UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	Docket No. RM21-17-000

COMMENTS OF

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COMMENTS OF AMERICANS FOR A CLEAN ENERGY GRID

Americans for a Clean Energy Grid (ACEG)[1] appreciates the opportunity to provide comments in support of the Commission's Notice of Proposed Rulemaking (NOPR) on transmission planning and cost allocation reforms.[2] Transmission planning must be designed to benefit customers by identifying and building the most effective transmission solutions that will protect reliability and resiliency and meet the changing resource mix and demand. The expansive record developed to date demonstrates that proactive and comprehensive regional and interregional transmission planning is needed to achieve both an efficient level of transmission investment and ensure that transmission costs are just and reasonable and not unduly discriminatory or preferential. The Commission's proposed reforms in this docket are a critical next step in safeguarding the integrity of the Nation's electric system, and ACEG encourages the Commission to act expeditiously in both enacting a final rule that will advance the construction of

[1] ACEG represents a diverse coalition of stakeholders focused on the need to expand, integrate and modernize the high-capacity grid in the United States. The ACEG coalition includes multi-state utilities and merchant transmission owners that develop, own, and operate transmission, trade groups that include transmission owners and transmission equipment manufacturers among their members, renewable energy trade groups and advocates, environmental advocacy organizations, buyers and consumers of energy, and energy policy experts. ACEG seeks to educate the public, opinion leaders, and public officials about the needs and potential of the transmission grid. These comments do not necessarily reflect the views of individual members.

[2] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022) (NOPR).

high-capacity long-range regional transmission solutions and continuing to review additional measures that are needed to support interregional transmission development.

I. SUMMARY OF COMMENTS

Prior Commission actions demonstrate a long history regarding the need for regional planning: the 1993 Regional Transmission Group Policy Statement and Order Nos. 888, 2000, 890, and 1000 all advanced regional transmission planning and development in different ways. While these past initiatives have served the purpose for which they were intended at the time, electricity usage and generation resource development have evolved. The record developed in response to the Advanced Notice of Proposed Rulemaking (ANOPR)[3] in this proceeding provides substantial evidence that current Commission transmission planning and cost allocation processes are leading to inefficient transmission infrastructure investment.[4] In the ANOPR comments, 174 entities advocated for some form of proactive long-term planning for the future resource mix, including 59 consumer organizations.[5]

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[3] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 86 FR 40266 (July 15, 2021), 176 FERC ¶ 61,024 (2021) (ANOPR).

[4] NOPR at P 47 ("[W]e preliminarily find that the Commission's regional transmission planning and cost allocation requirements fail to require public utility transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs; (2) adequately account on a forward-looking basis for known determinants of transmission needs driven by changes in the resource mