners argue that this is clear in looking at the relationship of section 7 of the NGA to sections 4 and 5 of the NGA, which parallel sections 205 and 206 of the FPA. They assert that section 7 of the NGA, giving the Commission the authority to regulate pipeline construction, would not have been necessary if sections 4 and 5 of the NGA (which parallel sections 205 and 206 of the FPA) already allowed the Commission to regulate such construction.[387] In addition, Sponsoring PJM Transmission Owners state that it is significant that, when deliberating on the FPA, Congress rejected provisions that would have given the Commission authority to order a utility to fix the services, equipment, or facilities it is responsible for maintaining upon determining they were improperly maintained.[388]

348. Sponsoring PJM Transmission Owners also analogize the right of first refusal to *Interstate Commerce Commission* v. *Pennsylvania.*[389] They contend that the court in *CAISO* v. *FERC* looked to this case because the court in *Interstate Commerce Commission* v. *Pennsylvania* interpreted the Interstate Commerce Act upon which Part II of the FPA is based and which likewise authorized the regulation of practices affecting rates.[390] Sponsoring PJM Transmission Owners assert the court in *Interstate Commerce Commission* v. *Pennsylvania* made clear that it was manifestly concerned about practices that directly related to the jurisdictional service provided customers (which was rail service), rather than the railroads' decisions regarding the means to provide such service.[391]

349. Instead of finding that any rate is unjust and unreasonable, Baltimore Gas & Electric argues that the Commission states that there may be a superior alternative practice to the present federal right of first refusal regime. Baltimore Gas & Electric asserts that this is contrary to well-settled law, which requires that if the existing method is just and reasonable, then that is the end of the section 206 inquiry even if an alternative method may be better.[392] Baltimore Gas & Electric asserts that the Commission violated this ratemaking precept by conflating its consideration of the federal right of first refusal mechanism for designating new transmission construction and operation responsibility with its consideration of an alternative selection process that the Commission prefers.

350. PSEG Companies assert that elimination of the federal right of first refusal was arbitrary and capricious because the ''remedy'' far exceeded the purported harm. Similarly, Baltimore Gas & Electric asserts that proportionality between the identified problem and the remedy ''is the key,'' and that if the Commission found isolated problems, a market-wide remedy would be inappropriate.[393] Similarly, Baltimore Gas & Electric asserts that the Commission must adduce hard facts, and that the remedy should be narrowly tailored to fit the facts.

351. With regard to the Commission's determination that the existence of a federal right of first refusal creates an opportunity for undue discrimination and preferential treatment against nonincumbent transmission developers, several petitioners argue that the Commission cannot rely on the FPA's undue discrimination provisions in sections 205 and 206 because these provisions only protect customers of public utilities, and not nonincumbent transmission developers.[394] They argue

[385] Baltimore Gas & Electric at 12 (quoting *CAISO* v. *FERC,* 372 F.3d at 403).

[386] Southern Companies at 103–104 (citing *CAISO* v. *FERC,* 372 F.2d at 395).

[387] Sponsoring PJM Transmission Owners. Similarly, Sponsoring PJM Transmission Owners assert that section 402 of the Transportation Act of 1920 (superseded by 49 U.S.C. 10901 (2010)), which provided the Interstate Commerce Commission with approval authority for railway extensions, would not have been necessary if practices affecting rates included construction decisions.

[388] Sponsoring PJM Transmission Owners at 11 (citing *Duke Power Co.* v. *Fed. Power Comm'n,* 401 F.2d 930, 943 n.106 (D.C. Cir. 1968)). They add that, although the statutory interpretations of later Congresses is not determinative of the statutory intent of an earlier Congress, it is informative that when Congress granted backstop siting authority to the Commission in the Energy Policy Act of 2005, it established clear limits that constrain the exercise of that authority. *Id.* (citing 16 U.S.C. 824p (2010); *Piedmont Envtl. Council* v. *FERC,* 558 F.3d 304 (4th Cir. 2009). They also state that section 1211 of the EPAct 2005 expressly states that the new electric reliability provisions do not authorize the Commission to order the construction of additional transmission facilities. *Id.* (referencing 16 U.S.C. 824o(i)(2)).

[389] Sponsoring PJM Transmission Owners at 9–10 (citing *Interstate Commerce Commission* v. *Pennsylvania,* 242 U.S. 208 (1916) (*ICC* v. *Pennsylvania*)).

[390] Sponsoring PJM Transmission Owners at 9–10 (citing *ICC* v. *Pennsylvania,* 242 U.S. 208)).

[391] Sponsoring PJM Transmission Owners at 9–10 & n.20 (citing *ICC* v. *Pennsylvania,* 242 U.S. 208; *Duncan* v. *Walker,* 533 U.S. 167, 174 (2001)).

[392] Baltimore Gas & Electric at 10–11 (citing *Complex Consol. Edison Co. of N.Y.* v. *FERC,* 165 F.3d 992, 1003 (D.C. Cir. 1999); *Pub. Serv. Comm'n of N.Y.* v. *FERC,* 642 F.2d 1335 (D.C. Cir. 1980) *cert. denied,* 454 U.S. 879 (1981); *Kern River Gas Transmission Co.,* Opinion No. 486–E, 136 FERC ¶ 61,045 (2011)).

[393] PSEG Companies at 33 (quoting *Public Utils. Comm'n of the State of Cal.* v. *FERC,* 462 F.3d 1027, 1054 (9th Cir. 2006)).

[394] *See, e.g.,* Southern Companies at 62 (citing *Pub. Serv. Co. of Ind., Inc.* v. *FERC,* 575 F.2d 1204, 1213 (7th Cir. 1978); *see St. Michaels Util. Comm'n* v. *FPC,* 377 f.2d 912, 915 (4th Cir. 1967)); Sponsoring PJM Transmission Owners at 12 (citing *Maine Pub. Serv. Co.* v. *FPC,* 579 F.2d 659, 664 (1st Cir. 1978)); *see also, e.g., FPC* v. *Sierra Pacific Power Co.,* 350 U.S. 348, 355 (1956); *Mun. Light Bds.* v. *FPC,* 450 F.2d 1341, 1348 (D.C. Cir. 1971); Baltimore Gas & Electric; Large Public Power Council; Ad Hoc Coalition of Southeastern Utilities at 59 (citing *Pub. Serv. Co. of Ind.* v. *FERC,* 575 F.2d 1203, 1213 (7th Cir. 1978); *St. Michaels util. Comm'n* v. *FPC,* 377 F.2d 912, 915 (4th Cir. 1967); *City of Frankfort, Ind.* v. *FERC,* 678 F.2d 699, 707 (7th Cir. 1982) (*Frankfort* v. *FERC*); *Towns of Alexandria, Minn.* v. *FPC,* 555 F.2d 1020, 1028 (D.C. Cir. 1977)); Oklahoma Gas and Electric Company at 7–8 (citing *St. Michaels Util. Comm'n* v. *FPC,* 377 F.2d at 915; *Pub. Serv. Co. of Ind., Inc.* v. *FERC,* 575 F.2d at 1212 (stating that the intent of the statute's undue discrimination protections ''is

that had Congress intended to grant the Commission such authority, it would have done so.[395] Large Public Power Council and Ad Hoc Coalition of Southeastern Utilities note that the court, in the *City of Frankfort,* stated that section 205 provisions ''regarding unlawful preference or advantage in setting of public utility rates requires that utility customers be treated fairly.'' [396] They also cite *Public Service Co. of Ind.* where the court stated that ''the anti-discrimination policy in section 205(b) is violated * * * where one consumer has its rates raised significantly above what other similarly-situated customers are paying.'' [397] Oklahoma Gas & Electric Company contends that neither of the cases the Commission cites support a different conclusion, claiming that, in *Gulf States,* the Commission addressed the narrow question of whether public utilities could ''employ tariff provisions to foreclose wholesale competition,'' [398] and that in *Otter Tail,* the Supreme Court held that the FPA was not intended ''to be a substitute for, or to immunize Otter Tail from, antitrust regulation.'' [399]

352. Petitioners also argue that the Commission lacks the authority to remedy all instances of undue discrimination, and only is responsible for promoting competition if anticompetitive behavior has a direct effect on rates.[400] In support, Sponsoring PJM Transmission Owners argue that *CAISO* v. *FERC* demonstrates that the Commission could not remedy a discriminatory governance structure of an independent system operator, and that the Supreme Court has held that the Commission does not have the authority to remedy racial discrimination in a utility's hiring practices.[401] Furthermore, Sponsoring PJM Transmission Owners argue that the Commission cannot rely on the court's affirmation of Order Nos. 436 [402] and 888 [403] as support for its asserted authority to remedy any and all discrimination. Furthermore, Sponsoring PJM Transmission Owners, similar to Oklahoma Gas & Electric, assert that the court in *Otter Tail Power Co.* v. *United States* concluded that the Commission lacked the authority to compel interconnection based on antitrust considerations alone.[404] Sponsoring PJM Transmission Owners also argue that *Gulf States Utilities Co.,*[405] cited by the Commission, did not assert responsibility to promote competition in the abstract. Sponsoring PJM Transmission Owners assert that this lack of authority to act solely on antitrust considerations, in the absence of an impact on jurisdictional services, contrasts with the Commission's authority to compel open access as a remedy for undue discrimination in transmission access, a jurisdictional service.[406]

353. Several petitioners contend that even if the Commission had the authority to address discrimination against nonincumbents, no undue discrimination against nonincumbents exists for the Commission to remedy under section 206.[407] Instead, some petitioners argue that Order No. 1000 institutionalizes undue discrimination against incumbent transmission owners in violation of the FPA and APA because it mandates similar treatment for incumbent transmission owners and nonincumbent transmission developers when they are not similarly situated.[408] In support, petitioners argue that the Commission failed to consider evidence of the full scope of risks faced by incumbent utilities.[409] For instance, several petitioners argue that incumbents have an obligation to serve customers and must comply with state legal and regulatory requirements, while nonincumbents are free to pick and choose among transmission investment options.[410] Others argue that incumbents are obligated to build under RTO contracts.[411]

354. Some petitioners also argue that it is unclear whether nonincumbent developers will have the same responsibilities as incumbent developers when operating their facilities. For instance, petitioners question whether there is a practical enforcement mechanism to ensure that a nonincumbent developer will build its transmission facility and then safeguard it from threats, such as cyber attacks.[412] Transmission Dependent Utility Systems argue that even if the nonincumbent developer were to be assessed penalties for reliability violations, NERC penalties may be insufficient for a merchant transmission developer that, in the absence of a franchised service territory obligation, may walk away from its contractual commitments or become financially unable to meet them.

355. In related arguments, some petitioners disagree with the Commission's conclusion that the federal right of first refusal is not dependent on an obligation to build.[413] They argue that the obligation to build under an RTO or ISO is not an ''option,'' but rather imposes a duty of diligence in fulfilling construction obligations. Baltimore Gas & Electric argues that the Commission has misconstrued what a federal right of first refusal is, which it argues is another way of saying that it has a right of notification from PJM whenever PJM determines that transmission needs to be built in Baltimore Gas & Electric's service area since Baltimore Gas & Electric is required to build it. Baltimore Gas & Electric argues that the Commission's ruling on this issue is invalid because

to protect consumers from being placed at a competitive disadvantage with other [similar customers]''); *Frankfort* v. *FERC,* 678 F.2d at 707 ; *Towns of Alexandria, Minn.* v. *FPC,* 555 F.2d 1020, 1028 (D.C. Cir. 1977)).

[395] Oklahoma Gas & Electric at 6 (citing *Dunk* v. *Penn. Pub. Util. Comm'n,* 252 A.2d 589, 591–92 (Pa. 1969)). It also contrasts the absence of such language in the FPA with the Natural Gas Act and Part I of the FPA (addressing hydroelectric facilities).

[396] Ad Hoc Coalition of Southeastern Utilities at 59 (quoting *Frankfort* v. *FERC,* 678 F.2d at 704); Large Public Power Council at 32 (quoting *Frankfort* v. *FERC,* 678 F.2d at 707).

[397] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities at 59–60 (quoting *Pub. Serv. Co. of Ind.* v. *FERC,* 575 F.2d at 1213); Large Public Power Council at 32 (quoting *Pub. Serv. Co. of Ind., Inc.* v. *FERC,* 575 F.2d at 1213).

[398] *Gulf States Utils. Co.,* 5 FERC ¶ 61,066 at 61,098 (1978).

[399] *Otter Tail Power Co.* v. *United States,* 410 U.S. 366, 374–75 (1973) (*Otter Tail* v. *U.S.*).

[400] Sponsoring PJM Transmission Owners at 14; Ad Hoc Coalition of Southeastern Utilities at n.176 (citing *Entergy Services Inc.,* 64 FERC ¶ 61,001 at ¶ 61,013, n.66 (1993); *Cargill, Inc.* v. *Montfort of Colorado, Inc.,* 479 U.S. 104, 115–117 (1976)).

[401] Sponsoring PJM Transmission Owners at 12 (citing *CAISO.* v. *FERC,* 372 F.3d 400; *NAACP* v. *FPC,* 425 U.S. 662 (1976)).

[402] *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol,* Order No. 436, FERC Stats. & Regs. ¶ 30,665, at 31,502 (1985).

[403] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.,* Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888–A, FERC Stats. & Regs. ¶ 31,048, *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)).

[404] Sponsoring PJM Transmission Owners at 14 (citing 410 U.S. 366 (1973)).

[405] *Gulf States Util. Co.,* 5 FERC ¶ 61,066 at 61,098.

[406] Sponsoring PJM Transmission Owners at 15 (citing *Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667, 686 (D.C. Cir. 2000)).

[407] *See e.g.,* Ameren; PSEG Companies; and MISO Transmission Owners Group.

[408] *See, e.g.,* MISO Transmission Owners Group 2; and Ameren.

[409] *See, e.g.,* Ameren; Southern Companies; and MISO Transmission Owners Group 2.

[410] *See, e.g.,* Ameren; PSEG Companies; MISO Transmission Owners Group; and Southern Companies.

[411] *See, e.g.,* MISO Transmission Owners Group 2; and PSEG Companies.

[412] *See, e.g.,* Baltimore Gas & Electric; and Transmission Dependent Utility Systems.

[413] *See, e.g.,* Baltimore Gas & Electric; and MISO.

the Commission failed to appreciate what a federal right of first refusal is. MISO states that since it does not own any transmission facilities, it needs to rely on the transmission owners' obligation to build under the Transmission Owners Agreement to ensure MISO's ability to fulfill its transmission planning and expansion responsibilities as an RTO. MISO states that its membership could be significantly eroded and its existence could be jeopardized, as well as its rate significantly affected, if the Commission were to modify this fundamental element of MISO's structure as an RTO.

356. PSEG Companies contend that the elimination of the federal right of first refusal is a taking in violation of the Fifth Amendment to the U.S. Constitution because it renders meaningless the contractually-based consideration transmission owners received when they transferred control of their transmission facilities to ISOs/RTOs. They note that takings may not only be regulatory in nature but could include contractual takings.[414] According to PSEG Companies, language in the PJM Transmission Owners Agreement created the reasonable investment-backed expectation among incumbent transmission owners that they could participate in an RTO arrangement and commit to build everything needed for reliability purposes while still preserving fundamental rights, such as the right to build in their respective zones. PSEG Companies conclude that the Commission's impairment of this contractual right of first refusal creates unspecified economic injuries that, without just compensation, violate the U.S. Constitution.

(a) Commission Determination

357. We affirm the decision in Order No. 1000 that the Commission has the legal authority under section 206 of the FPA to require the elimination of federal rights of first refusal as practices that have the potential to lead to Commission-jurisdictional rates that are unjust and unreasonable or unduly discriminatory or preferential.[415] At the outset, it is important to emphasize the scope of the Commission's requirement to eliminate federal rights of first refusal. In Order No. 1000, the Commission required public utility transmission providers to remove from Commission-jurisdictional tariffs and agreements provisions that grant a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation.[416] The Commission did not, however, require public utility transmission providers to remove a federal right of first refusal for local transmission facilities or upgrades to an incumbent transmission provider's own transmission facilities, and did not alter an incumbent transmission provider's use and control of an existing right of way.[417]

358. We affirm the decision in Order No. 1000 that a federal right of first refusal is a practice that falls squarely within the interpretation of a practice affecting rates.[418] To this end, contrary to the argument of some petitioners, the Commission affirms that the *CAISO* v. *FERC* decision supports the Commission's position. As discussed in Order No. 1000, the court in *CAISO* v. *FERC* explained that the Commission is empowered under section 206 to assess practices that directly affect or are closely related to a public utility's rates and ''not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so.''[419] As explained in Order No. 1000, we meet this standard because here we are focused on the effect that federal rights of first refusal in Commission-approved tariffs and agreements have on competition and in turn the rates for jurisdictional transmission services. For example, as the Commission explained in Order No. 1000, the selection of transmission facilities in a regional transmission plan for purposes of cost allocation is directly related to costs that will be allocated to jurisdictional ratepayers.[420] The ability of an incumbent transmission provider to discourage or preclude participation of new transmission developers through discriminatory rules in a regional transmission planning process, and in particular, the inclusion of a federal right of first refusal, can have the effect of limiting the identification and evaluation of potential solutions to regional transmission needs.[421] This in turn can directly increase the cost of new transmission development that is recovered from jurisdictional customers through rates.[422]

359. Sponsoring PJM Transmission Owners argue that section 7 of the NGA, which gives the Commission authority to regulate pipeline construction, demonstrates that had Congress desired to give the Commission authority over construction of transmission lines it would have done so. However, Sponsoring PJM Transmission Owners misconstrue the Commission's actions in Order No. 1000. As the Commission explicitly stated in Order No. 1000, it is not regulating construction of new transmission facilities because that is a matter reserved to the states.[423] Instead, the Commission acted under its legal authority in section 206 to require the elimination of provisions in federally-regulated tariffs establishing practices in the regional transmission planning process that affect rates. The authority to authorize construction and siting of new transmission facilities is distinct from the authority to require public utility transmission providers to engage in an open and transparent regional transmission planning process designed to ensure that the more efficient or cost-effective solutions to regional transmission needs are selected in the regional transmission plan for purposes of cost allocation.

360. Contrary to Baltimore Gas & Electric's arguments, the Commission made a finding in Order No. 1000 that granting an incumbent transmission provider a federal right of first refusal with respect to transmission facilities selected in a regional transmission plan for purposes of cost allocation can lead to rates for Commission-jurisdictional services that are unjust and unreasonable or otherwise result in undue discrimination by public utility transmission providers.[424] Consistent with section 206, the Commission acted to remedy an unjust and unreasonable or unduly discriminatory or preferential practice by requiring public utility transmission providers to eliminate such provisions from Commission-jurisdictional tariffs or agreements and adopt the nonincumbent transmission developer reforms. In addition, the Commission's decision to require public utility transmission providers to adopt the nonincumbent transmission developer reforms was an appropriate, and adequately tailored, remedy in light of the Commission's conclusion that it is not in the economic self-interest of public utility transmission providers to permit new entrants to develop

[414] PSEG Companies at 36 (citing *Tahoe-Sierra Preservation Council, Inc.* v. *Tahoe Regional Planning Agency,* 535 U.S. 302, 332 (2002); *Armstrong* v. *United States,* 364 U.S. 40, 49 (1960)).

[415] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 284.

[416] *Id.* P 226.

[417] *Id.*

[418] *Id.* P 285.

[419] *CAISO* v. *FERC,* 372 F.3d at 403.

[420] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 289.

[421] *Id.* P 284.

[422] *Id.*

[423] *Id.* P 287 (''Eliminating a federal right of first refusal in Commission-jurisdictional tariffs and agreements does not, as some commenters contend, result in the regulation of matters reserved to the states, such as *transmission construction,* ownership or siting.'' (emphasis added)).

[424] *Id.* PP 253, 284.

transmission facilities.[425] For instance, some commenters supported eliminating all federal rights of first refusal. On balance, however, the Commission determined that incumbent transmission providers should be able to maintain an existing federal right of first refusal for certain types of new transmission projects, including a local transmission facility and upgrades to its existing transmission facilities. The Commission clarified that its actions were not intended to diminish the significance of an incumbent transmission provider's reliability or service obligations.[426]

361. In addition to affirming our decision to act to remedy unjust and unreasonable rates, we affirm, on an independent and alternative basis, the decision in Order No. 1000 that the elimination of any federal rights of first refusal from Commission-jurisdictional tariffs and agreements is necessary to address opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within regional transmission planning processes.[427] In Order No. 1000, the Commission explained that ''it has a responsibility to consider anticompetitive practices and to eliminate barriers to competition.'' [428] We continue to believe, as the Commission found in Order No. 1000, that we have a duty to consider anticompetitive practices and to eliminate barriers to competition consistent with the FPA.[429]

362. Petitioners rely on *City of Frankfort* and *Public Service Co. of Ind.* in support of their contention that section 206's prohibition on undue discrimination only protects customers of public utilities. However, the court did not, as petitioners would imply, set forth limits on who the Commission may, acting under its section 206 authority, protect from unduly discriminatory practices. Instead, the cases cited by petitioners address the applicability of section 206 in the context of a regulated utility appearing to provide favorable rates or terms to one customer, and the courts in those cases do not address whether section 206 may be used as a basis for eliminating unduly discriminatory or preferential practices between competitors. In addition, we continue to conclude that the Commission's action is in accordance with its responsibility to eliminate unduly discriminatory or preferential practices in regional transmission planning processes.

363. While we agree with petitioners that argue that the Commission does not have the authority to remedy every instance of undue discrimination, given the FPA's emphasis on promoting competition, the Commission has a responsibility to eliminate unduly discriminatory practices that come within the Commission's subject matter jurisdiction under section 201 of the FPA, which includes the transmission of electric energy in interstate commerce.[430] In Order No. 1000, the Commission found that ''federal rights of first refusal create opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes.'' [431] Accordingly, the Commission has acted consistent within its authority to eliminate and remedy practices that it found to be unduly discriminatory and anticompetitive. In any event, the Commission has not based its decision solely on competition concerns because, in the alternative, the Commission acted to remedy the potential for unjust and unreasonable rates for Commission-jurisdictional services in addition to promoting competition among potential transmission developers.

364. We disagree with petitioners' argument that Order No. 1000 institutionalizes undue discrimination against incumbent transmission providers. Petitioners argue that the Commission failed to consider the full scope of risks faced by incumbent transmission providers, and thus erroneously concluded that incumbent transmission providers and nonincumbent transmission developers are similarly situated. For example, some petitioners argue that many incumbent transmission providers have obligations to build placed on them under RTO and ISO member agreements. However, as explained in Order No. 1000, nonincumbent transmission developers that build a transmission facility in an RTO or ISO and become members of that RTO or ISO will be subject to the same relevant obligations that apply to incumbent transmission providers that are members of an RTO or ISO.[432] For instance, nonincumbent transmission developers also will have an obligation to expand their transmission facilities if directed to by the RTO or ISO consistent with the RTO's or ISO's tariff or governing agreement.

365. Other petitioners argue that incumbent transmission providers are not similarly situated to nonincumbent transmission developers because incumbent transmission providers, unlike nonincumbent transmission developers, must comply with reliability standards and have an obligation to serve customers. They further argue that having a federal right of first refusal is necessary to comply with these standards and obligations. While public utility transmission providers must comply with reliability standards and some public utility transmission providers have an obligation to serve,[433] we disagree that eliminating federal rights of first refusal amounts to discrimination in favor of nonincumbent transmission developers. Instead, as we stated in Order No. 1000, we are merely removing barriers to participation by all potential transmission providers in the regional transmission planning process subject to our jurisdiction. Moreover, as explained in Order No. 1000, all owners and operators of bulk-power system transmission facilities, including nonincumbent transmission developers, that successfully develop a transmission project, are required to be registered as Functional Entities [434] and must comply with all applicable reliability standards.[435] Similarly, transmission facilities selected in a regional transmission plan for purposes of cost allocation owned by a nonincumbent transmission developer would be subject to any applicable open access requirements. Accordingly, we continue to believe that the nonincumbent transmission developer reforms will not result in undue discrimination against incumbent transmission developers.

366. Similarly, we disagree with Oklahoma Gas and Electric Company that the nonincumbent transmission developer reforms materially alter the business of a public utility that has been responsible for, and entitled to earn a return from, construction of its own transmission system. As we explained in Order No. 1000, while public utilities are entitled to receive a reasonable

[425] *Id.* P 256.

[426] *Id.* P 262.

[427] *Id.* P 286.

[428] *Id.*

[429] *See Gulf States Utils. Co.,* 5 FERC ¶ 61,066 at 61,098; *Otter Tail* v. *U.S.,* 410 U.S. at 374 (''the history of Part II of the Federal Power Act indicates an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest.'').

[430] 16 U.S.C. 824.

[431] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 286.

[432] *Id.* P 265.

[433] *Id.*

[434] We use the term Functional Entity to refer to any user, owner or operator of the bulk power system that is responsible for complying with a NERC reliability standard as that term is defined in section 215(a)(3) of the FPA.

[435] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 266 (citing 18 CFR part 39.2(a) (2011)).

return on their investment, they will no longer be entitled to receive from the Commission a preferential right to make those investments in new transmission facilities that are selected in a regional transmission plan for purposes of cost allocation under the provisions of Order No. 1000.[436] Inherent in Oklahoma Gas and Electric Company's argument is that incumbent transmission providers have traditionally had the opportunity to build transmission facilities for their own transmission systems. Nothing in Order No. 1000 prohibits an incumbent transmission provider from choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not selected for selection in a regional transmission plan for purposes of cost allocation.[437]

367. We are not persuaded by Baltimore Gas & Electric's argument that a federal right of first refusal is simply the recognition of an obligation to build. In Order No. 1000, we acknowledged that a public utility transmission provider may have accepted an obligation to build in relation to its membership in an RTO or ISO, but the Commission did not agree that that obligation is necessarily dependent on the incumbent transmission provider having a corresponding federal right of first refusal to prevent other entities from constructing and owning new transmission facilities located in that region.[438] We continue to believe that an obligation to build in relation to membership in an RTO or ISO is not necessarily dependent on an incumbent transmission provider having a corresponding federal right of first refusal to prevent other entities from constructing and owning new transmission facilities located in that region,[439] and Baltimore Gas & Electric has provided no evidence to the contrary. Moreover, while eliminating a federal right of first refusal may change the benefits and obligations associated with membership in an RTO or ISO, we affirm our finding in Order No. 1000 that changing the benefits and obligations is necessary to correct practices that have the potential to lead to unjust and unreasonable rates for Commission-jurisdictional transmission service.[440] Similarly, we disagree with MISO that the nonincumbent transmission developer reforms will discourage entities from maintaining membership in an RTO or ISO, because, as explained in Order No. 1000, there are a variety of factors that public utility transmission providers must weight when evaluating the benefits and burdens of RTO/ISO membership.[441]

368. We also are not convinced by PSEG Companies' argument that requiring public utility transmission providers to eliminate a federal right of first refusal for transmission projects that are selected in the regional plan for purposes of cost allocation violates the Takings Clause of the Fifth Amendment. Nor do we agree that Order No. 1000 destroys or materially impairs PSEG Companies' purported contractual right to build in their respective service areas or zones. Although some contractual rights are ''property'' within the meaning of the Taking Clause,[442] the Commission has not impaired this alleged contractual right of first refusal. Order No. 1000 continues to permit an incumbent transmission provider, such as PSEG Companies, 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.[443]

369. Even assuming that Order No. 1000 impinges upon this alleged contractual right, PSEG Companies have not met their ''substantial burden'' to show ''whether a regulation 'reaches a certain magnitude' in depriving an owner of the use of property.'' [444] Just as ''legislation [that] readjust[s] rights and burdens is not unlawful solely because it upsets otherwise settled expectations,'' [445] the Order No. 1000 regulations regarding the federal right of first refusal are not unconstitutional takings solely because the regulations impact the benefits and burdens of transmission owner agreements. Furthermore, in arguing that Order No. 1000 operates to take their property, PSEG Companies have a burden to demonstrate the economic injury they expect to incur if they are denied the future exclusive opportunity to build transmission facilities in their service territory.[446] They have not met this burden in their rehearing request.

370. Finally, PSEG Companies also have not argued that Order No. 1000 appropriates their alleged contractual right of first refusal for public use. Nor could the Commission be said to be taking the federal right of first refusal so that another entity could use it for public purposes.[447] Rather, we require the elimination of such provisions so that incumbent transmission providers and nonincumbent transmission developers will have an opportunity on a comparable basis to propose new transmission facilities for selection in the regional transmission plan for purposes of cost allocation.[448] For these reasons, we find that the elimination of federal rights of first refusal does not constitute a taking under the Fifth Amendment's Taking Clause.

ii. Arguments That the Commission Is Inappropriately Regulating the Construction of Transmission

371. Several petitioners argue that the Commission's reforms impermissibly infringe on state jurisdiction to authorize construction and operation of transmission lines.[449] Ameren states that section 201(a) expressly provides that the Commission does not have authority over matters that are subject to regulation by the states, and that states have historically exercised jurisdiction over siting and construction of transmission facilities. Ameren asserts that had Congress wished to expand the Commission's jurisdiction, it would have done so by adding new sections to the FPA, such as sections 215 and 216, which gave the Commission expanded authority over reliability. Wisconsin PSC also argues that FPA sections 201 and 206 do not create a federal right to authorize transmission line construction.[450] According to PSEG

[436] *Id.* P 269.

[437] *Id.* P 262.

[438] *Id.* P 261.

[439] *Id.*

[440] *Id.*

[441] *Id.* P 265.

[442] *Connolly* v. *Pension Guaranty Corp.,* 475 U.S. 211, 224 (1986) (holding that congressional action that impinged upon employers' contractual rights did not constitute an unconstitutional taking).

[443] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 262.

[444] *District Intown Props. Ltd. Pshp.* v. *District of Columbia,* 198 F.3d 874, 878 (D.C. Cir. 1999) (citing *Pennsylvania Coal Co.* v. *Mahon,* 260 U.S. 393, 413 (1922)).

[445] *Connolly,* 475 U.S. at 223.

[446] *See Connolly,* 475 U.S. at 225 (to determine whether there is a ''taking,'' the Court evaluates three factors: ''(1) The economic impact of the regulation on the claimant; (2) the extent to which the regulation has interfered with investment-backed expectations; and (3) the character of the governmental action).

[447] *See Omnia,* 261 U.S. at 508–13 (holding that, while government requisition of steel frustrated a contract for delivery of steel, the government action was not an appropriation for public purposes that required just compensation).

[448] *Accord Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277, 1284 (D.C. Cir. 2007) (finding that anti-discrimination rules commonly burden the obligated parties and that the burden imposed did not create an unconstitutional taking of private property).

[449] *See, e.g.,* Wisconsin PSC; Baltimore Gas & Electric; Ameren; and PSEG Companies.

[450] Wisconsin PSC at 14–15 (citing *Dunk* v. *Pennsylvania Pub. Util. Comm'n,* 434 Pa. 41, 44–45, 252 A.2d 589, 591–92, *cert. denied,* 396 U.S. 839 (1969)).

Companies, the removal of the federal right of first refusal ''immediately, directly and irreparably impacts'' the decision of who gets to site, construct, and own transmission facilities in a transmission owner's zone, and incumbent transmission owners will no longer have the threshold right to build in their respective state service territories to satisfy their obligations under state law. In addition, Baltimore Gas & Electric argues that the federal right of first refusal has nothing to do with the Commission's limited backstop authority over transmission construction.[451]

372. Ameren requests clarification that, in implementing the requirement to remove any federal right of first refusal from Commission-jurisdictional tariffs and agreements, incumbent transmission owners that have a state certified service area or local franchise service area retain the sole right to build infrastructure and serve customers in that service territory. Ameren asserts the Commission also should clarify that it does not have the authority to preempt a state law or regulation of this type. However, Southern Companies assert that the Commission should explicitly state that Order No. 1000 preempts the state-mandated duty to serve native load to the extent that a nonincumbent sponsors a transmission project needed to fulfill that duty to serve. They argue that Order No. 1000's requirements will impair the ability of incumbents to comply with their state-mandated duty to serve native load, and that these provisions might be used to argue that incumbents should be subject to ramifications under state law for a nonincumbent's delay, abandonment, or other possible wrong doing.

373. Other petitioners point out that, unlike the NGA, the FPA does not grant the Commission any authority over construction or ownership of transmission facilities.[452] Wisconsin PSC states that Order No. 1000 confusingly implies the existence in the FPA of a federal ability to confer a right to construct, which is not in the FPA, whereas the FPA reserved such authority to state jurisdiction.[453] Wisconsin PSC argues that in *Connecticut Light & Power Co.* v. *FERC,* the Supreme Court engages in an extensive discussion that suggests that even though the particular facilities and activities of a person determine whether the person is a public utility subject to the FPA, there is a limit to the agency's jurisdiction.[454] Southern Companies also state that the decision to construct or invest in a transmission facility does not belong to the Commission, except as required to grant or maintain service for transmission service customers.[455] They argue there is no authority for the proposition that the Commission may require a public utility transmission provider to plan for, construct, or fund any new transmission facility involuntarily.

374. Some petitioners argue that existing rights of first refusal in Commission-approved RTO/ISO tariffs and agreements were crafted and negotiated expressly to ensure that each incumbent load-serving transmission owner could continue to fulfill its state-imposed service obligations.[456] Baltimore Gas & Electric states that the federal right of first refusal stems from the natural monopoly franchise service obligations that retail public utilities must abide by, in part through their Commission-jurisdictional wholesale transmission lines. According to Baltimore Gas & Electric, Commission-jurisdictional tariffs and agreements merely acknowledge the right of first refusal that Baltimore Gas & Electric had before joining PJM and others had before joining other RTOs and ISOs. Thus, Baltimore Gas & Electric argues that there is no such thing as a federal right of first refusal derived from a Commission tariff, but rather a right of first refusal in a Commission tariff connotes that the transmission owner retained its existing state-granted right of first refusal when it voluntarily submitted itself to the regional planning process of whatever RTO or ISO it opted to join, if any.

375. Moreover, MISO contends that the removal of such provisions would place MISO in the role of deciding who should construct planned transmission facilities. It states that state law, not federal, governs the preconditions associated with the siting and construction of transmission and the appurtenant rights associated with such construction including, but not limited to, the right of eminent domain. As such, MISO argues that its role under Order No. 1000 should not be to determine who should build specific transmission projects identified through its transmission planning process because it has not been vested with any rights by any state legislature or state commission regarding the construction of the facilities that may be deemed necessary as a result of the MISO Transmission Expansion Plan process or any other plan developed by MISO and its stakeholders. Therefore, MISO requests that the Commission reconsider Order No. 1000's generic requirement regarding the elimination of rights of first refusal from jurisdictional tariffs and agreements, insofar as that requirement would entail modification of the Transmission Owners Agreement provisions on the transmission owners' right to build, and related tariff provisions.

376. Southern Companies argue that the Commission seeks to regulate who has the right to construct and own transmission facilities by regulating who is entitled to the benefits of the regional and interregional cost allocation processes. Southern Companies argue that nothing in section 206 confers upon the Commission authority to require, authorize, or regulate who will construct or own transmission facilities or sponsor a transmission project in a transmission planning process.[457] Similarly, Ad Hoc Coalition of Southeastern Utilities argues that although the Commission does not directly mandate construction according to regional plans, this distinction may prove to be immaterial as the financially punitive effect of constructing redundant transmission facilities makes deference to nonincumbent transmission developers effectively mandatory.[458] Large Public Power Council makes a similar argument. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council assert that this creates a dilemma for incumbent transmission developers that must effectively defer to the plans of nonincumbent developers but also must continue to satisfy their service obligations while complying with potentially costly mandatory and enforceable reliability standards.

(a) Commission Determination

377. We affirm the Commission's finding in Order No. 1000 that the nonincumbent transmission developer reforms do not result in the regulation of matters reserved to the states, such as transmission construction, ownership or

[451] Baltimore Gas & Electric at 5 (citing 16 U.S.C. 824p).

[452] *See, e.g.,* Southern Companies; and Wisconsin PSC.

[453] Wisconsin PSC at 13–14 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 334, 340).

[454] Wisconsin PSC at 14 (citing 324 U.S. 515, 525–27 (1945)).

[455] Southern Companies at 102 (citing *Alabama Power Co.* v. *FERC,* 993 F.2d 1557 (D.C. Cir. 1993)).

[456] Ameren; MISO Transmission Owners Group 2; and PSEG Companies. PSEG Companies state that their points in this regard are buttressed by comments from Pennsylvania PUC, ITC, and SPP.

[457] Southern Companies at 60 (citing *Northern Gas Co.* v. *Kansas Comm'n,* 372 U.S. 84, 91–93 (1963)).

[458] Ad Hoc Coalition of Southeastern Utilities at 57 (citing *Associated Gas,* 824 F.2d at 1000–01).

siting.[459] As the Commission explained in Order No. 1000, the nonincumbent transmission developer reforms are focused solely on public utility transmission provider tariffs and agreements subject to the Commission's jurisdiction and are not intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.[460]

378. We disagree with petitioners that argue that the Commission needs new authority in the FPA to adopt the nonincumbent transmission developer reforms, as these arguments rest on the faulty premise that the Commission is somehow regulating the construction of transmission facilities. Order No. 1000 does not address transmission construction. Instead, the nonincumbent transmission developer reforms in Order No. 1000 ensure that nonincumbent transmission developers have a comparable opportunity to incumbent transmission developers/providers to submit transmission projects for evaluation and potential selection in the regional transmission plan for purposes of cost allocation. These reforms further provide that a nonincumbent transmission developer's project that is selected in the regional transmission plan for purposes of cost allocation will not be subject to any federal right of first refusal, which must be eliminated, except in certain limited circumstances. The reforms do not, however, speak to which entity may ultimately construct any transmission facilities. Moreover, we note that we agree with Baltimore Gas & Electric that eliminating a federal right of first refusal is unrelated to the Commission's authority under section 216 of the FPA.[461]

379. We disagree with petitioners that argue that eliminating a federal right of first refusal preempts state law, or is otherwise prohibited by state law. As noted above, the Commission made clear that its reforms are focused on Commission-jurisdictional tariffs and agreements, and are not intended to preempt state or local laws or regulations. Moreover, as explained in greater detail below, an incumbent transmission provider has several choices for meeting its reliability needs and service obligations. In particular, Order No. 1000 permits an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not selected for regional cost allocation.[462]

380. In response to Wisconsin PSC, we note that the Commission specifically declined in Order No. 1000 to adopt the proposal in the rulemaking that would have required public utility transmission providers in the regional transmission planning process to provide transmission developers a right to construct and own a transmission facility selected in a regional transmission plan for purposes of cost allocation.[463] The Commission also declined to a provide transmission developer with an ongoing right to build and own a transmission project that it proposed but that was not selected.[464] Because the Commission did not adopt these proposals, we do not need to address whether the Commission has the authority to grant them.

381. In response to Baltimore Gas & Electric's argument that Commission-jurisdictional tariffs and agreements merely acknowledge a right of first refusal that it had before joining PJM, we affirm the statement in Order No. 1000 that ''[t]his Final Rule does not require removal of references to such state or local laws or regulations from Commission-approved tariffs or agreements.'' [465] Accordingly, such a right based on a state or local law or regulation would still exist under state or local law even if removed from the Commission-jurisdictional tariff or agreement, and nothing in Order No. 1000 changes that law or regulation, for Order No. 1000 is clear that nothing therein is ''intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to construction of transmission facilities.'' [466]

382. We disagree with MISO that eliminating a federal right of first refusal would put it in the position of deciding who should construct planned transmission facilities. Rather, the transmission planning and cost allocation reforms in Order No. 1000 are designed to allow the public utility transmission providers in a transmission planning region to evaluate whether new transmission facilities would efficiently and cost-effectively meet their transmission needs, as well as to provide a cost allocation method for those facilities selected in the regional transmission plan for purposes of cost allocation. We acknowledge that a decision made to select a new transmission facility in the regional transmission plan for purposes of cost allocation may affect which entity ultimately constructs and owns transmission facilities. However, we reiterate that nothing in Order No. 1000 creates any new authority for the Commission nor public utility transmission providers acting through a regional transmission planning process to site or authorize the construction of transmission projects. Furthermore, Order No. 1000 does not prohibit an incumbent transmission provider from having a federal right of first refusal for a new local transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.

iii. Arguments That the Commission Must Meet the *Mobile-Sierra* Public Interest Standard Before Requiring Federal Rights of First Refusal To Be Removed From Agreements

383. Several petitioners argue that the Commission cannot modify a contractual federal right of first refusal without first making a determination that the federal right of first refusal seriously harms the public, which they argue the Commission failed to do.[467] MISO Transmission Owners Group 2 argues that in *Mobile-Sierra,* the U.S. Supreme Court found that the Commission must presume that the rate set out in a freely-negotiated wholesale energy contract meets the just and reasonable requirement, and that this presumption can be overcome only if the Commission concludes that the contract seriously harms the public interest. MISO Transmission Owners Group 2 also argues that other Supreme Court precedent found that the Commission cannot base its demand that public utility transmission providers modify existing contracts on a finding that the existing contract provisions may lead to rates that are unjust and unreasonable.[468]

[459] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 287.

[460] *Id.*

[461] 16 U.S.C. 824p (2006). Section 216 addresses the designation and siting of transmission facilities within National Interest Electric Transmission Corridors.

[462] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 262.

[463] *Id.* P 338.

[464] *Id.* P 340.

[465] *Id.* P 253 n.231.

[466] *Id.* P 287.

[467] *See, e.g.,* Ameren; Sponsoring PJM Transmission Owners at 21 (citing *Morgan Stanley Capital Group* v. *Pub. Util. Dist. No. 1 of Snohomish City.,* 554 U.S. 527, 545–46 (2008)); Baltimore Gas & Electric; PSEG Companies at 9–11, 14–15 (citing comments from Oklahoma Gas & Electric Co., Ad Hoc Coalition of Southeastern Utilities, North Dakota & South Dakota Commissions, Alabama PSC, Southern Companies, Baltimore Gas & Electric Co., MidAmerican, Pacific Gas & Electric, PJM, PSEG Companies, and Southern California Edison); MISO; MISO Transmission Owners Group 2; Northern Tier Transmission Group.

[468] MISO Transmission Owners Group 2 at 32 (citing *Morgan Stanley Capital Group, Inc.* v. *Public Utility Dist. No. 1,* 554 U.S. 527 (2008) and *NRG*

384. Some petitioners state that the federal right of first refusal is embodied in the PJM Transmission Owner's Agreement, and thus assert that the Commission must make a *Mobile-Sierra* finding before it can modify the agreement.[469] PSEG Companies argue that the Commission cannot make such a finding because nothing in Order No. 1000 or in the rulemaking record would support such a conclusion.

385. Other petitioners also argue that Order No. 1000 does not discuss how existing contractual rights of first refusal, such as that in the Midwest ISO Transmission Owners Agreement, seriously harm the public interest.[470] MISO states that while Order No. 1000 purports to avoid addressing *Mobile-Sierra* issues with regard to any particular jurisdictional agreement, the Commission erred in requiring generically in this proceeding a modification that it cannot require specifically for each jurisdictional agreement without determining that the retention of such a right in the particular agreement is against the public interest, unjust, unreasonable, or unduly discriminatory or preferential, or otherwise anticompetitive. MISO further argues that with respect to the public interest standard, the Commission cannot make a generic finding as a substitute for the specific finding it must make before declaring that the provisions of a particular agreement are contrary to the public interest.

386. In addition, PSEG Companies disagree with the statement in Order No. 1000 that this issue can be deferred until the compliance stage of this proceeding. Specifically, they take issue with the Commission's conclusion that the record was insufficient to address National Grid's comment regarding *Mobile-Sierra* and the ISO–NE operating agreement, stating that if the Commission had serious evidence of harm to the public interest then it should have had no difficulty in articulating it in Order No. 1000. PSEG Companies assert that it is ironic that while the Commission chose to engage in nationwide abrogation of individual contracts in a generic rulemaking, it seeks to avoid the required analysis on the ground that a rulemaking proceeding is an inappropriate vehicle for such an analysis. They also argue that the Commission's decision to defer review of the *Mobile-Sierra* protections to the compliance stage has no basis in law, explaining that the Commission is bound by law to apply the standard before abrogating any contracts. PSEG Companies state that the compliance stage is not the appropriate procedural stage to address this issue because under *Mobile-Sierra* the Commission has the burden to make its public interest finding and it is not the contracting parties' burden to defend the provisions that the Commission seeks to modify.[471]

387. Sunflower, Mid-Kansas, and Western Farmers request a partial stay of Order No. 1000's effectiveness, at least for RTOs that have limited federal rights of first refusal, if the Commission does not grant their requests for rehearing and clarification, so that RTOs are not required to remove any federal right of first refusal provisions until Order No. 1000 is final and non-appealable. They argue that it is highly likely that Order No. 1000 will be appealed and that the rehearing and appeals process may span several years. Sunflower, Mid-Kansas, and Western Farmers assert that stakeholders will be irreparably harmed if this portion of Order No. 1000 is effective before the appeals process is complete, citing the time and resources needed to modify existing tariffs and, more important, the loss of SPP transmission owners' rights that cannot be restored if the courts rule against the Commission on this issue.

(a) Commission Determination

388. The Commission affirms its decision in Order No. 1000 to address arguments that an individual contract contains a federal right of first refusal that is protected by a *Mobile-Sierra* provision when it reviews the compliance filings made by public utility transmission providers. We continue to find that the record in this rulemaking proceeding is not sufficient to address the specific issues raised regarding individual agreements. Accordingly, we reject arguments that the Commission must address in this generic rulemaking proceeding whether any particular agreement is protected by a *Mobile-Sierra* provision. Furthermore, in response to PSEG Companies, the Commission decided in Order No. 1000 when it will address the issue of whether a federal right of first refusal provision is protected by *Mobile-Sierra;* it did not and cannot shift the burden to defend such provisions to contracting parties.

389. As the Commission explained in Order No. 1000, a public utility transmission provider that considers its contract to be protected by a *Mobile-Sierra* provision may present its arguments as part of its compliance filing. We clarify, however, that any such compliance filing must include the revisions to any Commission-jurisdictional tariffs and agreements necessary to comply with Order No. 1000 as well as the *Mobile-Sierra* provision arguments. The Commission will first decide, based on a more complete record, including the viewpoints of other interested parties, whether the agreement is protected by a *Mobile-Sierra* provision, and if so, whether the Commission has met the applicable standard of review such that it can require the modification of the particular provisions.[472] If the Commission determines that the agreement is protected by a *Mobile-Sierra* provision and that it cannot meet the applicable standard of review, then the Commission will not consider whether the revisions submitted to the Commission-jurisdictional tariffs and agreements comply with Order No. 1000. However, if the Commission determines that the agreement is not protected by a *Mobile-Sierra* provision or that the Commission has met the applicable standard of review, then the Commission will decide whether the revisions to the Commission-jurisdictional tariffs and agreements comply with Order No. 1000 and, if such tariffs and agreements are accepted, would become effective consistent with the approved effective date. As a result, the Commission is not requiring public utility transmission providers to eliminate a federal right of first refusal before the Commission makes a determination regarding whether an agreement is protected by a *Mobile-Sierra* provision and whether the Commission has met the applicable standard of review, while at the same time the Commission is ensuring that the Order No. 1000 compliance process proceeds expeditiously and efficiently.

390. We also deny Sunflower, Mid-Kansas, and Western Farmers' request for a partial stay of the requirement to remove a federal right of first refusal from Commission-jurisdictional tariffs and agreements. In considering requests for a stay, the Commission has applied the standards set forth in section 705 of

Power Marketing, LLC v. *Maine PUC,* 130 S.Ct. 693 (2010)).

[469] *See, e.g.,* Sponsoring PJM Transmission Owners; Baltimore Gas & Electric; and PSEG Companies.

[470] Ameren at 16 (citing Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation, Third Revised Rate Schedule FERC No. 1); MISO; MISO Transmission Owners Group 2.

[471] PSEG Companies at 13 (citing *Wisconsin Public Power, Inc.* v. *FERC,* 493 F.3d 239 (D.C. Cir. 2007)).

[472] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 292.

the Administrative Procedure Act,[473] and has granted a stay ''when justice so requires.'' [474] In deciding whether justice requires a stay, the Commission considers several factors, including: (1) Whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing the stay may substantially harm other parties; and (3) whether a stay is in the public interest.[475] The Commission's general policy is to refrain from granting stays of its orders to assure definiteness and finality in Commission proceedings.[476] If the party requesting the stay is unable to demonstrate that it will suffer irreparable harm absent a stay, the Commission need not examine the other factors.[477] As the D.C. Circuit has explained, a harm must be both certain and actual rather than theoretical, and ''mere injuries, however substantial, in terms of money, time and energy necessarily expended in the absence of a stay are not enough.''[478]

391. Sunflower, Mid-Kansas, and Western Farmers' request for stay fails to meet the first criterion, which requires it to show that it will suffer irreparable injury without a stay of the requirement to eliminate a federal right of first refusal. They argue that they must spend time and resources to modify existing tariffs. However, we find that this type of economic loss is not sufficient to warrant a stay. Furthermore, while Sunflower, Mid-Kansas and Western Farmers may lose the opportunity to exercise a federal right of first refusal, it amounts to speculation to assert that this will necessarily cause Sunflower, Mid-Kansas and Western Farmers to lose the opportunity to build a transmission project that they could have exercised a federal right of first refusal to build. They also will still have the opportunity to submit projects for evaluation and potential selection in the regional transmission plan for purposes of cost allocation as well as to build local transmission projects.[479] Thus, the harm that Sunflower, Mid-Kansas and Western Farmers argue that they will suffer is speculative because Sunflower, Mid-Kansas and Western Farmers cannot point to a specific transmission project that they will lose the right to construct and own at this time, or in the immediate future. Accordingly, we find that Sunflower, Mid-Kansas and Western Farmers have not shown that they will suffer irreparable harm absent a stay of the nonincumbent transmission developer reforms in Order No. 1000.[480]

2. *Requirement To Remove a Federal Right of First Refusal From Commission-Jurisdictional Tariffs and Agreements, and Limits on the Applicability of That Requirement*

a. Final Rule

392. In Order No. 1000, the Commission directed public utility transmission providers to 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.[481] However, Order No. 1000 also limited the applicability of that elimination requirement in important ways. The Commission stated that its focus was on the set of transmission facilities that are evaluated at the regional level and selected in the regional transmission plan for purposes of cost allocation, and that it was not requiring removal from Commission-jurisdictional tariffs and agreements of federal rights of first refusal as applicable to a local transmission facility.[482] Additionally, the Commission explained that the reforms do not affect the right of an incumbent transmission provider to build, own, and recover costs for upgrades to its own transmission facilities, such as in the case of tower change outs or reconductoring, regardless of whether an upgrade has been selected in a regional transmission plan for purposes of cost allocation.[483] The Commission further noted that the reforms are not intended to alter an incumbent transmission provider's use and control of its existing rights-of-way, the retention, modification, or transfer of which remain subject to the relevant law or regulation that granted the right-of-way.[484]

393. In a separate section of Order No. 1000, the Commission stated that 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 public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project.'' By contrast, the Commission explained that an '''incumbent transmission developer/provider' is an entity that develops a transmission project within its own retail distribution service territory or footprint.'' [485]

394. The Commission also distinguished between a transmission facility in a regional transmission plan and a transmission facility selected in a regional transmission plan for purposes of cost allocation.[486] The Commission also defined the term ''local transmission facility,'' which it stated is a transmission facility located solely within a public utility's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation.[487]

b. Requests for Rehearing and Clarification

395. Several petitioners seek rehearing or clarification regarding the implementation of the removal of a federal right of first refusal for projects that are selected in the regional transmission plan for purposes of cost allocation.[488] Northern Tier Transmission Group requests that the Commission clarify the types of Commission-jurisdictional agreements that are subject to Order No. 1000's federal right of first refusal prohibition as well as the types of provisions that constitute federal rights of first refusal. Northern Tier Transmission Group asserts that these clarifications are necessary to determine which bilateral

[473] 5 U.S.C. 705 (2006).

[474] *Id.*

[475] *See, e.g., CMS Midland, Inc.,* 56 FERC ¶ 61,177 at P 61,631 (1991), *aff'd sub nom. Mich. Mun. Coop. Group* v. *FERC,* 990 F.2d 1377 (D.C. Cir.), *cert. denied,* 510 U.S. 990 (1993).

[476] *Id.*

[477] *Id.*

[478] *Wisconsin Gas Co.* v. *FERC,* 785 F.2d 699, 674 (D.C. Cir. 1985).

[479] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 318.

[480] Moreover, though unnecessary to support our denial of this motion for stay, we note that issuing a stay here may substantially harm other parties, thereby violating the second factor the Commission considers in whether to grant a stay. As the Commission has explained, greater participation by transmission developers in the transmission planning process may lower the cost of new transmission facilities for transmission customers, enabling more efficient or cost-effective solutions to regional transmission needs. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 291. Accordingly, because the removal of a federal right of first refusal applies only to new transmission facilities selected in a regional transmission plan for purposes of cost allocation, granting a stay of the requirement to eliminate a federal right of first refusal would delay these potential cost-saving and efficiency benefits for all entities in the region for the duration of the stay.

[481] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 313.

[482] *Id.* P 318.

[483] *Id.* P 319.

[484] *Id.*

[485] *Id.* P 225.

[486] *Id.* PP 63–66.

[487] *Id.* PP 63–64.

[488] *See, e.g.,* Northern Tier Transmission Group; Duke; AEP; AEP; Sunflower, Mid-Kansas, and Western Farmers; and Dayton Power and Light.

agreements are affected by the rule and the types of provisions that are prohibited in future contracts. In addition, Northern Tier Transmission Group argues that the modification of bilateral agreements undermines the balance of the agreements, and therefore must be accomplished in accordance with relevant Commission precedent.

396. Some petitioners seek clarification of what Order No. 1000 intends when referring to ''nonincumbent transmission developer'' and ''incumbent transmission developer/provider.''[489] Transmission Access Policy Study Group and APPA state that the definitions of nonincumbent transmission developer and incumbent transmission developer/provider would exclude most municipal electric systems and electric cooperatives, as well as other public power entities. For example, Transmission Access Policy Study Group and APPA argue that because most non-public utility transmission developers have retail distribution service territories, they would not qualify as nonincumbent transmission developers under the first part of the definition. They also argue that non-public utility transmission providers, as defined in section 201(f) of the FPA, are not public utilities under FPA section 201(e); thus they would not qualify as nonincumbent transmission developers under the second part of the definition. Transmission Access Policy Study Group believes that this limitation was inadvertent and that the Commission should correct this error while at the same time keeping in mind that some references to ''nonincumbent transmission developer'' may in fact be intended to apply only to jurisdictional entities.

397. APPA notes that Order No. 1000 at P 227 requires incumbent transmission developers/providers to develop a framework that includes provisions regarding how best to address participation by nonincumbent transmission developers. Therefore, APPA and Transmission Access Policy Study Group are concerned that, if non-public entities do not qualify as nonincumbent transmission developers, incumbent transmission providers will not include provisions to address their participation. Accordingly, they ask the Commission to make clear that non-public utility transmission developers can be considered nonincumbent transmission developers.

398. APPA also argues that, given these definitions, incumbent transmission developers/providers may develop a framework that prevents public power utilities from participating in joint ownership of regional transmission projects. On rehearing, APPA requests that the Commission clarify that this result was not intended and that the Commission revise the relevant definitions to allow for participation by public power entities in transmission projects.Otherwise, APPA requests rehearing of this issue on the grounds that the definitions are unduly discriminatory as applied to public power utilities and preferential as applied to public utilities and other for-profit entities, in violation of sections 205 and 206 of the FPA.

399. Some petitioners seek guidance or clarification regarding the term ''footprint'' as it is used in the definitions of a ''local transmission facility'' and ''incumbent transmission developer.''[490] American Transmission and ITC Companies interpret the term footprint to be directed at entities, such as transmission-only companies, that do not have retail distribution service territories, and thus expands the definitions of an incumbent and a local transmission facility instead of further defining retail distribution service territory. If the Commission instead clarifies that the term is intended to further define retail distribution service territory, then American Transmission seeks rehearing of the definition of incumbent transmission developer, arguing that it is arbitrary and capricious and discriminatory to exclude transmission-only companies from the definition.It argues that it should be considered an incumbent because it is subject to the mandatory NERC reliability standards for its facilities. As for the definition of a local transmission facility, ITC Companies state that they have no local transmission plans and that all transmission projects they propose are evaluated and included under the MISO or SPP Transmission Expansion Plans and are not ''merely rolled up.'' However, ITC Companies state that these projects may be located solely within the footprint of one or more of the ITC Companies.

400. Wisconsin PSC adds that American Transmission, for example, is effectively an incumbent transmission provider with a footprint equivalent to the aggregate franchise territories of its wholesale load-serving entity customers. Wisconsin PSC asserts that categorizing American Transmission as a nonincumbent transmission developer would treat it as a merchant transmission developer in its home territory of the last ten years and compel it to double up on the essentially local planning processes as if it was a merchant, even though it currently conducts regional planning in coordination with MISO's regional planning.Wisconsin PSC asserts that the extra costs from such duplicative planning would be unjust and unreasonable and therefore it requests that the Commission clarify the categorization of nonincumbent transmission developer to exclude transmission-only entities.

401. Duke seeks confirmation that a nonincumbent transmission developer either becomes an incumbent transmission developer/provider when its project is energized, if not sooner, or that the provisions of paragraph 319 of Order No. 1000, relating to upgrades and use of rights-of-way, apply to nonincumbents that construct projects. Also, according to Duke, the term ''retail distribution,'' as used in the definitions of nonincumbent transmission developer and incumbent transmission developer/provider, modifies ''service territory'' but not ''footprint.''Thus, Duke contends that, under this interpretation, the nonincumbent developer of an actual project will eventually have a footprint and thus become an incumbent as to that limited footprint. However, if the Commission clarifies that nonincumbents never become incumbents, then it requests that the Commission nonetheless grant nonincumbents the same rights described in paragraph 319 of Order No. 1000 as to its own facilities and rights of way and describe when those rights would exist. It recommends that a nonincumbent obtains a federal right of first refusal no later than energization of its facilities.At a minimum, Duke requests detailed clarification on this issue so as to avoid litigation on compliance.

402. Edison Electric Institute seeks clarification that public utility transmission providers constructing new facilities in their ''footprint'' pursuant to service obligations imposed on them under federal, state, or local law or under long-term contracts are included in the definition of incumbent transmission providers. It notes that some transmission facility-owning public utilities may lack a retail distribution service territory, and that other transmission facility-owning public utilities with retail distribution service territories may need to construct new transmission facilities that are not fully contained within those retail

[489] *See, e.g.,* Transmission Access Policy Study Group; and APPA.

[490] *See, e.g.,* ITC Companies; LS Power; American Transmission; Wisconsin PSC; and Edison Electric Institute.

distribution territories. Thus, it seeks clarification that both kinds of transmission facility-owning public utilities continue to have the same right to construct reliability projects not subject to regional cost allocation where necessary to meet their reliability needs or service obligations. It also seeks confirmation that the use of the term ''footprint'' is intended to capture new facility construction that may be separate from a retail distribution service territory but is nonetheless being constructed by an incumbent transmission owning utility to meet reliability or service obligation needs, adding that this clarification would tie the right of an incumbent transmission provider to choose to build facilities not submitted for regional cost allocation to the existence of a service obligation under federal, state, or local law or under long-term contracts. To the extent that the Commission intended to grant this right in favor of some public utility transmission provider service obligations and not others, Edison Electric Institute argues that the Commission is required to explain and justify its decision.

403. Other petitioners request clarification or rehearing as to how to determine whether a project is considered a regional or local project.[491] For instance, LS Power requests clarification of how the Commission intends to apply this local exemption. LS Power states that the Commission did not explain how a footprint might differ from a retail distribution area, which may have a different meaning in different states. Also, LS Power states that while a retail distribution area is a familiar concept, it does not provide a geographic-based definition.For example, a utility may own a transmission line that geographically extends beyond its retail service area that it may believe should be part of its footprint, but that line may cross into another transmission provider's geographical retail distribution area which the other transmission provider considers to be part of its footprint. LS Power also states that joint ownership of a substation or transmission line is common, where several entities all have rights to use the capacity of the line. LS Power also claims that it is unclear how this definition would be applied in the context of an RTO, where the transmission provider's footprint covers the entire region.

404. Accordingly, LS Power requests clarification that within and outside an RTO, a ''local transmission facility'' is one that is located within the geographical boundaries of the retail distribution service territory served by the public utility transmission provider as of the effective date of Order No. 1000 and interconnecting solely to the public utility transmission provider's existing facilities. LS Power continues that where there are affiliated public utility transmission providers located in adjacent and electrically connected geographic areas, they may be treated as a single transmission owner only if, as of the date Order No. 1000 became effective, the affiliates have, in the past, conducted joint planning and maintained a single transmission rate applicable to service provided by all such affiliates regardless of the customer's location within the retail distribution area of a single affiliate and, where located in a RTO, proffered a single local plan to the RTO and participated in RTO affairs as a single transmission owner (e.g., voting rights under all jurisdictional agreements). LS Power further states that any projects connecting, in whole or in part, to facilities owned by another transmission owner or to jointly owned facilities would not constitute local facilities. Last, it argues that ''local'' should be defined as of the effective date of Order No. 1000, because the area in which an incumbent transmission owner can claim an exemption to the elimination of the federal right of first refusal should not be the subject of corporate structuring.

405. Duke asserts that the primary difficulty in differentiating regional and local projects is that there are many ways to interpret the phrase ''transmission facilities selected in a regional transmission plan for purposes of cost allocation.'' According to Duke, many RTOs have adopted cost allocation approaches for all types of projects and that even local projects ultimately are included in the ''regional plan.'' In addition, Duke asserts that a pricing zone that consists of the retail distribution service territory of a single load-serving entity that was also a transmission provider is an anomaly, and that it is more likely that a typical pricing zone will consist of a public utility transmission provider and more than one retail load-serving entity with a service territory, such as, for instance, a non-jurisdictional distribution and/or transmission company. Accordingly, Duke seeks clarification that, under a zonal approach to cost allocation, a facility whose costs are allocated under an RTO tariff to a single RTO pricing zone, and which is located in that pricing zone, be deemed a local facility.

406. Duke also adds that, under a non-RTO model or dominant provider model, all the load in a single zone would be network load of the public utility transmission provider, with any other transmission owners receiving credits for their integrated transmission facilities. Accordingly, Duke requests clarification that the Commission intended that single zone facilities may be classified as local facilities, as long as the general construct under a non-RTO model, or dominant provider model, is met. Duke adds that any proposals for 're-zoning' meant to evade the impact of the removal of a federal right of first refusal can be addressed on compliance. If the Commission clarifies that a single zone facility under no circumstances can be a local facility, then Duke asserts that the Commission would effectively obliterate the federal right of first refusal in virtually every ISO and RTO, which could cause significant exoduses from ISOs and RTOs or cause ISOs and RTOs to completely overhaul their entire cost allocation processes.

407. Petitioners also seek clarification that a project that is selected in the plan, but for which the costs are assigned to a single utility, is considered a local facility for purposes of the applicability of the requirement to remove the federal right of first refusal.[492] Specifically, Duke asks whether the focus is on the result of a cost allocation method or the area over which the method is applied such as an entire region. Duke urges the Commission to adopt the results approach, and clarify that if any cost allocation approach results in a single zone being allocated the costs of a facility, then an RTO should be permitted to deem the facility as local and therefore, apply a federal right of first refusal. Duke seeks clarification that facilities that have any costs allocated outside a single zone, even if such facilities are physically in a single zone, will be presumed to be regional, unless they are an upgrade to existing facilities.

408. Dayton Power and Light also asserts that the Commission should clarify that when all of a facility's costs are assigned to a single utility zone, the tariff could continue to permit a federal right of first refusal. However, Dayton Power and Light also seeks clarification as to whether a facility that is allocated solely to one utility zone using a regional cost allocation method should be treated differently for purposes of a federal right of first refusal from a facility that is allocated predominately to one utility zone, and if so, where the break-point should be. Sunflower, Mid-

[491] *See, e.g.,* Duke; and AEP.

[492] *See, e.g.,* Duke; AEP; and Dayton Power and Light.

Kansas, and Western Farmers seek clarification (or, alternatively, rehearing) that the definition of ''regionally funded'' excludes projects where costs allocated to a region are not at least a majority of the total costs.

409. In addition, ITC Companies and Xcel request clarification of ''selected in a regional transmission plan for purposes of cost allocation'' as it applies to the transmission facilities that are approved by MISO under its MISO Transmission Expansion Plan or by SPP under its SPP Transmission Expansion Plan.[493] Xcel states that Order No. 1000 creates ambiguity by assuming that the cost allocation for local zone projects, such as in MISO and SPP, is not identified in the regional RTO tariff process.[494] Xcel states that it believes that, under Order No. 1000, the costs for a project selected in the MTEP or STEP may permissibly be assigned to a single zone, whether that zone includes the facilities of a single transmission owner or whether a transmission owner has facilities that are included in other zones, through a regional cost allocation method, and that such an allocation is not precluded by Order No. 1000.

410. ITC Companies argue that MISO cost allocation methods fall along a continuum that on one end includes 100 percent allocation on a systemwide basis for multi-value projects, and on the other end are participant funded projects assumed by project sponsors. They state that in SPP 100 percent of the costs of Base Plan Upgrades 300kV and above are allocated to a regionwide annual transmission revenue requirement and recovered through a regionwide charge. They thus assert that it is unclear whether certain projects would be considered ''transmission facilities selected * * * for purposes of cost allocation'' under Order No. 1000.[495] ITC Companies request clarification that this term means those projects approved in a regional transmission plan and which are also approved for 100 percent regional cost allocation.They argue that if the Commission does not clarify this term, if a project becomes ineligible for federal rights of first refusal when any of the costs of that project are borne by customers beyond the local zone or footprint in which that project is located, the construction of more efficient, cost-effective multi-purpose projects with broad regional benefits will be discouraged. They maintain that incumbent transmission owners will oppose projects with broader benefits in favor of less efficient projects for which their rights of first refusal are preserved. They assert that projects will be designed to avoid minor enhancements that would benefit a region, but which would not justify a stand-alone, purely economic project.

411. On the other hand, Western Independent Transmission Group argues that the Commission failed to provide a reasoned explanation of why it did not remove the federal right of first refusal for local transmission facilities, and why it is not unduly discriminatory or preferential to uphold the federal right of first refusal for facilities not in a plan for purposes of cost allocation. Western Independent Transmission Group also argues that Order No. 1000 did not address in adequate detail the boundary between transmission projects for which independent transmission developers have a right to compete, and those projects that are reserved solely to the incumbent transmission provider. According to Western Independent Transmission Group, the most obvious instance where the Commission's failure to address the subject may have significant competitive impacts on transmission planning is the distinction between public policy projects and transmission projects initiated through the generation interconnection process. Western Independent Transmission Group argues that, particularly in California, where the vast majority of approved transmission projects in the most recent 2010/2011 planning cycle were initiated through the generator interconnection process, the Commission's unwillingness to address this issue effectively left incumbent utilities with a total monopoly over the transmission built in response to renewable energy development.

412. Petitioners also seek clarification of what is to be considered an upgrade to an existing transmission facility such that the elimination of the federal right of first refusal does not apply. For example, Duke seeks clarification that if an incumbent transmission owner cuts into its own existing transmission line to construct a new 345 kV substation that is needed for stability due to local growth on its system, such a substation, even if a share of its costs are allocated to all pricing zones in a region, would be covered by the federal right of first refusal under the ''upgrades to its own transmission facilities'' carve out. If not, then Duke asserts that a region should be able to take this policy into account in implementing Order No. 1000, such that a region could alter its cost allocation method so that the type of project described above is not subject to any regional cost allocation if the region decides such projects merit a federal right of first refusal.

413. Similarly, ITC Companies seek clarification that the prohibition on a federal right of first refusal does not apply to a transmission upgrade that requires expansion of an existing right-of-way in order to be expanded. ITC Companies argue that retaining a federal right of first refusal for upgrades that require an expansion of an existing right of way is necessary to avoid unintended and adverse consequences that would undermine the optimal and cost-effective development of the grid.

414. Finally, petitioners also request rehearing of the Commission's decision to eliminate incumbent utility transmission providers' existing rights to construct reliability projects.[496] Xcel believes that incumbent transmission providers, particularly franchised utilities with an obligation to serve, should retain the right to construct transmission projects necessary for the utility to provide reliable service to their native load customers and to comply with NERC mandatory reliability standards. Xcel asserts that this federal right of first refusal does not need to be unlimited and supports the inclusion of a 90-day election period during which the incumbent transmission provider would be required to indicate its decision to move forward with the designated project. Xcel contends that the Commission's attempt to address utility providers' concerns by eliminating certain penalty responsibilities fails to recognize that utilities have an obligation to serve and are not merely worried about financial penalties.

c. Commission Determination

415. We affirm the decision in Order No. 1000 to require the elimination of a federal right of first refusal from Commission-jurisdictional tariffs and agreements for transmission facilities selected in a regional transmission plan for purposes of cost allocation. In response to Northern Tier Transmission Group, the phrase ''a federal right of first refusal'' refers only to rights of first refusal that are created by provisions in

[493] ITC Companies; Xcel at 20 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at n.299).

[494] Xcel at 20 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at n.299).

[495] ITC Companies specifically ask about the following: (1) MISO Baseline Reliability Projects eligible for 20 percent regional cost allocation but whose costs can be 100 percent allocated to the host zone pursuant to power flow modeling; (2) MISO Market Efficiency Projects eligible for 20 percent regional cost allocation; and (3) SPP Base Plan Upgrades eligible for 33 percent regional cost allocation.

[496] *See, e.g.,* Xcel; and Edison Electric Institute.

Commission-jurisdictional tariffs or agreements.[497]

416. In response to petitioners' concerns, we also clarify several of the terms used in Order No. 1000, starting with the term ''nonincumbent transmission developer.'' In doing so, we first affirm the definition of incumbent transmission developer/provider as ''an entity that develops a transmission project within its own retail distribution service territory or footprint.'' [498] Given this definition, we clarify that a ''nonincumbent transmission developer'' is any entity that is not an incumbent transmission developer/provider. We believe that this clarification, along with the others made in this order, addresses the concerns expressed by Transmission Access Policy Study Group and APPA that the definitions of nonincumbent transmission developer and incumbent transmission developer/provider in Order No. 1000 would exclude certain municipal electric systems and electric cooperatives, as well as other public power entities.

417. However, as discussed more fully below, we find that in order for a non-public utility to be considered a nonincumbent transmission developer, it must satisfy the enrollment requirement if it or an affiliate has load in the transmission planning region where it proposes a transmission project for selection in the regional transmission plan for purposes of cost allocation as would any other potential transmission developer.[499] As an initial matter, we note that the Commission did not intend through its definition of nonincumbent transmission developer in Order No. 1000 to exclude any transmission developer, including a non-public utility transmission developer, from being able to propose transmission projects and have them evaluated and selected by a regional transmission planning process for purposes of cost allocation, so long as that transmission developer abides by the same requirements as those imposed on public utility transmission providers. Allowing entities, such as non-public utility transmission developers, the opportunity to potentially propose a transmission project as a nonincumbent transmission developer furthers the Commission's goal in Order No. 1000 of ensuring that all transmission developers have a comparable opportunity to incumbent transmission developers/providers to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation.

418. However, we also recognize that it would be fundamentally unfair and thereby may lead to an unjust and unreasonable or unduly discriminatory or preferential result to allow a transmission developer, whether it is a public utility transmission developer or a non-public utility transmission developer, to seek regional cost allocation for a proposed transmission project in a transmission planning region in which it or an affiliate has load, but where neither it, nor that affiliate, has enrolled in that region where its load is located. Such a result would permit a transmission developer to allocate the costs of its project to other entities in the region pursuant to that region's cost allocation method—without first enrolling itself or its affiliate in the transmission planning region in which its load is located and potentially being allocated costs for other transmission projects for which it is found to be a beneficiary.[500]

419. Therefore, Order No. 1000's reforms regarding the submission and evaluation of proposals for potential selection in a regional transmission plan for purposes of cost allocation will apply to a transmission developer that has load or an affiliate within an area that would normally be considered a geographic part of a transmission planning region if the transmission developer or its affiliate transmission provider in that area enrolls in the transmission planning region in which that load is located. We believe that in most cases, it should be clear where an entity's load is located and therefore the region in which it would be expected to enroll. However, should disputes arise over the choice of a region, we will address them on a case-by-case basis utilizing the standard found in Order No. 890 and Order No. 1000, which provides that ''the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions.'' [501] We emphasize that an entity, including a non-public utility transmission developer, that does not have load within a transmission planning region may propose a transmission project for evaluation and potential selection in that region's transmission plan for purposes of cost allocation without enrolling in that region, as long as it satisfies the transmission planning region's other requirements for doing so, such as meeting the qualification criteria for proposing projects found in Order No. 1000.

420. Turning to other terms used in Order No. 1000, we also clarify that the phrase ''retail distribution,'' as used in the definitions of incumbent transmission developer/provider, nonincumbent transmission developer and local transmission facility, does not modify footprint. Instead, the term ''footprint,'' as used in these definitions was intended to include, but not be limited to, the location of the transmission facilities of a transmission-only company that owns and/or controls the transmission facilities of formerly vertically-integrated utilities, as well as the location of the transmission facilities of any other transmission-only company.

421. In response to Duke, we agree that a nonincumbent transmission developer will have a footprint at the time that its transmission facility is energized. As such, we clarify that a nonincumbent transmission developer will then become an incumbent transmission developer/provider for that energized transmission facility and will thereafter have all the rights and obligations that accrue to such entities under Order No. 1000, such as being able to maintain a federal right of first refusal for local transmission facilities and upgrades to those transmission facilities.

422. In response to Edison Electric Institute, we note that there are a great variety of fact patterns that may fall under its request. For example, Edison Electric Institute does not explain whether the new transmission facility would go through the retail distribution service territory of the incumbent transmission owning utility, that of another entity, or an ''unassigned'' territory. Thus, we decline to find generically that any particular transmission facility, whether it is needed to meet a reliability, economic, or transmission need driven by a Public Policy Requirement, developed outside of an *existing* retail distribution service territory or footprint, should be considered a part of that entity's footprint.

[497] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 253 n.231.

[498] *Id.* P 225.

[499] We refer to non-public utility entities that seek to propose projects in a regional transmission planning process as ''non-public utility transmission developers,'' which may include both non-public utility transmission providers that already own and operate transmission facilities and transmission-dependent non-public utilities that may wish to develop, construct, or own transmission facilities in the future.

[500] For discussion of enrolling in a transmission planning region, see the Regional Transmission Planning Requirements section. *See* discussion *supra* at section III.A.2.c.

[501] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 160 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 527).

423. We clarify that Order No. 1000 does not require elimination of a federal right of first refusal for a new transmission facility if the regional cost allocation method results in 100% of the facility's cost being allocated to the public utility transmission provider in whose retail distribution service territory or footprint the facility is to be located. Accordingly, we clarify that the term ''selected in a regional transmission plan for purposes of cost allocation'' excludes a new transmission facility if the costs of that facility are borne entirely by the public utility transmission provider in whose retail distribution service territory or footprint that new transmission facility is to be located. Although public utility transmission providers in a transmission planning region may determine, based on non-discriminatory evaluation criteria, that a proposed transmission facility is likely to have regional benefits so that the transmission facility's costs should be allocated regionally, it is not until the cost allocation method is applied that the beneficiaries are identified.

424. Petitioners request clarification about whether a transmission facility is a local transmission facility if it is selected in a regional transmission plan for purposes of cost allocation and the costs are allocated to a single pricing zone in which the proposed transmission facility is to be located, and that zone consists of more than one transmission provider. In general, any regional allocation of the cost of a new transmission facility outside a single transmission provider's retail distribution service territory or footprint, including an allocation to a ''zone'' consisting of more than one transmission provider, is an application of the regional cost allocation method and that new transmission facility is not a local transmission facility. For example, transmission-owning members of an RTO may not retain a federal right of first refusal by dividing the RTO into East and West multi-utility zones and allocating costs just within one zone consisting of more than one transmission provider. However, we recognize in response to Duke's request that special consideration is needed when a small transmission provider is located within the footprint of another transmission provider. For instance, a regional cost allocation method might allocate costs to an area consisting of one transmission provider that has within its borders one or more smaller utilities that largely depend on its transmission system but nevertheless own a little transmission of their own, so that they too are transmission providers. This situation is not necessarily ''a zone consisting of more than one transmission provider'' as this term is used in this order. If the cost of a new transmission facility is allocated entirely to an area consisting of one transmission provider that has one or more smaller transmission providers within its borders, this might qualify as a local cost allocation, not a regional cost allocation. However, as petitioners point out, there may be a continuum of examples that range from (i) one small municipality with a single small transmission facility located within a transmission provider's footprint, to (ii) a ''zone'' consisting of many public utility and nonpublic utility transmission providers. Accordingly, we will address whether a cost allocation to a multi-transmission provider zone is regional on a case-by-case basis based on the specific facts presented. Specific situations may be included in a compliance filing along with the filed regional cost allocation method or methods.

425. We disagree with Western Independent Transmission Group's assertion that the Commission failed to provide a reasoned explanation of its decision not to require the elimination of a federal right of first refusal for local transmission facilities. In Order No. 1000, the Commission recognized that incumbent transmission providers may have reliability needs or service obligations.[502] Accordingly, Order No. 1000 does not prevent an incumbent transmission provider from meeting its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not selected in a regional transmission plan for purposes of cost allocation.[503] Thus, we affirm the decision in Order No. 1000 not to require elimination from Commission-jurisdictional tariffs and agreements a federal right of first for a local transmission facility.[504] We also note in response to Western Independent Transmission Group that the Commission found that issues related to the generator interconnection process and to interconnection cost recovery were outside the scope of Order No. 1000.[505] Order No. 1000 did not establish any new requirements with respect to the generator interconnection process, and we are not persuaded to address the generator interconnection process on rehearing.

426. In response to requests for clarification regarding what the Commission considers to be an upgrade, we note that in Order No. 1000, the term upgrade means an improvement to, addition to, or replacement of a part of, an existing transmission facility. The term upgrades does not refer to an entirely new transmission facility. The concept is that there should not be a federally established monopoly over the development of an entirely new transmission facility that is selected in a regional transmission plan for purposes of cost allocation to others. However, neither is the Commission eliminating the right of an owner of a transmission facility to improve its own existing transmission facility by allowing a third-party transmission developer to, for example, propose to replace the towers or the conductors of a transmission line owned by another entity.[506] It is not feasible, however, to list every type of improvement or addition, or name all the parts of lines, towers and other equipment that may be replaced or otherwise upgrades, and we will not do so here.

427. In response to ITC Companies, we clarify that the requirement to eliminate a federal right of first refusal does not apply to any upgrade, even where the upgrade requires the expansion of an existing right-of-way. The issue is not whether the upgrade would be located in an existing right-of-way, but whether the new transmission facility is an upgrade to an incumbent transmission provider's own facilities. Furthermore, the Commission reiterates that the nonincumbent transmission developer reforms were not intended to alter an incumbent transmission provider's use and control of its existing rights-of-way under state law.[507]

428. We affirm the decision in Order No. 1000 to require the elimination of a federal right of first refusal for reliability projects. Allowing incumbent transmission providers to maintain a federal right of first refusal, even with a limited 90-day election period as proposed by Xcel, would discourage

[502] *Id.* P 262. The Commission defined a local transmission facility as a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in a regional transmission plan for purposes of cost allocation. An incumbent transmission provider would retain the option of meeting its local reliability needs or obligations to serve by building a transmission facility in its retail distribution service territory or footprint. *Id.* at P 63.

[503] *Id.* In P 262 of Order No. 1000, the Commission used the term ''submitted for regional cost allocation'' where we intended ''selected in a regional transmission plan for purposes of cost allocation.'' We provide that clarification here.

[504] *Id.* P 318.

[505] *Id.* P 760.

[506] *Id.* P 319.

[507] *Id.*

transmission developers from proposing transmission projects that may be a more efficient or cost-effective solution to meet regional transmission needs, resulting in rates for jurisdictional transmission services that are unjust and unreasonable or unduly discriminatory or preferential. The fact that a particular transmission facility is intended to meet a reliability need does not change our responsibility to eliminate practices that result in unjust and unreasonable or unduly discriminatory or preferential rates. Furthermore, Order No. 1000 includes several reforms that ensure that incumbent transmission providers will be able to satisfy their reliability needs and service obligations, even when they are relying on a nonincumbent transmission developer's project to meet a reliability need. Specifically, Order No. 1000 includes a reevaluation requirement that requires public utility transmission providers in a region to have procedures in place to identify when delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions to ensure that an incumbent transmission provider can meets its reliability needs or service obligations.[508] Moreover, we note again that Order No. 1000 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 and that are not selected in a regional transmission plan for purposes of cost allocation.[509] Accordingly, we disagree with petitioners that argue that a federal right of first refusal for reliability project is necessary for incumbent transmission providers to meet reliability needs or service obligations.

429. In response to LS Power's concerns regarding the definition of a local transmission facility, we clarify that a local transmission facility is one that is located within the geographical boundaries of a public utility transmission provider's retail distribution service territory, if it has one, otherwise the area is defined by the public utility transmission provider's footprint. Thus, if the public utility 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. In the case of an RTO or ISO whose footprint covers the entire region, we clarify that local transmission facilities are defined by reference to the retail distribution service territories or footprints of its underlying transmission owing members. We also clarify that the extent of a public utility transmission provider's retail distribution service territory or footprint is not to be measured as of the effective date of Order No. 1000, but is the retail distribution service territory or footprint in existence during the regional transmission planning cycle. We decline to provide any of the further clarifications regarding the definition of a local transmission facility as requested by LS Power and will address such matters during the compliance process based on a more complete record.

430. Finally, in response to petitioners' concerns over which facilities are selected in a regional transmission plan for purposes of cost allocation, and for which a federal right of first refusal must therefore be eliminated, we clarify that if any costs of a new transmission facility are allocated regionally or outside of a public utility transmission provider's retail distribution service territory or footprint, then there can be no federal right of first refusal associated with such transmission facility, except as provided in this order.

3. Framework To Evaluate Transmission Projects Submitted for Selection in the Regional Plan for Purposes of Cost Allocation

431. In Order No. 1000, the Commission required each public utility transmission provider to revise its OATT to describe the features of an acceptable framework for project identification and selection. The Commission required that this framework include: (1) Qualification criteria to submit a transmission project for selection in the regional transmission plan for purposes of cost allocation; (2) specification of the information that must be submitted by a prospective transmission developer in support of the transmission project it proposes in the regional transmission planning process and the date by which such information must be submitted to be considered in a given transmission planning cycle; (3) a description of 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; and (4) provisions allowing a nonincumbent transmission developer to have the same eligibility as an incumbent transmission provider to use a regional cost allocation method or methods for any sponsored transmission facility selected in the regional transmission plan for purposes of cost allocation. Last, the Commission declined to require public utility transmission providers to revise their OATTs to provide a transmission developer a right to construct and own a transmission facility and also declined to allow a transmission developer to maintain for a defined period of time its right to build and own a transmission project that it proposed but that is not selected.[510]

a. Qualification Criteria To Submit a Transmission Project for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

i. Final Rule

432. The Commission required each public utility transmission provider to revise its OATT to demonstrate that the regional transmission planning process in which it participates has established qualification criteria that are not unduly discriminatory or preferential for determining an entity's eligibility to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a nonincumbent transmission developer.[511] The Commission explained that the criteria must provide each potential transmission developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop, construct, own, operate, and maintain transmission facilities.[512] The Commission found that one-size-fits-all qualification criteria would not be appropriate, and that it is important for each transmission planning region to have the flexibility to formulate qualification criteria that best fits its transmission planning processes and addresses the particular needs of the region, so long as the criteria are fair and not unreasonably stringent when applied to either the incumbent transmission provider or a nonincumbent transmission developer.[513]

[508] *Id.* P 329.

[509] *Id.* P 262.

[510] *Id.* PP 323–40.

[511] *Id.* P 323.

[512] *Id.*

[513] *Id.* P 324.

ii. Requests for Rehearing and Clarification

433. Several petitioners seek rehearing of the Commission's requirement that the regional planning process develop qualification criteria.[514] They assert that Order No. 1000 creates an unreasonable disparity between who establishes the criteria for a nonincumbent to be deemed qualified to propose and construct a transmission project and who bears the risk if such nonincumbent does not perform.[515] They state that each incumbent transmission provider remains responsible for meeting its reliability and system security obligations in the event that the nonincumbent fails to perform, but must rely on qualification criteria developed by the region planning process. They state that this disparity is unreasonable, arbitrary and capricious, and should be revised to be more consistent with the model provided for in Order No. 890–A, which allows the transmission provider to establish reasonable credit criteria.[516] They also believe this would allow each incumbent transmission provider that bears the greatest risk of non-performance of a nonincumbent to better manage such risk.[517]

434. Other petitioners request that the Commission standardize the qualification criteria or otherwise clarify that certain criteria are impermissible.[518] NextEra argues that there should be a standardized qualification requirement rather than the flexible approach adopted in Order No. 1000 because it believes that such flexibility could permit incumbents to devise qualification criteria that create barriers to entry. NextEra states that, unlike other areas of Order No. 1000 that endorse flexibility, there is no reason to believe that financial and technical qualification criteria for new transmission entrants should vary by region. NextEra points to the Commission's actions in standardizing generator interconnection procedures under Order No. 2003 and credit reform rules under Order No. 741. NextEra also suggests that the Commission look to the qualification criteria established by ERCOT and CAISO as examples. Alternatively, NextEra states that the Commission should initiate a negotiated rulemaking to develop consensus criteria, which it states is the course the Commission followed in developing Order No. 2003.

435. LS Power requests that the Commission clarify that the qualification criteria for entities that want to propose a project in the regional transmission planning process are limited to financial and technical matters. It also asks that the qualification criteria not operate as a barrier to entry and should not include a qualification that a new entrant be an existing public utility under state law or have upfront siting authority. It contends that a new entrant would not be able to achieve state public utility status at the assignment stage because it is most often granted after the assignment of the transmission project. LS Power similarly argues that the selection criteria used to evaluate a project also should not require that a project sponsor be an existing public utility under state law or have upfront siting authority before it can be assigned a project. LS Power contends that such selection criteria would also act as a barrier to entry in that states most often grant public utility status and eminent domain authority after the assignment of the transmission project.

436. APPA requests that the Commission require that the minimum participation criteria developed by incumbent transmission developers/providers be fair and not unreasonably stringent as applied to public power utilities.

437. Transmission Access Policy Study Group seeks clarification that the qualification criteria facilitate transmission dependent utility joint ownership, and states that qualification criteria designed for proposals submitted by a single entity could unintentionally and needlessly foreclose beneficial project participation by multiple joint owners.

438. New York Transmission Owners request that transmission planning regions be permitted to require NERC registration for nonincumbent transmission developers as a precondition to being assigned a reliability project.

iii. Commission Determination

439. We affirm Order No. 1000's requirement that the public utility transmission providers in each transmission planning region must establish, in consultation with stakeholders, appropriate qualification criteria for determining an entity's eligibility to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation. As required under Order No. 1000, these qualification criteria must not be unduly discriminatory or preferential and must provide each potential transmission developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop, construct, own, operate, and maintain transmission facilities.[519] We disagree with petitioners that this approach creates an unreasonable disparity between who establishes the criteria for a nonincumbent transmission developer to be deemed qualified to propose and construct a transmission project and who bears the risk if such nonincumbent transmission developer does not perform. Order No. 1000 makes clear that it is public utility transmission providers themselves, in consultation with stakeholders, that are responsible for complying with Order No. 1000 and that must develop the qualification criteria for review by the Commission on compliance.[520]

440. The Commission declines to adopt standardized qualification criteria, as urged by NextEra. While the Commission's acknowledges NextEra's concern that qualification criteria could act as a barrier to entry, the Commission believes that there may be legitimate differences between regions that may justify differences in the qualification criteria. Each region is faced with its own set of challenges in building new transmission facilities, and regions should be permitted to account for those differences in their qualification criteria. For this same reason, the Commission will not adopt certain minimum qualification criteria. Regarding LS Power's petition that the qualification criteria be limited to financial and technical matters, we point out that Order No. 1000 states that ''[t]he qualification criteria must provide each potential transmission developer the opportunity to demonstrate that it has the necessary financial resources and technical expertise to develop,

[514] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; and Southern Companies.

[515] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; and Southern Companies.

[516] Ad Hoc Coalition of Southeastern Utilities at 62 (citing Order No. 890–A, Attachment L (Creditworthiness Procedures) to Pro Forma OATT; Order No. 890 at P 1659); Southern Companies at 63 (citing *Preventing Undue Discrimination and Preference in Transmission Serv.,* Order No. 890–A, 121 FERC ¶ 61,297, Attachment L (2007)).

[517] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; and Southern Companies.

[518] *See, e.g.,* NextEra; LS Power; and New York Transmission Owners.

[519] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 323.

[520] We reiterate that ''the qualification criteria required [in Order No. 1000] should not be applied to an entity proposing a transmission project for consideration in the regional transmission planning process if that entity does not intend to develop the proposed transmission project. The Order No. 890 transmission planning requirements allow any stakeholder to request that the transmission provider perform an economic planning study or otherwise suggest consideration of a particular transmission solution in the regional transmission planning process.'' *Id.* P 324 n.304.

construct, own, operate and maintain transmission facilities,'' but also permits each transmission planning region flexibility to formulate qualification criteria that best fit its transmission planning processes and addresses the particular needs of the region.[521]

441. We clarify in response to LS Power that it would be an impermissible barrier to entry to require, as part of the qualification criteria, that a transmission developer demonstrate that it either has, or can obtain, state approvals necessary to operate in a state, including state public utility status and the right to eminent domain, to be eligible to propose a transmission facility. As the Commission emphasized in Order No. 1000, and reiterates here, the qualification criteria must be fair and not unreasonably stringent when applied to an incumbent transmission provider and a nonincumbent transmission developer.[522] The Commission will review on compliance whether any proposed qualification criterion is unreasonably stringent when applied to nonincumbent transmission developers such that the criteria act as an unreasonable barrier to entry.[523]

442. If a transmission facility is selected in the regional transmission plan for purposes of cost allocation, the Commission clarifies that the transmission developer of that transmission facility must submit a development schedule that indicates the required steps, such as the granting of state approvals, necessary to develop and construct the transmission facility such that it meets the transmission needs of the region. As part of the ongoing monitoring of the progress of the transmission project once it is selected, the public utility transmission providers in a transmission planning region must establish a date by which state approvals to construct must have been achieved that is tied to when construction must begin to timely meet the need that the project is selected to address. If such critical steps have not been achieved by that date, then the public utility transmission providers in a transmission planning region may remove the transmission project from the selected category and proceed with reevaluating the regional transmission plan to seek an alternative solution.

443. We believe that there are a number of benefits to this approach. First, it ensures that transmission developers that have the technical and financial capability to build a transmission facility, and meet other nondiscriminatory and non-preferential criteria, are eligible to propose a transmission facility for evaluation and selection, thereby increasing the universe of potential facilities evaluated and selected to meet a region's transmission needs. Second, it gives a nonincumbent transmission developer the opportunity to propose a transmission facility while it seeks to obtain necessary state approvals or otherwise seeks to comply with applicable state law or regulation. Third, it provides the public utility transmission providers in a transmission planning region with the ability to monitor the development of a transmission facility selected in the regional transmission plan for purposes of cost allocation, as well as the ability to remove that new transmission facility if its developer is unable to meet an established date by which the critical development step of obtaining necessary state approvals must be achieved.

444. We also deny New York Transmission Owners' request that the public utility transmission providers in a transmission planning region be permitted to require a transmission developer to demonstrate that it has registered with NERC as a precondition to being assigned a reliability project. As the Commission explained in Order No. 1000, all entities that are users, owners or operators of the electric bulk power system must register with NERC for performance of applicable reliability functions.[524] The procedures for registering as a Functional Entity are set by NERC and approved-by the Commission under section 215,[525] and it is not appropriate for the Commission to amend or interpret those procedures here under a section 206 action by requiring all public utility transmission providers to revise their tariffs to provide that a potential transmission developer must register with NERC if not otherwise required under the NERC procedures, merely to be eligible to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation.

b. Evaluation of Proposals for Selection in the Regional Transmission Plan for Purposes of Cost Allocation

i. Final Rule

445. The Commission required each public utility transmission provider to amend its OATT to describe 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.[526] The Commission explained that this process must comply with the Order No. 890 transmission planning principles, ensuring transparency, and the opportunity for stakeholder coordination. The Commission further explained that the evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not selected in the regional transmission plan for purposes of cost allocation.[527] Finally, the Commission declined to require public utility transmission providers to revise their OATTs to provide a right to construct and own a transmission facility and also declined to allow a transmission developer to maintain for a defined period of time its right to build and own a transmission project that it proposed but that was not selected.[528]

ii. Requests for Rehearing and Clarification

446. Western Independent Transmission Group seeks rehearing of the Commission's rejection of its proposal to require the use of an independent third party observer to oversee evaluation and selection of competing transmission projects to ensure that the process is being managed fairly and efficiently.

447. Illinois Commerce Commission argues that it is necessary for the Commission to provide more specificity regarding the practical means by which transmission providers can facilitate competition between alternative proposals. It suggests that the transmission provider identify the planning needs to be met and then solicit developers to submit alternative plans to address those needs. Illinois Commerce Commission explains that this formalized process would provide a non-discriminatory and objective method for the transmission provider to

[521] *Id.* PP 323–24.

[522] *Id.* P 324.

[523] Importantly, Order No. 1000 did not provide transmission developers with a right to construct; rather, it required ''that a nonincumbent transmission developer must have the same eligibility as an incumbent transmission developer to use a regional cost allocation method or methods for any sponsored transmission facility selected in the regional transmission plan for purposes of cost allocation.'' *See id.* P 332.

[524] *Id.* P 342.

[525] NERC, Rules of Procedures (effective March 15, 2012), *available at http://www.nerc.com/files/NERC_ROP_Effective_20120315.pdf.*

[526] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 328.

[527] *Id.*

[528] *Id.* P 338.

evaluate alternative proposals, and argues that the Commission erred in not requiring such a process.

448. Similarly, FirstEnergy Service Company seeks clarification that regional transmission planning processes need only consider proposals that respond to identified needs, such that a ''needs first'' approach is acceptable. In support, FirstEnergy Service Company argues that a planning model that requires the regional planning process to analyze every individual proposal would render the process less manageable, timely, and effective. FirstEnergy Service Company also argues that, through Order No. 890, the Commission already has put in place the mechanisms necessary to encourage innovative transmission proposals.

449. LS Power requests that the Commission affirmatively clarify on rehearing that, if a region uses a sponsorship model for the assignment of projects, the regions must treat an application for a project by a nonincumbent transmission owner no differently from any other applicant, and that sponsors that meet nondiscriminatory sponsorship criteria are to be assigned construction and ownership of the projects they sponsor unless the regional planning entity adequately justifies assignment of the project to another entity, as PJM was required to do in the *Primary Power* case.[529] It states that without this explicit statement, some will attempt to assign projects to non-sponsor incumbent transmission owners on the basis of an inaccurate reading of paragraph 338, where the Commission declined to adopt any right to construct or ongoing sponsorship rights.

450. LS Power also requests that the Commission clarify that in a region using a sponsorship model rather than a competitive bidding model, the process established by each public utility transmission provider must include a specific mechanism to select, in a nondiscriminatory manner, among competing qualified sponsors of identical projects, or, as a backstop if no mechanism is agreed upon, to assign such projects equally among qualified entities that have sponsored identical projects. It explains that to the extent that only one of the sponsors has sponsored the same project in an immediately prior planning cycle, that the entity should have preference over those entities newly sponsoring the project. LS Power further suggests that the Commission should include a provision for ongoing sponsorship rights, with some recognition or benefit to an entity for continuing to advocate viable projects, at least between the continuing sponsor and new sponsors of the same project. Additionally, LS Power states that another mechanism to select among multiple sponsors of identical projects is to select the entity that is willing to guarantee the lowest net present value of its annual revenue requirement.

451. In addition, LS Power requests that the Commission clarify that to meet the ''not unduly discriminatory process'' requirement, the selection criteria must meet certain minimum standards. It states that the Commission should clarify that when cost estimates are part of selection criteria, costs must be scrutinized in an equal manner whether the project is sponsored by an incumbent or independent.

iii. Commission Determination

452. The Commission affirms the decision in Order No. 1000 to require each public utility transmission provider to amend its OATT to describe a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in a regional transmission plan for purposes of cost allocation.[530] We also affirm the Commission's decision not to require public utility transmission providers to use an independent third party observer to oversee the evaluation and selection of competing transmission projects. In Order No. 1000, the Commission encouraged public utility transmission providers to consider ways to minimize disputes, such as through additional transparency mechanisms.[531] However, the Commission did not mandate any particular approach, and is not persuaded now that an independent third party observer is necessary or appropriate in all regions. Moreover, the Commission noted that the requirements of the dispute resolution principle of Order No. 890 apply to the regional transmission planning process.[532] Thus, if a dispute cannot be resolved by public utility transmission providers in the regional transmission planning process, entities may take advantage of that transmission planning region's dispute resolution provision. Additionally, as noted in Order No. 1000, public utility transmission providers in consultation with other stakeholders in a region may, if they choose, propose to use an independent third-party observer and we will review any such proposal on compliance.[533]

453. While Order No. 1000 permits the public utility transmission providers in a region to adopt a ''needs first'' approach to transmission planning such as that advocated by the Illinois Commerce Commission and FirstEnergy Service Company, the Commission declined to adopt a one-size-fits-all approach to transmission planning. The Commission believes that there are many different approaches to transmission planning and requires only that the transmission planning process adopted by a transmission planning region satisfy the transmission planning principles discussed in Order No. 1000 and this order. Thus, we decline to rule in the abstract in advance of the compliance filings whether any particular transmission planning process is the only appropriate process for all regions.

454. The Commission clarifies that the public utility transmission providers in a transmission planning region must use the same process to evaluate a new transmission facility proposed by a nonincumbent transmission developer as it does for a transmission facility proposed by an incumbent transmission developer. In Order No. 1000, the Commission required each public utility transmission provider to adopt a transparent and not unduly discriminatory evaluation process that complies with the Order No. 890 transmission planning principles.[534] However, this requirement does not preclude public utility transmission providers in regional transmission planning processes from taking into consideration the particular strengths of either an incumbent transmission provider or a nonincumbent transmission developer during its evaluation.[535]

455. The Commission denies LS Power's other requests for rehearing regarding the selection of a transmission developer. The Commission declined to address the selection of a transmission developer in Order No. 1000. Aside from requiring the public utility transmission providers in a region to establish criteria to assess a transmission developer's qualifications to have its proposed transmission project considered for selection in a

[529] LS Power at 6 (*Primary Power, LLC,* 131 FERC ¶ 61,015, at P 65 (2010)).

[530] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 328.

[531] *Id.* P 330.

[532] *Id.* P 330 n.306.

[533] Order No. 1000, FERC Stats. & Regs. ¶ 31,323.

[534] *Id.* P 328.

[535] *See id.* P 260 (''An incumbent public utility transmission provider is free to highlight its strengths to support transmission project(s) in the regional transmission plan, or in bids to undertake transmission projects in regions that choose to use solicitation processes.'').

regional transmission plan for purposes of cost allocation, Order No. 1000 also requires public utility transmission providers in a region to adopt transparent and not unduly discriminatory criteria for selecting a new transmission project in a regional transmission plan for purposes of cost allocation. We decline to set certain minimum standards for the criteria used to select a transmission facility in a regional transmission plan for purposes of cost allocation other than to require that these selection criteria be transparent and not unduly discriminatory. We also find that this purpose is met adequately by the transmission planning principles of Order No. 890. We also anticipate that selection criteria will vary from transmission planning region to transmission planning region in accordance with each transmission planning region's needs, just as other aspects of regional transmission planning processes will vary, and LS Power has not persuaded us that such flexibility is inappropriate. However, we clarify that when cost estimates are part of the selection criteria, the regional transmission planning process must scrutinize costs in the same manner whether the transmission project is sponsored by an incumbent or nonincumbent transmission developer.

456. If a transmission project is selected in a regional transmission plan for purposes of cost allocation, Order No. 1000 requires that the transmission developer of that transmission facility (whether incumbent or nonincumbent) must be able to rely on the relevant cost allocation method or methods within the region should it move forward with its transmission project.[536] We are not persuaded to change this approach on rehearing. Further, we reiterate that we do not require public utility transmission providers in a region to adopt a provision for ongoing sponsorship rights, for the reasons set out in Order No. 1000. The Commission concluded that granting transmission developers an ongoing right to build sponsored transmission projects could adversely impact the regional transmission planning process.[537] We are not persuaded to reverse our decisions on the selection of transmission developers. While we acknowledge LS Power's concerns, we do not believe they warrant any revision of the selection of transmission developers at this time given the diversity of methods for selecting transmission developers used around the nation.

c. Reevaluation of Regional Transmission Plans When There Is a Project Delay and Reliability Compliance Obligations of Transmission Developers

i. Final Rule

457. In Order No. 1000, the Commission required each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those proposed by the incumbent transmission provider, to ensure the incumbent transmission provider can meet its reliability needs or service obligations.[538]

458. The Commission also explained that if a violation of a NERC reliability standard by an incumbent would result from a nonincumbent transmission developer's decision to abandon a transmission facility meant to address such a violation, the incumbent transmission provider does not have the obligation to construct the nonincumbent's project.[539] Rather, the incumbent transmission provider must identify the specific NERC reliability standard(s) that would be violated and submit a mitigation plan to address the violation.[540] The Commission explained that if the incumbent public utility transmission provider follows the NERC-approved mitigation plan, the Commission will not subject it to enforcement action for the specific NERC reliability standard violation(s) caused by a nonincumbent transmission developer's decision to abandon a transmission facility.[541]

459. The Commission also noted that, when a nonincumbent transmission developer becomes subject to the requirements of FPA section 215 and the regulations thereunder, it will be required to comply with all applicable reliability obligations, including registering with NERC for performance of applicable reliability functions.[542] The Commission stated that if there are concerns about when compliance with NERC registration and reliability standards would be triggered, the appropriate forum to raise these questions and request clarification is the NERC process.[543]

ii. Requests for Rehearing and Clarification

460. Some petitioners question whether the reevaluation requirement set forth in Order No. 1000 are sufficient to protect incumbent transmission providers from the repercussions related to a nonincumbent's failure to build a project in time.[544] For instance, these petitioners argue that the Commission failed to protect incumbent transmission providers from the increased risk of violations of state reliability or resource adequacy requirements, and other state service obligations.[545] MISO Transmission Owners Group 2 also adds that the incumbent utility could face civil liability, state regulatory sanctions, and financial harm resulting from damage to its own facilities or the facilities of another entity caused by the action of the nonincumbent.

461. Some commenters argue that incumbent developers should not be burdened with monitoring the status of a nonincumbent developer's progress. Specifically, if the reevaluation requirement would obligate incumbents to discover or address nonincumbent delays prior to being notified by the nonincumbent, Southern Companies request rehearing of this requirement in Order No. 1000.[546] Southern Companies also request rehearing of the reevaluation requirement to the extent it could inhibit, prevent or slow an incumbent's decision to address a delay or the implementation of its corrective plan. Similarly, Southern California Edison requests that the Commission require regional transmission planning entities to develop protocols for how such transmission planning entities will: (1) Be kept apprised by nonincumbent developers of the status of their projects; and (2) notify the applicable incumbent transmission owner that it needs to develop a mitigation plan because a project has been delayed or abandoned by a nonincumbent developer. In addition, Southern Companies contend that each incumbent transmission provider and planning authority should be permitted

[536] *Id.* P 339.

[537] *Id.*

[538] *Id.* P 329.

[539] *Id.* P 344.

[540] *Id.*

[541] *Id.*

[542] *Id.* P 342.

[543] *Id.* P 343.

[544] *See, e.g.,* Southern Companies; Edison Electric Institute; MISO Transmission Owners Group 2; and Xcel.

[545] *See, e.g.,* Edison Electric Institute; and MISO Transmission Owners Group 2.

[546] Southern Companies at 78 (citing *McElroy Electronics Corp.* v. *FCC,* 990 F.2d 1351, 1358 (D.C. Cir. 1993)).

to reevaluate its own local transmission plan to determine whether a nonincumbent's delay in constructing a regional facility will adversely impact reliability on the incumbent's system. In addition, Southern Companies argue that because the reevaluation requirement does not protect against the need to implement operational adjustments, Order No. 1000 fails to protect against service reliability problems and fails to weigh the adverse impacts against the benefits that the Commission foresees.

462. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council also assert that there is no substantial evidence for concluding, as the Commission does in paragraph 263 of Order No. 1000, that the potential costs associated with a delayed or abandoned nonincumbent transmission facility are remediable by a reevaluation of the regional plan. For example, Large Public Power Council explains that by the time construction delays place a system at risk, the damage will have been done, since such delays will postdate the planning that contemplated the facilities at issue, often by several years. As such, it maintains that even if the incumbent utility can step in with sufficient lead-time so that reliability is not threatened, and the cost of this activity is recoverable, there is little that can be done to save ratepayers from the associated costs, and there is no basis to conclude that nonincumbent participation in the transmission development process will therefore be worth it.

463. Several petitioners seek rehearing and clarification of the Commission's decision to allow incumbent transmission providers to implement a NERC mitigation plan to avoid an enforcement action if a nonincumbent transmission developer abandons a project needed to meet a reliability need. For example, Xcel asserts that Order No. 1000's discussion of a NERC mitigation plan may involve interrupting load under certain conditions, or implementing rolling outages. Xcel argues that this degradation of service to end use customers is contrary to the fundamental purposes of FPA section 215 and would also result in a loss of revenues to the utility.

464. Transmission Dependent Utility Systems argue that Order No. 1000 sheds no light on whether its mitigation plan solution is realistic or available and does not address who will be responsible for maintaining power if neither the incumbent nor the nonincumbent transmission provider can be held accountable for completion or maintenance of reliability-driven projects. Similarly, PSEG Companies argue that the problem of abandonment by a nonincumbent of a project needed for reliability cannot be fixed by reliability standards or by mitigation plans submitted in ''compliance'' with those standards. They state that the Commission failed to recognize that NERC reliability standards will not be applicable to a nonincumbent developer unless and until the project is constructed and in-service.

465. Petitioners point out possible difficulties that may arise because similar terms have distinct meanings in a public utility transmission provider's OATT under FPA 205 and the reliability standards under FPA 215. Several petitioners argue that it is not always a public utility transmission provider that is responsible for conducting a reevaluation or developing a mitigation plan.[547] For instance, Southern Companies argue that public utility transmission providers do not conduct transmission planning or evaluate or reevaluate transmission plans. Instead, Southern Companies argue that planning authorities and transmission planners are the appropriate entities to determine the impacts of a delay on local plans and are responsible for meeting reliability and service obligations, including the state-mandated duty to serve native load. Southern Companies argue that the Commission cannot remove or dilute that responsibility by delegating it to another entity without preempting state law. Southern Companies state that if Order No. 1000 does not intend the term ''public utility transmission provider'' to mean Transmission Service Provider under the NERC Functional Model, the Commission must grant rehearing to determine what category of Registered Entity is meant, or extend the commencement of the 12-month compliance window until NERC has determined which category of Registered Entity is appropriate to conduct the activities required by Order No. 1000.[548] Furthermore, Edison Electric Institute seeks clarification that an incumbent transmission provider need not have a retail distribution service territory and need not construct the new facilities entirely within its retail distribution service territory to qualify for protection from an enforcement action as described in paragraph 344 of Order No. 1000.

466. In addition, PSEG Companies argue that using the term ''transmission provider'' creates confusion because, under the NERC Functional Model, the term could apply to a number of different functions, and these different functions are very different even if in ISO/RTO regions the ''transmission provider'' is the ISO/RTO. PSEG Companies argue that the Commission erred by seeking to impose the responsibility to develop a ''mitigation plan'' onto incumbent transmission owners, and that this requirement demonstrates that the Commission misunderstands the NERC process. Thus, according to PSEG Companies, the process for addressing nonincumbents' abandonment of facilities would not work as envisioned, at least in the ISO/RTO context where the transmission owner is not responsible for planning the system and would not be responsible for filing a mitigation plan in the event of abandonment.

467. Other petitioners request clarification regarding the scope of the waiver. Edison Electric Institute recommends that the Commission use NERC terminology to clarify the scope of the waiver. Other petitioners argue that if the waiver applies only to the incumbent transmission provider as defined in Order No. 1000, the application is too narrow.[549] In addition to the incumbent transmission provider, Edison Electric Institute argues that the protection from an enforcement action should extend to other entities that might be found in violation of a reliability standard, such as balancing authorities and reliability coordinators. APPA agrees and adds that all of the transmission providers will be adversely affected to at least some extent due to the interconnected nature of the transmission network. Transmission Dependent Utility Systems add that third parties with NERC reliability obligations for certain transmission facilities, such as municipal utilities and rural electric cooperatives, also should be held harmless from penalties and NERC enforcement actions if a nonincumbent transmission developer abandons or fails to maintain a project needed to address reliability concerns. For example, even though Southern California Edison considers CAISO to be the transmission provider, Southern California Edison asserts that it develops and implements NERC mitigation plans as the NERC registered

[547] *See, e.g.,* PSEG Companies; and Southern Companies.

[548] We note that the capitalized terms refer to specific terms used in the NERC Reliability Standards.

[549] *See, e.g.,* Edison Electric Institute; Southern California Edison; and APPA.

transmission owner and therefore should be entitled to protection.

468. Southern Companies also request rehearing of Order No. 1000's failure to explain its departure from existing policy and regulations regarding mitigation plans. Southern Companies argue that requiring an incumbent to submit a mitigation plan for a nonincumbent's abandonment of necessary facilities would bestow upon the incumbent the impossible task of ensuring that another entity will not make poor business decisions, go bankrupt, or otherwise abandon or cancel its projects. Furthermore, Southern Companies state that Order No. 1000 indicates the incumbent may need to construct redundant and duplicate facilities to guard against the potential of nonincumbent delay or abandonment of its project. In addition, Southern Companies request rehearing to the extent incumbents are required to propose a corrective action for review by the regional process because such a requirement would impair service reliability.[550] Southern Companies also request clarification that the costs of the delayed regional facility will not be allocated to an incumbent that constructs a local transmission solution to meet its reliability or service needs in the face of delay.

469. Petitioners also argue that the protection from an enforcement action should be applicable to any project that an incumbent relies on to satisfy its reliability obligations, including reliability, public policy or economic-based projects.[551] Southern California Edison points out that a project intended to address a NERC violation or other reliability concerns may be dependent on another transmission project being completed first, including a public policy or economic project. Ameren argues that such other projects, which may have received regional cost allocation, will almost certainly have some measure of reliability effect because the grid is interconnected and that the failure of any such project could cause a blackout.

470. Some petitioners seek clarification that the protections found in paragraph 344 will prevent the Commission, NERC, or a Regional Entity from considering a violation that is covered by this protection, or a mitigation plan developed to address such a violation, as a prior violation when determining the penalty for a new violation.[552] Moreover, Edison Electric Institute seeks clarification that the protections described in paragraph 344 will apply to any Reliability Standard violation, including an operationally-focused violation, resulting from abandonment of a project by a nonincumbent transmission developer. Edison Electric Institute asserts that it is unfair to provide protection only for violations specifically envisioned at the time the project was conceived. Finally, Edison Electric Institute seeks clarification that the safe harbor provision will prevent the Commission, NERC, or a Regional Entity from considering a violation that is covered by this safe harbor protection or a mitigation plan developed to address such a violation as a prior violation when determining the penalty for a new violation.

471. Southern California Edison requests that the Commission clarify that an incumbent transmission owner will not be subject to an enforcement action or any other sanction or penalty if it cannot follow or implement an approved mitigation plan for reasons beyond its control. It states that after Order No. 1000, a transmission owner may be asked to develop a mitigation plan without much of the key information, which means an incumbent transmission owner may not be able to develop an infallible mitigation plan and should not be penalized if implementation of its plan is delayed or if the plan needs to be revised to reflect new information that becomes known to the incumbent when the mitigation efforts are underway.

472. In addition, Southern California Edison requests that the Commission clarify that penalties, sanctions, or enforcement actions also will not be levied against an incumbent transmission owner for reliability problems that arise from the actions of a nonincumbent transmission developer in connection with delays of a transmission facility, or the operation or maintenance thereof.

473. Southern California Edison also argues that the Commission should clarify that, as long as the incumbent transmission owner submits its mitigation plan to an appropriate regional entity, the transmission owner should not face any enforcement actions, penalties or sanctions while the mitigation plan is pending approval. Southern California Edison states that it does not submit mitigation plans directly to NERC, but instead initially submits its plan for approval to the Regional Entity. Therefore, Southern California Edison states that there will be some inevitable delay between the time that a transmission owner submits a mitigation plan and the time that the plan is approved by NERC, and argues that it should not be penalized for such inevitable delay.

474. Some petitioners argue that the Commission's reevaluation and enforcement provisions in Order No. 1000 are inconsistent with section 215 of the FPA, and fail to adequately protect incumbents.[553] For example, Edison Electric Institute asserts that if an incumbent transmission provider violates state resource adequacy or reliability requirements, it may be subject to significant monetary penalties and other sanctions, which the Commission's grant of protection from a section 215 enforcement action has no effect on and cannot preempt. Edison Electric Institute argues that the Commission failed to discuss these implications and has thus engaged in arbitrary and capricious decision-making and should grant rehearing to remove the right of first refusal for reliability projects.

475. Xcel argues that Order No. 1000 ignores the substantial record evidence that the policies adopted are inconsistent with the objectives of section 215 of the FPA and the Commission's initiatives to improve electric system reliability through mandatory standards. Xcel contends that forcing utility transmission providers to rely on a third party to fulfill section 215 obligations does not constitute reasoned decision-making. Southern Companies add that Order No. 1000's nonincumbent requirements pose threats to reliability and economic service by forcing disintegration of the transmission network. MISO Transmission Owners Group 2 argues that nothing in EPAct 2005 authorizes the Commission to provide blanket waivers of critical reliability standards for the purposes of achieving some policy preference unrelated to the enforcement of mandatory reliability standards.

476. Southern Companies also argue that the Commission impermissibly uses section 206 to impose reliability requirements instead of using its section 215 authority. Southern Companies argue that this action violates the Whole Act Rule by making section 215's goal of protecting reliability subservient to section 206.[554] Accordingly, Southern

[550] Southern Companies at 81–82 (citing *Motor Vehicle Mfrs. Assoc. of the United States, Inc.* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 43 (1983)).

[551] *See, e.g.,* Southern California Edison; Xcel; Ameren; and Edison Electric Institute.

[552] *See, e.g.,* Edison Electric Institute; and Southern California Edison.

[553] *See, e.g.,* Xcel; Southern Companies; and MISO Transmission Owners Group 2.

[554] Southern Companies at 77 n.251 (citing 5 U.S.C. 706).

Companies assert that the Commission should have gone through the Commission-approved NERC standards and enforcement processes established pursuant to section 215 of the FPA, the Commission's regulations, and Commission precedent, rather than unilaterally developing these reliability-related reevaluation and enforcement protections and imposing their requirements onto users, owners, and operators of the bulk-power system. Southern Companies argue the enforcement action waiver is inconsistent with, and may conflict with existing NERC Reliability Standards.

iii. Commission Determination

477. The Commission affirms its decision to require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those proposed by the incumbent transmission provider, to ensure the incumbent transmission provider can meet its reliability needs or service obligations.[555] As the Commission explained in Order No. 1000, the focus here is on ensuring that adequate processes are in place to determine whether delays associated with completion of a transmission facility selected in a regional transmission plan for purposes of cost allocation have the potential to adversely affect an incumbent transmission provider's ability to fulfill its reliability needs or service obligations. We believe that if these processes are followed, incumbent transmission providers should be able to meet reliability related requirements.

478. In response to Xcel's and Southern Companies' argument that the reevaluation requirement does not protect against the need to implement operational adjustments, the present operationally-focused NERC reliability standards require Functional Entities to operate so that the portion of the system that is in service at that time will be capable of delivering the output of generation to firm demand and transfers within the applicable performance criteria. Accordingly, a Functional Entity must prepare its system to operate regardless of whether a transmission project is delayed or abandoned. Thus, the Commission concludes that there is no need to set requirements in addition to those already established in the applicable NERC reliability standards.

479. In response to those petitioners concerned that they must individually monitor the status of a nonincumbent transmission developer's progress in developing its transmission facility selected in the regional transmission plan for purposes of cost allocation, we note that transmission planners and transmission developers already routinely communicate regarding the status of the construction of a transmission project. Consistent with applicable NERC Reliability Standards, a Functional Entity remains responsible for complying with all applicable Reliability Standards, such as studying performance of its system and deciding when it must develop corrective plans to ensure that its system responds reliably as prescribed by those standards.[556] As such, we emphasize that Order No. 1000 does not change any obligations an incumbent transmission provider, as a Functional Entity, may have under the NERC Reliability Standards to monitor a nonincumbent transmission developer's progress in developing its transmission facility selected in the regional transmission plan for purposes of cost allocation. Furthermore, Order No. 1000 left it to public utility transmission providers in a transmission planning region to adopt procedures in their OATTs for reevaluating transmission facilities selected in the regional transmission plan for purposes of cost allocation. We continue to believe this approach is appropriate.

480. The Commission also affirms, with certain clarifications, its decision in Order No. 1000 to not subject an incumbent public utility transmission provider to a penalty for a violation of a NERC reliability standard caused by a nonincumbent transmission developer's decision to abandon a transmission facility if the incumbent public utility transmission provider has identified the violation and submitted a NERC mitigation plan to address it.[557] The Commission used ''enforcement action'' in Order No. 1000, but is not using this term here because ''enforcement action'' also could imply that Registered Entities are not going to be required to mitigate any NERC reliability standards violations. The Commission clarifies that, although it will not seek penalties, it will ensure that Registered Entities implement appropriate mitigation plans.

481. The Commission agrees with petitioners that argue that entities other than incumbent public utility transmission providers may violate a NERC reliability standard in the event that a nonincumbent transmission developer abandons a transmission facility. In some regions, the incumbent public utility transmission provider may not be the entity responsible for complying with the NERC reliability standards implicated by the abandonment of a nonincumbent transmission developer's project. We also agree with Ameren and other petitioners that argue that the abandonment of a nonincumbent transmission project that is designed to meet economic needs or transmission needs driven by a Public Policy Requirement could impact reliability. Therefore, we clarify that the Commission will not subject a Registered Entity[558] to a penalty for a violation of a NERC reliability standard caused by a nonincumbent transmission developer's decision to abandon any type of transmission facility selected in the regional transmission plan for purposes of cost allocation if, on a timely basis, that Registered Entity identifies the violation and complies with all of its obligations under the NERC reliability standards to address it.

482. The remaining requests for rehearing or clarification posit enforcement situations that are uncertain or speculative. We decline to rule on these requests for rehearing or clarification because we find that they are premature. We believe that, with the clarifications granted above, entities have sufficient information to understand when the Commission will not subject a Registered Entity to enforcement action for a violation of a NERC reliability standard caused by a nonincumbent transmission developer's decision to abandon a transmission facility. Furthermore, many of these petitions in effect argue that the Commission should not have required

[555] Order 1000, FERC Stats. & Regs. ¶ 31,323 at P 329.

[556] NERC Reliability Standards in the Facility Connection and Transmission Planning series ensure evaluation of the reliability impact of the new facilities connections, and coordination and results sharing by the entities involved, as well as development of corrective plans if reliability requirements are not met when projects are delayed or abandon.

[557] Order 1000, FERC Stats. & Regs. ¶ 31,323 at P 344.

[558] We use the term Registered Entity to refer an owner, operator, or user of the Bulk Power System, or the entity registered as its designee for the purpose of compliance, that is included in the NERC Compliance Registry. *See,* North American Electric Reliability Corporation, Compliance Monitoring and Enforcement Program, Appendix 4C to the Rules of Procedures (effective Jan. 31, 2012), *available at: http://www.nerc.com/files/Appendix_4C_CMEP_20120131.pdf.*

public utility transmission providers to eliminate a federal right of first refusal from Commission jurisdictional-tariffs and agreements in Order No. 1000. The Commission has adequately explained in Order No. 1000 and in this order the need for eliminating a federal right of first refusal.

483. Finally, contrary to arguments by petitioners, the Commission was not required to use its section 215 authority to adopt the reevaluation requirements or to state the circumstances under which it would exercise its enforcement discretion. Rather, the reevaluation requirement is a tariff obligation not a reliability obligation under section 215. Furthermore, in stating the circumstances under which the Commission would exercise its enforcement discretion, the Commission did not create new, or modify existing, NERC reliability standards. Had the Commission done so, it would be required to adopt a reliability standard through its authority set out in section 215. Instead, the Commission appropriately exercised its discretion under section 215 enforcement authority to set forth a particular circumstance when it will not e penalize a Registered Entity.

d. Recovery of Abandoned Plant Costs and Backstop Authority

i. Final Rule

484. In Order No. 1000, the Commission found that when an incumbent transmission provider is called upon to complete a transmission project that it did not sponsor, there would be a basis for the incumbent transmission provider to be granted abandoned plant recovery for that transmission facility, upon the filing of a petition for declaratory order requesting such rate treatment or a request under section 205 of the FPA.[559]

ii. Requests for Rehearing

485. APPA and Transmission Access Policy Study Group question the Commission's decision to grant abandoned plant cost recovery to an incumbent transmission provider in certain circumstances. Transmission Access Policy Study Group and APPA argue that granting incumbent transmission providers abandoned cost recovery under Order No. 1000 is an unjustified deviation from Order No. 679's case-by-case approach. Transmission Access Policy Study Group raises several questions that it asserts highlight the need for the Commission to look at the facts of each request for abandoned plant recovery rather than committing the public in all circumstances to pay for unfinished projects. APPA argues that abandoned plant cost recovery is an incentive that should be granted on a case-by-case basis where the granting of such an incentive is shown to be necessary and appropriate.

486. Southern California Edison also notes that Order No. 1000 states in paragraph 344 that the incumbent transmission owner does not have an obligation to construct a transmission facility intended to address a possible NERC violation, but then states in paragraph 267 that there may be circumstances when an incumbent may be called upon to complete a project that it did not sponsor. Southern California Edison requests that the Commission clarify: (1) How the statements in paragraphs 267 and 344 should be reconciled so that they are consistently interpreted and implemented; (2) in which situations a transmission provider may be required to complete a transmission facility it did not sponsor; and (3) what that completion obligation entails.

487. Southern California Edison also seeks clarification that Order No. 1000 does not preclude regions from applying backstop transmission development obligations to all participating transmission owners in the region and allows regions that impose backstop obligations to apply them on an equivalent basis among incumbents and nonincumbents. Southern California Edison argues that to require only incumbents to serve as the safety-net for all nonincumbent projects would impose a burden upon incumbents that could impede their ability to compete for projects. On the other hand, Xcel recommends that tariffs incorporate a backstop that reflects the incumbent utility's obligation as provider of last resort to build transmission needed for reliability even if the incumbent does not exercise a right of first refusal and no one else offers to build it.

488. Southern California Edison requests clarification that the incumbent transmission owner will be fully compensated for mitigation costs through ''grid-wide'' rates to offset the substantial burden of developing and implementing mitigation plans. In addition, Edison Electric Institute seeks clarification that an incumbent transmission provider that steps in to complete an abandoned reliability project in the circumstances discussed in paragraph 344 of Order No. 1000, it has no obligation to purchase the facilities, materials, or any other assets related to the abandoned project, at cost or otherwise. It argues that such a requirement would provide unwarranted financial protections for nonincumbent transmission developers, and remove one of the key incentives to complete a project once begun. Similarly, Southern Companies argue that Order No. 1000 will discriminate in favor of third party developers at the expense of an incumbent's native load and OATT customers unless the Commission ensures that developers of regional projects are held responsible and accountable for any and all adverse effects of their construction delays or abandonments upon incumbents, including any increased costs caused thereby.[560]

iii. Commission Determination

489. In response to Transmission Access Policy Study Group and APPA, we clarify that we will, consistent with Order No. 679,[561] grant abandoned plant recovery on a case-by-case basis. Order No. 1000 did not provide a blanket grant of abandoned plant recovery, but merely stated that where an incumbent transmission provider is called upon to complete a transmission project that another entity has abandoned, this would be a basis for the incumbent transmission provider to be granted abandoned plant recovery for that transmission facility, upon the filing of a petition for declaratory order requesting such rate treatment or a request under section 205 of the FPA.[562]

490. In response to Southern California Edison, nothing in Order No. 1000 requires an incumbent transmission provider to construct a nonincumbent transmission developer's transmission project selected in the regional transmission plan for purposes of cost allocation if it abandons a transmission facility.[563] We note, however, that some RTOs and ISOs may have the authority under their tariff or membership agreements to direct a member to build a transmission facility under certain circumstances.[564] Further, Order No. 1000 did not address the issue of backstop construction authority or responsibility for any transmission project, whether undertaken initially by an incumbent or a nonincumbent transmission developer. Accordingly,

[559] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 267.

[560] Southern Companies at 83–84 (citing *Chicago* v. *FPC,* 385 F.2d 629, 637 (D.C. Cir. 1967)).

[561] Order No. 679, FERC Stats. & Regs. ¶ 31,222.

[562] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 267.

[563] *Id.* P 344.

[564] *See, e.g.,* PJM Consolidated Transmission Owners Agreement at section 4.2.1.We note that a nonincumbent transmission developer that becomes a member of an RTO or ISO may be subject to an obligation to build that applies to transmission-owning members.

this issue is beyond the scope of this proceeding, and we will not address it on rehearing.

491. In response to Southern California Edison's request that incumbent transmission providers be compensated for the cost of developing implementing a mitigation plan through ''grid-wide'' rates, we did not provide a generic answer in Order No. 1000 and do not do so here. That is, we are not deciding here whether a transmission provider may recover, or how it may recover, the costs that result from complying with the Reliability Standards if a nonincumbent transmission developer delays or abandons a needed transmission project.

492. In response to Edison Electric Institute, the Commission does not require under Order No. 1000 that an incumbent transmission developer purchase the facilities, materials, or any other assets related to an abandoned project that the incumbent transmission provider determines it must complete. However, Order No. 1000 also does not preclude an incumbent transmission developer from purchasing such facilities, materials or other assets if it believes it is prudent to do so.

C. Interregional Transmission Coordination

1. Interregional Transmission Coordination Requirements

a. Interregional Transmission Coordination Procedures and Geographical Scope

i. Final Rule

493. In Order No. 1000, the Commission required each public utility transmission provider, through its regional transmission planning process, to establish further procedures with each of its neighboring transmission planning regions for the purpose of (1) 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; and (2) jointly evaluating such facilities, as well as jointly evaluating those transmission facilities that are proposed to be located in more than one transmission planning region.[565] Furthermore, the Commission required each public utility transmission provider, through its regional transmission planning process, to describe the methods by which it will identify and evaluate interregional transmission facilities and to include a description of the type of transmission studies that will be conducted to evaluate conditions on neighboring systems for the purpose of determining whether interregional transmission facilities are more efficient or cost-effective than regional facilities.[566]

494. In Order No. 1000, the Commission also required each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection to implement the interregional transmission coordination requirements.[567] The Commission defined an interregional transmission facility as one that is located in two or more transmission planning regions.[568] The Commission declined to require, but did not prohibit, joint evaluation of other facilities or study of the effects in a second region of a new transmission facility proposed to be located in a single transmission planning region.[569] The Commission explained that to do otherwise could have the effect of mandating interconnectionwide transmission planning, because a transmission facility located within one transmission planning region can have effects on many systems in the interconnection, which could trigger a chain of multiregional evaluation processes. Furthermore, the Commission observed that its interregional transmission coordination requirements will assist transmission planners in understanding and managing the effects of a transmission facility located in one region on a neighboring region.[570]

ii. Requests for Rehearing and Clarification

495. AEP asks the Commission to ensure that the interregional coordination requirements apply to transmission needs driven by public policy requirements. Otherwise, AEP states, planners will settle on less efficient and less cost-effective solutions, which increase costs. AEP argues that it is arbitrary and capricious for the Commission not to require consideration of needs driven by public policy requirements as part of interregional coordination, in light of its findings on the importance of public policy considerations in the Final Rule. AEP also argues that requiring consideration of transmission needs driven by public policy requirements within a region but not between regions places too much emphasis and importance on the decisions about configuration of the planning regions given that the Commission has declined to prescribe the geographic scope of any transmission planning region.

496. Bonneville Power states that certain aspects of Order No. 1000 indicate that formal procedures need to cover only identification and joint evaluation rather than planning and developing interregional transmission facilities. If this is what the Commission meant, then Bonneville Power requests that the Commission so clarify.

497. On rehearing, MISO Transmission Owners Group 1 and Wisconsin PSC request that the Commission expand the definition of an interregional transmission facility. Specifically, MISO Transmission Owners Group 1 requests that the Commission find that transmission facilities physically located within one region can be considered interregional transmission facilities when they provide sufficient benefits as determined in accordance with the applicable interregional agreement or OATTs, and can be eligible for interregional cost allocation pursuant to criteria set forth in that agreement or those OATTs. Wisconsin PSC makes a similar argument. Wisconsin PSC also requests that the Commission remove the single-region limitation, and instead limit evaluation of a single-region project to interregional transmission planning processes that involve no more than two transmission planning regions. Wisconsin PSC adds that the Commission could further limit consideration by requiring the project sponsor to publicly identify a single-region transmission facility as benefiting the other affected region to ensure that a project does not ''fly under the radar.''[571] Both Wisconsin PSC and MISO Transmission Owners Group 1 argue that their respective definitions eliminate the Commission's concern

[565] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 396.

[566] *Id.* P 398.

[567] *Id.* P 415.

[568] *Id.* P 482 n.374.

[569] Nevertheless, consistent with Cost Allocation Principle 4, each regional transmission planning process must identify the consequences of a proposed new transmission facility for other transmission planning regions. The Commission also stated that Order No. 1000 did not affect any obligations that public utility transmission providers may otherwise have to assess the effects of new transmission facilities on other systems, including, but not limited to, any other requirement of the OATT for interconnection studies, any requirement under the NERC reliability standards, and the requirements of Good Utility Practice. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 416 n.351.

[570] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 416.

[571] Wisconsin PSC at 6–7.

that expanding the scope of interregional transmission coordination would lead to interconnectionwide transmission planning.

498. Furthermore, MISO Transmission Owners Group 1 argues that the Commission should expand the definition because the expanded definition would help ensure that the costs of such facilities are allocated in a manner that is at least roughly commensurate with the benefits received. Wisconsin PSC asserts that requiring regions to jointly consider single-region projects in the interregional planning process would diminish the risk of inadvertent free ridership, ensure that intended beneficiaries of a project are allocated a share of the project costs, and expand the set of potential cost-effective transmission solutions to regional transmission needs. Wisconsin PSC adds that not eliminating this exclusion may create a specific violation of the application of the cost causation/beneficiaries pay principles articulated in *Illinois Commerce Comm'n* v. *FERC,* which require beneficiaries of a transmission project to pay a roughly commensurate share of project costs.[572]

499. Wisconsin PSC and MISO Transmission Owners Group 1 also argue that it is especially important to expand the definition because MISO has extensive seams with neighboring RTOs and other regions. Wisconsin PSC adds that it is virtually impossible for MISO to plan a transmission line in those areas without providing potential benefits to PJM load. Thus, it argues that the single-region limitation would increase the free ridership that the Commission seeks to deter.

iii. Commission Determination

500. We deny AEP's arguments that Order No. 1000's interregional transmission coordination requirements do not adequately provide for consideration of transmission needs driven by Public Policy Requirements. In Order No. 1000, the Commission determined that interregional transmission coordination neither requires nor precludes longer-term interregional transmission planning, including the consideration of transmission needs driven by Public Policy Requirements.[573] Order No. 1000 stated that whether and how to address this issue with regard to interregional transmission facilities is a matter for public utility transmission providers, through their regional transmission planning processes, to resolve in the development of compliance proposals.[574] We clarify that Order No. 1000 does not require or prohibit consideration of transmission needs driven by Public Policy Requirements as part of interregional transmission coordination. However, such considerations are required through the regional transmission planning process, which is an integral part of interregional transmission coordination because all interregional transmission projects must be selected in both of the relevant regional transmission planning processes in order to receive interregional cost allocation. Therefore, consideration of transmission needs driven by Public Policy Requirements is an essential part of the evaluation of an interregional transmission project, not as part of interregional transmission coordination, but rather as part of the relevant regional transmission planning processes. As such, we continue to believe that the decision of whether and how to address these issues with regard to interregional transmission facilities in the regional transmission planning processes is a matter for public utility transmission providers to work out with their stakeholders in the development of compliance proposals.[575]

501. We clarify for Bonneville Power that Order No. 1000 only requires the development of a formal procedure to identify and jointly evaluate interregional transmission facilities that are proposed to be located in neighboring transmission planning regions.[576] We emphasize, however, that while the Commission does not require any particular type of studies to be conducted, the purpose of identifying and jointly evaluating interregional transmission facilities is to determine whether they may more efficiently or cost-effectively meet transmission needs than regional transmission facilities.[577]

502. We decline to expand the definition of an interregional transmission facility adopted in Order No. 1000, as requested by MISO Transmission Owners Group 1 and Wisconsin PSC. As the Commission explained in Order No. 1000, requiring joint evaluation of the effects of a new transmission facility proposed to be located solely in a single transmission planning region could, in effect, mandate interconnectionwide transmission planning. This is because transmission facilities located in one transmission planning region often have effects on multiple neighboring systems, which could trigger a chain of multilateral evaluation processes.[578] While the definitions of an interregional transmission facility proposed by MISO Transmission Owners Group 1 and Wisconsin PSC could help to restrict the range of proposed new transmission facilities subject to joint evaluation, we disagree that they are sufficient to address the Commission's concern that expanding the definition of an interregional transmission facility adopted in Order No. 1000 could mandate interconnectionwide transmission planning. Adopting MISO Transmission Owners Group 1 and Wisconsin PSC's expanded definitions of an interregional transmission facility could still, in effect, mandate that certain transmission projects located solely in a single transmission planning region be planned on a multilateral, if not interconnectionwide, basis, and we are not persuaded that such a requirement is necessary at this time. The Commission exercised its discretion in this rulemaking to improve regional transmission planning and bilateral interregional transmission coordination in a manner that does not have the effect of requiring interconnectionwide planning. Moreover, we reiterate here the Commission's conclusion in Order No. 1000 that imposing multilateral or interconnectionwide transmission coordination requirements at this time could frustrate the progress being made in the ARRA-funded transmission planning initiatives.[579]

503. We also do not believe it is necessary to expand the definition of an interregional transmission facility, as argued by Midwest ISO Transmission Owners Group 1 and Wisconsin PSC, in order to ensure that the costs of a transmission facility located in a single transmission planning region that benefits a neighboring transmission planning region are allocated commensurately with the benefits it provides. As we explain more fully below,[580] these arguments fail to take into account the relationship between the Commission's cost allocation reforms and the other reforms contained in Order No. 1000 and the need to balance a number of factors to ensure that the reforms achieve the goal of improved transmission planning. In particular, as we stated in Order No. 1000, these reforms establish a closer link between regional transmission planning and cost allocation, both of

[572] Wisconsin PSC at 5 (citing 576 F.3d 470 (7th Cir. 2009)).

[573] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 401.

[574] *Id.* P 401.

[575] *Id.*

[576] *Id.* P 435.

[577] *Id.* P 398.

[578] *Id.* P 416.

[579] *Id.* P 417.

[580] *See* discussion *infra* at section 0.

which involve the identification of beneficiaries. In light of that closer link, we continue to find that allowing one region to allocate costs unilaterally to entities in another region would effectively impose an affirmative burden on stakeholders to actively monitor transmission planning processes in numerous other regions in which they could be identified as beneficiaries and thus be subject to cost allocation. This would essentially result in interconnectionwide transmission planning with corresponding cost allocation, albeit conducted in a highly inefficient manner.[581]

504. We note, however, that the public utility transmission providers in neighboring transmission planning regions may negotiate an agreement to share the costs of a particular transmission facility with the beneficiaries in another transmission planning region, as they always have been free to do.[582] Further, nothing in Order No. 1000 precludes public utility transmission providers in consultation with stakeholders from voluntarily developing and proposing interregional transmission coordination procedures providing for the joint evaluation by more than one transmission planning region of a transmission facility located solely in one transmission planning region should the public utility transmission providers in neighboring transmission planning regions agree to do so.[583] Also, we reiterate that Order No. 1000's limited requirements for bilateral interregional transmission coordination do not prohibit either voluntary multilateral interregional transmission coordination or planning, or the development of stronger bilateral coordination agreements than the rule requires.

505. Finally, Wisconsin PSC specifically mentions that transmission lines in MISO often provide potential benefits to PJM load. As the Commission recognized in Order No. 1000, MISO and PJM developed a cross-border cost allocation method in response to Commission directives related to their intertwined configuration that permits them, in certain cases, to allocate to one RTO or ISO the cost of a transmission facility that is located entirely within the other RTO or ISO. We reiterate here that Order No. 1000 does not require MISO and PJM to revise their existing cross-border cost allocation method in response to Cost Allocation Principle 4.[584]

2. Implementation of the Interregional Transmission Coordination Requirements

a. Procedure for Joint Evaluation

i. Final Rule

506. The Commission required the developer of an interregional transmission project to first propose its transmission project in the regional transmission planning processes of each of the neighboring regions in which the transmission facility is proposed to be located. The submission of an interregional transmission project in each regional transmission planning process will trigger the procedure under which the public utility transmission providers, acting through their regional transmission planning processes, will jointly evaluate the proposed transmission project.[585] The Commission required that joint evaluation be conducted in the same general timeframe as, rather than subsequent to, each transmission planning region's individual consideration of the proposed transmission project.[586] For an interregional transmission facility to receive cost allocation under the interregional cost allocation method or methods developed pursuant to Order No. 1000, the Commission required that the transmission facility be selected in both of the relevant regional transmission plans for purposes of cost allocation.[587] Finally, the Commission directed each public utility transmission provider, through its transmission planning region, to develop procedures by which differences in planning criteria can be identified and resolved for purposes of jointly evaluating a proposed interregional transmission facility.[588]

ii. Requests for Rehearing and Clarification

507. Joint Petitioners and ITC Companies seek rehearing of the Commission's requirement that both neighboring transmission planning regions must agree to include a proposed interregional transmission facility in their respective regional transmission plans for it to be eligible for interregional cost allocation. Instead, Joint Petitioners argue that the Commission should require the preparation and approval of an interregional plan, or at the very least, provide a mechanism by which a sponsor of an interregional transmission project can obtain Commission review of a disagreement or failure to act by and among affected planning regions. They assert that requiring each region to include an interregional facility in its respective plan is counterproductive because the Commission did not require the consistent use of specific planning horizons or the performance of particular scenario analyses for purposes of regional planning. Additionally, Joint Petitioners contend that even if a project is determined to be the most efficient, cost-effective project for the broader region composed of both planning regions, either region may veto the project because those broader benefits are not considered in the individual regional plans.

508. WIRES states that the planning experiences of RTOs and ISOs and the record in this proceeding contain many examples of planning procedures and criteria that are suitable for two regions to coordinate their planning efforts. WIRES adds that adopting these procedures, which establish fixed timelines for decision, data exchange requirements, planning assumptions, and standard modeling techniques, along with clear opportunities for exceptions where necessary, would shorten and rationalize planning processes without dictating outcomes. WIRES asserts that technical conferences could be useful for developing a consensus on these matters.

iii. Commission Determination

509. We deny Joint Petitioners' and ITC Companies' request for rehearing of Order No. 1000's requirement that an interregional transmission facility must be selected in each relevant regional transmission plan for purposes of cost allocation to be eligible for cost allocation under the interregional cost allocation method or methods.[589] Rather, we reaffirm this requirement. As stated above, Order No. 1000 establishes a closer link between transmission planning and cost allocation. As discussed more fully below in the section on stakeholder participation,[590] Order No. 1000 provides for stakeholder involvement in the consideration of an interregional transmission facility primarily through the regional transmission planning processes.[591] We

[581] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 660.

[582] *Id.* P 658.

[583] *Id.* P 416.

[584] *Id.* P 662.

[585] *Id.* P 436.

[586] *Id.* P 439.

[587] *Id.* P 436.

[588] *Id.* P 437.

[589] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 436.

[590] *See* discussion *infra* at section 0.

[591] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 465; *see also id.* P 443.

therefore conclude that this requirement is necessary to ensure that stakeholders have an opportunity to provide meaningful input with respect to proposed interregional transmission facilities before such facilities are selected in each relevant regional transmission plan for purposes of cost allocation.

510. We disagree with Joint Petitioners' contention that Order No. 1000 did not require consistency in planning horizons or scenario analyses. In Order No. 1000, the Commission directed each public utility transmission provider, through its transmission planning region, to develop procedures by which differences in the data, models, assumptions, planning horizons, and criteria used to study a proposed interregional transmission project can be identified and resolved for purposes of jointly evaluating an interregional transmission project.[592] This approach allows regions the flexibility to develop procedures that work for them, while still addressing the concern that joint evaluation of a proposed interregional transmission facility cannot be effective without some effort by neighboring transmission planning regions to harmonize differences in the data, models, assumptions, planning horizons, and criteria used to study a proposed transmission project.[593] We therefore decline to adopt WIRES' suggestion that we require that public utility transmission providers implement certain specific planning procedures or criteria, or that we hold a technical conference to consider such matters.

511. Moreover, we decline to require the preparation and approval of an interregional transmission plan or to adopt a mechanism for the Commission to review neighboring transmission planning regions' disagreements about or failure to act on a proposed interregional transmission facility as requested by Joint Petitioners. Joint Petitioners have not convinced us that such measures are necessary in this generic rulemaking. As the Commission found in Order No. 1000, the interregional transmission coordination reforms do not require the creation of a distinct interregional transmission planning process to produce an interregional transmission plan or the formation of interregional transmission planning entities. Rather, the requirement is for public utility transmission providers to consider whether the local and regional transmission planning processes result in transmission plans that meet local and regional transmission needs more efficiently and cost-effectively, after considering opportunities for collaborating with public utility transmission providers in neighboring transmission planning regions.[594] However, as the Commission stated in Order No. 1000, public utility transmission providers may voluntarily engage in interregional transmission planning and, as relevant, rely on such a planning process to comply with the interregional transmission coordination requirements of Order No. 1000.[595]

512. Finally, we understand Joint Petitioners' concern that a transmission planning region may decline to select an interregional transmission project in its regional transmission plan for purposes of cost allocation if the project does not sufficiently benefit that region, even if it is the more efficient or cost-effective project for the broader multiregional area. This is another version of the argument made by petitioners that prefer interconnectionwide transmission planning to regional transmission planning. However, we decline to require interconnectionwide planning in this rulemaking for the reasons set out in Order No. 1000 and summarized above. We understand that, under the interregional transmission coordination procedures of Order No. 1000, an interregional transmission facility is unlikely to be selected for interregional cost allocation unless each transmission planning region benefits or the transmission planning region that benefits compensates the region that does not through a separate agreement—and that this feature would not necessarily apply for interconnectionwide planning. We continue to believe however that, under the regional transmission planning approach adopted in Order No. 1000, it is appropriate for each transmission planning region to determine for itself whether to select in its regional transmission plan for purposes of cost allocation an interregional transmission facility that extends partly within its regional footprint based on the information gained during the joint evaluation of an interregional transmission project.

b. Stakeholder Participation

i. Final Rule

513. In Order No. 1000, the Commission did not require the interregional transmission coordination procedures to meet the requirements of the transmission planning principles required for local planning (under Order No. 890) and regional planning (under Order No. 1000).[596] The Commission explained that stakeholders will have the opportunity to participate fully in the consideration of interregional transmission facilities during the regional transmission planning process, because each region must select such a facility in its regional transmission plan for purposes of cost allocation in order for it to be eligible for interregional cost allocation.[597] The Commission also required public utility transmission providers to make transparent the analyses undertaken and determinations reached by neighboring transmission planning regions in the identification and evaluation of interregional transmission facilities.[598] Last, the Commission required that each public utility transmission provider give stakeholders the opportunity to provide input into the development of its interregional transmission coordination procedures and the commonly agreed-to language to be included in its OATT.[599]

ii. Requests for Rehearing and Clarification

514. Transmission Dependent Utility Systems and PSEG Companies argue that the Commission should have required public utility transmission providers to provide for more stakeholder participation in the interregional coordination process and procedures. Transmission Dependent Utility Systems also seek clarification or, in the alternative, argue that the Commission should require on rehearing, that stakeholders have a meaningful opportunity to participate in the development of the interregional coordination process before it is submitted to the Commission in a compliance filing, whether the process is reflected in the OATT or in a bilateral agreement.

515. In addition, Transmission Dependent Utility Systems argue that stakeholders must be allowed to participate throughout the process to ensure that load-serving transmission customers receive treatment comparable to the treatment transmission providers accord their retail and wholesale merchant functions, as required by sections 205 and 217(b)(4), Order No. 890, and the judicial requirement for reasoned decision-making.[600] PSEG

[592] *Id.* P 437.

[593] *Id.*

[594] *Id.* P 399.

[595] *Id.*

[596] *Id.* P 465.

[597] *Id.*

[598] *Id.*

[599] *Id.* P 466.

[600] Transmission Dependent Utility Systems at 18 (citing *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto Ins. Co.,* 463 U.S. 29, 43 (1983)).

Companies argue that Order No. 1000's assumption that this issue will be addressed under the regional processes is unsupported. They also argue that the lack of a specific requirement for stakeholder participation is inconsistent with some of the other interregional coordination requirements in Order No. 1000, including requirements related to joint evaluation of interregional projects and the determination of beneficiaries of such projects.

516. Moreover, Transmission Dependent Utility Systems argue that stakeholders must have a meaningful opportunity to participate in the early stages of the process for identifying and evaluating possible interregional solutions to transmission customer concerns. Similarly, PSEG Companies recommend that the Commission require that interregional coordination procedures include information on: (1) How transmission providers will facilitate stakeholder participation; (2) how market participants can propose ideas for cross-border projects and identify and submit concerns about problems in one region caused by activity in another (and how to address those concerns); and (3) how transmission providers will accommodate and track in a transparent manner all questions, comments, and other input from stakeholders regarding data posted on coordination activities, as well as transmission providers' responses.

517. Transmission Dependent Utility Systems also assert that Order No. 1000 fails to address their larger concern, which is that the interregional coordination processes fail to obligate public utility transmission providers to share with stakeholders the data exchanged among themselves, including study results, models, input data, and assumptions used in running those studies. Transmission Dependent Utility Systems are concerned that public utility transmission providers may contend that the obligation to share does not include load-serving customers. Further, Transmission Dependent Utility Systems state the Commission should clarify that the interregional planning data that is shared with load-serving entities must be sufficient to allow them to replicate the interregional planning study results, including models, base cases, data inputs, and assumptions. Transmission Dependent Utility Systems also believe it is important that benefit-to-cost analyses of interregional projects be transparent and verifiable to protect customers, ensure accuracy, and minimize *ex post facto* disputes regarding regional and interregional cost allocation.

iii. Commission Determination

518. First, we clarify for Transmission Dependent Utility Systems that each public utility transmission provider must provide stakeholders with a meaningful opportunity to provide input into the development of its interregional transmission coordination procedures before those procedures are submitted to the Commission in its compliance filing, whether those procedures are included in its OATT or reflected in an interregional transmission coordination agreement.[601] Accordingly, stakeholders must be afforded sufficient time to meaningfully comment on a public utility transmission provider's proposed interregional transmission coordination procedures as they are being developed.

519. In response to those petitioners that raise concerns regarding stakeholder participation in the interregional transmission coordination process, we reiterate the Commission's statement in Order No. 1000 that stakeholder participation in the consideration of interregional transmission facilities is an important component of interregional transmission coordination. Moreover, we also reiterate that stakeholders will have the opportunity to provide input with respect to the consideration of interregional transmission facilities when these facilities are being considered in the regional transmission planning process. As stated above, Order No. 1000 provides that only if an interregional transmission facility is selected in each region's transmission plan for purposes of cost allocation will that facility's cost be allocated to either region.[602] It is therefore through participation in the regional transmission planning process that stakeholders will have the primary opportunity to participate fully in the consideration of interregional transmission facilities. While nothing in Order No. 1000 prohibits an interregional transmission coordination process from providing for more direct stakeholder involvement in interregional transmission coordination, it may be the case that much of the interregional transmission coordination would occur through sharing computer modeling results regarding the effects and benefits of a proposed interregional transmission facility, which may be harder for a broad community of stakeholders to participate in than would face to face meetings be. If we are being asked to require there be in-person meetings for interregional transmission coordination with all stakeholders attending, we would be concerned about requiring a cumbersome process that could necessitate significant expense and travel time to multiple neighboring regions by the large number of stakeholders in each region. We continue to believe it is sufficient and appropriate to allow for consideration of stakeholder interests by requiring that any decision on interregional cost allocation be affirmed by each of the transmission planning regions involved.

520. For similar reasons, we decline to expand the requirements of Order No. 1000 regarding the types and sufficiency of interregional transmission coordination information to be exchanged between regions and provided to stakeholders. We therefore affirm Order No. 1000's requirement that, in order to facilitate stakeholder involvement, public utility transmission providers must, subject to appropriate confidentiality protections and CEII requirements, make transparent the analyses undertaken and determinations reached by neighboring transmission planning regions in the identification and evaluation of interregional transmission facilities.[603]

521. Further, we decline to adopt PSEG Companies' recommendation that the Commission require the interregional transmission coordination procedures to include information on how stakeholders in one transmission planning region can raise issues and solutions regarding activity in another transmission planning region. The regional transmission planning process already provides stakeholders with the opportunity to present such concerns, and we continue to believe that these concerns are best addressed in the first instance through the regional transmission planning process, particularly as the solution may not involve an interregional transmission facility.

522. In light of this, however, we clarify that each public utility transmission provider must describe in its OATT how its regional transmission planning process will enable stakeholders to provide meaningful and timely input with respect to the consideration of interregional transmission facilities. Moreover, as requested by PSEG Companies, we require that each public utility transmission provider must explain in its OATT how stakeholders and transmission developers can propose interregional transmission facilities for

[601] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 466.

[602] *Id.* P 465.

[603] *Id.*

the public utility transmission providers in neighboring transmission planning regions to evaluate jointly. This is consistent with Order No. 1000's requirement that on compliance, public utility transmission providers must describe the methods by which they will identify and evaluate interregional transmission facilities.[604]

IV. Cost Allocation

523. In Order No. 1000, the Commission required that each public utility transmission provider have in its OATT 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 (''regional cost allocation''); and that each public utility transmission provider within two (or more) neighboring transmission planning regions develop a method or set of methods for allocating the costs of new interregional transmission facilities that each of the two (or more) neighboring transmission planning regions selected for purposes of cost allocation because such facilities would resolve the individual needs of each region more efficiently or cost-effectively (''interregional cost allocation'').[605] The OATTs of all public utility transmission providers in a region must include the same cost allocation method or methods adopted by the region.

524. The regional and interregional cost allocation methods each must adhere to six regional and interregional cost allocation principles: (1) Costs must be allocated in a way that is roughly commensurate with benefits; (2) there must be no involuntary allocation of costs to non-beneficiaries; (3) a benefit to cost threshold ratio cannot exceed 1.25; (4) costs must be allocated solely within the transmission planning region or pair of regions unless those outside the region or pair of regions voluntarily assume costs; (5) there must be a transparent method for determining benefits and identifying beneficiaries; and (6) there may be different methods for different types of transmission facilities.[606] The Commission directed that, subject to these general cost allocation principles, public utility transmission providers in consultation with stakeholders would have the opportunity to agree on the appropriate cost allocation methods for their new regional and interregional transmission facilities, subject to Commission approval.[607] The Commission also found that if public utility transmission providers in a region or pair of regions could not agree, the Commission would use the record in the relevant compliance filing proceeding(s) as a basis to develop a cost allocation method or methods that meets the Commission's requirements.[608] Finally, the Commission emphasized that its cost allocation requirements are designed to work in tandem with its transmission planning requirements to identify more appropriately the benefits and the beneficiaries of new transmission facilities so that transmission developers, planners and stakeholders can take into account in the transmission planning process who would bear the costs of transmission facilities, if constructed.[609]

A. Legal Authority for Cost Allocation Reforms

1. Final Rule

525. In Order No. 1000, the Commission determined that its jurisdiction is broad enough to allow it to ensure that all beneficiaries of services provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those transmission facilities.[610] The Commission stated that this comports fully with the specific characteristics of transmission facilities and transmission services, and that the provisions of Order No. 1000 are necessary to fulfill the Commission's statutory duty of ensuring rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential.[611]

526. The Commission based its finding on the language of section 201(b)(1) of the FPA, which gives the Commission jurisdiction over ''the transmission of electric energy in interstate commerce.''[612] The Commission concluded that its jurisdiction therefore extends to the rates, terms and conditions of transmission service, rather than merely transactions for such transmission service specified in individual agreements.[613] Moreover, the Commission found that section 201(b)(1) gives the Commission jurisdiction over ''all facilities'' for the transmission of electric energy, and this jurisdiction is not limited to the use of those transmission facilities within a certain class of transactions.[614] As a result, the Commission stated that it has jurisdiction over the use of these transmission facilities in the provision of transmission service, which includes consideration of the benefits that any beneficiaries derive from those transmission facilities in electric service regardless of the specific contractual relationship that the beneficiaries may have with the owner or operator of these transmission facilities.[615]

527. The Commission also explained that neither section 205 nor section 206 of the FPA state or imply that an agreement is a precondition for any transmission charges.[616] The Commission also concluded that cost allocation cannot be limited to voluntary arrangements because if it were the Commission could not address free rider problems associated with new transmission investment, and it could not ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory.[617]

528. In addition, the Commission explained that its approach is consistent with the concept of cost causation, because a full cost causation analysis may involve ''an extension of the chain of causation''[618] beyond those causes captured in voluntary arrangements. The Commission explained that in order to identify all causes, it is necessary to some degree to begin with their effects, i.e., the benefits that they engender and then work back to their sources.[619] The Commission noted that this point was acknowledged in the Seventh Circuit's characterization of cost causation in *Illinois Commerce Commission*.[620] The Seventh Circuit stated that:

> 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.[621]

[604] *Id.* P 398.

[605] *Id.* P 482. For purposes of Order No. 1000, a regional transmission facility is a transmission facility located entirely in one region. An interregional transmission facility is one that is located in two or more transmission planning regions. A transmission facility that is located solely in one transmission planning region is not an interregional transmission facility. *Id.* P 482 n.374.

[606] *Id.* PP 622–93.

[607] *Id.* P 588.

[608] *Id.* P 482.

[609] *Id.* P 483.

[610] *Id.* P 531.

[611] *Id.*

[612] *Id.* P 532.

[613] *Id.*

[614] *Id.*

[615] *Id.*

[616] *Id.* P 533.

[617] *Id.* P 535.

[618] *Id.* P 536 (quoting *KN Energy,* 968 F.2d 1295 at 1302).

[619] *Id.*

[620] *Id.* P 537.

[621] *Id.* (quoting *Illinois Commerce Commission,* 576 F.3d at 476 (emphasis supplied)).

The court fully recognized that, to identify causes of costs, one must to some degree begin with benefits.[622]

529. Last, the Commission emphasized that its cost allocation reforms are a component of its transmission planning reforms, which require that, to be eligible for regional or interregional cost allocation, a proposed new transmission facility first must be selected in a regional transmission plan for purposes of cost allocation, which depends on a full assessment by a broad range of regional stakeholders of the benefits accruing from transmission facilities planned according to the reformed transmission planning processes.

2. Requests for Rehearing or Clarification

a. Petitioners' Arguments That the FPA Requires a Contract Before Costs Are Allocated

530. Several petitioners argue that the Commission does not have the jurisdiction to require that beneficiaries of service provided by specific transmission facilities bear the costs of those benefits regardless of their contractual relationship with the owner of those facilities.[623] They contend that the Commission's requirement to allocate costs without regard to whether there is a contract or service provided is inconsistent with the FPA.[624] For example, Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council assert that the Commission has confused the FPA's expression of jurisdiction in section 201 with the grant of substantive authority, and that the Commission's interpretation of what section 201 allows would make sections 205 and 206 superfluous. They also assert that the Commission's view of section 201 would also render section 203 superfluous and allow the Commission to compel sales or purchases of jurisdictional facilities when the public interest required it.

531. National Rural Electric Coops state that a contractual relationship is required as a basis for a jurisdictional rate or charge. They maintain that in providing for Commission regulation of rates ''for or in connection with the transmission or sale of electric energy,'' the FPA ties the Commission's rate authority directly to the jurisdictional service provided by those public utilities.[625] They argue that where an entity takes no jurisdictional service from a public utility, the Commission cannot permit the public utility to collect charges from that entity. Several other petitioners make similar arguments.[626] Large Public Power Council argues that the natural implication of terms in section 205 and 206 such as ''made,'' ''demanded,'' ''received,'' ''observed,'' ''charged,'' or ''collected'' is that they pertain to rates assessed to utility customers in connection with an agreement to take service.[627]

532. Large Public Power Council argues that the approach taken in Order No. 1000 to cost allocation for new transmission development is at odds with the Commission's requirement that interstate gas pipeline projects be self-sustaining and not be subsidized by existing services. Large Public Power Council states that courts have held that the Natural Gas Act and the FPA should be interpreted similarly, and the Commission must explain substantial discrepancies.

533. Sacramento Municipal Utility District argues that if the rates that the Commission regulates are for transmission service, it logically follows that only customers who receive the transmission service can be charged for it. Vermont Agencies contend that even if the statute were ambiguous, it would still be unreasonable to allocate costs on the beneficiary theory because it would not follow logically from the Commission's acknowledgement that it only regulates the provision of transmission service.

534. Sacramento Municipal Utility District argues that the Commission never disputed its arguments that: (1) In theory, a utility could build a facility and then claim that because it provided a benefit to someone remote from the facility, that entity—customer or not—should bear some of the costs; and (2) it cannot force unwilling customers to pay for additional service.[628] Sacramento Municipal Utility District argues that Order No. 1000 allows ''beneficiaries'' of new transmission facilities to be charged even if they are not getting a new service.[629]

535. National Rural Electric Coops also argue that FPA sections 205 and 206 require that costs and benefits be fairly allocated between the two parties providing and receiving jurisdictional service. They contend that the fact that there may be third-party beneficiaries to an agreement does not change the analysis. They state that, even though other utilities may look more like transmission customers than entities that benefit indirectly from increased transmission capacity and are not subject to jurisdictional rates, this does not mean that those utilities have greater legal or contractual obligations.

536. Coalition for Fair Transmission Policy argues that the Commission is incorrect in finding that it has the legal authority to authorize public utilities to charge third party beneficiaries for transmission facilities because the issue has not been squarely addressed by the courts.[630] It asserts that the matter has not merited analysis or discussion because it is an undisputed maxim that lawful rates are founded on privity of contracts.

537. Several petitioners disagree that free rider problems are a basis for the cost allocation requirements established in Order No. 1000.[631] Southern Companies argue that under Order No. 1000, the mere potential of free riders is absolute poison to the justness and reasonableness of a cost allocation methodology. They contend that Order No. 1000 does not explain who these free riders may be, what benefits might be taken without compensation, or whether in the absence of the new transmission, they would require and financially support their own new transmission. Southern Companies add that Order No. 1000 does not explain why complaints under section 206 are

[622] *Id.*

[623] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Coalition for Fair Transmission Policy; Large Public Power Council; National Rural Electric Coops; New York ISO at 4 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 539); New York PSC; New York Transmission Owners; Northern Tier Transmission Group at 5 (citing *Atlantic City Elec. Co.* v. *FERC,* 295 F.3d 1, 8 (D.C. Cir. 2002) (stating that in the absence of statutory authority authorization for its act, an agency's action is plainly contrary to law and cannot stand)); Sacramento Municipal Utility District; Southern Companies at 96–97 (citing *Illinois Commerce Comm'n,* 576 F.3d 470 (2009); *Morgan Stanley Capital Group, Inc.* v. *Pub. Util. Dist. No. 1 of Snohomish County, Washington et al.,* 554 U.S. 527, 533 (2008); *Ottertail Power Co.* v. *United States,* 410 U.S. 366, 374 (1973); *In re Permian Basin Area Rate Cases,* 390 U.S. 747, 822 (1968); *United Gas Pipeline Co.* v. *Mobile Gas Service Corp.,* 350 U.S. 332, 343 (1956)); and Vermont Agencies at 6, 10 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 532).

[624] *See, e.g.,* Coalition for Fair Transmission Policy; Southern Companies; National Rural Electric Coops; and Ad Hoc Coalition of Southeastern Utilities.

[625] National Rural Electric Coops at 14 (quoting 16 U.S.C. 824d(a)).

[626] *See, e.g.,* National Rural Electric Coops; New York ISO; Northern Tier Transmission Group; Sacramento Municipal Utility District; Southern Companies; and Vermont Agencies.

[627] Large Public Power Council at 35.

[628] Sacramento Municipal Utility District at 9 (citing *Exxon Mobil Corp.* v. *FERC,* 430 F.3d 1166, 1176–77 (D.C. Cir. 2005)).

[629] Sacramento Municipal Utility District at 9 & n.4.

[630] Coalition for Fair Transmission Policy at 20 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 540).

[631] *See, e.g.,* Ad Hoc Coalition of Southeastern Utilities; Large Public Power Council; and National Rural Electric Coops.

insufficient for resolving free rider problems.

538. Southern Companies also assert that the FPA does not allow the allocation of costs to third-party non-customers because it does not allow the Commission to regulate cost allocations or rate structures that apply to the conveyance of abstract nonjurisdictional ''benefits'' other than electricity. Southern Companies assert that the FPA requires that cost allocations and rate structures must apply to the conveyance of benefits that are the actual use of transmission facilities or services (or support services required to provide the same). They argue that *Mobil Oil Corp.* v. *FPC* supports this conclusion.[632] In that case, the court found that the Commission exceeded its authority when it required cost allocation and rate structures for certain nonjurisdictional liquids as part of the transportation of natural gas.[633]

539. Sacramento Municipal Utility District argues that the Commission is incorrect in determining that it can require non-public utilities participating in a regional planning organization to accept an allocation of costs for new transmission facilities approved by the regional entity as a condition of reciprocity, even if they have no customer relationship with the transmission provider. It also states that the Commission's longstanding position is that without evidence that two systems are in fact acting as one, the Commission cannot mandate the use of a single joint rate.[634] Sacramento Municipal Utility District argues that if the Commission cannot mandate the use of joint rates, it cannot mandate that an entity pay the rates charged by a utility with which it has no contractual or tariff-based customer/provider relationship at all.

540. Several petitioners argue that the courts have rejected attempts to impose cost liability without a contract for Commission-jurisdictional service.[635] For example, Southern Companies and Coalition for Fair Transmission Policy argue that the entire design of the FPA is based on the premise that those who impose charges have a service relationship with those on whom charges are levied.[636] They assert that this is supported by the Supreme Court's finding in *Morgan Stanley,* where it stated that ''the regulatory system created by the FPA is *premised* on contractual agreements voluntarily devised by the regulated companies.'' [637] Coalition for Fair Transmission Policy states that in *Otter Tail Power Co.* v. *United States,* the Supreme Court wrote that Congress had rejected a pervasive regulatory scheme for transmission planning and cost allocation ''in favor of voluntarily contractual relationships.'' [638]

541. Ad Hoc Coalition of Southeastern Utilities also asserts that a utility's ability to collect rates is a matter of its contractual relationship with its customers, and the Commission's authority is limited to reviewing rates and, if unlawful, to remedying them. It asserts that this is apparent on the face of the FPA, and it has been a fundamental building block of energy law since the Supreme Court articulated the *Mobile-Sierra* doctrine.[639] Ad Hoc Coalition of Southeastern Utilities argues that the *Mobile-Sierra* doctrine makes it clear that the Commission's oversight of utility rates is subordinate to parties' contractual rights. It argues that the Commission errs in its attempt to distinguish *Mobile-Sierra* on the ground that ''we are dealing here with conditions under which costs can be recovered in rates, not conditions under which contracts can be altered.'' [640] Large Public Power Council makes similar arguments and also asserts that while the Commission has the authority to alter the terms of a contract for service under FPA section 206, subject to the ''public interest'' standard, it cannot establish a right to recover costs where no contractual authority exists.

542. National Rural Electric Coops state that a central holding of the *Mobile-Sierra* cases was that the Commission's authority to review and modify jurisdictional rates does not confer new rights on the public utilities subject to the Commission's jurisdiction. They argue that Order No. 1000 is inconsistent with *Mobile-Sierra* in concluding that costs may be allocated to entities in the absence of contractual privity because neither section 205 nor section 206 of the FPA state or imply that an agreement is a precondition for any transmission charges. National Rural Electric Coops maintain that it is impermissible for the Commission to infer authority to act based on the lack of an express Congressional denial of such authority.[641]

543. Several petitioners maintain that both court and Commission precedent show that a section 205 filing requires a customer or other contractual relationship between the filing utility and the ratepayer.[642] New York Transmission Owners assert that FPA section 205 does not authorize a utility to submit (and does not authorize the Commission to accept) a rate filing where the utility lacks a contractual or customer relationship with the entities to which the rate will be charged. They state that an administrative agency cannot exceed the authority granted to it by Congress and that the agency's role is not to preempt Congressional action or to fill gaps where it believes federal action is needed.[643]

[632] 483 F.2d 1238 (D.C. Cir. 1973).

[633] Southern Companies at 100–101 (citing *Mobil Oil,* 483 F.2d 1238, 1248; also *Office of Consumers' Counsel* v. *FERC,* 655 F.2d 1132, 1148 (D.C. Cir. 1980)).

[634] Sacramento Municipal Utility District at 15 (citing *Ft. Pierce Utils. Comm'n* v. *FERC,* 730 F.2d 778 (D.C. Cir. 1984); *Richmond Power & Light* v. *FERC,* 574 F.2d 610 (D.C. Cir. 1978); *Alabama Power Co.* v. *FERC,* 993 F.2d 1557 (D.C. Cir. 1993); *Illinois Power Co.,* 95 FERC ¶ 61,183, at 61,144 (2002)).

[635] *See, e.g.,* Coalition for Fair Transmission Policy at 19–20 (citing *Morgan Stanley Capital Group, Inc.* v. *Public Utility District No. 1 of Snohomish County, Washington,* 554 U.S. 527, 533 (2008)); Illinois Commerce Commission; National Rural Electric Coops; New York PSC; Ad Hoc Coalition of Southeastern Utilities; and Large Public Power Council.

[636] Southern Companies at 97 (citing *Morgan Stanley Capital Group Inc.* v. *Pub. Util. Dist. No. 1 of Snohomish County, Washington,* 554 U.S. 527, 533 (2008); *Otter Tail Power Co.* v. *United States,* 410 U.S. 366, 374 (1973); *In re Permian Basin Area Rate Cases,* 390 U.S. 747, 822 (1968); *United Gas Pipeline Co.* v. *Mobile Gas Service Corp.,* 350 U.S. 332, 343 (1956)). *See also* Coalition for Fair Transmission Policy at 20–21.

[637] Southern Companies at 97–98 (quoting *Morgan Stanley,* 554 U.S. at 533 (2008) (citing and quoting with approval *Permian Basin Rate Cases,* 390 U.S. at 822); also citing *KN Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992) (''[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.'') (emphasis added); *Alabama Electric Cooperative, Inc.* v. *FERC,* 684 F.2d 20, 27 (D.C. Cir. 1982) (''Properly designed rates should produce revenue from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer.'') (emphasis added)). *See also* Coalition for Fair Transmission Policy at 20–21; New York PSC at 6.

[638] Coalition for Fair Transmission Policy at 20–21 (quoting *Otter Tail Power Co.* v. *United States,* 410 U.S. 366, 374 (1973)).

[639] Ad Hoc Coalition of Southeastern Utilities at 68 (citing *United Gas Pipe Line Co.* v. *Mobile Corp.,* 350 U.S. 332 (1955 (*Mobile*); *FPC* v. *Sierra Pacific Co.,* 350 U.S. 348 (1956) (*Sierra*)); *see also* Northern Tier Transmission Group at 6.

[640] Ad Hoc Coalition of Southeastern Utilities at 70 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 540).

[641] National Rural Electric Coops at 16 (citing *American Petroleum Institute* v. *EPA,* 52 F.3d 1113 (D.C. Cir. 1995); *Mobil Oil Corp.* v. *FPC,* 483 F.2d 1238 (DC Cir. 1973)).

[642] New York ISO at 4 (citing *In re Permian Basin Area Rate Cases,* 390 U.S. 747, 822 (1968)). *See also* New York ISO at 5–9 (citing *Midwest Indep. Transmission Sys. Operator, Inc.,* 131 FERC ¶ 61,173 (2010) and *Commonwealth Edison Co.,* 129 FERC ¶ 61,298 (2009), *order on reh'g,* 132 FERC ¶ 61,268 (2010)); Ad Hoc Coalition of Southeastern Utilities at 68–69 (citing 16 U.S.C. § 824d(a)); and New York Transmission Owners at 4.

[643] New York Transmission Owners at 5–6 (citing *California Indep. Sys. Operator Corp.* v. *FERC,* 372 F.2d 395, 398 (D.C. Cir. 2004) and *Office of Consumers' Counsel* v. *FERC,* 655 F.2d 1132, 1152 (DC Cir. 1980)).

544. Ad Hoc Coalition of Southeastern Utilities asserts that there is no Commission or court case approving an allocation of costs outside a contractual relationship. National Rural Electric Coops state that the Commission cited *Illinois Commerce Commission* for the proposition that to identify causes of costs, one must begin with benefits, but this statement does not address cost allocation in the absence of contractual privity when a non-customer is shown to benefit from a particular transmission project. They maintain that the court in *Illinois Commerce Commission* strongly suggested that costs must be recovered from customers when it noted that rates must ''reflect to some degree the costs actually caused by the *customer* who must pay them.'' [644] Southern Companies makes similar arguments. National Rural Electric Coops argue that Commission forbid cost allocations to non-customers when it refused to allow MISO to charge Green Mountain Energy Company (Green Mountain) for Seams Elimination Charge/Cost Adjustments/Assignment (SECA) costs under MISO's tariff because Green Mountain did not directly contract with MISO for transmission service, even though Green Mountain purportedly benefited from the transmission service.[645]

545. Vermont Agencies similarly argue that if the Commission is now asserting authority to allocate costs to non-customers, it failed to provide a reasonable basis for its change in course.[646] They state that *AEP* recognizes that utilities, in limited circumstances, can seek protection when they are forced to transmit for others, but an entity cannot build a transmission facility and then seek compensation for the benefit it provides to an entity that did not ask for it. Sacramento Municipal Utility District states that *AEP* provides no basis for charging an entity that simply benefits in some way from the new line's existence but has not caused loop flow through unscheduled deliveries.

546. Sacramento Municipal Utility District also reiterates its argument that the Commission relied upon cases for authority to allocate costs to non-customers that are inapt because they all involved situations where a customer/provider relationship existed.[647] It states that the Commission dismissed this argument in Order No. 1000 by stating that the issue was not before the court in any of those cases. It argues that the Commission did not defend its interpretation of these cases.[648] Moreover, Sacramento Municipal Utility District and Vermont Agencies assert that if the rationale for charging non-customers rests on cases the Commission now concedes are inapplicable, saying that those cases do not preclude it from allocating costs to non-customers does not answer just what does authorize the Commission to do so.

547. Sacramento Municipal Utility District also argues that the Commission's policy on cost allocation in Order No. 1000 would do more harm than good. For example, it contends that the risk of facing charges as an incidental beneficiary of a facility that a party did not want and will not use may discourage, rather than promote, regional cooperation.

b. Arguments That Order No. 1000's Cost Allocation Reforms Are Inconsistent With the Cost Causation Principle

548. Illinois Commerce Commission contends that the Commission misinterpreted the cost causation principle and failed to recognize the important distinction between cost causers and beneficiaries. It maintains that the applicable court decisions do not support equating cost causers and beneficiaries for purposes of cost allocation. It argues that the cost causation principle associates beneficiaries with cost causers only to the extent that the facilities might be delayed or not built without the revenues expected from them. Illinois Commerce Commission asserts that costs must be allocated primarily to such cost causers. Allocations to any other beneficiaries must be substantiated through an appropriate process.

549. Illinois Commerce Commission asserts that *Illinois Commerce Commission* makes it clear that when a line is planned to address the reliability concerns of one subregion of an RTO, there should be no cost allocations to others when the benefits to them are trivial or nonexistent.[649]

550. New York ISO states that transmission facilities may provide some greater or lesser degree of ''benefit'' to a broad range of system users, but showing that an entity receives some incidental benefit (based on a standard that has not yet been articulated) does not prove that the entity is receiving transmission service over that facility and should be assessed costs.

c. Arguments That the Commission Did Not Show That Existing Rates Are Unjust and Unreasonable

551. FirstEnergy Service Company and California ISO argue that the FPA does not authorize the Commission to require the filing of new rates without first finding that the existing rate is unjust, unreasonable, or unduly discriminatory or preferential. FirstEnergy Service Company maintains that the Commission concludes that the absence of clear cost allocation rules can impede the development of transmission facilities, which may adversely affect jurisdictional rates.[650] FirstEnergy Service Company argues that where no methodologies exist, the Commission cannot fulfill the basic requirement of section 206 that it find existing contracts or rates unjust, unreasonable, or unduly discriminatory or preferential. It maintains that section 206 applies to rates ''demanded, observed, charged or collected,'' not to rates that might apply to a future jurisdictional service.[651] FirstEnergy Service Company asserts that, if, on the other hand, there is an existing rate that applies to cost allocation for regional and interregional transmission facilities, then the Commission's conclusion that the absence of a rate is inapplicable, and the Commission does not find any such existing rates unjust or unreasonable. California ISO makes a similar argument. It also argues that the Commission cannot use section 206 to promote goals such as cost-effectiveness and transmission expansion, and rates are not unjust and unreasonable simply because another rate might be more just and reasonable.[652] California ISO states that its tariff already includes provisions that ensure the construction of needed

[644] National Rural Electric Coops at 20–21 (quoting *Illinois Commerce Commission,* 576 F.3d 470, 476 (7th Cir. 2009) (emphasis added by National Rural Electric Coops)).

[645] National Rural Electric Coops at 18 (citing *MISO,* 131 FERC ¶ 61,173 (2010) (SECA Order)).

[646] Vermont Agencies at 14–15 (citing *American Elec. Power Co.,* 49 FERC ¶ 61,377, at 62,381 (1986) (*AEP*); *Southern Cal. Edison Co.,* 70 FERC ¶ 61,087 (1995); *Midwest Indep. Transmission Sys. Operator, Inc.,* 131 FERC ¶ 61,173, at P 421 (2010)).

[647] Sacramento Municipal Utility District at 10–11 (citing *Midwest Indep. Transmission Sys. Operator, Inc.,* 109 FERC ¶ 61,168, P 60 (2004); *see also Midwest Indep. Transmission Sys. Operator, Inc.,* 113 FERC ¶ 61,194, P 1–4, 10 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.,* 122 FERC ¶ 61,084, P22 (2008); *Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d 1361 (D.C. Cir. 2004)).

[648] Sacramento Municipal Utility District at 11 (citing *Tennessee Gas Transmission Co.* v. *FERC,* 789 F.2d 61, 62–63 (D.C. Cir. 1986)).

[649] Illinois Commerce Commission contends that this is the case with respect to the projects at issue on remand in the *PJM Interconnection, LLC* matter in Docket No. EL06–121–006.

[650] FirstEnergy Service Company at 14 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 579).

[651] FirstEnergy Service Company at 18.

[652] California ISO at 18 (citing *Duke Energy Trading and Marketing, LLC,* 315 F.3d 377, 382 (D.C. Cir. 2003)).

projects, and it takes cost-effectiveness into consideration when choosing projects.

552. FirstEnergy Service Company also asserts that the courts have admonished the Commission for seeking to impose new rates without first determining that the existing rate is unjust, unreasonable, or unduly discriminatory or preferential.[653] It cites *Public Service Commission of New York* v. *FERC* in which the court disagreed with the Commission that it could act under section 4 of the NGA rather than section 5 in finding that an existing zone allocation in the utility's rates was unlawful and prescribing a new allocation because the utility had proposed a rate increase under section 4 of the NGA.[654] FirstEnergy Service Company states that the court reversed the Commission's decision because the Commission did not make a finding under section 5 of the NGA. FirstEnergy Service Company also cites other cases in which it states that the court rejected Commission filing requirements as an impermissible attempt to avoid the strictures of sections 4 and 5 of the NGA.[655]

553. FirstEnergy Service Company argues that the Supreme Court has found that the right to file new rates and contracts belongs solely to public utilities under the FPA.[656] It disagrees with the Commission's assertion that it is setting standards for filings under section 205 rather than interfering with public utilities' rights to file new rates,[657] it argues that Order No. 1000 directs transmission providers to amend their tariffs to include cost allocation provisions for regional and interregional facilities. FirstEnergy Service Company contends that the Commission may issue guidelines that will be used to determine whether future rates for regional and interregional facilities will be just and reasonable, but section 205 does not permit it to compel filings of rates or contracts.

554. Ad Hoc Coalition of Southeastern Utilities argues that the Commission cannot support its determination by simply finding that rates will be unjust and unreasonable without a cost allocation mechanism. As support for this position, Ad Hoc Coalition of Southeastern Utilities argues that the Commission's authority over practices affecting rates under section 206 is limited to practices that directly affect rates,[658] and effectively requires utilities to pay transmission developers for investments that the utilities do not use indirectly affects rates for jurisdictional service. Large Public Power Council makes similar arguments.

3. Commission Determination

555. Many petitioners object to the Commission's cost allocation reforms in Order No. 1000 based on what they consider to be fundamental principles concerning both the Commission's jurisdiction as well as the nature of transmission operations and the benefits they provide. Many of the arguments raised by petitioners share common themes, and we thus will address them collectively as far as possible. In order to do this comprehensively, we think it is important first to state briefly what the Commission did, and did not, require in Order No. 1000 with respect to cost allocation and to address some of the basic principles that inform those decisions.

556. The cost allocation reforms in Order No. 1000 are grounded in our determination that it is necessary to establish a closer link between regional transmission planning and cost allocation, both of which involve the identification of beneficiaries of new transmission facilities. Planning of new transmission facilities in a regional transmission planning process involves assessing how such facilities will affect the existing transmission grid and how they will benefit users of the grid within the relevant region.[659] Cost allocation for new transmission facilities that are selected in a regional transmission plan for purposes of cost allocation similarly involves assigning the costs of those facilities in a manner that accounts for the identified benefits. Recognizing this relationship, the Commission found that the lack of clear ex ante cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified during the transmission planning process. The Commission also found that linking transmission planning and cost allocation through the regional transmission planning process would increase the likelihood that transmission facilities in regional transmission plans are constructed.

557. This emphasis on a closer link between regional transmission planning and cost allocation also informs the cost allocation principles that the Commission adopted in Order No. 1000. The Commission found that in light of the need for a closer link between regional transmission planning and cost allocation, allowing one region to allocate costs unilaterally to entities in another region would impose too heavy a burden on stakeholders to actively monitor transmission planning processes in numerous other regions, from which they could be identified as beneficiaries and be subject to cost allocation. The Commission also stated that if it expected such participation, the resulting regional transmission planning processes could amount to interconnectionwide transmission planning with corresponding cost allocation. The Commission stated clearly that Order No. 1000 does not require either interconnectionwide transmission planning or interconnectionwide cost allocation. We reaffirm these findings here, as discussed further below with respect to Cost Allocation Principle 4.[660]

558. Against this backdrop, we note the actions that the Commission took in Order No. 1000 with respect to cost allocation are based on its jurisdiction under section 201(b)(1) of the FPA over the transmission of electric energy in interstate commerce and the facilities for such transmission and its duty to exercise it authority under sections 205 and 206 of the FPA to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.[661] The nature and scope of this authority must be viewed in the context of the specific characteristics of transmission facilities

[653] FirstEnergy Service Company at 16 (citing *Western Resources, Inc.* v. *FERC,* 9 F.3d 1568, 1578 (D.C. Cir. 1993); *Tenn. Gas Pipeline Co.* v. *FERC,* 860 F.2d 446 (D.C. Cir. 1988); *Northern Natural Gas Co.* v. *FERC,* 827 F.2d 779 (D.C. Cir. 1987); *Sea Robin Pipeline Co.* v. *FERC,* 795 F.2d 182 (D.C. Cir. 1986); *ANR Pipeline Co.* v. *FERC,* 771 F.2d 507 (D.C. Cir. 1985); *Panhandle E. Pipe Line Co.* v. *FERC,* 613 F.2d 1120 (D.C. Cir. 1980)).

[654] FirstEnergy Service Company at 16–17 (citing *Public Service Commission of New York* v. *FERC,* 642 F.2d 487 at 1344–45). FirstEnergy Service Company states that although the Court was describing the NGA, the FPA and NGA are interpreted in parallel. *FPC* v. *Sierra Pacific Power Co.,* 350 U.S. 348, at 353 (1956).

[655] FirstEnergy Service Company at 17 (citing *Public Service Commission of New York* v. *FERC,* 866 F.2d 487 (D.C. Cir. 1989) and *Consumers Energy Co.* v. *FERC,* 226 F.3d 777 (6th Cir. 2000)).

[656] FirstEnergy Service Company at 13 (quoting *United Gas Pipeline Co.* v. *Mobile Gas Ser. Co.,* 350 U.S. 332 at 341).

[657] FirstEnergy Service Company at 18 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 547).

[658] Ad Hoc Coalition of Southeastern Utilities at 73 (citing *California Independent System Operator* v. *FERC,* 372 F.3d at 403).

[659] Users of the regional transmission grid could be, for example, public utility transmission providers that may effectively rely on transmission facilities of another transmission provider in order to provide transmission service, whether or not there is a service agreement between those public utility transmission providers.

[660] *See* discussion *infra* at section 0.

[661] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 532, 535.

and their operation, among other considerations.[662]

559. Transmission operations are characterized by a number of unique features that are essential for understanding the Commission's position, and therefore they merit summarizing here. Electric energy does not travel on a preset path but rather along all available pathways in accordance with the laws of physics.[663] Continuous fluctuations in the demand for power and in generation operations affect power flows throughout the transmission grid. This means that electric energy received by an individual customer at any one time could be delivered over any number of transmission facilities that constitute the transmission grid. Changes in demand for or supply of electricity at any point in the system will change flows on all the transmission lines to varying degrees, often in ways that are not easily controlled.[664]

560. The courts have recognized this fundamental fact and have acknowledged that it has important implications for the Commission's regulation of transmission service. The DC Circuit has stated:

> * * * In order to determine a utility's cost of providing a transmission service, the Commission typically treats a transmission network * * * as an integrated system. In other words, all of the individual facilities used to transmit electricity are treated as if they were part of a single machine. The Commission takes this approach on the ground that a transmission system performs as a whole; the availability of multiple paths for electricity to flow from one point to another contributes to the reliability of the system as a whole. This principle has a strong basis in the physics of electrical transmission for there is no way to determine what path electricity actually takes between two points or indeed whether the electricity at the point of delivery was ever at the point of origin.
>
> As a corollary, in determining permissible prices for transmission services, the Commission treats each transmission customer not as using a single transmission path but rather as *using the entire transmission system*.[665]

In other words, in the case of transmission, there is only one service—service over the entire grid.[666]

561. The Commission appreciates that these prior decisions related to transmission rates for a single public utility transmission provider's facilities. However, the principle underlying those decisions is equally applicable across larger regions of the transmission system. Given the physics of power flows, and the ownership of transmission facilities in the United States, the actual transmission facilities that are affected by a particular transaction are owned by multiple, interconnected transmission providers irrespective of whether the transaction involves a single contract for transmission service with one of the owners of the transmission facilities or multiple contracts with all of the owners of the transmission facilities along a contract path. That is, the transmission grid constitutes a common infrastructure, ''a cohesive network moving energy in bulk.'' [667] Entities that contract for service on the transmission grid cannot ''choose'' to affect only the transmission facilities for which they have entered into a contract, as some petitioners contend. Similarly, those entities cannot claim that they are not using or benefiting from such transmission facilities simply because they did not enter a contract to use them.

562. We also note that in an interconnected electric transmission system, the enlargement of one path between two points can provide greater system stability, lower line losses, reduce reactive power needs, and improve the throughput capacity on other facilities. 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.[668] Any individual beneficiary of a new transmission facility has an incentive to defer investment in the anticipation that other beneficiaries in the region will value the project enough to fund its development. This can lead to situations in which no developer moves forward, adversely affecting development of transmission facilities and, as a result, rates for jurisdictional services.

563. The Supreme Court has stated that the Commission's jurisdiction is ''to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.'' [669] Indeed, the Supreme Court described the entire FPA as ''couched largely in the technical language of the electric art.'' [670]

564. Despite these considerations, many petitioners argue that the costs of new transmission facilities can only be allocated within a preexisting contractual relationship. These arguments are based on the assumption that only preexisting contracts define jurisdictional transmission service. In relying exclusively on contracts to perform this role, petitioners are advocating a legalistic test for assessing the scope of the Commission's jurisdiction that is inconsistent with the Supreme Court's interpretation of the FPA in *Connecticut Light & Power Co.* Contracts do not reflect the actual flow of electric energy on the transmission grid. Nor do contracts define or limit the benefits that an entity receives from its use of the transmission grid. To argue that costs for new transmission facilities can be allocated only through preexisting contractual relations means that some entities that will benefit from those transmission facilities simply cannot be allocated costs roughly commensurate with the benefits that they receive. This is inconsistent with the well-established Commission and judicial interpretation of the FPA and contrary to the requirement that transmission rates be just and

[662] As discussed further below, the Commission finds that there is a need to balance a number of factors to ensure that the reforms adopted in Order No. 1000 achieve the goal of improved planning and cost allocation for transmission in interstate commerce. *See* discussion *infra* at section 0.

[663] An interconnected AC transmission grid essentially functions as a single piece of equipment. *See, e.g., Tampa Electric Co.,* 99 FERC ¶ 61,192, at 61,796 (2002).

[664] *See, e.g.,* Jack A. Casazza, *Transmission Access and Retail Wheeling: The Key Questions, in Electricity Transmission Pricing and Technology* 81 (Michael Einhorn and Riaz Siddiqi eds., 1996); Narain G. Hingorani, *Flexible AC Transmission System (Facts), in id.* 242; Karl Stahlkopf, *The Second Silicon Revolution, in id.* 263.

[665] *Northern States Power Co.* v. *FERC,* 30 F.3d 177, 179 (DC Cir. 1994) (emphasis supplied) (*Northern States*); *see also Western Massachusetts Electric Company* v. *FERC,* 165 F.3d 922, 927 (DC Cir. 1999) (stating that ''[w]hen a system is integrated, any system enhancements are presumed to benefit the entire system'').

[666] We note that this principle is not, in itself, determinative of what would constitute a just and reasonable cost allocation method. For example, a regional cost allocation method must satisfy the principles set forth in Order No. 1000 and affirmed here, including that the costs of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is roughly commensurate with estimated benefits. *See, e.g.,* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 622.

[667] *Public Serv. Co. of Colo.,* 62 FERC ¶ 61,013, at 61,061 (1993).

[668] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 534–35.

[669] *Connecticut Light & Power Co.* v. *F.P.C.,* 324 U.S. 515, 529 (1945) (*Connecticut Light & Power Co.*).

[670] *Id.*

reasonable and not unduly discriminatory or preferential.[671]

565. This explains why the cost allocation provisions of Order No. 1000, which seek to allocate costs to beneficiaries in a region roughly commensurate with benefits they receive, are consistent with the statement in *Illinois Commerce Commission* that ''[a]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them.'' [672] Petitioners argue that because the court in *Illinois Commerce Commission* used the word ''customer'' in the quote above, it suggests that costs must be recovered from entities that have a preexisting contractual relationship with the entity seeking the cost allocation. However, given the nature of cost causation itself, some entities that actually cause costs would not be required to pay them if they could utilize the absence of a contractual relationship to shield themselves from an allocation of costs. Rather than contractual relationships, the benefits received by users of the regional transmission grid provide a basis for how costs should be allocated. Petitioners' argument would inappropriately revise the *Illinois Commerce Commission* court's explanation that the cost causation principle requires that ''all approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them'' by adding a further requirement that the customer also agree to be responsible for such costs. The court did not, however, reach such a conclusion. We thus reject the claim by Ad Hoc Coalition of Southeastern Utilities that the Commission's adherence to the cost causation principle is subordinate to parties' contractual rights.

566. Moreover, our interpretation of the court's use of ''customer'' in *Illinois Commerce Commission* is consistent with the statements that the court makes immediately thereafter. The court first notes that compliance with the principle involved is evaluated '' 'by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.'' ' [673] The court did not condition its statement on a need for a preexisting contractual relationship. Rather, the court allowed for a full comparison of costs for any party that imposed burdens on, and benefited from enhancement of, the network transmission grid. Furthermore, the court follows this by stating that ''[t]o 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.'' [674] That is precisely the role that the Commission's cost allocation reforms play within the context of its planning reforms. That the lack of *ex ante* cost allocation methods that identify the beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified in the transmission planning process.[675]

567. Some petitioners also argue that the Supreme Court's statement in *Morgan Stanley* that ''the regulatory system created by the [FPA] is premised on contractual agreements voluntarily devised by the regulated companies'' [676] means that a preexisting contractual relationship is an essential precondition of cost allocation. Given the nature of transmission grid operations, we disagree that this statement by the Supreme Court means that contracts, which will not fully reflect how transmission facilities are impacted by power flows, are the only device that defines what rates are just and reasonable and not unduly discriminatory or preferential. We do not read the importance that the Supreme Court ascribes to voluntary contracts in *Morgan Stanley* to imply that entities that use the transmission grid are entitled to structure their contractual arrangements so that they are shielded from paying costs that are roughly commensurate with the benefits that they receive. In any event, *Morgan Stanley* never stated that, by refusing to sign a contract, an entity benefiting from another's improvement of the regional transmission grid can limit its obligation to something less than an obligation to pay for all benefits that it receives.

568. The obligation under the FPA to pay costs allocated under a regional or interregional cost allocation method is imposed by a Commission-approved tariff concerning the charges made by a public utility transmission provider for the use of the public utility transmission provider's facility. Such use is voluntary, and it does not become less so because it is determined in part by immutable laws of physics. Voluntary use therefore also entails voluntary acceptance of the terms and conditions of use set forth in the tariff, including an applicable cost allocation.

569. We disagree with National Rural Electric Coops' argument that Order No. 1000 is conferring new rights on public utility transmission providers. We are not conferring new rights on public utility transmission providers when we seek to ensure that they can allocate the costs of their new transmission facilities to the beneficiaries of those facilities. Nor are we claiming a power based solely on the fact that there is not an express withholding of such power, as National Rule Electric Coops claim. We are acting under the provisions of section 206 of the FPA applied in accordance with the reasoning that we have set forth both here and in Order No. 1000.

570. In response to Large Public Power Council's argument that the references in sections 205 and 206 to rates ''made,'' ''demanded,'' ''received,'' ''observed,'' ''charged,'' or ''collected'' pertain to rates assessed to utility customers in connection with an agreement to take transmission service, we reiterate the Commission's finding in Order No. 1000 that ''nothing in these sections precludes flows of funds to public utility transmission providers through mechanisms other than agreements between the service provider and the beneficiaries of those transmission facilities.'' [677] As explained in further detail above, an entity that uses the transmission grid will necessarily use transmission facilities owned by multiple owners, and the FPA permits a public utility transmission provider to charge for the costs of using its transmission facilities.

571. Contrary to the claim of National Rural Electric Coops, all cost allocation contemplated by Order No. 1000 pertains to rates ''for or in connection with the transmission * * * of electric energy.'' Order No. 1000 does not permit a public utility transmission provider to collect charges other than in connection with the use of the transmission grid. In suggesting that it does, National Rural Electric Coops misconstrues the criteria for identifying the scope of transmission usage. That scope is defined by the transmission grid operations, not simply the terms of individual contracts, which can diverge

[671] We also note that Order No. 1000 states: ''Neither section 205 nor section 206 of the FPA state or imply that an agreement is a precondition for any transmission charges. These statutory provisions speak of rates and charges that are 'made,' 'demanded,' 'received,' 'observed,' 'charged,' or 'collected' by a public utility.'' Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 533.

[672] *Illinois Commerce Commission,* 576 F.3d 470 at 476 (internal citations omitted).

[673] *Id.* (internal citations omitted).

[674] *Id.*

[675] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 499.

[676] *Morgan Stanley,* 554 U.S. at 533.

[677] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 533.

from the underlying transmission grid operations. It is the purpose of the cost allocation method or methods required by Order No. 1000 to align cost responsibility with the reality of transmission grid operations in the case of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.[678]

572. Moreover, contrary to Large Public Power Council's argument, the cost allocation provisions of Order No. 1000 do not alter any existing contract provisions governing the use of existing transmission facilities and, therefore, are not inconsistent with *Mobile-Sierra* doctrine regarding revision of contracts. Order No. 1000 requires each public utility transmission provider to revise its OATT to include 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—not transmission facilities already in service.

573. We reject the characterization of the cost allocation requirements of Order No. 1000 as authorizing allocation of costs to third-party beneficiaries. Order No. 1000 authorizes allocation of costs to entities that benefit in their own right from new transmission facilities selected in a regional transmission plan for purposes of cost allocation. To the extent that an entity is not required to pay for a benefit that it receives, it is a free rider not a third party beneficiary. The fact that a free rider benefits from a transaction between two other entities does not make it a third party beneficiary, which is a legal concept that refers to parties that have a right to a benefit under a contract between two other entities. Such rights are not at issue here.

574. We thus also disagree with National Rural Electric Coops that Order No. 1000 suggests that charges could be imposed on ''third party beneficiaries'' such as ''[s]teel producers, crane operators, and wind turbine manufacturers who may find more customers for their products and services as a result of increased transmission capacity * * *.''[679] We note that Regional Cost Allocation Principle 1 provides that:

> In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements.[680]

While this statement explicitly is not intended to be an exhaustive recitation of possible benefits, our expectation is that additional types of benefits would be ''in connection with'' transmission of electric energy. We do not intend that these benefits should include such things as increased sales of goods and services used in the construction of new transmission facilities.

575. Likewise, in response to Southern Companies, Order No. 1000 does not authorize cost allocations or rate structures that apply to conveyance of ''benefits [that] are not the actual use of transmission facilities or services (or support services required to provide same).''[681] We see no inconsistency between the cost allocation provisions of Order No. 1000 and *Mobil Oil Corp.* v. *FPC,* as Southern Companies claim. In that case, the court held that the Commission had jurisdiction over rates for the transportation of natural gas on an interstate pipeline but not over rates for the transportation of certain non-jurisdictional liquid hydrocarbons that were also transported on the pipeline. The court held that the Natural Gas Act restricted the Commission's jurisdiction to rates for natural gas transportation.[682] Southern Companies maintains that Order No. 1000 authorizes rates for non-jurisdictional benefits that are analogous to the non-jurisdictional liquid hydrocarbons in *Mobil Oil Corp.* v. *FPC.* However, Order No. 1000 does not do this. It authorizes cost allocation for benefits consistent with Regional Cost Allocation Principle 1, which explicitly refers to matters that are subject to Commission jurisdiction. For the same reasons, we disagree with the claim of Vermont Agencies that Order No. 1000 authorizes allocation of costs to persons that benefit in some way from the existence of a transmission facility even if they use no transmission service at all.

576. In response to Southern Companies regarding free riders, we note that free riders for purposes of Order No. 1000 are entities who do not bear cost responsibility for benefits that they receive in their use of the transmission grid, specifically benefits they receive from new transmission facilities selected in a regional transmission plan for purposes of cost allocation. Such benefits include the traditional benefits that transmission facilities can provide, such as lowered congestion, increased reliability, and access to generation resources. Southern Companies state that the Commission does not address whether such entities would pursue or support new transmission facilities in the absence of a transmission project that is entitled to cost allocation, but this overlooks the purpose of the cost allocation requirements of Order No. 1000. They are intended to promote regional and interregional transmission planning that facilitates more efficient or cost-effective transmission infrastructure development. The lack of *ex ante* cost allocation methods that identify the beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified in the transmission planning process. For this reason, individual complaints under section 206 of the FPA would not suffice to overcome the free rider problem because litigating complaints burdens and unduly delays the transmission planning process. Individual complaint procedures thus do not permit effective transmission planning.

577. The Commission has not confused the FPA's expression of jurisdiction in section 201 with a grant of substantive authority. Ad Hoc Coalition of Southeastern Utilities and Large Public Power Council argue that according to the Commission's rationale, its jurisdiction under section 201 over transmission service and transmission facilities would also cover the matters for which specific authority is granted in sections 205 and 206, as well as section 203, thereby rendering those sections superfluous. As the Commission found in Order No. 1000, section 201 simply sets forth the facilities and transactions in interstate commerce that are subject to the Commission's jurisdiction under Part II of the FPA. Our authority to act in Order No. 1000 on matters subject to our jurisdiction arises under section 206 of the FPA, specifically our authority to establish requirements regarding transmission planning and cost allocation which are practices affecting rates. The Commission's jurisdiction permits that authority to be applied in a way that follows ''the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test,''[683] and Order No. 1000's

[678] As explained above, providing for such cost allocation will help to ensure that rates are just and reasonable and not unduly discriminatory or preferential as required by section 205 of the FPA. 16 U.S.C. 824d.

[679] National Rural Electric Coops at 21.

[680] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 622.

[681] Southern Companies at 99.

[682] *Mobil Oil Corp.* v. *FPC,* 483 F.2d 1238, 1246–47 (D.C Cir. 1973).

[683] *Connecticut Light & Power Co.,* 324 U.S. at 529.

application of the principle of cost causation is a reasonable exercise of that authority. However, such action is not based directly on section 201. It is based on section 206, which we apply to matters that are within the scope of our jurisdiction set forth in section 201. Moreover, we disagree with those petitioners that argue that our interpretation of section 201 in Order No. 1000 could render either section 203, section 205, or section 206 of the FPA superfluous, because as we explain above, section 201 sets forth the subject matter over which the Commission exercises its jurisdiction pursuant to those other sections.

578. Contrary to Large Public Power Council's contention, the cost allocation requirements of Order No. 1000 are not at odds with the Commission's policy on interstate gas pipeline development regarding subsidization of development by existing shippers. The requirements of Order No. 1000 are based on the principle of cost causation, which requires that costs be allocated in a way that is roughly commensurate with benefits. The principle of cost causation is intended to prevent subsidization by ensuring that costs and benefits correspond to each other. Indeed, in seeking to eliminate free riders on the transmission grid, Order No. 1000 seeks to eliminate a form of subsidization, as free riders by definition are entities who are being subsidized by those who pay the costs of the benefits that free riders receive for nothing.

579. We disagree with Sacramento Municipal Utility District's assertion that Order No. 1000 fails to prevent a utility from building a transmission facility and then simply claiming that a remote entity receives benefits from it and thus must bear some of the costs. Under Order No. 1000, for a regional cost allocation method to apply to a new regional or interregional transmission facility, the transmission facility must first be selected in a regional transmission plan or plans for purposes of cost allocation. This means that the public utility transmission providers in a region, in consultation with stakeholders, have evaluated a given facility and determined that it provides benefits that merit cost allocation under a regional method. As such, a developer of a transmission facility will not be entitled to recover costs from other entities without its facility being subject to the requirements of the regional transmission planning process, including the selection of its facility in the regional transmission plan for purposes of cost allocation.

580. We also disagree with Sacramento Municipal Utility District that Order No. 1000 forces unwilling customers to pay for additional transmission service or to be charged even if they are not getting a new transmission service. Order No. 1000 requires that new costs be allocated in a way that is roughly commensurate with the benefits derived from the new transmission facilities that are eligible for cost allocation in accordance with Order No. 1000. As discussed above, entities that receive benefits from these facilities in the course of their use of the transmission grid cannot be characterized as ''unwilling customers.'' New York ISO notes that benefits come in various degrees, and it maintains that entities should not be charged for an ''incidental benefit.'' But again, Order No. 1000 requires that costs be allocated in a way that is roughly commensurate with benefits, and the court stated in *Illinois Commerce Commission* that entities cannot be allocated costs for benefits that are trivial in relation to those costs.[684] All cost allocation methods will be subject to Commission review and approval, and issues related to the appropriateness of a particular method or methods can be raised at that time.

581. Sacramento Municipal Utility District's argument that joint rates are necessary for cost recovery in the case of a regional cost allocation under Order No. 1000, describes a false dilemma. It argues that without evidence that two systems are in fact acting as one, the Commission cannot mandate the use of a single joint rate, and if it cannot mandate the use of joint rates, it cannot mandate that an entity pay the rates charged by a utility with which it has no contractual or tariff-based customer/provider relationship. However, our position regarding the role of preexisting contractual relationships goes to the problem of cost allocation, not cost recovery, which Sacramento Municipal Utility District focuses on when it speaks of the payment of charges and which Order No. 1000 does not address.[685] Moreover, Order No. 1000 requires that the tariffs of transmission providers in a region contain the regional cost allocation method or methods, which means that in any event, there will be a tariff basis for implementing a cost allocation. We thus reject the claim that a regional cost allocation could be implemented only through a joint rate.

582. Turning to arguments that Order No. 1000 represents a change in policy expressed in prior cases, we disagree with National Rural Electric Coops' contention that the cost allocation provisions of Order No. 1000 are contradicted by the Commission's refusal to allow MISO to charge Green Mountain for SECA costs under MISO's tariff because Green Mountain did not directly contract with MISO for transmission service. In the SECA Order, the Commission found merely that Green Mountain's affiliate BP Energy, not Green Mountain, was responsible for paying the SECA charges because the contract between the affiliate and Green Mountain stipulated that BP Energy was responsible for paying MISO for network transmission service.[686] The Commission found that since SECA charges were intended to be surcharges assessed to the transmission customer taking transmission service, and BP Energy, not Green Mountain, was taking transmission service from MISO, BP Energy was responsible for paying the SECA charges.[687] The Commission emphasized on rehearing of the SECA Order that MISO's tariff specifically provided for its transmission customers to pay SECA charges, and therefore the fact that BP Energy was the transmission customer, not Green Mountain, was pivotal to the Commission's conclusion that BP Energy was responsible for the SECA charges.[688] This conclusion was based on a reading of the requirements of the MISO tariff, and as such, it cannot be read as establishing general principles regarding the authority of a public utility transmission provider to collect charges for the transmission of electric energy, as National Rural Electric Coops argue.

583. Vermont Agencies and Sacramento Municipal Utility District argue that the cost allocation reforms of Order No. 1000 represent a change in policy from the position that the Commission took in *AEP,* and they maintain that the Commission has failed to explain this change in policy. *AEP* dealt with unintended loop flows on existing facilities, which the Commission viewed as an operational issue that ''in the first instance'' was to be dealt with by ''the interconnected parties'' establishing ''mutually acceptable operating practices.''[689] The Commission also stated that if the party complaining of unintended loop flows on its facilities could show that they created ''a burden on its system, [it] can file a transmission service rate for

[684] *Illinois Commerce Commission,* 576 F.3d at 476.

[685] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 563.

[686] SECA Order, 131 FERC ¶ 61,173 at P 422.

[687] *Id.* P 423.

[688] 136 FERC ¶ 61,244 at P 205.

[689] *AEP,* 49 FERC ¶ 61,377, at 62,381.

Commission consideration which would account for any unauthorized loop flows.'' [690] Vermont Agencies and Sacramento Municipal Utility District describe Order No. 1000 as containing a policy change on this point because in their view, the Commission maintains in Order No. 1000 that ''it could allocate the costs of new transmission facilities to entities that somehow benefit from their existence—whether or not they take service from the utility,'' whereas *AEP* ''addresses the issue of compensation where the utility is involuntarily forced to provide service.'' [691] However, we see no fundamental difference between *AEP* and Order No. 1000 precisely because individual owners of facilities on an interconnected grid ''can file a transmission service rate for Commission consideration'' under *AEP.* Additionally, it is because such owners will often forgo grid enlargements that benefit many owners of other facilities who will not pay for these enlargements that Order No. 1000 seeks to ensure that the former may be compensated through a cost allocation to the latter.

584. We also disagree with Vermont Agencies and Sacramento Municipal Utility District that Order No. 1000 represents a change in policy because the Commission has ''rejected assessment of charges'' in situations such as that presented in *AEP.*[692] The Commission did not reject an assessment of charges in *AEP.* It stated that the operational issue in question was in the first instance to be dealt with through mutually acceptable operating practices, but a rate filing would be appropriate if the loop flows created a burden on the system. Moreover, Order No. 1000 does not deal with operating problems on existing transmission facilities but rather solely with benefits to be derived from new transmission facilities that regional participants themselves select as having broad regional benefits, and it deals with cost allocation for such new facilities as integral to transmission planning. In this respect, Order No. 1000 does not express a change a policy position taken in *AEP* because *AEP* does not deal with planning and cost allocation for new transmission facilities and expresses no policy with regard to these matters.

585. In response to Illinois Commerce Commission's argument that beneficiaries are to be associated with cost causers only to the extent that transmission facilities might be delayed or not built without the revenues expected from them, we note that it is for this reason that the cost allocation requirements of Order No. 1000 are necessary. By allocating costs in a way that is roughly commensurate with benefits, the requirements help to ensure that more efficient and cost-effective transmission solutions are implemented and that this occurs without undue delay. In addition, one of the purposes of the regional transmission planning process is to identify the beneficiaries of a proposed transmission facility. This addresses Illinois Commerce Commission's concern about the substantiation of benefits through an appropriate process.

586. We also disagree with Sacramento Municipal Utility District that the Commission's position on cost allocation is likely to do more harm than good by discouraging regional cooperation. On the contrary, Order No. 1000 is intended to encourage the development of more efficient and cost-effective transmission solutions to regional transmission needs, which will promote considerable economic benefits in the form of lower congestion, greater reliability, and greater access to generation resources. Therefore, we do not believe that the Commission's reforms will discourage cooperation when the potential gains from cooperation are so great.

587. Finally, several petitioners also argue that the Commission must first find an existing rate to be unjust, unreasonable or unduly discriminatory or preferential before it can take the actions regarding cost allocation that it took in Order No. 1000. We disagree that such a finding must be made case-by-case rather than generically. As explained above,[693] the Commission is not required to make individual findings concerning the rates of individual public utility transmission providers when proceeding under FPA section 206 by means of a generic rule.[694] Nor do we agree with FirstEnergy Service Company that Commission actions taken in a rulemaking cannot apply to future jurisdictional transmission service. Commission rulemakings are prospective in their effect, and when the Commission proceeds by rule it can conclude that ''*any* tariff violating the rule would have such adverse effects * * * as to render it 'unjust and unreasonable' '' within the meaning of section 206 of the FPA.[695] The effects that a tariff would have include effects on future jurisdictional transmission service.

588. We further disagree with FirstEnergy Service Company's assertion that where no cost allocation method or methods exist, the Commission cannot use section 206 as a basis for requiring them. The basis for the Commission's reforms in Order No. 1000 is that transmission planning for transmission service and the associated allocation of costs for new transmission facilities are practices that affect rates for purposes of section 206.[696] The Commission also explained that the allocation of transmission costs is often contentious and prone to litigation,[697] and that the lack of *ex ante* cost allocation methods that identify the beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified in the transmission planning process.[698] The absence of a cost allocation method or methods also has an adverse effect on rates by making it difficult to deal with free rider problems related to new facilities. The Commission's authority to require the adoption of a cost allocation method or methods arises directly from its authority under section 206 to ensure that practices that affect transmission rates, such as transmission planning, are just and reasonable and not unduly discriminatory or preferential.

589. FirstEnergy Service Company's argument that section 205 does not permit the Commission to require the filing of rates or contracts is equally flawed. Here, FirstEnergy Service Company is simply arguing that all rates are initially to be proposed by public utility transmission providers. However, the Commission is not requiring the proposal of a particular rate. It is requiring that public utility transmission providers have a cost allocation method or methods in their OATTs to ensure that the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation are properly allocated to beneficiaries. It is for public utility transmission providers to propose an actual method or methods. The Commission is simply requiring that any cost allocation method or methods that are proposed meet certain general

[690] *Id.*

[691] Vermont Agencies at 16; Sacramento Municipal Utility District at 14.

[692] Vermont Agencies at 16–17; Sacramento Municipal Utility District at 14.

[693] *See* discussion *supra* at section 0.

[694] *Associated Gas Distributors* v. *FERC,* 824 F.2d at 1008.

[695] *Id.* (emphasis in original).

[696] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 58.

[697] *Id.* P 498.

[698] *Id.* P 499.

principles established in Order No. 1000.

590. The case law cited by FirstEnergy Service Company to support the proposition that the Commission cannot impose a new rate without first determining that an existing rate is unjust, unreasonable, or unduly discriminatory or preferential reinforces our above points. All the cases that FirstEnergy Service Company cites in this connection involve situations in which the court found that the Commission had moved beyond rejecting a proposed rate to the task of redesigning it.[699] The Commission is not here ''imposing'' any rates, as it is not specifying, designing, or redesigning any rates. Instead it is requiring that all public utility transmission providers have a cost allocation method or methods for certain new transmission facilities that comply with a broad set of general principles.

591. We agree with California ISO that rates are not unjust and unreasonable simply because another rate might be more just and reasonable. However, this point applies in a situation where the status quo has been found to be just and reasonable and not unduly discriminatory or preferential, which is not the case here. California ISO argues that in its case such a finding is necessary because it has voluntarily included in its tariff provisions that ensure the construction of needed transmission projects, and it takes into account cost-effectiveness in choosing these transmission projects. This argument misconstrues the Commission's actions here, which are to ensure that certain minimum requirements pertaining to transmission planning and cost allocation are in place. California ISO's practices may already satisfy some of these requirements, in which case it need only explain how it satisfies them in its compliance filing.[700] This, however, does not show that there is no need for such requirements.

592. Ad Hoc Coalition of Southeastern Utilities questions the Commission's ability to require a cost allocation method or methods on the grounds that section 206 limits the Commission's authority over practices affecting rates to those that directly affect rates. Cost allocation is a practice that affects rates because the effect of a cost allocation method or methods is quite direct, as it determines who is responsible for specific costs. As explained above, Order No. 1000 found that the lack of a regional cost allocation method known in advance to transmission planners and the existence of free riders, result in inefficient transmission planning that impedes the development of more efficient and cost effective new transmission facilities, with the result that jurisdictional rates are higher than they would otherwise be. As we have noted previously, we disagree with Ad Hoc Coalition of Southeastern Utilities' contention that requiring utilities to pay for facilities that they do not use does not directly affect rates for jurisdictional transmission service and is therefore beyond the Commission's authority. This argument ignores the reality that any entity connected to the transmission grid may benefit from a transmission facility whether or not it is connected to, or specifically requests service from, a particular transmission facility for which costs have been allocated.[701] Order No. 1000's cost allocation reforms are therefore intended to ensure that all of these beneficiaries are allocated costs roughly commensurate with the benefits they receive in their use of the transmission grid, and we believe that such a requirement can be seen as directly affecting the rates for jurisdictional transmission service.

B. Cost Allocation Method for Regional Transmission Facilities

1. Final Rule

593. In Order No. 1000, the Commission required that each public utility transmission provider have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.[702] The Commission stated that if the public utility transmission provider is an RTO or ISO, then the cost allocation method or methods must be set forth in the RTO or ISO OATT.[703] In a non-RTO/ISO transmission planning region, the Commission required each public utility transmission provider located within the region to set forth in its OATT the same language regarding the cost allocation method or methods used in its transmission planning region.[704] In either instance, the Commission required that such cost allocation method or methods be consistent with the regional cost allocation principles adopted in Order No. 1000.[705]

594. The Commission did not specify how the costs of an individual regional transmission facility should be allocated.[706] It noted, however, that while each transmission planning region may develop a method or methods for different types of transmission projects, each such method or methods should apply to all transmission facilities of the type in question and would have to be determined in advance for each type of facility.[707] Additionally, the Commission acknowledged that cost containment is important, but declined to establish a corresponding cost allocation principle, primarily because cost containment concerns the level of costs, not how costs should be allocated among beneficiaries.[708]

595. With respect to cost allocation for a proposed transmission facility located entirely within one public utility transmission owner's service territory, the Commission found that a public utility transmission owner may not unilaterally apply the regional cost allocation method or methods developed pursuant to Order No. 1000.[709] However, the Commission also found that a proposed transmission facility located entirely within a public utility transmission owner's service territory could be determined by the public utility transmission providers in the region to provide benefits to others in the region and thus be selected in the regional transmission plan for purposes of cost allocation; then the cost of that transmission facility would be allocated according to that region's regional cost allocation method or methods.[710]

596. In Order No. 1000, the Commission also declined to make new findings with respect to pancaked rates, stating that it was beyond the scope of the proceeding.[711] The Commission further stated that it was not making any modifications to the Commission's pancaked rate provisions for an RTO under Order No. 2000.[712] However, the Commission noted that if rate pancaking was an issue in a particular transmission planning region, stakeholders could raise their concerns in the consultations leading to the compliance proceedings for Order No. 1000 or make a separate filing with the Commission under section 205 or 206 of the FPA, as appropriate.[713]

[699] *See, e.g., Western Resources, Inc.* v. *FERC,* 9 F.3d 1568, 1578–79 (D.C. Cir. 1993).

[700] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 565, 583.

[701] *Id.* P 625.

[702] *Id.* P 558.

[703] *Id.*

[704] *Id.*

[705] *Id.*

[706] *Id.* P 560.

[707] *Id.*

[708] *Id.* P 704.

[709] *Id.* P 564.

[710] *Id.*

[711] *Id.* P 764.

[712] *Id.*

[713] *Id.*

2. Requests for Rehearing and Clarification

597. North Carolina Agencies argue that the Commission's planning and cost allocation reforms represent major changes that have the potential to preempt state authority over bundled retail rates. They state that to date, the Commission has declined to exercise its authority over the transmission component of bundled retail rates and service despite pressure to do so and the U.S. Supreme Court's decision in *New York* v. *FERC*.[714] North Carolina Agencies assert that the Commission must recognize that the applicability of any cost allocation methods that result from Order No. 1000 is limited to unbundled transmission and cannot impinge on state jurisdiction with respect to bundled retail rates. Ad Hoc Coalition of Southeastern Utilities likewise contends that the allocation of the cost of regional transmission facilities to entities performing a retail sales function would preempt state commissions in setting bundled retail rates because under the Supremacy Clause, utilities will be entitled to recover their costs in retail rates.

598. Northern Tier Transmission Group also states that the Commission should clarify that it does not intend to set retail rates. It states that the Commission has not explained the relationship between the mandatory cost allocation process and the ability of a project proponent to recover the costs of a selected transmission facility.

599. In a related argument, Alabama PSC argues that Order No. 1000 fails to satisfy the requirements of the Administrative Procedure Act (APA)[715] because it lacks definiteness on how cost allocation will translate into recovery. It is concerned that the rule will result in stranded costs if a transmission provider cannot recover allocated costs because of the absence of an appropriate contractual vehicle and lead to cost shifting to others within the region. Alabama PSC also asserts that Commission is being inconsistent when it does not address cost recovery but then does not accept participant funding, which Alabama PSC describes as a form of cost recovery, as a regional cost allocation method. Southern Companies argue that if there is no payment obligation coinciding with a cost assignment, industry cannot presume that Order No. 1000's objective is to create a rate structure to induce transmission developers to participate more fully in regional transmission planning processes. They state that the Commission should address this issue in order to prevent parties from engaging in a futile exercise over the next eighteen months.

600. Several other petitioners also take issue with the Commission's determination to not address cost recovery issues in Order No. 1000. Sacramento Municipal Utility District argues that the issue with respect to cost recovery mechanisms is not the identity of the transmission provider, but whether the party being assessed charges is one of the provider's customers. It maintains that ''it is not a mere concern over form'' to expect an explanation of the mechanism for recovering a rate when the party being charged is not a customer.

601. Edison Electric Institute, NV Energy and Southern Companies argue that the Commission does not explain how costs can be allocated under a regional transmission plan in a non-RTO/ISO region without a contractual mechanism permitting the charging and collection of such costs. Edison Electric Institute acknowledges that a tariff could provide a contractual mechanism for the collection of allocated costs, but states that Order No. 1000 does not identify any mechanism for requiring the payment of costs in the absence of such an applicable tariff or agreement. Edison Electric Institute thus asserts that the Commission is not engaging in reasoned decision making when it concludes that it ''would permit recovery of costs from a beneficiary in the absence of a voluntary arrangement.''[716]

602. In the alternative, Edison Electric Institute argues that the Commission should clarify: (1) Whether allocation in a regional plan of costs to a beneficiary in a non-RTO/ISO region without a voluntary arrangement to pay creates an obligation of the beneficiary to pay those costs; and (2) if so, the mechanism for collecting such costs, including the source of the obligation of the beneficiary to pay. Southern Companies make a similar argument.

603. National Rural Electric Coops argue that the distinction between cost allocation and cost recovery in Order No. 1000 has no practical significance. NARUC argues that if cost allocation is distinct from cost recovery, it is not clear that the Commission's authority to set rates for transmission under the FPA provides the Commission with jurisdiction over cost allocation.

604. Northern Tier Transmission Group requests that the Commission clarify the relationship between cost allocation and cost recovery. It states that the ability to recover costs appears to be merely a factor that can be considered and acknowledged in the cost allocation process. Northern Tier Transmission Group asserts that this issue is material to the decision to participate in the construction of a project. Therefore a clarification of the intended relationship between cost allocation and cost recovery will better inform the methods developed for and the analysis performed by the regional and interregional transmission planning processes.

605. Northern Tier Transmission Group also asserts that the Commission has no authority under the FPA to require the imposition of transmission construction costs on non-jurisdictional beneficiaries or to impose cost recovery on the United States or any state including any political subdivision.[717] Edison Electric Institute states that paragraph 629 of Order No. 1000 states that non-jurisdictional transmission providers that do not participate in the regional planning process are not responsible for costs allocated in that process. It states that it is arbitrary and capricious to treat jurisdictional transmission providers and non-public utility transmission providers differently with respect to any obligation they may have, in the absence of a voluntary agreement, to pay costs allocated to them in a regional planning process.

606. Arizona Cooperative and Southwest Transmission argue that paragraph 629 in Order No. 1000 suggests that a non-public utility will be forced to accept the regional cost allocation, and may effectively forfeit its right to avoid an unduly discriminatory cost assignment if participating in the process means that it loses the ability to exercise its right to seek relief from the Commission. Arizona Cooperative and Southwest Transmission argue that non-participation is not a desirable answer to this problem, especially as an entity that does not participate could still get saddled with costs and would also forego the opportunity to have its own contributions to a more robust grid included in the regional plan.

607. Alabama PSC argues that if the regional planning process supersedes or replaces the output of a state integrated

[714] North Carolina Agencies at 4 (citing 535 U.S. 1 (2002)). North Carolina Agencies state that while *New York* v. *FERC* includes *dicta* suggesting that the Commission's authority is an open issue, the Court found that the jurisdictional issue is a difficult one. North Carolina Agencies at 5.

[715] Administrative Procedure Act, 5 U.S.C. 706(2)(A).

[716] Edison Electric Institute at 7–8.

[717] Northern Tier Transmission Group at 6 (citing 16 U.S.C. 824(e) and (f); *Bonneville Power Admin.* v. *FERC,* 422 F.3d 908 (9th Cir. 2005)).

resource plan that relies on participant funding, it will infringe on a state's prerogative to manage the costs borne by its consumers. Alabama PSC also states that Order No. 1000 incorrectly asserts that the cost allocation requirements conform fully with the position taken by the Alabama PSC. Instead, it states that its concern is that a regional process may identify electricity consumers in Alabama as receiving benefits from a new transmission project selected in a regional transmission plan for purposes of cost allocation, even if the supposed benefits are completely at odds with Alabama PSC's conclusions. Thus, even though Order No. 1000 states that consumers will not be assigned costs from which they derive no benefit, Alabama PSC remains concerned about this and maintains that states should have the option of vetoing such a course or opting out of any cost allocation.

608. Florida PSC argues that the cost allocation provisions of Order No. 1000 infringe on its jurisdiction. Florida PSC states that Florida utilities are vertically-integrated, and no part of the state is a member of an RTO or ISO. It thus retains authority over cost allocation. Florida PSC asserts that planning decisions under the new processes will affect wholesale rates that will flow to retail customers. Florida PSC thus argues that regions may find themselves paying higher retail rates for benefits realized only in a neighboring region. Florida PSC argues that the Commission does not have authority to assign cost recovery to retail rates for benefits not defined as such in the retail customers' region.

609. Transmission Access Policy Study Group argues that Order No. 1000 erred in finding that comments on access to regionally cost allocated facilities through regional tariffs at non-pancaked rates were beyond the scope of the proceeding.[718] It asserts that failing to address these issues leaves a void that must be filled before regional cost allocations can be implemented in non-RTO regions.[719] It believes that a regional tariff, with non-pancaked rates covering both existing and new facilities, is the best way to address these issues because such tariffs can solve cost allocation implementation issues and avoid the creation of new rate pancakes. Transmission Access Policy Study Group suggests that if the Commission does not grant rehearing, it should use its authority to induce transmission providers to adopt regional rates that eliminate pancaking and foster transmission investment.

610. Alternatively, Transmission Access Policy Study Group states that the Commission should require a process to address access issues at the compliance stage. It also argues that access should be addressed when a specific cost allocation is applied to a project. Transmission Access Policy Study Group states that in non-RTO regions, the Commission should require that access issues be addressed in the regional process for selection of an upgrade and the application of the regional cost allocation to a facility, as well as require filing of the specific cost allocation as applied to the particular project selected for regional cost allocation, with a description of how access will be provided and on what rates, terms, and conditions. Transmission Access Policy Study Group believes that specific applications of the regional cost allocation should be filed as soon as the constructor of the facility is identified, with access issues addressed at that time rather than when the facility is completed.[720] According to Transmission Access Policy Study Group, this will help address uncertainty caused by the absence of regional tariffs and Order No. 1000's preference for flexibility. Finally, Transmission Access Policy Study Group urges prompt public disclosure of the mechanism to provide access to regionally cost-allocated facilities, and it states that it is essential to address access issues before a proposed facility proceeds through the permitting and siting process.

611. Several petitioners question the Commission's decision not to address cost containment issues in Order No. 1000. For example, Illinois Commerce Commission argues that the Commission does not provide a good reason for not addressing cost containment, and that it must be addressed to prevent excessive costs, which is a fundamental part of any appropriate cost allocation method. Illinois Commerce Commission asserts that even if Order No. 1000 is not the appropriate forum, the Commission erred in failing to identify an alternative forum.

612. Wisconsin PSC requests that there be a mandate to consider cost overrun containment mechanisms. It argues that uncontained costs are as likely to undermine needed transmission development as a flawed cost allocation method or no method at all would. Wisconsin PSC states that Order No. 1000's distinction between the allocation of costs and the amount of costs is a hollow one because the key question for states and the customers who pay for the lines is the cost/benefit of the buildout.[721] It also argues that since the Commission saw fit to develop a fallback mechanism for situations where a project developer abandons a line that a transmission provider had depended upon for reliability and supply purposes; it should also have a fallback mechanism for cost overruns, which pose a much greater prospect of harm to the consuming public.

3. Commission Determination

613. We affirm Order No. 1000's requirement that each public utility transmission provider have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.[722] In Order No. 1000, the Commission did not specify how the costs of an individual regional transmission facility should be allocated.[723] It noted, however, that while each transmission planning region may develop a method or methods for different types of transmission projects, each such method or methods should apply to all transmission facilities of the type in question and would have to be determined in advance for each type of facility.[724] We continue to believe that such an approach is necessary to ensure that the rates, terms, and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential. This is because in the absence of clear cost allocation rules, there is a greater potential that pubic utility transmission providers and nonincumbent transmission developers may be unable to develop transmission facilities that are determined by the region to meet their needs.[725]

614. In response to Alabama PSC's argument that a state should be permitted to veto any particular cost allocation if it disagrees with the outcome, we reiterate Order No. 1000's finding declining to mandate veto rights

718 Transmission Access Policy Study Group at 40 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 549, 764).

719 Transmission Access Policy Study Group asserts that Order No. 1000's focus on cost allocation as disassociated from service relationships heighten these concerns.

720 Transmission Access Policy Study Group notes that Order No. 1000 does not address timing of the filing of specific applications of the regional cost allocation.

721 Wisconsin PSC at 10–11 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 704–05 (2007)).

722 Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 558.

723 *Id.* P 560.

724 *Id.*

725 *Id.* P 559.

for state committees. However, as stated in Order No. 1000, the Commission does not preclude public utility transmission providers from proposing such mechanisms on compliance if they choose to do so.[726] We emphasize that any such mechanisms must be consistent with the goals of Order No. 1000's transmission planning and cost allocation reforms, an important part of which are to provide that costs are allocated to beneficiaries roughly commensurate with the benefits that they receive.

615. In response to Alabama PSC's concern that the Commission's cost allocation reforms could lead to stranded transmission costs due to the absence of a necessary contractual vehicle, we note that entities that receive benefits are subject to a Commission-approved transmission tariff. The existence of obligation arising under such a tariff is sufficient to ensure that there will be no stranded costs, and the question of specific recovery mechanisms is beyond the scope of this proceeding. This point applies equally to Southern Companies' concern about payment obligations that correspond to cost assignments.

616. Additionally, we find no merit in the arguments advanced to challenge our position in Order No. 1000 that cost allocation and cost recovery are distinct issues and our determination not to address matters of cost recovery there.[727] We therefore affirm the Commission's decision in Order No. 1000 that cost recovery is a separate issue, and we will not specify how costs can be recovered for transmission projects that are selected in the regional transmission plan for purposes of cost allocation. The U.S. Supreme Court has found that the Commission has broad discretion in determining which issues to address in a particular proceeding.[728] While we will not address cost recovery in this proceeding, we note that cost recovery may be considered as part of a region's stakeholder process in developing a cost allocation method or methods to comply with Order No. 1000. Therefore, to the extent that cost recovery provisions are considered in connection with a cost allocation method or methods for a regional or interregional transmission facility, public utility transmission providers may include cost recovery provisions in their compliance filings.

617. We thus reject Sacramento Municipal Utility District's contention that Order No. 1000 is deficient because it does not explain the mechanism for recovering a cost "when the party being charged is not a customer." [729] Sacramento Municipal Utility District's claim of deficiency is premised on the proposition that costs cannot be allocated in a situation where an entity does not have a preexisting contractual relationship with the entity that will recover the costs. It considers a cost allocation in this situation to be a cost allocation to a non-customer. We have addressed this issue at length above. Because we disagree with Sacramento Municipal Utility District's premise, we disagree that our decision not to address cost recovery in Order No. 1000 makes the order deficient. This conclusion applies equally to Sacramento Municipal Utility District's assertion that it is not a mere concern over form to expect an explanation of the mechanism for recovering a charge when the party being charged is not a customer.

618. Edison Electric Institute seeks clarification on how costs can be recovered from a beneficiary in the absence of an applicable tariff or agreement. Edison Electric Institute's request is based on its reading of paragraph 506 of Order No. 1000, which it notes states that the Commission "would permit recovery of costs from a beneficiary in the absence of a voluntary arrangement." However, this statement is simply part of a summary of the Commission's ruling in *AEP*. This summary does not imply that Order No. 1000 contemplates the recovery of costs from a beneficiary in the absence of an applicable tariff or agreement. All tariffs will be required to contain an appropriate cost allocation method or methods.

619. In response to Alabama PSC, the Commission was not being inconsistent on the issue of cost recovery when it found that participant funding, which it describes as a form of cost recovery, cannot be a regional cost allocation method. This argument assumes that cost allocation and cost recovery are not distinct issues. The Commission's position is that they are distinct—a point that Alabama PSC does not challenge—and thus when it concluded that participant funding cannot serve as a regional cost allocation method, the Commission was not making a conclusion regarding cost recovery mechanisms. As a result, the Commission was not taking an action that was inconsistent with its position that it would not address cost recovery in Order No. 1000. We address the prohibition against participant funding as a regional cost allocation method elsewhere in this order. Similarly, we disagree with Northern Tier Transmission Group that the Commission is impermissibly imposing recovery of transmission construction costs on non-jurisdictional entities, as Order No. 1000 did not address matters of cost recovery.

620. Moreover, we disagree with petitioners' arguments that Order No. 1000's cost allocation provisions infringe on state authority over the siting and permitting of transmission facilities, or that they infringe on integrated resource planning. Petitioners have not demonstrated anything persuasive to support their comments. More generally, as we discuss in the cost allocation legal authority section above, we have ample authority under the FPA to require public utility transmission providers to file regional and interregional cost allocation methods, and we direct petitioners to that section for a fuller discussion of the Commission's legal authority.

621. We disagree with those petitioners who claim the Commission is seeking to regulate bundled retail rates. North Carolina Agencies provide no clear explanation for their position. Indeed, they state only that there is a potential for the Commission to regulate bundled retail rates. As for Ad Hoc Coalition of Southeastern Utilities' arguments, we disagree that requiring the implementation of a method to allocate the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation amounts to regulation of bundled retail rates.[730] As discussed in Order No. 1000 and in this order, we have ample legal authority to adopt the Order No. 1000 cost allocation reforms.[731] We also affirm Order No. 1000's discussion of this issue, namely, that:

> [I]t is not clear why cost allocations consistent with this Final Rule would affect state jurisdiction differently from existing cost allocations. In any event, we find that such arguments are premature. It is inappropriate for the Commission to decide such issues generically in a rulemaking, as such issues should be decided based on

[726] *Id.* P 502.

[727] *Id.* P 563.

[728] *Mobil Oil Exploration & Producing Southeast, Inc.* v. *United Distribution Companies,* 498 U.S. 211, 230 (1991). *See also Tennessee Valley Municipal Gas Association* v. *FERC,* 140 F.3d. 1085, 1088 (D.C. Cir. 1998).

[729] Sacramento Municipal Utility District at 11.

[730] Ad Hoc Coalition of Southeastern Utilities at 74.

[731] *See, e.g.,* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 530–49; *see also* discussion *supra* at section 0 and discussion *supra* at section IV.A.3.

specific facts and circumstances, none of which are presented here.[732]

Accordingly, we reiterate here that in this generic rulemaking proceeding, these issues are not presented for Commission determination.

622. To the extent a non-public utility transmission provider exercises its discretion to enroll as a transmission provider in a regional transmission planning process, it may be allocated costs roughly commensurate with the benefits that it is determined to receive from new transmission facilities selected in the regional transmission plan for purposes of cost allocation.[733] We disagree with Arizona Cooperative and Southwest Transmission that a non-public utility transmission provider will effectively forfeit its rights to avoid undue discrimination by participating in the regional transmission planning process for several reasons. First, the choice of whether to enroll in the regional transmission planning process, and thus be subject to being determined to be a beneficiary for which cost allocation is appropriate, remains with each non-public utility transmission provider. Second, it will have a voice in the process of determining the cost allocation method, and if it believes that the result is unduly discriminatory, it maintains the right to intervene in the compliance proceeding when that method is filed at the Commission. Third, for future applications of the method to actual new facilities, a non-public utility transmission provider could exercise any right it has in the regional transmission planning process to withdraw rather than accept the allocation of costs.[734] And finally, non-public utility transmission providers choosing to remain in the transmission planning region notwithstanding dissatisfaction with a particular application of the cost allocation method may file with the Commission for a FPA 206 determination that the approved method is no longer just and reasonable or is unduly discriminatory or preferential in practice.

623. We affirm the Commission's finding in Order No. 1000 that this is not the proper proceeding to address rate pancaking issues. If rate pancaking is an issue in a particular transmission planning region, stakeholders may raise their concerns in the consultations leading to the compliance proceedings for Order No. 1000 or make a separate filing with the Commission under section 205 or 206 of the FPA, as appropriate.[735] The Commission has the discretion to determine which issues to address in a particular proceeding.[736]

624. With regard to concerns related to access to new transmission facilities for which an entity has been allocated costs pursuant to a regional or interregional cost allocation method, the Commission believes that the appropriate forum to consider such issues in the first instance is in the regional transmission planning process for each transmission planning region. Each regional transmission planning process must provide entities who will receive regional or interregional cost allocation an understanding of the identified benefits on which the cost allocation is based. The Commission anticipates that regions may approach these issues in different ways and thus will allow public utility transmission providers, in consultation with stakeholders, to address these issues as they develop the regional and interregional cost allocation methods for their transmission planning region. We note that entities may utilize the existing OATT provisions regarding Order No. 890 dispute resolution, which will also apply to the new transmission planning and cost allocation processes adopted under Order No. 1000, if they disagree with the public utility transmission provider's identification of benefits and beneficiaries for a regional or interregional transmission facility selected in the regional transmission plan for purposes of cost allocation.

625. We affirm the Commission's decision in Order No. 1000 that cost containment issues relate to the level of costs and not how costs should be allocated among beneficiaries.[737] As the Commission emphasized in Order No. 1000, this proceeding relates to transmission planning reforms, including the role of cost allocation in transmission planning, not the level of transmission costs,[738] and therefore this proceeding is not the appropriate forum for addressing the transmission cost containment issues raised by petitioners. However, as with cost recovery, we note that cost containment may be considered as part of a region's stakeholder process in developing a cost allocation method or methods to comply with Order No. 1000. Therefore, to the extent that cost containment provisions are considered in connection with a cost allocation method or methods for a regional or interregional transmission facility, public utility transmission providers may include transmission cost containment provisions in their compliance filings.

C. Cost Allocation Method for Interregional Transmission Facilities

1. Final Rule

626. In Order No. 1000, the Commission required each public utility transmission provider in a transmission planning region to have, together with the public utility transmission providers in its own transmission planning region and a neighboring transmission planning region, a common method or methods for allocating the costs of a new interregional transmission facility among the beneficiaries of that transmission facility in the two neighboring transmission planning regions in which the transmission facility is located. The Commission explained that the cost allocation method or methods used by the pair of neighboring transmission regions can differ from the cost allocation method or methods used by each region to allocate the cost of a new interregional transmission facility within that region.[739] The Commission stated that in an RTO or ISO region, the method must be filed in the OATT.[740] Additionally, the Commission stated that in a non-RTO/ISO transmission planning region, the same common cost allocation method or methods must be filed in the OATT of each public utility transmission provider in the transmission planning region.[741] In either instance, the Commission stated that such cost allocation method or methods must be consistent with the interregional cost allocation principles adopted in Order No. 1000.[742]

627. The Commission also clarified that it would not require each transmission planning region to have the same interregional cost allocation method or methods with each of its neighbors.[743] Order No. 1000 provided that each pair of transmission planning

[732] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 548.

[733] *See* discussion *supra* at PP 0–0.

[734] To accommodate the participation of non-public utility transmission providers, the relevant tariffs or agreements governing the regional transmission planning process could establish the terms and conditions of orderly withdrawal for non-public utility transmission providers that are unable to accept the allocation of costs pursuant to a regional or interregional cost allocation method. *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 820.

[735] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 764.

[736] *Mobil Oil Exploration & Producing Southeast, Inc.* v. *United Distribution Companies,* 498 U.S. 211, 230 (1991). *See also Tennessee Valley Municipal Gas Association* v. *FERC,* 140 F.3d. 1085, 1088 (D.C. Cir. 1998).

[737] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 704.

[738] *Id.*

[739] *Id.* P 578.

[740] *Id.*

[741] *Id.*

[742] *Id.*

[743] *Id.* P 580.

regions may develop its own approach to interregional cost allocation that satisfies both transmission planning regions' needs and concerns, as long as that approach satisfies the interregional cost allocation principles.[744]

628. The Commission did not specify how the costs for an individual interregional transmission facility should be allocated.[745] However, the Commission stated that while transmission planning regions can develop a different cost allocation method or methods for different types of transmission projects, such a cost allocation method or methods should apply to all transmission facilities of the type in question and each cost allocation method would have to be determined in advance for each type of transmission facility.[746] Also, the Commission adopted the requirement that an interregional transmission facility must be selected in a relevant regional transmission plan for purposes of cost allocation to be eligible for interregional cost allocation pursuant to the interregional cost allocation method or methods.[747]

629. The Commission also noted that as it made clear in its discussion of Cost Allocation Principle 4,[748] costs may be assigned only on a voluntary basis to a transmission planning region in which an interregional transmission facility is not located.[749] The Commission noted that, given this option, regions are free to negotiate interregional transmission arrangements that allow for the allocation of costs to beneficiaries that are not located in the same transmission planning region as any given interregional transmission facility.[750]

630. In addition, the Commission clarified that the requirement to coordinate with neighboring regions applies to public utility transmission providers within a region as a group, not to each individual public utility transmission provider acting on its own. For example, within an RTO or ISO, the RTO or ISO would develop an interregional cost allocation method or methods with its neighboring regions on behalf of its public utility transmission owning members.[751]

[744] *Id.*

[745] *Id.* P 581.

[746] *Id.*

[747] *Id.*

[748] *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at section IV.E.5.

[749] *Id.* P 582.

[750] *Id.*

[751] *Id.* P 584.

2. Requests for Rehearing or Clarification

631. Several petitioners seek clarification of the Commission's interregional cost allocation requirements. California ISO seeks clarification that one planning region cannot allocate costs to a neighboring transmission planning region for a transmission line that interconnects to the system of the neighboring region but that the neighboring region has not determined is needed and has not included in its transmission plan.

632. MISO Transmission Owners Group 1 requests clarification that Order No. 1000's statement that a transmission owner in an RTO or ISO can comply with the proposed interregional cost allocation mandates through participation in the RTO and ISO is not intended to alter a transmission owner's section 205 rights or the division of section 205 filing rights between an RTO and its transmission owners. It states that if the Commission does not provide this clarification, the Commission must grant rehearing because limiting the section 205 filing rights of transmission owners would be contrary to judicial precedent.[752]

633. Transmission Dependent Utility Systems request clarification that transmission customer load-serving entities should be able to review and comment on the development of interregional cost allocation methods and have their input considered and addressed before public utility transmission providers make their compliance filings. Transmission Dependent Utility Systems assert this is necessary to ensure consistency with the non-discrimination requirements of FPA section 205.

3. Commission Determination

634. As stated in Order No. 1000, the Commission requires that each public utility transmission provider in a transmission planning region must have, together with the public utility transmission providers in its own transmission planning region and a neighboring transmission planning region, a common method or methods for allocating the costs of a new interregional transmission facility among the beneficiaries of that transmission facility in the two neighboring transmission planning regions in which the transmission facility is located.[753] We continue to believe that the absence of clear cost allocation rules for interregional transmission facilities can impede the development of such transmission facilities due to the uncertainty regarding the allocation of responsibility for associated costs, potentially adversely affecting rates for jurisdictional services causing them to become unjust and unreasonable or unduly discriminatory or preferential.[754]

[752] MISO Transmission Owners Group 1 at 13–14 (citing *Atlantic City Electric Co.* v. *FERC,* 295 F.3d 1 (D.C. Cir. 2002)).

[753] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 579.

635. In response to California ISO's request that we clarify that another region could not impose costs on it for an interregional transmission facility without approval, Order No. 1000 states that, for an interregional transmission facility to receive interregional cost allocation, each of the neighboring transmission planning regions in which the interregional transmission facility is proposed to be located must select the facility in its regional transmission plan for purposes of cost allocation.[755] As such, we believe that it is clear that, if one of the regional transmission planning processes does not select the interregional transmission facility to receive interregional cost allocation, neither the transmission developer nor the other transmission planning region may allocate the costs of that interregional transmission facility under the provisions of Order No. 1000 to the region that did not select the interregional transmission facility.

636. In response to MISO Transmission Owners Group 1, we clarify that the Order No. 1000 interregional cost allocation requirements are not intended to alter the section 205 rights of transmission owners and RTOs.

637. In response to Transmission Dependent Utility Systems, we clarify that all interested parties, including transmission customer load-serving entities, must have the opportunity to participate in the process of developing the interregional cost allocation method or methods. As the Commission stated in Order No. 1000, in developing appropriate cost allocation methods for their regional and interregional transmission facilities, public utility transmission providers must consult with stakeholders.[756] The Commission also stated that stakeholder input in the development of a cost allocation method or methods should ensure that the method or methods ultimately agreed upon is balanced and does not favor any

[754] *Id.*

[755] *Id.* P 436.

[756] *Id.* P 482.

particular entity.[757] Consistent with Order No. 890, the Commission defined ''stakeholder'' in Order No. 1000 as including any party interested in the regional transmission planning process.[758] As such, we view stakeholder participation, including that by load-serving entities, as an important aspect of the development of compliance filings to meet the requirements of Order No. 1000.

D. Principles for Regional and Interregional Cost Allocation

1. Use of a Principles-Based Approach

638. In Order No. 1000, the Commission required each public utility transmission provider to show on compliance that its cost allocation method or methods for regional cost allocation and its method or methods for interregional cost allocation are just and reasonable and not unduly discriminatory or preferential by demonstrating that each method satisfies the six cost allocation principles.[759] The Commission took a principles-based approach because it recognized that regional differences may warrant distinctions in cost allocation methods among transmission planning regions. The Commission explained that the six regional cost allocation principles apply to, and only to, a cost allocation method or methods for new regional transmission facilities selected in a regional transmission plan for purposes of cost allocation.[760] Likewise, the Commission stated that the six analogous interregional cost allocation principles apply to, and only to, a cost allocation method or methods for a new transmission facility that is located in two neighboring transmission planning regions and accounted for in the interregional transmission coordination procedure in an OATT.[761] Additionally, the Commission stated that the cost allocation principles do not apply to other new transmission facilities and therefore did not foreclose the opportunity for a developer or individual customer to voluntarily assume the costs of a new transmission facility.[762]

639. The Commission declined to adopt a default regional or interregional cost allocation method, but stated that in the event of a failure to reach an agreement on a cost allocation method or methods, it would use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets its proposed requirements.[763]

a. Arguments That Principles-Based Cost Allocation Methods Are Unfair and Arguments Related to Commission Determination of Cost Allocation Method Pursuant to the Compliance Process

640. Illinois Commerce Commission argues that Order No. 1000 appears to require transmission providers to be responsible for estimating project benefits, which effectively delegates the Commission's authority over rates and to define what constitutes benefits. It maintains that delegating this authority to the transmission provider and the stakeholder process does not ensure that planning criteria and cost allocation methods based on benefits will be just and reasonable.

641. Illinois Commerce Commission asserts that the stakeholder process may neglect the interests of some load-serving entities that will bear the costs of transmission investment when the interests of those load-serving entities are not aligned or directly conflicts with the majority of load-serving entities and other stakeholders within the region. It cites *Illinois Commerce Commission* as an example of an outcome where the majority of stakeholders agreed to spread costs in eastern PJM to utilities in western PJM, and the Commission deferred to this ''regional consensus'' while acknowledging there was none. Illinois Commerce Commission states that the Seventh Circuit disagreed and found that one group of utilities' desire to be subsidized by another is no reason in itself for giving them their way.

642. Illinois Commerce Commission further argues that delegating the Commission's obligation to ensure just and reasonable rates to a stakeholder process violates section 205 due process rights of interested parties because it imposes an undue burden on parties to participate in a new and costly process without providing the funding to participate. It contends that the process will lack a public administrative record, making it difficult for interested parties who would have otherwise intervened in a normal administrative process to follow the proceeding. Illinois Commerce Commission states that the right of parties to bring a section 206 complaint is an inadequate remedy in light of these issues.

643. Several petitioners seek rehearing of the Commission's statement that if an agreement on a cost allocation method is not reached, it will use the record to develop a method or methods for the region, arguing that the Commission does not have the authority to do so.[764] Florida PSC argues that this provision encroaches on Florida's jurisdiction because the Commission does not have authority to assign cost recovery to retail customers.[765] Kentucky PSC also argues that the due process requirements of the state integrated resource planning and certificate of public convenience and necessity processes is being replaced by majoritarian processes backed by the threat that the Commission will determine cost allocation processes if the regional group cannot.

644. Illinois Commerce Commission argues that Order No. 1000 implies that if there is consensus, the Commission will accept that compliance filing. Illinois Commerce Commission seeks rehearing of the meaning of ''consensus'' if it means here something different from ''agreement.'' [766] It argues that the term is insufficient to protect those who may be harmed by a majority. Additionally, Illinois Commerce Commission argues that requiring a consensus means that minority interests will always lose, which is unduly discriminatory on its face, and forcing minority interests to bring a section 206 complaint is insufficient to protect their interests and overly burdensome.

645. New York Transmission Owners seek clarification that the Commission will impose a cost allocation method on transmission planning regions only as a last resort after consensus has been encouraged through mediation and other alternative dispute resolution procedures.

646. Transmission Dependent Utility Systems seek clarification, or in the alternative rehearing, that compliance filings must document the opportunities for customer input in the development of regional and interregional cost allocation methods as well as the basis relied upon for disregarding any such input. They argue that this information is necessary to gauge the inclusiveness and transparency of the processes for developing cost allocation methods.

i. Commission Determination

647. We affirm the Commission's decision that the appropriate approach is for public utility transmission providers to develop regional and interregional cost allocation methods based on the six cost allocation

[757] *Id.* P 671.

[758] *Id.* P 143.

[759] *Id.* P 603.

[760] *Id.*

[761] *Id.*

[762] *Id.*

[763] *Id.* PP 607, 610.

[764] *See, e.g.,* Georgia PSC; Illinois Commerce Commission; and Florida PSC.

[765] Florida PSC at 7 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 607).

[766] Illinois Commerce Commission at 35.

principles described in Order No. 1000, thereby allowing public utility transmission providers the flexibility to develop cost allocation methods that best suit regional needs. The Commission disagrees that Order No. 1000 is delegating the Commission's authority over rates to define what constitutes benefits. The proper context for further consideration of ''benefits'' and ''beneficiaries'' is in the Commission's review of compliance proposals and a record before the Commission.[767] As the Commission explained in Order No. 1000, the cost allocation principles do not prescribe a uniform approach, but provide the public utility transmission providers in consultation with the stakeholders in each region the opportunity to first develop their own method or methods, and recognized that regional differences may warrant distinctions in cost allocation methods.[768] It would be inconsistent with the regional flexibility provided in Order No. 1000 for the Commission to prescribe a uniform approach to determining benefits or beneficiaries when a multitude of factors vary across transmission planning regions and the entire country.

648. In response to concerns that a stakeholder process is an inappropriate way to allocate costs, we note that the Commission has previously found, and the D.C. Circuit has affirmed, that a stakeholder process is appropriate when unresolved issues may be better addressed in a forum featuring broad stakeholder input, and where a transmission solution can be better tailored to meet regional transmission needs through broad input from interested participants that may not otherwise participate in a Commission proceeding.[769] The public utility transmission providers and stakeholders that make up the region are intimately familiar with the transmission needs of their region. Therefore, they are in the best position to develop, and submit to the Commission for review, a cost allocation method or methods that complies with the six cost allocation principles and best meets the transmission planning region's needs. This does not amount to a delegation of Commission authority because the Commission ultimately will determine whether the method or methods are just and reasonable and interested parties will continue to have an opportunity to support or oppose the cost allocation methods proposed in the compliance filings at the Commission.[770]

649. It also does not interfere with section 205 rights or otherwise impose an undue burden on parties to participate in new and costly processes. The transmission planning and cost allocation processes in Order No. 1000 are not entirely new, but rather build on the reforms to the processes already required by Order No. 890, in which all interested parties should already be participating. In any event, with regard to state regulators, such as Illinois Commerce Commission, we have already explained above that, consistent with Order Nos. 1000 and 890, they may request that the public utility transmission providers in their region propose a mechanism in their compliance filings providing for state regulators to recoup the costs of their participation in the regional transmission planning process.[771] In addition, interested parties retained their section 206 rights to file a complaint if they have concerns about the process or the method or methods proposed. Illinois Commerce Commission has not provided a reason that section 206 would not be an appropriate remedy and not identified specific facts to illustrate a scenario where it would not be able to obtain an adequate remedy under section 206.

650. We also affirm the Commission's decision in Order No. 1000 that, in the event of a failure to reach an agreement on a cost allocation method or methods, the Commission will use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets Order No. 1000's cost allocation principles.[772] This provision does not infringe upon state jurisdiction, as suggested by the Florida and Kentucky PSCs, because, as discussed above, states retain whatever jurisdiction they have over retail rates.

651. In response to Illinois Commerce Commission's argument regarding whether a ''consensus'' of stakeholders is synonymous with ''agreement,'' and if so, that such an approach would allow the majority to override minority interests when making compliance filings, we reiterate our finding in Order No. 1000 that ''the Commission will consider in response to compliance filings all issues raised by commenters, such as what constitutes an impasse, [and] whether there should be deference to the majority * * *.''[773] Accordingly, we decline to speculate in advance of these compliance filings the extent to which the Commission would give weight to the majority of public utility transmission providers and stakeholders in a region.

652. In response to New York Transmission Owners, we reiterate that the Commission will use the record in the relevant compliance filings as a basis to develop a cost allocation method or methods for a transmission planning region when the transmission planning region fails to reach an agreement. To this end, we note that in response to a directive to do so in Order No. 1000,[774] the Commission's staff has been made available to assist public utility transmission providers and stakeholders in the various regions around the country in reaching an agreement on a compliance filing. The Commission also noted in Order No. 1000 that the procedural mechanisms used by it in response to compliance filings will depend on the nature of remaining disputes and what issues are still at stake that are preventing the public utility transmission providers in each transmission planning region or pair of transmission planning regions from reaching a consensus.[775] Accordingly, in advance of such compliance filings, we decline to specifically endorse any particular procedural method for resolving cost allocation disputes brought forward in compliance filings; mediation or other alternative dispute resolution procedures, as suggested by New York Transmission Owners are certainly viable methods to encourage consensus and will be considered if necessary at the appropriate time.

653. In response to Transmission Dependent Utility Systems' request that compliance filings must document the opportunities for customer input provided, as well as the basis relied upon for disregarding any such customer input, we do not believe any clarification of Order No. 1000 is necessary. Order No. 1000 already provides that ''[p]ublic utility transmission providers must document in their compliance filings the steps they have taken to reach consensus on a cost allocation method or set of methods to comply with this Final Rule, as thoroughly as practicable, and provide whatever information they view

[767] *Id.* P 624.

[768] *Id.*

[769] *Braintree Elec. Light Dept.* v. *ISO New England, Inc.,* 128 FERC ¶ 61,008 (2009) (citing *MISO,* 125 FERC ¶ 61,038, at P 19 (2008); *Pepco Energy Servs.* v. *PJM Interconnection, L.L.C.,* 124 FERC ¶ 61,008, at P 24 (2008); *PSC of Wis.* v. *FERC,* 545 F.3d 1058, 1063 (D.C. Cir. 2008)).

[770] *PSC of Wis.* v. *FERC,* 545 F.3d at 1064.

[771] *See* discussion *supra* at section 0. (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 162 and quoting Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574 n.339 and P 586)).

[772] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 607.

[773] *Id.* P 609.

[774] *Id.* P 14.

[775] *Id.* P 609.

as necessary for the Commission to make a determination of the appropriate cost allocation method or methods.'' [776]

2. Cost Allocation Principle 1—Costs Allocated in a Way That Is Roughly Commensurate With Benefits

654. In Order No. 1000, the Commission adopted the following Cost Allocation Principle 1 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 1: The cost 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. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements.

and

Interregional Cost Allocation Principle 1: The costs of a new interregional transmission facility must be allocated to each transmission planning region in which that transmission facility is located in a manner that is at least roughly commensurate with the estimated benefits of that transmission facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements.[777]

655. However, the Commission stated that it was not prescribing a particular definition of ''benefits'' or ''beneficiaries'' in Order No. 1000.[778] In the Commission's view, the proper context for consideration of these matters is in the regional stakeholder meetings in the first instance, followed by Commission consideration of these matters on review of compliance proposals and the record before the Commission.[779]

656. The Commission also stated that if a non-public utility transmission provider makes the choice to become part of the transmission planning region and it is determined by the transmission planning process to be a beneficiary of certain transmission facilities selected in the regional transmission plan for purposes of cost allocation, that non-public utility transmission provider is responsible for the costs associated with such benefits.[780]

657. Additionally, in Order No. 1000, the Commission found that issues related to the generator interconnection process and to interconnection cost recovery were outside the scope of the rulemaking proceeding.[781] The Commission stated that Order No. 2003 [782] sets forth the procedures for the interconnection of a large generating transmission facility to the bulk power system.[783] Additionally, the Commission emphasized that Order No. 1000 did not set forth any new requirements with respect to such procedures for interconnecting large, small, or wind or other generation facilities.[784] Therefore, the Commission determined that Order No. 1000 was not the proper proceeding for commenters to raise issues about the interconnection agreements and procedures under Order Nos. 2003, 2006 [785] or 661.[786]

a. Requests for Rehearing or Clarification

658. Several petitioners seek rehearing or clarification regarding the lack of a definition of ''benefits'' in Order No. 1000. Illinois Commerce Commission argues that by failing to establish definitions and standards for transmission providers to implement in identifying project benefits, the Commission has placed transmission providers in conflict with majority desires in the stakeholder process because an RTO is obligated to act in the interests of its transmission owning members. It argues that RTO behavior has been more accommodating to transmission owning utilities than captive ratepayers, and this issue will be exacerbated with less Commission oversight.

659. Arizona Cooperative and Southwest Transmission also argue that there is insufficient Commission oversight of the definition and measurement of benefits. It argues that ''benefits'' can, within the context of a network, become so pliable as to become meaningless, especially as applied to individual situations. Arizona Cooperative and Southwest Transmission add that different outcomes are apt to flow from how benefits are defined. Public utilities may value needs and interests differently from other stakeholders, and customers and entities will not all have the same needs and interests. Arizona Cooperative and Southwest Transmission are concerned that it may be deemed to receive benefits that have little or nothing to do with its needs.

660. Georgia PSC and Florida PSC seek clarification of the definition of benefits and what constitutes too narrow or too broad a definition. Florida PSC asserts that leaving this question to the stakeholder and subsequent compliance process creates the possibility that regions will adopt a definition of benefits that does not meet whatever undefined standard the Commission may have in mind. It argues that this approach limits regional autonomy in an undefined way, even though the Commission states that regions are free to determine their own definitions of benefits.

661. Georgia PSC and Florida PSC also seek clarification of what benefits must be quantifiable and based on existing policies in state and federal law. Florida PSC argues that ambiguities on this issue and what constitutes too broad or narrow a definition of benefits violate the Due Process Clause ''fair notice'' requirement.[787]

662. Other petitioners argue that the definitions of ''benefits'' and ''beneficiary'' were left too broad.[788] Kentucky PSC argues that the Commission erred in failing to define ''cost causer'' and ''beneficiary.'' [789] It asserts that recently there has been considerable dispute over the meaning of cost causer and when an entity becomes a beneficiary of a new or expanded facility developed by others. Kentucky PSC is concerned that there is no requirement that cost allocation processes account for proximity to a project, which it asserts is directly related a project's actual benefits in terms of improving reliability, reducing congestion, and opening markets. It contends that it appears that a project may be eligible for cost allocation solely

[776] *Id.* P 607.

[777] *Id.* P 622.

[778] *Id.* P 624.

[779] *Id.*

[780] *Id.* P 629.

[781] *Id.* P 760.

[782] Order No. 2003, 68 FR 49846, FERC Stats. & Regs. ¶ 31,146, *order on reh'g,* Order No. 2003–A, 69 FR 15932, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, 70 FR 265, FERC Stats. & Regs. ¶ 31,171, *order on reh'g,* Order No. 2003–C, 70 FR 37661, FERC Stats. & Regs. ¶ 31,190, *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[783] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 760.

[784] *Id.*

[785] Order No. 2006, 70 FR 34189, FERC Stats. & Regs. ¶ 31,180, *order on reh'g,* Order No. 2006–A, 70 FR 71760, FERC Stats. & Regs. ¶ 31,196, *order granting clarification,* Order No. 2006–B, 71 FR 42587, FERC Stats. & Regs. ¶ 31,221.

[786] Order No. 661, 70 FR 34993 (Jun. 16, 2005), FERC Stats. & Regs. ¶ 31,186, *order on reh'g,* Order No. 661–A, FERC Stats. & Regs. ¶ 31,198.

[787] Florida PSC at 8 (citing *Trinity Broadcasting of Fla., Inc.* v. *FCC,* 211 F.3d 618, 628 (D.C. Cir. 2000)).

[788] *See, e.g.,* Coalition for Fair Transmission Policy; and PSEG Companies.

[789] Kentucky PSC at 5.

due to its ability to meet the public policy requirements of state or federal governments.[790] Kentucky PSC explains that there is no requirement that a state have a need for a project, which will result in ratepayers paying for projects that may not be located within their state and that are designed to meet other states' public policy requirements. It maintains that to exempt a state's ratepayers from cost allocation only if they will not benefit at present or in a ''future scenario'' appears to enable the majority in a regional planning entity to decide that a particular state's legislature will, or should, ultimately enact certain public policies or that the federal government will do so.

663. Likewise, Coalition for Fair Transmission Policy argues that not limiting the definition of ''benefits'' and ''beneficiary'' will lead to uncertainty and dispute.[791] It states that a beneficiary-pays approach is appropriate for certain types of projects, such as projects driven by reliability compliance obligations, because the relationship between specific transmission projects, reliability impacts, and the benefits of reliability are well established and capable of examination within a framework of existing transmission planning horizons and study methodologies. However, Coalition for Fair Transmission Policy asserts that it is difficult to define benefits and beneficiaries in a way that is just and reasonable and objectively verifiable for projects such as upgrades driven by economics and/or public policy requirements.

664. According to Coalition for Fair Transmission Policy, failure to define potential benefits correctly on compliance will have adverse economic and policy impacts. For instance, it maintains that if benefits are defined to include broad societal benefits of building renewables in a certain area, and that definition is used to justify cost socialization of transmission projects to that area, the generator or customer will not face the true costs of their resource decisions. Buyers may decide to buy from remote renewable resources that require long-distance transmission, rather than potentially lower cost local renewable resources, because they do not have to pay the full transmission costs. According to Coalition for Fair Transmission Policy, competitive wholesale markets using locational-marginal pricing would at that point begin to see price signals break down and become inefficient. It also argues that siting may become more difficult because those required to pay for lines they do not see benefit from will litigate both the cost and siting-approval processes.

665. Coalition for Fair Transmission Policy urges the Commission to limit regions to considering only benefits that: (1) Occur within the typical transmission planning horizon of the public utilities within the region that can be measured or projected through the kinds of transmission planning studies that are normally conducted; (2) are not speculative; and (3) are not based on ''societal'' benefits that are not embodied in existing federal and state public policy requirements.[792] It also argues that the Commission should clarify that regional transmission planning may not adopt presumptions that broad categorizations of types or classes of transmission lines driven by economic or public policy requirements have broad benefits and should be allocated widely. Also, Coalition for Fair Transmission Policy and North Carolina Agencies argue that the Commission should require that those seeking cost allocations for individual transmission projects be able to demonstrate quantifiable, observable and tangible reliability and economic benefits with reasonable particularity that is tied directly to those who will be required to pay under a cost allocation methodology. North Carolina Agencies argue that both the FPA and Commission precedent require the allocation of costs in proportion to the real reliability and economic benefits resulting from a transmission investment that can be measured or projected within the planning horizon.

666. In addition, Coalition for Fair Transmission Policy argues that the Commission should revise its cost allocation principles to assure that benefits are defined in way that conforms with what it asserts are established cost-causation standards, which include, among other things, tying cost allocation to the taking of transmission service.[793]

667. Coalition for Fair Transmission Policy maintains that while Order No. 1000 states that the Commission will fill in the gaps that it left in Order No. 1000 through the process of accepting or rejecting or requiring modification of proposed definitions, the courts have rejected this approach as contrary to law, arbitrary and capricious.[794] Coalition for Fair Transmission Policy asserts that the Commission must supply sufficient explanation to provide a reasonable benchmark and guidance in the development of compliance filings. Coalition for Fair Transmission Policy asserts that the lack of additional guidance creates a risk of stalemate at the regional level and a likelihood that the Commission ultimately would have to define the terms for a region. It argues that this would essentially penalize public utility transmission providers because the process is designed to fail and then be saved by the Commission.

668. Illinois Commerce Commission argues that there is no way to identify ''more efficient or cost effective'' transmission projects in the planning process without a meaningful estimation of benefits, and there is no way to assess whether a transmission provider has complied with the Commission's directive that costs be allocated at least roughly commensurate with benefits unless the level of benefits expected to be provided by a project to each load-serving entity have been determined.[795] It adds that if the Commission's requirements are not clear, there will be no basis to make compliance findings or to detect planning and cost allocation abuses.

669. Illinois Commerce Commission and MISO Northeast seek clarification that generators are subject to regional cost allocation. Illinois Commerce Commission requests clarification that costs can be recovered when the planning itself is undertaken to accommodate the interconnection of particular generators. It notes that Order No. 1000 ruled out participant funding as an acceptable regional or interregional cost allocation method, but Illinois Commerce Commission states that participant funding has applied to generation developers that agree to fund transmission network upgrades to enable their generator to be interconnected to the network. Illinois Commerce Commission requests clarification that Order No. 1000 does not prohibit transmission providers from finding generators to be cost causers or beneficiaries of new transmission facilities developed pursuant to the regional or interregional planning process and allocating costs to those generators accordingly. MISO Northeast likewise requests that the

[790] Kentucky PSC at 6 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 585).

[791] Coalition for Fair Transmission Policy at 8.

[792] Coalition for Fair Transmission Policy at 13.

[793] Coalition for Fair Transmission Policy at 15–16 (citing *Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d 1361, 1369 (D.C. Cir. 2004); citing *Illinois Commerce Commission* v. *FERC,* 576 F.3d at 474–77; citing *Pacific Gas & Electric Co.* v. *FERC,* 373 F.3d 1315, 1321 (D.C. Cir. 2004); quoting *Algonquin Gas Transmission Co.* v. *FERC,* 948 F.2d 1305, 1312–14 (D.C. Cir. 1991)).

[794] Coalition for Fair Transmission Policy at 14 (citing *Appalachian Power Co.* v. *EPA,* 208 F.3d 1015, 1020 (D.C. Cir. 2000)).

[795] Illinois Commerce Commission at 10.

Commission clarify that any regionwide cost allocation method adopted pursuant to Order No. 1000 must allocate costs to generators and end-users commensurate with the share of public policy benefits that they receive.

670. In contrast, NextEra argues that generators should not be responsible for costs not specified in interconnection agreements. It explains that Order No. 2003 recognized that generators must be able to identify all risks prior to entering into an interconnection agreement and commencing construction when it concluded that interconnection customers should only be responsible for costs specifically identified in their interconnection agreements.[796] It argues that it follows that generators should not be responsible for costs not identified in their interconnection agreements, and asserts that if costs could be so allocated, it would make the cost of project financing prohibitive because lenders would likely seek protection for such contingencies. NextEra thus urges the Commission to clarify that generators and other tie line owners will not be responsible for costs not specified in their interconnection agreements, which it argues is consistent with Order No. 1000's conclusion that costs cannot be involuntarily allocated to non-beneficiaries. Otherwise, NextEra argues, such unknowable and unworkable cost allocation creates unjust and unreasonable risks and would be inconsistent with Order No. 2003.

671. Illinois Commerce Commission also takes issue with the requirement in Order No. 1000 that cost allocation methods consider the benefits and costs of groups of new transmission facilities rather than requiring that each project satisfy the Commission's principles and requirements on its own merits. It argues that a portfolio approach to transmission planning allows the approval of projects that, when considered individually, are not cost beneficial.

672. Illinois Commerce Commission states that if individual projects are cost beneficial, and in the aggregate their estimated benefits are roughly commensurate with a postage stamp allocation, then an allocation according to the benefits of each project individually would result in an allocation roughly equivalent with a postage stamp allocation. It argues that this scenario would render the postage stamp allocation unnecessary. Therefore, Illinois Commerce Commission argues that the Commission erred by including the word ''aggregate'' in Principle 1 because it allows transmission providers to avoid demonstrating that each individual project is cost beneficial. It also argues that the Commission violated the FPA and case precedent in failing to remove postage stamp rates as a possible cost allocation method. Specifically, it maintains that it is incorrect to conclude that even when ''all customers within a transmission planning region are found to benefit from the use or availability of a transmission facility or class or group of transmission facilities,'' they all benefit roughly equally.[797] Illinois Commerce Commission also points to the Seventh Circuit's statement that an assertion of generalized system benefits is not sufficient to justify a cost allocation and that alleged benefits, without specific evidentiary support, are too speculative to be considered.

673. Finally, ELCON, AF&PA, and the Associated Industrial Groups argue that use of a postage stamp rate for cost allocation at the regional or interregional level is a form of cost socialization, and it is therefore inconsistent with the cost causation principle. They also maintain that the statement by the court in *Illinois Commerce Commission* that benefits be at least roughly commensurate with costs requires one to conclude that a postage stamp rate is an impermissible form of cost causation.

i. Commission Determination

674. We affirm Order No. 1000 and therefore deny those arguments requesting us to prescribe a particular definition of ''benefits'' or ''beneficiaries.'' As the Commission found in Order No. 1000, the proper context for further consideration of these matters is on review of compliance proposals and a record before us. Many of the petitioners here essentially expound on concerns they raised in the rulemaking proceeding that more specificity in Order No. 1000 itself is required because an overly broad or overly narrow definition of beneficiary or beneficiaries could lead to cost allocations that do not correspond to cost causation. However, as stated in Order No. 1000, we believe that concerns regarding overly narrow or broad interpretations of benefits will be addressed in the first instance during the process of public utility transmission providers consulting with their stakeholders as part of the development of a compliance filing. If such interpretations should emerge, we can more effectively ensure that the term is not given too narrow or broad a meaning by considering a specific proposal and a record than by attempting to anticipate and rule on all possibilities before the fact. This point applies equally to those petitioners that note the potential difficulties in quantifying benefits.[798] For this reason, we decline to adopt any of the many suggestions offered by petitioners in their requests for rehearing and clarification, including those who argue that only certain benefits, such as reliability benefits, should be considered, because determining other types of benefits is difficult or speculative.

675. In response to Illinois Commerce Commission's concern that by not providing a definition of ''benefits'' in Order No. 1000 the Commission would exacerbate an RTO's ability to favor its transmission owning members to the detriment of other stakeholders, we first note that we do not accept the premise that RTOs as a rule engage in such behavior. In any event, when each public utility transmission provider, including an RTO, proposes its cost allocation method or methods, the Commission will review the method or methods, including how benefits and beneficiaries are defined, to determine whether it complies with the requirements of Order No. 1000. This review will include an analysis of whether the cost allocation method or methods comply with Principle 1, which requires that the cost allocation method or method result in an allocation of costs roughly commensurate with benefits. If the compliance filing is unclear on these matters or if parties take issue with aspects of the compliance filing, such as the definition of benefits, the Commission will address those issues at that time.

676. We also disagree with petitioners, such as Georgia PSC and Florida PSC, who assert that by not defining benefits the Commission is limiting regional autonomy. By permitting public utility transmission providers in a region to define benefits collectively together with regional stakeholders, the Commission is enabling them to account for regional differences rather than prescribing a one-size-fits-all method that might not do so as effectively. We also decline to grant the requests of Georgia PSC and Florida PSC for clarification of what benefits must be quantifiable based on

[796] NextEra at 18 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 421).

[797] Illinois Commerce Commission at 16.

[798] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 624–25.

existing policies in state and federal law. Consistent with the discussion above, we believe that this is a matter that is best addressed in the first instance by the public utility transmission providers and their stakeholders in the development of the cost allocation methods for their regions. Furthermore, Florida PSC's argument that the fair notice requirement of the Due Process Clause requires a definition of benefits is without merit, as Florida PSC and all other stakeholders will have ample opportunity to participate in both in the development of the cost allocation methods for their regions, as well as in the Commission proceeding to review the compliance filings that incorporate those cost allocation methods.

677. Moreover, we note that, as applied by the courts, the Due Process standard has been held to allow for flexibility in the wording of an agency's rules and for a reasonable breadth in their construction.[799] In fact, the courts have recognized that ''by requiring regulations to be too specific, [courts] would be opening up large loopholes allowing conduct which should be regulated to escape regulation.'' [800] As the Supreme Court has noted, the degree of vagueness tolerated by the Constitution depends in part on the nature of the rules at issue.[801] In the case of economic regulation, the Supreme Court has found that the vagueness test must be applied in a less strict manner because, among other things, ''the regulated enterprise may have the ability to clarify the meaning of the regulation by its own inquiry, or by resort to an administrative process.'' [802]

678. We also note several petitioners' concerns that the definitions of ''benefits,'' ''beneficiary,'' and ''cost causer,'' are too broad, which they argue will lead to further disputes. As the Commission stated in Order No. 1000, the Commission is allowing flexibility to accommodate a variety of approaches which can better advance the goals of Order No. 1000, recognizing that regional differences may warrant distinctions in cost allocation method or methods.[803] This flexibility is provided so that public utility transmission providers and their stakeholders can develop cost allocation methods that best meet their region's needs. The Commission established the Cost Allocation Principles to provide general guidance to public utility transmission providers to limit uncertainty as they develop their compliance filings. However, for those cost allocation methods to be accepted by the Commission as Order No. 1000-compliant, they will have to clearly and definitively specify the benefits and the class of beneficiaries. Accordingly, we disagree with the premise of some petitioners' arguments that there will be uncertainty once the Commission accepts the cost allocation method or methods in exactly who is a beneficiary and how such determinations are made. That is the very purpose of requiring an *ex ante* cost allocation method: To be clear upfront about who is benefitting so that disputes are minimized and so that the transmission facilities selected in the regional transmission plan for purposes of cost allocation are more likely to be constructed.

679. Additionally, we agree with Illinois Commerce Commission's argument that there is no way to identify ''more efficient or cost effective'' transmission solutions, or to assess whether costs are being allocated at least roughly commensurate with benefits, without a meaningful estimation of benefits. However, we do not believe that this requires any change or clarification to Order No. 1000. As we explain above, while Order No. 1000 does not define benefits and beneficiaries, it does require the public utility transmission providers in each region to be definite about benefits and beneficiaries for purposes of their cost allocation methods. Once beneficiaries are identified, public utility transmission providers would then be able to identify what is the more efficient or cost effective transmission solution or assess whether costs are being allocated at least roughly commensurate with benefits.

680. With respect to generators being identified as beneficiaries and ultimately responsible for costs, we find that just as each transmission planning region retains the flexibility to define benefit and beneficiary, the public utility transmission providers in each transmission planning region, in consultation with their stakeholders, may consider proposals to allocate costs directly to generators as beneficiaries that could be subject to regional or interregional cost allocation. However, we emphasize that any effort to do so must not be inconsistent with the generator interconnection process under Order No. 2003 [804] because, as we stated in Order No. 1000, the generator interconnection process and interconnection cost recovery are outside the scope of this rulemaking. With this said, however, we are not minimizing the importance of evaluating the impact of generation interconnection requests during transmission planning, nor limiting the ability of public utility transmission providers to take requests for generator interconnections into account in developing assumptions to be used in the transmission planning process.[805] While we agree with NextEra that interconnection costs would be specified in interconnection agreements, we deny NextEra's request that the Commission clarify those are the only transmission costs for which generators could be responsible. The Commission determined in Order No. 2003 that interconnection service does not convey the right to flow output of the interconnection customer's generating facility onto the transmission provider's transmission system and does not constitute a reservation of transmission capacity.[806] Order No. 2003 states that the interconnection customer, load or other market participant would have to request either point-to-point or Network Integration Transmission Service under the Transmission Provider's OATT in order to receive the delivery service that is a prerequisite to flowing power onto the system.[807] As such, the interconnection customer could be subject to charges associated with transmission service that are not addressed in its interconnection agreement.

681. We affirm the Commission's finding in Order No. 1000 that in determining the beneficiaries of transmission facilities, Regional Cost Allocation Principle 1 should permit a regional transmission planning process to ''consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy

[799] *See Grayned* v. *City of Rockford,* 408 U.S. 110 (1971) (holding that an anti-noise ordinance was not vague where the words of the ordinance ''are marked by flexibility and reasonable breadth, rather than meticulous specificity.'').

[800] *See Ray Evers Welding Co.* v. *OSHRC,* 625 F.2d 726, 730 (6th Cir. 1980).

[801] *See Village of Hoffman Estates* v. *The Flipside, Hoffman Estates, Inc.,* 455 U.S. 489 (1981).

[802] *See id.* at 498.

[803] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 624.

[804] Order No. 2003, 68 FR 49846, FERC Stats. & Regs. ¶ 31,146, *order on reh'g,* Order No. 2003–A, 69 FR 15932, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, 70 FR 265, FERC Stats. & Regs. ¶ 31,171, *order on reh'g,* Order No. 2003–C, 70 FR 37661, FERC Stats. & Regs. ¶ 31,190, *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[805] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 760.

[806] Order No. 2003, 68 FR 49846, FERC Stats. & Regs. ¶ 31,146 at P 767.

[807] *Id.*

Requirements.''[808] Order No. 1000 was not intended to restrict regional choice in the transmission planning and cost allocation process as petitioners request.

682. Accordingly, we continue to believe that it is appropriate to allow public utility transmission providers in a transmission planning region to propose a cost allocation method that considers the benefits and costs of a *group* of new transmission facilities, although they are not required to do so.[809] As such, we deny Illinois Commerce Commission's arguments that ask us to decide in advance that such an approach is inappropriate and at odds with cost causation. We reiterate that if public utility transmission providers in a region in consultation with their regional stakeholders choose to propose and adequately support a cost allocation method or methods that considers the benefits and costs of a group of new transmission facilities, Order No. 1000 would not require a facility-by-facility showing, so long as the aggregate cost of the transmission facilities in the group is allocated roughly commensurate with aggregate benefits.[810] Such an approach could be reasonable if it, for instance, enables a transmission planning region to prioritize its new transmission facilities in such a way as to ensure benefits from the facilities and maximize the number of system users who will share in those benefits.

683. We also decline to forbid in advance the potential use of a postage stamp cost allocation method. We continue to believe that a postage stamp cost allocation method may be appropriate where all customers within a specified transmission planning region are found to benefit from the use or availability of a transmission facility or class or group of transmission facilities, especially if the distribution of benefits associated with a class or group of transmission facilities is likely to vary considerably over the long depreciation life of the transmission facilities amid changing power flows, fuel prices, population patterns, and local economic considerations.[811] As such, we believe that public utility transmission providers, if they choose to do so in consultation with stakeholders, should be permitted to make the case in their compliance filings that a postage stamp cost allocation is consistent with Principle 1's requirement that all costs be allocated roughly commensurate with benefits. To this end, we agree with Illinois Commerce Commission that any such case would have to do more than make a mere assertion of generalized system benefits. Last, we decline to address Illinois Commerce Commission's arguments related to the MISO MVP proceeding in Docket No. ER10–1791–000 as outside the scope of this proceeding.

3. Cost Allocation Principle 2—No Involuntary Allocation of Costs to Non-Beneficiaries

a. Final Rule

684. The Commission adopted the following Cost Allocation Principle 2 for both regional and interregional cost allocation:

> Regional Cost Allocation Principle 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.

and

> Interregional Cost Allocation Principle 2: A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that transmission facility.[812]

685. The Commission also required that every cost allocation method or methods provide for allocation of the entire prudently incurred cost of a transmission project to prevent stranded costs.[813]

b. Requests for Rehearing or Clarification

686. PSEG Companies argue that Principle 2's ''likely future scenarios'' language is problematic because it could easily result in the expansion of the class of customers that are labeled beneficiaries as more scenarios are introduced, thus making cost allocation determinations more likely to be inexact and speculative.[814] They further state that Order No. 1000's statement that benefits must be ''identifiable'' does not cure the defect, particularly because Order No. 1000 allows not only transmission providers to identify the beneficiaries of proposed projects based on ''likely future scenarios,'' but also allows them to develop such scenarios based on potential public policy requirements.[815] PSEG Companies argue that allowing transmission providers to exercise unfettered discretion in identifying beneficiaries under future scenarios will allow them to act arbitrarily and capriciously, and that the expansive interpretations of ''benefits'' and ''beneficiaries'' would permit the allocation of costs based on tenuous associations with benefits, contrary to *Illinois Commerce Commission*.[816]

687. ITC Companies seek clarification that a ''likely future scenario'' that would justify an allocation of costs for new transmission facilities includes the transmission planning scenarios being used by a transmission provider to prepare a regional transmission plan.[817] ITC Companies state that one helpful clarification would be to confirm that, if a project is shown to have benefits for a zone or customer in one or more of the planning scenarios generally used by the transmission provider to prepare a regional transmission plan, those benefits satisfy Principle 2 and support the allocation of costs to the beneficiaries.

688. Long Island Power Authority seeks clarification that entities not subject to a Public Policy Requirement will have an opportunity to demonstrate this fact for purposes of cost allocation. Long Island Power Authority acknowledges, however, that where an approved project provides multiple benefits, it could be appropriate for an entity to be allocated that portion of a project's costs that are unrelated to fulfilling certain public policy goals, provided that the economic and reliability related costs were allocated according to the economic and reliability procedures of the region, or as agreed upon by neighboring regions.

c. Commission Determination

689. We affirm Order No. 1000's adoption of Regional and Interregional Cost Allocation Principle 2. Accordingly, we deny PSEG Companies' request for rehearing, which largely repeats arguments it made in the rulemaking proceeding. The Commission disagreed with PSEG Companies in Order No. 1000 that basing a determination of who constitutes a ''beneficiary'' on ''likely future scenarios'' necessarily would result in inexact and speculative proposed transmission plans and cost allocation methods.[818] The Commission explained that scenario analysis is a common feature of electric power

[808] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 622.

[809] *Id.* P 627.

[810] *Id.* P 641.

[811] *Id.* P 605.

[812] *Id.* P 637.

[813] *Id.* P 640.

[814] PSEG Companies at 41–42.

[815] PSEG Companies at 42–43.

[816] PSEG Companies at 43–44. PSEG Companies also cite to *Transcontinental Gas Pipe Line Corp.,* 112 FERC ¶ 61,170 (2005), where the Commission rejected reliance on a claim of generalized system benefits as a basis for allocating gas pipeline upgrade costs to existing shippers.

[817] ITC Companies at 14.

[818] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 626.

system planning, and that it believed that public utility transmission providers are in the best position to apply it in a way that achieves appropriate results in their respective transmission planning regions.[819] We disagree that the use of ''likely future scenarios'' and Public Policy Requirements will expand the class of customers who will be identified as beneficiaries. The Commission stated in the discussion on Cost Allocation Principle 1 above that the identification of beneficiaries is based on the principle of cost causation. Accordingly, the scenario analysis is not unfettered. It is limited to scenarios in which a beneficiary is identified as such on the basis of the cost causation principle.

690. In response to ITC Companies, we therefore clarify that public utility transmission providers may rely on scenario analyses in the preparation of a regional transmission plan and the selection of new transmission facilities for cost allocation. If a project or group of projects is shown to have benefits in one or more of the transmission planning scenarios identified by public utility transmission providers in their Commission-approved Order No. 1000-compliant cost allocation methods, Principle 2 would be satisfied.

691. In response to Long Island Power Authority's request that the Commission clarify that entities have the opportunity to demonstrate that a transmission project proposed to meet a given Public Policy Requirement is not applicable to them and provides no benefit to them, we affirm the Commission's statement in Order No. 1000 that consideration of regional transmission needs driven by Public Policy Requirements must follow the cost allocation principles. For instance, Cost Allocation Principle 1 makes clear that Long Island Power Authority will be allocated only costs that are roughly commensurate with the benefits it receives from a transmission facility or facilities. Additionally, Cost Allocation Principle 2 states that those that receive no benefit from new transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities.[820] Given this, if it is true that Long Island Power Authority would not benefit from a transmission project or group of projects designed to meet a regional transmission need driven by a Public Policy Requirement, the transmission planning region's cost allocation method or methods would not be permitted to allocate any costs to it. As Long Island Power Authority acknowledges, even if it does not need the transmission facility to meet a Public Policy Requirement of its own, it nevertheless may receive other economic or reliability benefits from a proposed transmission facility and then the cost allocation method may allocate the costs for the economic or reliability benefits received.

[819] *Id.*

[820] *Id.* P 219.

4. Cost Allocation Principle 3—Benefit to Cost Threshold Ratio

a. Final Rule

692. The Commission adopted the following Cost Allocation Principle 3 for both regional and interregional cost allocation:

Regional Cost Allocation Principle 3: If a benefit to cost threshold is used to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation, it must not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. A public utility transmission provider in a transmission planning region may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a higher ratio.

and

Interregional Cost Allocation Principle 3: If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a transmission facility with significant positive net benefits from cost allocation. The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.[821]

693. The Commission stated that Cost Allocation Principle 3 did not require the use of a benefit to cost ratio threshold.[822] However, if a transmission planning region chooses to have such a threshold, the principle limited the threshold to one that is not so high as to block inclusion of many worthwhile transmission projects in the regional transmission plan.[823] Further, it allowed public utility providers in a transmission planning region to use a lower ratio without a separate showing and to use a higher threshold if they justify it and the Commission approves a greater ratio.[824]

[821] *Id.* P 646.

[822] *Id.* P 647.

[823] *Id.*

b. Request for Rehearing or Clarification

694. Transmission Dependent Utility Systems seek clarification, or in the alternative rehearing, that stakeholders will have access to the data necessary to replicate any benefit-to-cost analysis that public utility transmission providers conduct pursuant to Cost Allocation Principle 3. They state that the Commission did not respond in Order No. 1000 to their argument that Cost Allocation Principle 3 be modified to ensure that implementation of any cost benefit analysis is transparent to load serving entity transmission customers.

c. Commission Determination

695. We find that it is not necessary to modify Cost Allocation Principle 3 to require transparency in the implementation of the benefit to cost analysis because this requirement already exists in Cost Allocation Principle 5. The language in Regional Cost Allocation Principle 5 and Interregional Cost Allocation Principle 5 states that ''[t]he cost allocation method and data requirements for determining benefits and identifying beneficiaries * * * must be transparent with adequate documentation to allow a stakeholder to determine how they were applied.'' [825] Accordingly, we believe that it is clear that the transparency requirement in Cost Allocation Principle 5 applies to any benefit to cost analysis subject to Cost Allocation Principle 3, such that all data relating to the benefit to cost ratio must be transparent. Additionally, the Order No. 890 transparency principle requires ''transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans.'' [826]

5. Cost Allocation Principle 4—Allocation To Be Solely Within Transmission Planning Region(s) Unless Those Outside Voluntarily Assume Costs

a. Final Rule

696. The Commission adopted the following Cost Allocation Principle 4 for both regional and interregional cost allocation:

[824] *Id.*

[825] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 668.

[826] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 471.

Regional Cost Allocation Principle 4: The allocation method for the cost of a transmission facility selected in a regional transmission plan must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs. However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if the original region agrees to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the beneficiaries in the original region.

and

Interregional Cost Allocation Principle 4: Costs allocated for an interregional transmission facility must be assigned only to transmission planning regions in which the transmission facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that transmission facility is not located. However, interregional coordination must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if the transmission providers in the regions in which the transmission facility is located agree to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of such upgrades among the beneficiaries in the transmission planning regions in which the transmission facility is located.[827]

b. Requests for Rehearing or Clarification

697. Several petitioners argue that Principle 4 is inconsistent with cost causation.[828] Energy Future Coalition Group and AEP assert that the Commission should require beneficiaries in adjoining regions to contribute to the costs of new transmission facilities. They assert that otherwise it is likely that intraregional transmission projects that are in the public interest, and would benefit customers in multiple regions, will fail.

698. Energy Future Coalition Group argues that the Commission disregarded the beneficiary pays principle by providing that costs for a transmission facility located in one region may be allocated to beneficiaries in another region only if those beneficiaries volunteer to pay those costs.[829] Energy Future Coalition Group, Joint Petitioners, and AEP add that the Commission's decision fails to address the concern about free-riders. AEP argues that the Commission's decision is contrary to its findings that the FPA and court precedent[830] require all rates to ''reflect to some degree the costs actually caused by the customer who must pay them,'' and ''[t]o 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.''[831] AEP argues that this cost causation principle applies to all identifiable beneficiaries, not only those who voluntarily agree to pay the costs associated with the facilities. AEP further argues that the Commission's policy results in unjust and unreasonable rates that discriminate against a set of customers.

699. Joint Petitioners further argue that it is arbitrary to follow the beneficiary pays principle within a region, but not across regions, when the Commission has declined to define what these regions should be and when they may have little or no electrical significance. AEP makes a similar argument. Energy Future Coalition Group and AEP also argue that there will be a perverse incentive to create regional boundaries for the purpose of evading cost responsibility for nearby transmission facilities. AEP adds that the choice between a regional and an interregional project configuration would make an enormous difference with respect to cost allocation, but that there may be very little difference in the distribution of benefits or the physical design of the project.

700. Energy Future Coalition Group notes that the Commission held that within a given region, costs of a new project built wholly within the service territory of one transmission provider can be allocated to beneficiaries throughout the region if there is a clear regional benefit. It argues that this is directly analogous to the potential for extraregional benefits from a regional transmission project and asserts that the Commission unaccountably reaches the opposite conclusion as to the possibility of broader interregional cost allocation for a regional project with broader benefits.

701. Energy Future Coalition Group argues that the Commission can ensure that the attenuated assessments of benefits are avoided by providing that interregional planning and cost allocation are required for a project located wholly within one region only when: (1) The extraregional benefits are directly related to the proposed transmission project, not to assumed electricity market reactions or influences; (2) the identified extraregional benefits are enjoyed in an adjacent planning region; and (3) the extraregional benefits are similar in nature to the benefits for which costs are proposed to be allocated within the region where the facility is proposed.[832]

702. Joint Petitioners suggest that to limit the stakeholder burden of monitoring transmission planning in other regions, and in keeping with the evidence of the broad benefits of extra high voltage transmission, Regional Cost Allocation Principle 4 and Interregional Cost Allocation Principle 4 should be limited to transmission projects less than 345 kV. Joint Petitioners recommend that for projects at 345 kV and above, the Commission should expand its interregional coordination requirements to require that a regional planning entity notify its neighbors when it is considering such an extra high voltage project. Joint Petitioners state that the neighboring transmission planning region then could have an opportunity to participate in the planning process through which the project's beneficiaries will be determined or may conduct its own planning process to consider the project. They suggest similar opportunities should be provided in the regional planning process.

703. Similarly, AEP proposes that the Commission expand the scope of ''interregional transmission facilities'' to include new facilities located solely within a single region in certain circumstances, such as where the facilities are extra high voltage facilities that provide demonstrable benefits to the neighboring region.[833] AEP adds that identification of potential beneficiaries will be strictly limited to a region that adjoins the region in which the facility will be located, and would specifically exclude any region that does not have a direct interconnection with the region in which the new facility is located. AEP asserts that this approach addresses several of the Commission's concerns and does not place any undue burden on stakeholders.[834]

[827] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 657.

[828] *See, e.g.,* Joint Petitioners; Energy Future Coalition Group; and AEP.

[829] Energy Future Coalition Group at 9 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 582).

[830] AEP at 7 (citing *Illinois Commerce Commission* v. *FERC,* 576 F.3d 470 (7th Cir. 2009); *K N Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992); *Midwest ISO Transmission Owners* v. *FERC,* 373 F.3d 1361, 1369 (D.C. Cir. 2004); *Sithe/Independent Power Partners, L.P.* v. *FERC,* 285 F.3d 1, 5 (D.C. Cir. 2002)).

[831] AEP at 8 (quoting *Illinois Commerce Commission* v. *FERC,* 576 F.3d at 476).

[832] Energy Future Coalition Group at 11.

[833] AEP at 14.

[834] AEP adds that the Commission should find that the transmission planning provisions of the

704. MISO argues that Cost Allocation Principle 4 should not preclude an RTO from allocating to a withdrawing RTO member the cost of eligible transmission upgrades located solely in the RTO and approved before the withdrawal. It states that in recently accepting MISO's tariff provisions regarding multi-value projects, the Commission specifically found just and reasonable tariff provisions that authorize allocating to a withdrawing transmission owner the cost of a multi-value project approved before the withdrawal, although the associated facility will be located only in a MISO state.

705. Vermont Agencies note that while Order No. 1000 states that it will not authorize the allocation of costs of facilities located in one region to entities located in another region, because Order No. 1000 does not define ''region'' it could be read to claim authority to force market participants into a region where they will be subject to cost allocation plans agreed upon by the participants in that region.[835]

706. Finally, North Carolina Agencies state that while the Commission approves Principle 4, the Commission also states that if there are benefits of a new transmission project to a public or non-public utility within a region that has no transmission arrangement with the entity building the project, costs can still be allocated to that utility if it is found to benefit from the project. According to North Carolina Agencies, the Commission has committed error by not recognizing this apparent contradiction in the foregoing statements, as well as by stating that the costs of new transmission projects may be allocated involuntarily to those that lack any sort of connection to the transmission project in question.

c. Commission Determination

707. We affirm Regional and Interregional Cost Allocation Principle 4. Accordingly, we deny the arguments of those petitioners that ask us to expand the scope of Cost Allocation Principle 4 to permit a transmission planning region where a new transmission facility is located to allocate costs of the facility unilaterally to a neighboring region that benefits from it. Such arguments fail to take into account the relationship between the Commission's cost allocation reforms and the other reforms contained in Order No. 1000 and the need to balance a number of factors to ensure that the reforms achieve the goal of improved planning and cost allocation for transmission in interstate commerce.

708. In Order No. 1000, the Commission acknowledged that its approach may lead to some beneficiaries of transmission facilities escaping cost responsibility because they are not located in the same transmission planning region as the transmission facility. Nonetheless, the Commission found this approach to be appropriate since Order No. 1000 establishes a closer link between regional transmission planning and regional cost allocation, both of which involve the identification of beneficiaries. In light of that closer link, the Commission found that allowing one region to allocate costs unilaterally to entities in another region would impose too heavy a burden on stakeholders to actively monitor transmission planning processes in numerous other regions, from which they could be identified as beneficiaries and be subject to cost allocation. The Commission noted that if it expected such participation, the resulting regional transmission planning processes could amount to interconnectionwide transmission planning with corresponding cost allocation, albeit conducted in a highly inefficient manner. The Commission further explained that it is not requiring either interconnectionwide transmission planning or interconnectionwide cost allocation.[836]

709. Moreover, the discussion above highlights the importance that the ability to participate in the transmission planning and cost allocation process has for the Commission's transmission planning reforms. While the Commission concluded in Order No. 1000 that cost allocation is not dependent on a preexisting contractual relationship, we also think it is important that any entities that will be responsible for costs have an opportunity to participate in the process through which they will be allocated costs. This follows directly from the requirement of Order No. 890 that transmission planning be open and transparent. It also promotes a close link between transmission planning and cost allocation and helps to ensure fairness, which ultimately promotes successful transmission planning. Entities outside of a region may not be capable of being full participants in each and every region's transmission planning process in which they could potentially be allocated transmission costs. Unilateral allocation of costs to them thus could undermine rather than promote the linking of cost allocation and transmission planning.

710. Energy Future Coalition Group, Joint Petitioners, and AEP state that failing to revisit Cost Allocation Principle 4 does not address the Commission's concerns about free riders. North Carolina Agencies argue that the Commission's adoption of Cost Allocation Principle 4 contradicts the Commission's finding that costs can still be allocated to any entity that benefits from a new transmission facility without a transmission arrangement. As noted above, the Commission acknowledged in Order No. 1000 that its decision ''may lead to some beneficiaries of transmission facilities escaping cost responsibility because they are not located in the same transmission planning region as the transmission facility.''[837] However, the Commission's cost allocation reforms represent a significant advance over current practices, and it is important to balance the possibility that some beneficiaries could escape cost responsibility against the larger goal of linking cost allocation with the transmission planning process for the purpose of improving that process. Additionally, as noted in our discussion of the need for the Commission's reforms, transmission planning is more likely to succeed if it is understood in advance how the costs of planned facilities will be allocated. While a preexisting contract is not necessary to establish a cost allocation, we believe that an ability to participate in the process in which costs are allocated is important as it promotes the improved transmission planning that Order No. 1000 seeks to achieve. The Commission acknowledged in Order No. 1000 that some beneficiaries could escape cost responsibility as a result of the decision not to allow costs to be allocated outside the region in which a transmission facility is located, but the implementation of any policy often requires one to balance a number of considerations, which we believe Cost Allocation Principle 4 does appropriately.

711. For these same reasons, we decline to adopt the suggestions made by those petitioners that attempt to address the burden on stakeholders to participate in several transmission planning regions, by for example, limiting extraregional cost allocation to higher voltage facilities or by requiring that costs be allocated only to regions adjacent to the one in which a transmission facility is located. While

joint operating agreement between PJM and MISO meet the requirements of the Final Rule for interregional transmission coordination without the need to justify the process in a compliance filing.

[835] Vermont Agencies at 9.

[836] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 660.

[837] *Id.*

we agree that these suggestions might mitigate the burden on some stakeholders, we nevertheless are not convinced that they are sufficient to ensure that the Commission is not through this rulemaking proceeding effectively requiring interconnectionwide transmission planning. In any event, nothing in Order No. 1000 would prohibit regions from voluntarily agreeing to bear the costs for transmission facilities located in neighboring regions and from which they receive a benefit. Doing so is not inconsistent with Cost Allocation Principle 4.[838]

712. We further disagree with petitioners that this determination will result in arbitrary drawing of regional boundaries to avoid cost allocation. In Order No. 890, the Commission determined that ''the scope of a transmission planning region should be governed by the integrated nature of the regional power grid and the particular reliability and resource issues affecting individual regions.'' [839] Consistent with that guidance, regions already have defined themselves for purposes of transmission planning. The Commission appreciates that these regional boundaries may change in response to Order No. 1000, but any such changes will be subject to Commission review on compliance to ensure that they continue to be appropriate. In response to Vermont Agencies' concerns about entities being forced into regions against their will, we note that in Order No. 1000, the Commission found that a transmission planning region ''is one in which public utility transmission providers, in consultation with stakeholders and affected states, *have agreed to participate* in for purposes of regional transmission planning and development of a single regional transmission plan.'' [840]

713. We agree with AEP that there can be cases where a project can have similar transmission flow impacts whether it is configured regionally or interregionally. However, we conclude that the regional and interregional transmission planning and coordination requirements of Order No. 1000 provide sufficient opportunities for analyzing the potential benefits of new transmission facilities, whether regional or interregional in configuration.

714. In response to MISO, we clarify that Cost Allocation Principle 4 does not preclude an RTO from allocating to a withdrawing RTO member the cost of eligible transmission upgrades located solely in the RTO and approved before the withdrawal pursuant to a Commission-approved RTO agreement.

6. Whether To Establish Other Cost Allocation Principles

a. Final Rule

715. In Order No. 1000, the Commission stated that it did not believe that any additional cost allocation principles were necessary at that time.[841]

b. Requests for Rehearing

716. ELCON, AF&PA, and the Associated Industrial Groups argue that Order No. 1000 should address whether the costs of new transmission occasioned by low capacity factor resources should be allocated on a capacity basis. They assert that the Commission devoted no substantive consideration to this issue, and deferred it to the regional transmission planning processes. ELCON, AF&PA, and the Associated Industrial Groups assert that FERC provided no explanation for why this issue is better addressed by regional planning agencies. For example, they argue that allocating the fixed costs of transmission facilities intended to transmit wind energy to load centers on a volumetric basis inappropriately subsidies wind energy, which is inconsistent with resource neutrality and economically efficient resource allocation. Moreover, ELCON, AF&PA, and the Associated Industrial Groups argue that allocating these costs on any basis other than a capacity basis would unfairly penalize and significantly increase costs for those customers that have invested in operational changes to minimize consumption during system peak periods.

c. Commission Determination

717. We disagree with ELCON, AF&PA, and the Associated Industrial Groups' assertion that the Commission dismissed their proposal for new principles that would address cost allocation on a capacity basis without explanation. In Order No. 1000, the Commission declined to adopt additional principles proposed by commenters because the Commission believed that to do so would limit the flexibility provided to public utility transmission providers in proposing the appropriate cost allocation method or methods for their transmission planning region or pair of transmission planning regions.[842] We continue to believe this to be the case, and we therefore affirm the Commission's decision on this issue.

E. Application of Cost Allocation Principles

1. Participant Funding

a. Final Rule

718. In Order No. 1000, the Commission found that participant funding is permitted, but not as a regional or interregional cost allocation method.[843] The Commission explained that if proposed as a regional or interregional cost allocation method, participant funding would not comply with the regional or interregional cost allocation principles adopted in Order No. 1000.[844] The Commission explained, however, that these principles do not in any way foreclose the opportunity for a transmission developer, a group of transmission developers, or one or more individual transmission customers to voluntarily assume the costs of a new transmission facility.[845]

b. Requests for Rehearing or Clarification

719. Several petitioners request rehearing or clarification of the Commission's finding that participant funding cannot be the regional or interregional cost allocation method.[846] Ad Hoc Coalition of Southeastern Utilities states that, as a matter of policy, new long-line transmission facilities that span utility service areas must be supported by ascertainable demand, and that the most economically sound way to determine what facilities should be built, and at what price, is for those entities that will use the facilities to pay for them. ELCON, AF&PA, and the Associated Industrial Groups argue that prohibiting participant funding as a regional or interregional cost allocation method creates a new free rider problem. According to them, participants who, from an economic perspective, should be funding transmission, and could do so most expeditiously, will now have an incentive not to do so, because the cost will be allocated to other more peripheral beneficiaries as part of the regional transmission planning process.

720. ELCON, AF&PA, and the Associated Industrial Groups argue that the Commission's explanation of why participant funding should be

[838] *Id.* PP 658–59.

[839] *Id.* P 160 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 527).

[840] *Id.* P 160 (emphasis added).

[841] *Id.* P 705.

[842] *Id.*

[843] *Id.* P 723.

[844] *Id.*

[845] *Id.* P 724.

[846] *See, e.g.,* Illinois Commerce Commission; ELCON, AF&PA, and the Associated Industrial Groups; Arizona Cooperative; Ad Hoc Coalition of Southeastern Utilities; and Southern Companies.

prohibited is both arbitrary and inconsistent when compared to determinations made by the Commission in Order No. 1000 concerning other cost allocation approaches. For instance, they state that the Commission was willing to leave the decision of whether postage stamp rate allocation is an appropriate cost allocation method to regional planning entities. ELCON, AF&PA, and the Associated Industrial Groups argue that Order No. 1000 subjects the two different cost allocation methods to widely divergent standards of scrutiny with no explanation as to why such differential treatment would be appropriate. They also seek clarification that Order No. 1000 allows participant funding to be used as the default for certain types of projects on a category basis where participant funding best matches cost causation principles.

721. Arizona Cooperatives and Southwest Transmission are concerned that Order No. 1000 does not recognize the benefits of participant funding. For instance, Arizona Cooperatives and Southwest Transmission state that under participant funding, the cost of associated transmission is bundled with generation. If the bundled price is excessive, then the project does not attract customers and an unworthy investment is avoided.

722. Southern Companies argue that the Commission's treatment of participant funding in Order No. 1000 is overly vague and unexplained. They state that the Commission should refine its guidance on rehearing to define ''participant funding'' more narrowly and in terms of the issue that Order No. 1000 seeks to address, rather than categorically excluding it. Southern Companies state the Commission should clarify that participant funding is only impermissible as a cost allocation method if there are identified beneficiaries and those beneficiaries would receive non-trivial, direct benefits and would be expected to participate in the facilities as a transmission customer or co-owner but for others valuing the new transmission facility more and agreeing to go ahead and support the project financially.

723. Southern Companies repeats arguments made above that the Supreme Court held the FPA is premised on the concept of voluntary sale and purchase of jurisdictional services and the courts have uniformly applied cost causation principles only in the setting of relationships where privity exists. Therefore, it asserts that participant funding may well be the only cost allocation method or rate structure that is lawful for new regional and/or interregional transmission projects as envisioned by Order No. 1000. Southern Companies assert that without a privity relationship between the developer of a project and those expected to fund the project, there is no lawful basis upon which to impose a rate, and no assurance that any rate would be in connection with the provision of a jurisdictional service. Large Public Power Council and Ad Hoc Coalition of Southeastern Utilities also state that the Commission's rejection of participant funding confounds a basic precept of the FPA that a utility's ability to recover its costs rests on a contractual relationship with its customers.

724. Southern Companies assert participant funding is consistent with cost causation and represents a proven-way of getting the costs of such regional and/or interregional transmission facilities allocated, paid and constructed on a timely basis.[847] Southern Companies add that given the Commission's objective to foster more development, categorical *ex ante* exclusion of a cost allocation method that has a proven track record of success does not reflect reasoned decision making. Large Public Power Council also believes that the only economically sound way to determine what facilities should be built, and at what price, is to have those entities that will use the facilities pay for them.

725. On the other hand, Transmission Dependent Utility Systems commend the Commission's ruling that participant funding cannot be used as a regional or interregional cost allocation method. Transmission Dependent Utility Systems also request that the Commission reaffirm its long-held policy prohibiting ''and'' pricing.[848] Transmission Dependent Utility Systems assert the Commission should confirm that any limited use of participant funding in the future will be bound by the Commission's same long-standing precedent.[849]

c. Commission Determination

726. We affirm Order No. 1000's determination that participant funding is permitted, but not as a regional or interregional cost allocation method.[850] We therefore continue to believe that if proposed as a regional or interregional cost allocation method, participant funding will not comply with the regional or interregional cost allocation principles adopted above. We remain concerned that reliance on participant funding as a regional or interregional cost allocation method increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development. Because of this, it is likely that some transmission facilities identified in the regional transmission planning process as more efficient or cost-effective solutions would not be constructed in a timely manner or would not be constructed at all, adversely affecting ratepayers. Moreover, reliance on participant funding as a regional or interregional cost allocation method leaves a transmission developer with no opportunity to allocate costs to beneficiaries identified in the regional transmission planning process, even if the developer's transmission facility is identified as a more efficient or cost-effective solution and is selected in the regional transmission plan for purposes of cost allocation. In light of this prospect, a transmission developer may decline to propose such a transmission facility in the regional transmission planning process.

727. The Commission rejected participant funding as a regional or interregional cost allocation method because it does not comply with the regional or interregional cost allocation principles set forth in Order No. 1000. This is because participant funding by its nature does not assess transmission project benefits in regional or interregional terms. For this reason, it does not ensure that the allocation of costs will be roughly commensurate with benefits, since its focus is limited to transmission project participants rather than the regional or interregional impact of a transmission project. Many petitioners describe what they consider to be advantages of participant funding, but these descriptions and the arguments based on them do not show how participant funding satisfies the

[847] Southern Companies at 109 (citing Bryan K. Hill September 28, 2010 Affidavit at 31–32).

[848] Transmission Dependent Utility Systems at 31 (citing *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 694 n.111 (2003), *order on reh'g,* Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160 (2004), *order on reh'g,* Order No. 2003–B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub. nom. Nat'l Ass'n of Regulatory Utils. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007)).

[849] Transmission Dependent Utility Systems at 31 (citing *Inquiry Concerning the Comm'n's Transmission Pricing Policy for Transmission Services Provided by Pub. Utils. Under the Fed. Power Act,* 55 Fed. Reg. 55,031, FERC Stats. & Regs. ¶ 31,005, at 31,142–43 (1994), *clarified,* 71 FERC ¶ 61,195 (1995); *Am. Elec. Power Co.,* 67 FERC ¶ 61,168 (1994)); *see also Pennsylvania Elec. Co.* v. *FERC,* 11 F.3d 207 (D.C. Cir. 1993).

[850] *See* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 723–29.

specific requirements or policy goals of Order No. 1000.

728. However, as Order No. 1000 made clear, we are not finding that participant funding leads to improper results in all cases. For example, a transmission developer may propose a project to be selected in the regional transmission plan for purposes of regional cost allocation but fail to satisfy the transmission planning region's criteria for a transmission project selected in the regional transmission plan for purposes of cost allocation. Under such circumstances, the developer could either withdraw its transmission project or proceed to ''participant fund'' the transmission project on its own or jointly with others. In addition, it is possible that the developer of a facility selected in the regional transmission plan for purposes of cost allocation might decline to pursue regional cost allocation and, instead, rely on participant funding. Moreover, nothing in Order No. 1000 forecloses the opportunity for a transmission developer, a group of transmission developers, or one or more individual transmission customers to voluntarily assume the costs of a new transmission facility. Accordingly, Order No. 1000 does not prohibit or, as Southern Companies assert, ''categorically'' exclude the use of participant funding.

729. The Commission nowhere intended to suggest that participant funding has no place in the development of transmission infrastructure. As noted by Southern Companies, participant funding can result in timely construction of transmission facilities in many circumstances. Transmission developers who see particular advantages in participant funding remain free to use it on their own or jointly with others. This simply means that they would not be pursuing regional or interregional cost allocation. ELCON, AF&PA, and the Associated Industrial Groups do not explain what they mean by the use of participant funding ''as the default for certain types of projects,'' [851] and we are not persuaded that the type of transmission project involved affects the ability of participant funding to satisfy the cost allocation principles of Order No. 1000.

730. The Commission did not state in Order No. 1000 that entities who support participant funding must show that it is uniquely the cost allocation method that follows ''but for'' cost causation principles, as ELCON, AF&PA, and the Associated Industrial Groups contend. The Commission simply stated that entities who had argued that it was such a method had not demonstrated that this was the case and that, moreover, the contention was at odds with existing precedent on cost causation.[852]

731. Southern Companies maintain that participant funding means different things to different people and that the Commission should define it more narrowly for purposes of Order No. 1000. However, Southern Companies do not describe the different meanings of participant funding that they have in mind, and we therefore do not know what further refinements it believes would be in order.[853] The Commission stated in Order No. 1000 that ''[u]nder a participant funding approach to cost allocation, the costs of a transmission facility are allocated only to those entities that volunteer to bear those costs.'' [854] In addition, the Commission noted in Order No. 1000 that the Proposed Rule cited to a number of concrete examples of the participant funding approach.[855] We think that this provides sufficient guidance on the meaning of participant funding for purposes of Order No. 1000.

732. We disagree that precluding participant funding as a regional and interregional cost allocation method creates a new free rider problem by creating an incentive for what ELCON, AF&PA, and the Associated Industrial Groups describe as entities who should be funding a transmission project not to fund it in the hope of an allocation to additional beneficiaries. The primary goal of Order No. 1000's cost allocation principles is to ensure that costs of regional transmission facilities selected in a regional transmission plan for purposes of cost allocation are allocated to beneficiaries in the region roughly commensurate with the benefits that they receive. It is unlikely that entities which benefit from such transmission facilities would decline to fund them. Moreover, we disagree with the argument that preclusion of participant funding as a regional or interregional cost allocation method creates an incentive not to develop a transmission project. On the contrary, a transmission developer will have the option of using participant funding or submitting its transmission project for evaluation in the regional transmission planning process to be selected for regional or interregional cost allocation. If its transmission project is selected in the regional transmission plan for purposes of cost allocation, the transmission developer would be able to allocate costs to beneficiaries consistent with the relevant cost allocation method, an opportunity that not only encourages development but also promotes development of more efficient or cost-effective transmission solution to regional and interregional transmission needs.

733. We think that this point helps illuminate why participant funding does not constitute an appropriate regional or interregional cost allocation method. Entities that might develop a transmission project through participant funding remain free to do so. However, exclusive reliance on such an approach creates an incentive not to consider potential regional or interregional transmission needs. It thus is not a method that is tailored to promote better regional and interregional transmission planning.

734. We deny Southern Companies' request for clarification on the situations in which participant funding should be impermissible. Southern Companies asserts that participant funding should only be impermissible if there are identified beneficiaries and those beneficiaries would receive non-trivial, direct benefits and would be expected to participate in the facilities as a transmission customer or co-owner but for others valuing the new transmission facility more and agreeing to go ahead and support the project financially. The

[851] ELCON, AF&PA, and the Associated Industrial Groups at 16.

[852] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 726.

[853] Southern Companies only state that the Commission's ''categorical exclusion'' of participant funding had created a need to state specifically in Order No. 1000 (in response to Entergy) that prohibition of participant funding as a regional cost allocation mechanism ''is not intended to modify existing pro forma OATT transmission service mechanisms for individual transmission service requests or requests for interconnection service.'' Southern Companies at 106 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 729). Southern Companies state that specifying this was important because long-term firm transmission service is a form of participant funding that addresses free rider issues, and this demonstrates the need for greater clarity on what the Commission is prohibiting. *Id.* However, Order No. 1000 does not create a ''categorical exclusion'' of participant funding, only an exclusion of the use of participant funding as a regional cost allocation method. We therefore do not see how the continued use of existing mechanisms for individual transmission service requests affects our conclusions on the use of participant funding for new transmission facilities selected in a regional transmission plan for purposes of cost allocation. As a result, we do not see the need for further refinements in the meaning of participant funding for purposes of Order No. 1000. We think that the two very different contexts at issue in Southern Companies' argument—firm transmission service requests and regional transmission planning—make such analogies inappropriate.

[854] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 486 n.375 (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 128).

[855] *Id. See* Proposed Rule, FERC Stats. & Regs. ¶ 32,660 at P 128.

focus of the cost allocation reforms of Order No. 1000 is on transmission projects that are selected in the regional transmission plan for purposes of cost allocation, not the circumstances under which voluntary use of participant funding is appropriate.

735. We disagree with ELCON, AF&PA, and the Associated Industrial Groups who see inconsistency in the Commission's willingness to allow consideration of postage stamp rates as a cost allocation method, but not participant funding. As we noted above, Order No. 1000 found that a postage stamp cost allocation method may be appropriate where all customers within a specified transmission planning region are found to benefit from the use or availability of a transmission facility or class or group of transmission facilities, especially if the distribution of benefits associated with a class or group of transmission facilities is likely to vary considerably over the long depreciation life of the transmission facilities amid changing power flows, fuel prices, population patterns, and local economic considerations.[856] Accordingly, unlike participant funding, if such a showing can be made, a postage stamp cost allocation would meet Cost Allocation Principle 1's requirement that costs be allocated roughly commensurate with benefits. Participant funding, on the other hand, is incapable of meeting the regional or interregional cost allocation principles set forth in Order No. 1000, because by its nature it is not a cost allocation method that accounts for potential regional or interregional benefits.

736. We clarify, in response to Transmission Dependent Utility System's request, that Order No. 1000 did not address or change the Commission's policy on ''and'' pricing.[857] Order No. 1000 applies only to transmission projects that are selected in the regional transmission planning process for purposes of cost allocation. Participant funding cannot be the regional or interregional cost allocation method under Order No. 1000. Therefore, if a project's costs are allocated under a participant funding method, by definition, it was not selected in the regional transmission planning process for purposes of cost allocation.[858]

737. Lastly, a number of petitioners argue that participant funding is the form of cost allocation that corresponds to what they assert is a requirement that cost allocation be premised on a contractual relationship. As we explained above,[859] we reject the interpretation of the FPA that petitioners have offered, specifically that the FPA requires a contractual relationship before rates can be assessed. Contracts do not define or limit the benefits that a transmission customer receives from the entire transmission grid, which the courts have recognized in finding that the customer relationship is to the transmission grid as a whole, rather than the dictates of contracts.[860] Therefore, petitioners' arguments that the Commission's finding that participant funding cannot be the regional or interregional cost allocation method are unfounded.

F. Other Cost Allocation Issues

1. Final Rule

738. In Order No. 1000, the Commission reiterated the approach it took in Order No. 890, requiring that generation, demand resources, and transmission be treated comparably in the regional transmission planning process.[861] Also, the Commission stated that while the consideration of non-transmission alternatives to transmission facilities may affect whether certain transmission facilities are in a regional transmission plan, the Commission concluded that the issue of cost recovery for non-transmission alternatives was beyond the scope of the cost allocation reforms adopted in Order No. 1000, which are limited to allocating the costs of new transmission facilities.[862]

2. Requests for Rehearing or Clarification

739. California State Water Project argues that on rehearing the Commission should require all public utilities to exempt sponsors of demand-based transmission alternatives from Order No. 1000's benefits-based cost allocation, as well as apply time-sensitive cost allocation. Specifically, it argues that customers investing in demand-based non-transmission alternatives and sponsors of demand-based transmission alternatives should not be subject to benefits-based cost allocation that in effect imposes discriminatory double billing for both the transmission alternative provided and for unused transmission automatically deemed to provide benefits. Moreover, it adds that the Commission has stated that customers' ability to modify their behavior in response to price signals benefits the entire grid and is among the best means of holding down costs and countering market power.[863]

740. California State Water Project also argues that the rule unduly discriminates against demand-based non-transmission alternatives as it stressed the need for clear cost allocation to promote transmission construction, yet declined to consider compensation and cost allocation for demand-based non-transmission alternatives. California State Water Project states that in the Energy Policy Act of 2005 Congress declared that the national policy of the United States is to promote demand response and to eliminate unnecessary barriers to demand response.[864] It also states that the Commission followed up on this policy in Order No. 719, stating that ''[a]ny reforms must ensure that demand response resources are treated on a basis comparable to other resources.''[865] California State Water Project adds that under the FPA the Commission also must not permit undue discrimination against such resources. It notes that the Commission has applied this principle to avert undue discrimination against various kinds of resources, such as the measures to remedy undue discrimination against non-incumbent transmission developers in Order No. 1000.[866]

741. California State Water Project recommends that the Commission

[856] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 605.

[857] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g,* Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[858] The Commission made clear in Order No. 1000 that transmission facilities that are selected in the regional transmission plan for purposes of cost allocation may not comprise all of the transmission facilities in the regional transmission plan, and therefore, participant funded facilities may be included in the regional transmission plan for other purposes. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 63.

[859] *See* discussion *supra* at section 0.

[860] *See* discussion *supra* at section 0.

[861] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 779.

[862] The Commission also recognized that, in appropriate circumstances, alternative technologies may be eligible for treatment as transmission for ratemaking purposes. Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 779 & n.563.

[863] California State Water Project at 18 (quoting Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 41).

[864] California State Water Project at 9–10 (citing Energy Policy Act of 2005, Pub. L. 109–58, § 1252(f), 119 Stat. 594 (2005)).

[865] California State Water Project at 10 (quoting Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 14).

[866] California State Water Project at 11 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,669; Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 229).

incorporate benchmarks or metrics to support periodic evaluation of its success or failure in achieving nondiscriminatory promotion of both physical transmission upgrades and non-transmission alternatives. It argues that incorporating such benchmarks will ensure that the Commission and all concerned undertake appropriate improvements on a timely basis.

742. Transmission Dependent Utility Systems point out that in their comments during the Order No. 1000 proceeding, they requested that the Commission align local, regional and interregional planning and cost allocation processes and methods with formula rate protocols because those who pay the costs of needed new transmission infrastructure should not learn about projects for the first time in formula rate updates. In particular, Transmission Dependent Utility Systems argue that to the extent project upgrade costs are not discussed in the planning processes with stakeholders, a separate FPA section 205 filing must be made for recovery of these costs. It argues that most public utility transmission providers have incentive rates and that the formula rate annual update process provides only limited opportunity to review and challenge costs included in the formula rate update filing. Transmission Dependent Utility Systems argue that their requested link between formula rate cost recovery and the local and regional planning and interregional coordination processes is within the scope of issues raised in this proceeding because it is a safeguard needed to ensure that load-serving customers, which pay for the costs of transmission upgrades, have a meaningful role in the development of regional and interregional projects and the allocation of the costs of those projects. Transmission Dependent Utility Systems further assert that Order No. 1000 failed to address this issue in a manner that comports with reasoned decision-making.[867]

743. Dayton Power and Light requests clarification that the Commission will issue a separate order on remand from the Seventh Circuit on Opinion No. 494[868] in the near future that will specify a cost allocation mechanism for new high voltage facilities that complies with the Order No. 1000 principles.[869] Dayton Power and Light states that failing to issue an order on remand would lead to renewed litigation a year from now to address the same issues using substantially the same evidence that is already before the Commission for decision and waste the resources of PJM members, PJM, and the Commission and its staff.

744. Dayton Power and Light urges the Commission to state explicitly that the use of the Distribution Factor analysis complies with the Order No. 1000 cost allocation principles. In support, Dayton Power and Light states that PJM has used distribution factor analysis to allocate the costs of new PJM facilities operating at less than 500 kV without question or challenge.

3. Commission Determination

745. We deny California State Water Project's arguments and affirm Order No. 1000's determination that cost allocation for non-transmission alternatives is beyond the scope of this proceeding, which is limited to allocating the costs of new transmission facilities. In response to California State Water Project's suggestions regarding time-sensitive rates and the establishment of benchmarks, we affirm Order No. 1000, and therefore, will not establish minimum requirements governing which non-transmission alternatives should be considered or the appropriate metrics to measure non-transmission alternatives against transmission alternatives. We continue to believe that those considerations are best managed among the stakeholders and the public utility transmission providers participating in the regional transmission planning process.[870]

746. We deny Transmission Dependent Utility Systems' request that we address a link between formula rates and cost allocation as beyond the scope of this proceeding. As we note above, and as we found in Order No. 1000, we are not addressing cost recovery issues here.[871] In any event, we disagree with Transmission Dependent Utility Systems' premise that those who pay for project upgrade costs that are selected in a regional transmission plan for purposes of cost allocation under the provisions of Order No. 1000 may learn about these costs for the first time when flowed through a formula rate, when there would be only a limited opportunity to review the costs.[872] As is clear in Order No. 1000, any entity can participate in the regional transmission planning process and costs will be allocated only for those regional and interregional transmission facilities that have been selected in the regional transmission plan for purposes of cost allocation.[873] Therefore, Transmission Dependent Utility Systems will have a meaningful opportunity to participate in the development of regional and interregional transmission projects and the allocation of the costs of those transmission projects, whether or not these are incorporated into formula rates, through their ability to participate in the regional transmission planning process. Additionally, as noted above, in identifying the benefits and beneficiaries for a new transmission facility, the regional transmission planning process must provide entities who will receive regional or interregional cost allocation an understanding of the identified benefits on which the cost allocation is based, all of which would occur prior to the recovery of such costs through a formula rate.

747. In response to Dayton Power and Light's request that the Commission find that the use of the distribution factor analysis complies with Order No. 1000 cost allocation principles, we reiterate what the Commission said in Order No. 1000 in response to commenters making similar arguments. We decline to prejudge whether any existing cost allocation method complies with the requirements of Order No. 1000. To the extent that Dayton Power and Light believes that to be the case in its transmission planning region, it can take such a position during the development of compliance proposals and during Commission review of compliance filings.[874] Last, with respect to the timing concerns Dayton Power and Light describes regarding the relationship between our order on remand from the U.S. Court of Appeals for the Seventh Circuit on Opinion No. 494 and the development of an Order No. 1000-compliant cost allocation method in PJM, the Commission has since issued an order in the Opinion No. 494 proceeding.[875]

V. Compliance and Reciprocity

A. Compliance

1. Final Rule

748. The Commission required that each public utility transmission provider must submit a compliance filing within twelve months of the

[867] Transmission Dependent Utility Systems at 31 (citing *K N Energy Inc.* v. *FERC,* 968 F.2d 1295, 1303)).

[868] *PJM Interconnection, L.L.C.,* 130 FERC ¶ 61,052 (2010).

[869] Dayton Power and Light at 2, 4 (citing *Illinois Commerce Commission* v. *FERC,* 576 F.3d 470).

[870] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 155.

[871] *Id.* P 563.

[872] In any event, we note that when ratepayers learn of other formula costs is outside the scope of this proceeding.

[873] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 503.

[874] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 565.

[875] *PJM Interconnection, L.L.C.,* 138 FERC ¶ 61,230 (2012).

effective date of Order No. 1000 revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the local and regional transmission planning and cost allocation requirements set forth in Order No. 1000. The Commission also required each public utility transmission provider to submit a compliance filing within eighteen months of the effective date of Order No. 1000 revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements set forth therein with respect to interregional transmission coordination procedures and an interregional cost allocation method or methods.[876]

2. Requests for Rehearing or Clarification

749. Duke requests that the Commission rule on requests for clarification as soon as possible before issuance of an Order No. 1000 rehearing order so that stakeholders' compliance efforts are not interrupted or entirely disrupted. MISO requests that the Commission clarify that RTOs and ISOs are not required to make any changes to their tariffs or processes in connection with the participation of non-jurisdictional entities in regional or interregional planning and cost allocation processes. According to MISO, requiring the development of a regional plan and cost allocation process with an entity that has no such corresponding mandate is unreasonable, and it may not be possible to comply with such a requirement because compliance would depend entirely on the desire of such non-jurisdictional entities to coordinate. MISO states that at most, the Commission should require that Commission-jurisdictional entities engage in a good faith effort at regional coordination, planning, and cost allocation with non-jurisdictional entities.

750. NextEra seeks clarification that generator tie line owners that have OATTs on file can seek waiver of compliance with Order No. 1000 requirements, as the Commission has previously found that such lines are not integrated with the regional transmission grid for ratemaking purposes. It suggests that there may be confusion as to whether such tie line owners can seek waiver because of use of the word ''and'' rather than ''or'' when Order No. 1000 states that entities must seek waivers of Order Nos. 888, 889, *and* 890. NextEra contends that if the Commission intended to mean ''or,'' then the vast majority of tie line owners would not be subject to Order No. 1000.[877] It also urges the Commission to adopt a broad-based waiver that focuses on the nature of a radial line, which it argues would be consistent with the intent of the transmission planning process. NextEra argues that the fact that such tie lines are not integrated in the transmission grid should not be ignored. It states that the nature of a radial line does not change simply because one tie line owner may provide interconnection and transmission service to affiliates and have waivers from Order Nos. 888, 889, and 890 while another may provide the same service under an OATT to non-affiliates. NextEra states further that no generation tie lines should be required to participate in the regional transmission planning process unless they voluntarily choose to do so.[878]

3. Commission Determination

751. In response to Duke, we believe that addressing the requests for clarification of Order No. 1000 in this order is appropriate. Many of the requests for clarification are linked with requests for rehearing and are thus best addressed in the same order. Moreover, the Commission considered the need for providing timely clarifications in issuing this order now, and we believe that its issuance now allows stakeholders adequate time to address these clarifications in their compliance processes.

752. We clarify for MISO that a public utility transmission provider will not be deemed out of compliance with Order No. 1000 if it demonstrates that it made a good faith effort, but was ultimately unable, to reach resolution with neighboring non-public utility transmission providers on a regional transmission planning process, interregional transmission coordination procedures, or a regional or interregional cost allocation method.

753. In response to NextEra, we clarify that Order No. 1000's determination that it ''applies to public utilities that own, control or operate interstate transmission facilities other than those that have received waiver of the obligation to comply with Order Nos. 888, 889, and 890''[879] was meant to provide assurance to those entities that have existing waivers of those three rules that they would not also have to seek waiver of Order No. 1000 in order to obtain waiver from it. This is consistent with the approach the Commission took to waivers in Order No. 890.[880] This determination, however, was not meant to affect the ability of an entity that does not have a waiver to seek one. The Commission will entertain requests for waiver of Order No. 1000 on a case-by-case basis from any entity, including a generation tie line owner, that believes it meets the criteria for such waiver, which the Commission made clear in Order No. 1000 remains unchanged from that used to evaluate requests for waiver under Order Nos. 888, 889, and 890.[881]

B. Reciprocity

1. Final Rule

754. In Order No. 1000, the Commission found that to maintain a safe harbor tariff, a non-public utility transmission provider must ensure that the provisions of that tariff substantially conform, or are superior, to the *pro forma* OATT as it has been revised by Order No. 1000.[882] The Commission stated that it was encouraged that, based on the efforts that followed Order No. 890, both public utility and non-public utility transmission providers collaborate in a number of regional transmission planning processes.[883] Therefore, the Commission did not believe it was necessary to invoke its authority under FPA section 211A, which gives it authority to require non-public utility transmission providers to provide transmission services on a comparable and not unduly discriminatory or preferential basis.[884] However, the Commission stated that if it finds on the appropriate record that non-public utility transmission providers are not participating in the transmission planning and cost allocation processes required by Order

[876] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 792.

[877] NextEra at 16.

[878] NextEra at 17 (citing *Southern Cal. Edison Co.,* 117 FERC ¶ 61,103 (2006); *Mansfield Mun. Elec. Dept.* v. *New England Power Co.,* 97 FERC ¶ 61,134 (2001)).

[879] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 832.

[880] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at n.105 (''The Commission clarifies that existing waivers of the obligation to file an OATT or otherwise offer open access transmission service in accordance with Order No. 888 shall remain in place. The reforms to the *pro forma* OATT adopted in this Final Rule therefore do not apply to transmission providers with such waivers, although we expect those transmission providers to participate in the regional planning processes in place in their regions, as discussed in more detail in section V.B. Whether an existing waiver of OATT requirements should be revoked will be considered on a case-by-case basis in light of the circumstances surrounding the particular transmission provider.''); *see also* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 36.

[881] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 832.

[882] *Id.* P 815.

[883] *Id.*

[884] *Id.*

No. 1000, the Commission may exercise its authority under FPA section 211A on a case-by-case basis.[885] The Commission also emphasized that it is not modifying the scope of the reciprocity provision as established in Order No. 890.[886] However, the Commission noted that it expects all public and non-public utility transmission providers in an existing regional transmission planning process comprised of both public and non-public utility transmission providers to participate in the transmission planning and cost allocation processes set forth in Order No. 1000. The Commission also noted that those non-public utility transmission providers that take advantage of open access under an OATT, including the OATT's new provisions for improved transmission planning and cost allocation, should be expected to follow the same requirements as public utility transmission providers.[887]

2. Requests for Rehearing or Clarification

755. Petitioners request rehearing of Order No. 1000's reciprocity requirement, arguing that the Commission is changing the scope of the principle of reciprocity under Order Nos. 888 and 890. For example, Large Public Power Council states that reciprocity as initially conceived in Order No. 888 was a matter of fundamental fairness. It states that this concept was clarified in Order No. 2004–A, where the Commission found that service provided by a non-public utility transmission provider did not have to be identical to the service provided by an investor-owned utility, only comparable to the service the non-public utility would receive for its own purposes. Large Public Power Council explains that Order No. 1000 appears to hold that a non-public utility's obligation to provide reciprocal service outside a safe harbor tariff includes an obligation to participate in the planning and cost allocation processes implemented pursuant to Order No. 1000. Large Public Power Council states that including these planning and cost allocation obligations within a non-public utility's reciprocity obligations would modify the scope of reciprocity, and thus requests that the Commission clarify whether this is its intention.

756. Likewise, National Rural Electric Coops state that it appears that the Commission misstated the reciprocity requirement in Order No. 1000 when it stated in paragraph 819 that ''the non-public utility transmission provider that owns, controls or operates transmission facilities *must* provide comparable transmission service that it is capable of providing on its own system.'' [888] They assert that under the Commission's existing reciprocity requirement, a non-public utility transmission provider is not obligated to provide such service, because a public utility transmission provider is not obligated to refuse to provide service if a non-public utility transmission provider does not reciprocate. Rather, they point out that there are three alternatives available to non-public utilities to meet the reciprocity requirement, including obtaining a waiver from, or entering into a bilateral agreement with, the public utility transmission provider from which the non-public utility seeks service, and that providing service under a safe harbor tariff is only one alternative. National Rural Electric Coops state that only a few non-public utilities have Commission-approved reciprocity tariffs and significant disputes could arise from the unintentional language in Order No. 1000. They state that clarification would help to minimize controversies over the scope of non-public utilities' obligations with respect to regional planning and cost allocation, and would be consistent with the Commission's statement that it is not proposing any changes to the reciprocity provision of the *pro forma* OATT or any other document.

757. Sacramento Municipal Utility District also states that by asserting that all non-public utilities must abide by Order No. 1000's transmission planning and cost allocation provisions if they take open access service, the Commission both: (1) Eviscerates the waiver option expressly contemplated under Order Nos. 888 and 890 and (2) creates an automatic trigger directly at variance with the principle that non-public utilities must reciprocate if asked to do so. Sacramento Municipal Utility District points out that Order Nos. 888 and 890 unambiguously require safe harbor candidates to adopt tariffs that match or exceed the terms of the pro forma OATT. It argues, however, that the Commission's interpretation in Order No. 1000 that non-public utilities without safe harbor tariffs that take service under open access tariffs also are automatically bound to follow the transmission planning and cost allocation provisions of Order No. 1000 improperly conflates the safe harbor tariff provisions found in Order Nos. 888 and 890 since markedly different reciprocity requirements apply when a non-public utility does not employ a safe harbor tariff.

758. Sacramento Municipal Utility District further argues that the Commission's longstanding policy has been that reciprocity under Order Nos. 888 and 890 only obligates the non-public utility to provide transmission service to individual public utility transmission providers requesting reciprocity as a condition of obtaining their transmission service if a non-public utility has not sought a ''safe-harbor'' tariff.[889] Sacramento Municipal Utility District argues that the actual provisions of Order Nos. 888 and 890 make clear that a reciprocity obligation is not automatic, is purely bilateral and applies only to the transmission provider that asks the non-public utility to reciprocate.[890] Thus, Sacramento Municipal Utility District states that the Commission's determination that the act of taking service from a public utility with a regional cost allocation plan in its open access tariff automatically triggers the non-public utility's reciprocity obligation under Order Nos. 888 and 890 constitutes an arbitrary and unexplained departure from the policies established in those orders.[891]

759. Bonneville Power further argues that the Commission is inappropriately attempting to regulate Bonneville Power and other non-public utility transmission providers under section 206 of the FPA. In support, Bonneville Power asserts that the Commission's action is more extreme than its attempt to impose refund liability on non-public utilities in, for example, *BPA* v. *FERC*.[892] Bonneville Power contends that in that case, the court held the Commission lacked refund authority over non-public utilities that participated in a power market established by a public utility. Bonneville Power argues that the Commission is similarly imposing cost responsibility on non-public utilities under section 206 absent statutory authority to do so. Bonneville Power contends that if the Commission denies

[885] *Id.*

[886] *Id.* P 816.

[887] *Id.* P 818.

[888] National Rural Electric Coops at 5–6 (quoting Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 819).

[889] Sacramento Municipal Utility District at 3.

[890] Sacramento Municipal Utility District at 18 (citing *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Serv. By Pub. Utils; Recovery of Stranded Costs by Pub. Utils. And Transmitting Utils.*, Order No. 888–A, FERC Stats. & Regs. ¶ 31,048, at P 30, 180–81(1997)).

[891] Sacramento Municipal Utility District at 3 (citing *FCC* v. *Fox Television Stations*, Inc., 129 S. Ct. 1800, 1811 (2009); *Greater Boston Television Corp.* v. *FCC*, 444 F.2d 841, 952 (D.C. Cir. 1970), *cert. denied*, 403 U.S. 923 (1971)).

[892] Bonneville Power at 17 (citing *BPA* v. *FERC*, 422 F.3d 908, 921 (9th Cir. 2005)).

clarification that the regional planning process determination would not be binding on Bonneville Power and that instead, it and transmission developers could use the cost allocation analysis as input to their negotiations and other required statutory processes, then the Commission is directly regulating Bonneville Power by not allowing Bonneville Power to follow its own statutory authority in implementing cost allocation in place of the Commission's policy adopted under section 206, which the Commission cannot do.

760. Sacramento Municipal Utility District argues that the Commission lacks the authority to mandate regional transmission planning and therefore it cannot attach an obligation to accept the cost allocation agreement negotiated under a regional transmission planning process that the non-public utility was not mandated to join. Sacramento Municipal Utility District therefore contends that since non-public utilities under section 201(f) are not subject to section 205 and 206, they cannot be required as a condition of reciprocity to accept cost allocation agreements that the Commission has no authority to impose even on public utilities.

761. Sacramento Municipal Utility District states that when a non-public utility takes service from a jurisdictional public utility, it will pay a tariff rate approved by the Commission, and a reciprocity provision is simply unnecessary to ensure proper cost recovery. Sacramento Municipal Utility District argues that if the non-public utility takes no service from a transmission provider that has constructed a new facility approved by a regional transmission planning body, and the costs of that facility are not properly included in the rates of other transmission providers from whom the non-public utility does take service, the reciprocity provision should be completely inapplicable.

762. Moreover, Sacramento Municipal Utility District argues that cost allocation is not a transmission service so that a non-public utility requesting only transmission service can be deemed to have reciprocated only by participating in regional cost allocation. Similarly, Bonneville Power contends that the Commission should not condition a non-jurisdictional transmitting utility's ability to receive transmission service from a public utility on the non-jurisdictional utility's inclusion of Order No. 1000's planning and cost allocation reforms in its own tariff because the provisions of Order No. 1000 go well beyond the basic provision of transmission service and are not the type of provisions that reasonably fall within the reciprocity construct.

763. Edison Electric Institute seeks clarification that section 6 of the OATT, which codifies the reciprocity requirement, enables a public utility to refuse transmission service to unregulated transmitting utilities that refuse to participate in regional transmission planning and cost allocation processes. Furthermore, Edison Electric Institute seeks clarification that, to satisfy the reciprocity requirements, unregulated transmitting utilities must fulfill each of the compliance requirements imposed on public utilities. If unregulated transmitting utilities do not, then Edison Electric Institute argues that the Commission should clarify that they have failed to offer the ''comparable'' service required under section 6 of the OATT.

764. Large Public Power Council seeks clarification that the Commission did not intend that it would enforce reciprocity tariff provisions itself. Large Public Power Council states that if the Commission does intend to enforce the reciprocity provisions itself, Large Public Power Council seeks rehearing. Large Public Power Council argues that to date, the Commission has not intimated that it has authority to enforce these provisions with respect to a non-public utility, which is consistent with case law finding that a non-public utility's involvement in Commission-jurisdictional service does not authorize the Commission to regulate the non-public utility.

765. Other petitioners argue that the Commission does not have authority under section 211A to compel a non-public utility transmission provider to participate in planning or pay for regional or interregional transmission projects.[893] For instance, Large Public Power Council asserts that section 211A makes it plain that the Commission's authority is limited to compelling a non-public utility to provide transmission service at rates and on terms and conditions that are essentially inward looking. As such, Large Public Power Council contends that the Commission cannot redefine the terms under which service is to be provided under section 211A in a manner that would give the Commission broader authority than that given by Congress. Accordingly, it states that the Commission does not have the authority to compel non-public utilities to contribute to new regional or interregional cost allocation mechanisms, or to operate according to Commission-approved transmission plans directing the level and nature of transmission investment.

766. Sacramento Municipal Utility District asserts that section 211A of the FPA makes clear that the comparability the Commission is empowered to enforce is comparability to the transmission services the non-public utility provides to itself, and that if a non-public utility chooses not to participate in a regional cost allocation process as part of its service to itself, it cannot be compelled to participate or to accept a regional cost allocation plan under section 211A. Bonneville Power contends that the Commission is inappropriately attempting to indirectly regulate non-public utility transmission providers by suggesting that it will use section 211A to obtain their compliance with mandatory cost allocation. Sacramento Municipal Utility District and Bonneville Power, therefore, argue that the Commission should remove its statement that it will use section 211A against non-public utility transmission providers to obtain compliance with Order No. 1000. Sacramento Municipal Utility District alternatively urges the Commission to clarify that its interpretation is not binding and is without prejudice to the rights of non-public utilities to challenge such an interpretation in any actual case in which the Commission invokes the authority to mandate non-public utility participation in regional planning and cost allocation.

767. On the other hand, Edison Electric Institute argues that the Commission erred by relying on non-public utility transmission providers to voluntarily participate in regional transmission planning and cost allocation processes.[894] Edison Electric Institute argues that the Commission should have exercised its authority under section 211A to ensure that unregulated transmitting utilities comply with the transmission planning and regional cost allocation provisions on the same terms and conditions as jurisdictional public utilities. Edison Electric Institute also asserts that the Commission has not demonstrated or otherwise explained why mandatory action is required in the case of public utility but is not required for non-public utility transmission providers. Edison Electric Institute asserts that both sets of utilities own transmission facilities, provide transmission service to customers, and may currently

[893] *See, e.g.,* Large Public Power Council; Sacramento Municipal Utility District; and Bonneville Power.

[894] Edison Electric Institute at 26 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 815).

participate in regional transmission planning processes.

768. Edison Electric Institute asserts that the Commission is authorized through section 211A to act ''by rule'' to require unregulated transmitting utilities to remedy discriminatory transmission rates and practices.[895] Edison Electric Institute states that the Commission has recognized that section 211A allows it to require an unregulated transmitting utility to provide transmission services on a comparable and not unduly discriminatory basis. Edison Electric Institute further states that section 211A contains the same ''unduly discriminatory or preferential'' standard found in section 206. Thus, Edison Electric Institute concludes that FPA section 211A, along with section 206, vests the Commission with the duty to eliminate undue discrimination and to ensure open access to transmission across the entire interstate grid.

769. Edison Electric Institute argues that the Commission's decision to rely on voluntary compliance is ill-founded and inadequate because there is no indication that non-jurisdictional utilities will voluntarily comply. It also argues that since Order No. 888, non-jurisdictional utilities have not fully embraced voluntary compliance with the Commission's open access reforms. Furthermore, Edison Electric Institute argues that allowing non-public utilities to participate voluntarily injects uncertainty in transmission planning and cost allocation, especially in areas that are predominately served by unregulated entities. Edison Electric Institute asserts that participants in regional transmission planning and cost allocation processes should not have to wait to know whether an unregulated transmitting utility, and potential beneficiary of a transmission project, is going to be subject to regional cost allocation. Edison Electric Institute adds that it also is unclear if, when, and how the Commission will exercise its authority under section 211A. Edison Electric Institute asserts that the lack of certainty, layered on to the short period for compliance, will undermine confidence in the planning and regional cost allocation processes and hinder their development.

770. Edison Electric Institute requests that the Commission clarify and strengthen the obligations of unregulated transmitting utilities to facilitate full compliance with regional planning and cost allocation provisions, and make clear when and how it will act on a case-by-case basis under section 211A. In addition, Edison Electric Institute states that the Commission has the authority to direct unregulated transmitting utilities to comply with the requirements in Order No. 1000, whether it learns of non-compliance through a complaint or on its own motion. Edison Electric Institute argues that failure by the Commission to act would be an abdication of its obligation to ensure non-discriminatory treatment in transmission service.

3. Commission Determination

771. In response to petitioners who are concerned that the Commission is modifying the scope of the reciprocity requirement under Order Nos. 888 and 890, we clarify that the reciprocity requirement remains unchanged. A non-public utility transmission provider may continue to satisfy the reciprocity condition in one of three ways. First, it may provide service under a tariff that has been approved by the Commission under the voluntary ''safe harbor'' provision of the *pro forma* OATT. A non-public utility transmission provider using this alternative submits a reciprocity tariff to the Commission seeking a declaratory order that the proposed reciprocity tariff substantially conforms to, or is superior to, the *pro forma* OATT. The non-public utility transmission provider then must offer service under its reciprocity tariff to any public utility transmission provider whose transmission service the non-public utility transmission provider seeks to use. Second, the non-public utility transmission provider may provide service to a public utility transmission provider under a bilateral agreement that satisfies its reciprocity obligation. Finally, the non-public utility transmission provider may seek a waiver of the reciprocity condition from the public utility transmission provider.[896]

772. We affirm the Commission's determination in Order No. 1000 that to maintain a reciprocity tariff under the voluntary ''safe harbor'' provision, a non-public utility transmission provider must ensure that the provisions of that tariff substantially conform, or are superior, to the *pro forma* OATT and its Attachment K as these have been revised by Order No. 1000.[897] As such, if a non-public utility transmission provider wishes to maintain its safe harbor tariff, it will need to ensure that it addresses Order No. 1000's transmission planning and cost allocation reforms, so that it continues to substantially conform, or be superior, to the *pro forma* OATT.

773. As we note above, the other two ways of satisfying the reciprocity requirement also remain intact. For example, a non-public utility transmission provider seeking service from a public utility transmission provider may seek to enter into a bilateral agreement with the public utility transmission provider that addresses that public utility transmission provider's desire for reciprocity. In such case, a public utility transmission provider may agree to provide service to a non-public utility transmission provider without requiring that non-public utility transmission provider to provide reciprocal service under terms and conditions that are necessarily substantially conforming with, or superior to, the *pro forma* OATT, which includes the transmission planning and cost allocation reforms in Order No. 1000. With respect to such bilateral agreements, the Commission in Order No. 888–A stated that it ''must leave these agreements to case-by-case determinations.'' [898] In doing so, the Commission stated that the terms and conditions that ''may be necessary for a non-public utility to provide reciprocal service to the public utility in a bilateral agreement is necessarily a fact-specific matter not susceptible to resolution in a generic rulemaking proceeding.'' [899] As such, we deny Edison Electric Institute's request for generic clarification that section 6 of the *pro forma* OATT, which codifies the reciprocity requirement, would allow a public utility transmission provider to refuse service to a non-public utility transmission provider that refused to enroll in the regional transmission planning and cost allocation processes. However, we note that in Order No. 888–A, the Commission also made clear that ''a public utility may refuse to provide open access transmission service to a non-public utility if its denial is based on a good faith assertion that the non-public utility has not met the Commission's reciprocity requirements.'' [900] While we will

[895] Edison Electric Institute at 27 (quoting 16 U.S.C. 824j–1(b)).

[896] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 799 & n.574 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163 (citing Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,285–86)).

[897] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 815 and Appendix C: *Pro Forma* Open Access Transmission Tariff.

[898] Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,289.

[899] *Id.*

[900] *Id.* This approach is also consistent with Order No. 890 where the Commission stated that ''[u]nder the reciprocity provision in section 6 of the *pro forma* OATT, if a public utility seeks transmission service from a non-public utility to which it provides open access transmission service, the non-public utility that owns, controls, or operates

continue to address such matters on a case-by-case basis consistent with Order No. 888–A, we nevertheless note our finding in Order No. 1000 that those that ''take advantage of open access, including improved transmission planning and cost allocation, should be expected to follow the same requirements as public utility transmission providers.'' [901] Finally, a public utility transmission provider remains free to waive any reciprocity requirement for a non-public utility transmission provider that seeks service from it.

774. We further clarify in response to National Rural Electric Coops that, in the absence of a safe harbor tariff, a non-public utility transmission provider's obligation to a public utility transmission provider to provide a comparable transmission service that it is capable of providing on its own system begins when that public utility transmission provider requests comparable reciprocal service from the non-public utility transmission provider.[902] We also clarify for Large Public Power Council that the Commission did not intend that it would enforce reciprocity tariff provisions sua sponte, except insofar as the Commission permits a public utility transmission provider to refuse to offer open access transmission service to that non-public utility transmission provider, in accordance with Order No. 888.

775. Because the reciprocity provisions of Order Nos. 888, 890, and 1000 do not impose any requirement on non-public utility transmission providers, we reject Bonneville Power's and Sacramento Municipal Utility District's arguments that the Commission is attempting to regulate non-public utility transmission providers. As the Commission stated in Order No. 1000, non-public utility transmission providers are free to decide whether they will seek transmission service that is subject to the Commission's jurisdiction, and the Commission does not exercise jurisdiction over them when it determines the terms under which public utility transmission providers must provide that transmission service.[903] As such, the reciprocity provision of Order No. 1000 does not require non-public utility transmission providers to comply with the Order No. 1000 transmission planning and cost allocation reforms. In addition, as explained above in the discussion of our legal authority to implement Order No. 1000's transmission planning reforms, we disagree with Sacramento Municipal Utility District's contention that the Commission lacks the authority to mandate regional transmission planning for public utility transmission providers.[904]

776. In response to Sacramento Municipal Utility District's concern that a reciprocity provision is ''unnecessary to ensure proper cost recovery,'' [905] and Bonneville Power's and Sacramento Municipal Utility District's concerns that the transmission planning and cost allocation reforms should be outside the reciprocity construct, we disagree. Any non-public utility transmission provider that takes transmission service from a public utility transmission provider after implementation of Order No. 1000 is likely to benefit from the new OATT provisions of the public utility transmission providers in that region providing for improved regional transmission planning and for regional cost allocation commensurate with benefits for selected facilities, as provided in Order No. 1000. We therefore in Order No. 1000 applied the reciprocity provisions of Order Nos. 888 and 890 to provide that it is within the Commission's discretion to allow a public utility transmission provider to refuse to offer open access transmission service to any non-public utility transmission provider that does not provide comparable reciprocal transmission service insofar as it is capable of doing so, including regional planning and cost allocation. However, we reiterate a clarification made above that it is only when a non-public utility transmission provider actually makes the choice to become part of a transmission planning region by enrolling in that region that it would be subject to the regional and interregional cost allocation methods for that region.[906]

777. In response to Bonneville Power's and Sacramento Municipal Utility District's contention that certain provisions of Order No. 1000, such as those relating to cost allocation, go beyond the provision of transmission service and thus should not be incorporated in the Commission's reciprocity condition, we reiterate that both transmission planning and cost allocation are integral and essential components of the provision of transmission service. The transmission planning and cost allocation reforms adopted in Order No. 1000 are intended to facilitate the development of a robust transmission system capable of providing improved open access transmission service and to help ensure that transmission rates are just and reasonable and not unduly discriminatory or preferential.

778. We decline to address petitioners' arguments concerning the scope of our authority under FPA section 211A in this proceeding because the Commission did not act under FPA section 211A in Order No. 1000.[907] As the Commission stated in Order No. 1000, the success of the transmission planning process set forth therein will be enhanced if all transmission owners participate. The Commission further stated that non-public utility transmission providers will benefit greatly from the improved transmission planning and cost allocation processes required for public utility transmission providers because a well-planned grid is more reliable and provides more available, less congested paths for the transmission of electric power in interstate commerce.[908]

VI. Information Collection Statement

779. The Office of Management and Budget (OMB) requires that OMB approve certain information collection and data retention requirements imposed by agency rules.[909] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

780. Previously, the Commission submitted to OMB the information collection requirements arising from Order No. 1000 and OMB approved those requirements. In this order, the Commission is making no substantive changes to those requirements, but has provided clarifications that require public utility transmission providers, and transmission developers, to collect additional information. Therefore, the Commission finds it necessary to make

transmission facilities must provide comparable transmission service that it is capable of providing on its own system. Under the *pro forma* OATT, a public utility may refuse to provide open access transmission service to a non-public utility if the non-public utility refuses to reciprocate.'' Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163.

[901] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 818.

[902] *Id.* P 819 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 163).

[903] *Id.*

[904] *See* discussion *supra* at section 0.

[905] Sacramento Municipal Utility District at 20.

[906] *See* discussion *supra* at section 0.

[907] Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 821.

[908] *Id.* P 818.

[909] 5 CFR 1320.11(b).

a formal submission to OMB for review and approval under section 3507(d) of the Paperwork Reduction Act of 1995.[910]

781. The burden estimates in this order on rehearing and clarification of Order No. 1000 represent the incremental burden changes related only to the new and revised requirements set forth in this order. It also should be noted that the burden estimates are averages for all of the filers.

Burden Estimate and Information Collection Costs: The estimated Public Reporting burden and cost for the new and revised requirements contained in this order follow.

FERC–917—New and revised reporting requirements in order 1000–A in RM10–23	Annual number of respondents (Filers)	Annual number of responses	Hours per response	Total annual hours in year 1	Total annual hours in subsequent years
Transmission Providers (TP) develop & maintain enrollment process defining how entities make choice to become part of trans. planning region; and include (& maintain) in OATT a list of all pub. & non-pub. utility trans. providers enrolled as TP in planning region.	132	1	2 in Year 1; 1 in Yrs. 2 & 3	264	132
Transmission Developers (TD) submit development schedule (if selected in regional plan for cost allocation).	140	1	4 (each in Yrs. 1–3)	560	560
TP describe in OATT how regional trans. planning process gives stakeholders chance to participate & how stakeholders & TD can propose interregional trans. facilities for TP in neighboring region to evaluate jointly.	132	1	5 in Year 1; 0.5 in Yrs. 2&3	660	66
To the extent that a TP considers either cost containment or cost recovery provisions as part of cost allocat. method for regional or interregional facility, such provisions may be included in its compliance filing.	132	1	18 in Year 1; 1 in Yrs. 2&3	2,376	132
Total Estimated Additional Burden Hours, for FERC–917 due to Order 1000–A in RM10–23.	....	....	....	3,860	890

Cost to Comply:

Year 1: $440,040 [3,860 hours × $114 per hour[911]]

Subsequent Years: $101,460 [890 hours × $114 per hour]

Title: FERC–917

Action: Clarification to Collection.

OMB Control No.: 1902–0233.

Respondents: Transmission Developers and Public Utility Transmission Providers. An RTO or ISO also may file some materials on behalf of its members.

Frequency of Responses: Initial filing and subsequent filings.

Necessity of the Information:

782. Building on the reforms in Order No. 890, the Federal Energy Regulatory Commission provides these clarifications to the amendments to the *pro forma* OATT to correct certain deficiencies in the transmission planning and cost allocation requirements for public utility transmission providers adopted in Order No. 1000. The purpose of Order No. 1000 is to strengthen the *pro forma* OATT, so that the transmission grid can better support wholesale power markets and ensure that Commission-jurisdictional services are provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory or preferential. We expect to achieve this goal through Order No. 1000 by reforming electric transmission planning requirements and establishing a closer link between cost allocation and regional transmission planning processes.

783. Interested persons may obtain information on reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, email: *DataClearance@ferc.gov*, Phone: (202) 502–8663, fax: (202) 273–0873. Comments concerning the collection of information and the associated burden estimate(s), may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–4638, fax (202) 395–7285]. Due to security concerns, comments should be sent electronically to the following email address: *oira_submission@omb.eop.gov*. Comments submitted to OMB should include OMB Control No. 1902–0233 and Docket No. RM10–23–001.

VII. Document Availability

784. 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 (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

785. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary,

[910] 44 U.S.C. 3507(d).

[911] The estimated cost of $114 an hour is the average of the hourly costs of: Attorney ($200), consultant ($150), technical ($80), and administrative support ($25).

type the docket number excluding the last three digits of this document in the docket number field.

786. User assistance is available for eLibrary and the Commission's Web site during normal business hours from FERC 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*.

VIII. Effective Date and Congressional Notification

787. Changes to Order No. 1000 made in this order on rehearing and clarification will be effective on July 2, 2012. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule on rehearing and clarification of Order No. 1000 is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Note: The following appendices will not be published in the *Code of Federal Regulations.*

Appendix A: Abbreviated Names of Petitioners

Abbreviation	Petitioner names
Ad Hoc Coalition of Southeastern Utilities	Central Electric Power Cooperative, Inc.; Dalton Utilities; Georgia Transmission Corporation; JEA; MEAG Power; Orlando Utilities Commission; Progress Energy Service Company, LLC (on behalf of Progress Energy Carolinas, Inc. and Progress Energy Florida, Inc.); South Carolina Electric & Gas Company; South Carolina Public Service Authority (Santee Cooper); and Southern Company Services, Inc. (on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company).
AEP	American Electric Power Service Corporation.
Alabama PSC	Alabama Public Service Commission.
Ameren	Ameren Services Company.
American Transmission	American Transmission Company LLC.
APPA	American Public Power Association.
Arizona Cooperative and Southwestern Transmission.	Arizona Electric Power Cooperative, Inc. and Southwest Transmission Cooperative, Inc.
AWEA	American Wind Energy Association.
Baltimore Gas & Electric	Baltimore Gas & Electric Company.
Bonneville Power	Bonneville Power Administration.
California ISO	California Independent System Operator Corporation.
California State Water Project	California Department of Water Resources State Water Project.
Coalition for Fair Transmission Policy	CMS Energy Corporation; Consolidated Edison; DTE Energy Company; Progress Energy, Inc.; Public Service Enterprise Group; SCANA Corporation; Southern Company.[912]*
Dayton Power and Light	Dayton Power and Light Company (The).
Duke	Duke Energy Corporation.
Edison Electric Institute	Edison Electric Institute.
ELCON, AF&PA, and the Associated Industrial Groups.	Electricity Consumers Resource Council, American Forest and Paper Association, Electricity Consumers Resource Council; American Chemistry Council; Association of Businesses Advocating Tariff Equity; Carolina Utility Customers Association; Coalition of Midwest Transmission Customers; Florida Industrial Power Users Group; Georgia Industrial Group-Electric; Industrial Energy Users—Ohio; Oklahoma Industrial Energy Consumers; PJM Industrial Customer Coalition; West Virginia Energy Users Group; and Wisconsin Industrial Energy Group.
Energy Future Coalition Group	Energy Future Coalition; American Wind Energy Association; Center for Energy Efficiency and Renewable Technologies; Center for Rural Affairs; Climate and Energy Project; Denali Energy Inc.; Fresh Energy; Gradient Resources, Inc.; Iberdrola Renewables; Interwest Energy Alliance; Natural Resources Defense Council; Project for Sustainable FERC Energy Policy; Solar Energy Industries Association; The Stella Group, Ltd.; Union of Concerned Scientists; Western Grid Group; Wind on the Wires; and WIRES.*
FirstEnergy Service Company	FirstEnergy Service Company, on behalf of FirstEnergy Companies: Ohio Edison Company; Pennsylvania Power Company; The Cleveland Electric Illuminating Company; The Toledo Edison Company; American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Metropolitan Edison Company; and Pennsylvania Electric Company, and FirstEnergy Solutions Corp. and their respective electric utility subsidiaries and affiliates.
Florida PSC	Florida Public Service Commission.
Georgia PSC	Georgia Public Service Commission.
Illinois Commerce Commission	Illinois Commerce Commission.
ITC Companies	International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; ITC Great Plains, LLC; and Green Power Express LP.
Joint Petitioners	American Electric Power Corp.; AWEA; Iberdrola Renewables; ITC Holdings Corp.; NextEra Energy, Inc.; MidAmerican Energy.
Kentucky PSC	Kentucky Public Service Commission.
Large Public Power Council	Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities; Colorado Springs Utilities; CPS Energy (San Antonio); ElectriCities of North Carolina; Grant County Public Utility District; IID Energy (Imperial Irrigation District); JEA (Jacksonville, FL); Long Island Power Authority; Los Angeles Department of Water and Power; Lower Colorado River Authority; MEAG Power, Nebraska Public Power District; New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; and Tacoma Public Utilities.*

Abbreviation	Petitioner names
Long Island Power Authority	Long Island Power Authority and LIPA.
LS Power	LS Power Transmission, LLC.
MEAG Power	MEAG Power.
MISO	Midwest Independent System Transmission Operator, Inc.
MISO Transmission Owners Group 1	The Midwest ISO Transmission Owners for this filing consist of: Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; American Transmission Company LLC ("ATC"); City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Great River Energy; Indianapolis Power & Light Company; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana- Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; and Wolverine Power Supply Cooperative, Inc.
MISO Transmission Owners Group 2	The Midwest ISO Transmission Owners for this filing consist of: Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; and Wolverine Power Supply Cooperative, Inc.
MISO Northeast	MISO Northeast Transmission Customers of Consumers.
NARUC	National Association of Regulatory Utility Commissioners.
National Rural Electric Coops	National Rural Electric Cooperative Association.
NV Energy	Nevada Power Company and Sierra Pacific Power Company.
New York ISO	New York Independent System Operator, Inc.
New York PSC	New York State Public Service Commission.
New York Transmission Owners	Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; New York Power Authority; Long Island Power Authority; New York State Electric & Gas Corporation; and Niagara Mohawk Power Corporation; Orange and Rockland Utilities, Inc.; and Rochester Gas and Electric Corporation.
NextEra	NextEra Energy, Inc.
North Carolina Agencies	North Carolina Utilities Commission and Public Staff of the North Carolina Utilities Commission.
Northern Tier Transmission Group	Northern Tier Transmission Group.
Oklahoma Gas and Electric Company	Oklahoma Gas and Electric Company.
PPL Companies	PPL Electric Utilities Corporation; Lower Mount Bethel Energy, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; PPL University Park, LLC; PPL EnergyPlus, LLC; PPL GreatWorks, LLC; PPL Maine, LLC; PPL Wallingford Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; PPL Renewable Energy, LLC; PPL Montana, LLC; PPL Colstrip I, LLC; PPL Colstrip II, LLC; Louisville Gas and Electric Company; Kentucky Utilities Company; and LG&E Energy Marketing LLC.*
PSEG Companies	Public Service Electric and Gas Company; PSEG Power LLC; and PSEG Energy Resources & Trade LLC.
Sacramento Municipal Utility District	Sacramento Municipal Utility District.
South Carolina Regulatory Staff	South Carolina Office of Regulatory Staff.
Southern California Edison	Southern California Edison Company.
Southern Companies	Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; and Southern Power Company.
Sponsoring PJM Transmission Owners	Certain Sponsoring PJM Transmission Owners (American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Metropolitan Edison Company; Monongahela Power Company; Pennsylvania Electric Company; The Potomac Edison Company; Trans-Allegheny Interstate Line Company; and West Penn Power Company (collectively, the FirstEnergy Companies); Baltimore Gas and Electric Company; The Dayton Power and Light Company; Duquesne Light Company; Public Service Electric and Gas Company; PSEG Power LLC and PSEG Energy Resources & Trade LLC (collectively, PSEG Companies); and Virginia Electric and Power Company).
Sunflower, Mid-Kansas and Western Farmers	Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC and Western Farmers Electric Cooperative.
Transmission Access Policy Study Group	Transmission Access Policy Study Group.
Transmission Dependent Utility Systems	Arkansas Electric Cooperative Corporation; Golden Spread Electric Cooperative, Inc.; Kansas Electric Power Cooperative, Inc.; North Carolina Electric Membership Corporation; and Seminole Electric Cooperative, Inc.; and PowerSouth Energy Cooperative.*
Vermont Department of Public Service and the Vermont Public Service Board.	Vermont Department of Public Service and the Vermont Public Service Board
Western Independent Transmission Group	Western Independent Transmission Group.

Abbreviation	Petitioner names
WIRES	Working Group for Investment in Reliable and Economic Electric Systems.
Wisconsin PSC	Public Service Commission of Wisconsin.
Xcel	Xcel Energy Services Inc.

Appendix B: *Pro Forma* Open Access Transmission Tariff

Pro Forma OATT

Attachment K

Transmission Planning Process

Local Transmission Planning

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in Order No. 890: Coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. The planning process also shall provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890.

The description of the Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions and data underlying a transmission plan;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;

(vi) The dispute resolution process;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(ix) The relevant cost allocation method or methods.

Regional Transmission Planning

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000. The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider's regional transmission planning process shall satisfy the following seven principles, as set out and explained in Order Nos. 890 and 1000: Coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The regional transmission planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890.

The regional transmission planning process shall include a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region. The regional transmission planning process shall be clear that enrollment will subject enrollees to cost allocation if they are found to be beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation. Each Transmission Provider shall maintain a list of enrolled entities in the Transmission Provider's Tariff.

Nothing in the regional transmission planning process shall include an unduly discriminatory or preferential process for transmission project submission and selection.

The description of the regional transmission planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for enrollment in the regional transmission planning process;

(ii) The process for consulting with customers;

(iii) The notice procedures and anticipated frequency of meetings;

(iv) The methodology, criteria, and processes used to develop a transmission plan;

(v) The method of disclosure of criteria, assumptions and data underlying transmission plan;

(vi) The obligations of and methods for transmission customers to submit data;

(vii) Process for submission of data by nonincumbent developers of transmission projects that wish to participate in the transmission planning process and seek regional cost allocation;

(viii) Process for submission of data by merchant transmission developers that wish to participate in the transmission planning process;

(ix) The dispute resolution process;

(x) The study procedures for economic upgrades to address congestion or the integration of new resources;

(xi) The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and

(xii) The relevant cost allocation method or methods.

The regional transmission planning process must include a cost allocation method or methods that satisfy the six regional cost allocation principles set forth in Order No. 1000.

Interregional Transmission Coordination

The Transmission Provider, through its regional transmission planning process, must coordinate with the public utility transmission providers in each neighboring transmission planning region within its interconnection to address transmission planning coordination issues related to interregional transmission facilities. The interregional transmission coordination procedures must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions (i) with respect to each interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. The interregional transmission coordination procedures shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider must ensure that the following requirements are included in any applicable interregional transmission coordination procedures:

(1) A commitment to coordinate and share the results of each transmission planning region's regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than

[912] A "*" indicates that the composition of this group has changed since the Final Rule proceeding.

separate regional transmission facilities, as well as a procedure for doing so;

(2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions;

(3) An agreement to exchange, at least annually, planning data and information; and

(4) A commitment to maintain a Web site or email list for the communication of information related to the coordinated planning process.

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or methods for allocating between the two transmission planning regions the costs of a new interregional transmission facility that is located within both transmission planning regions. Such cost allocation method or methods must satisfy the six interregional cost allocation principles set forth in Order No. 1000 and must be included in the Transmission Provider's Tariff.

[FR Doc. 2012–12418 Filed 5–30–12; 8:45 am]

BILLING CODE 6717–01–P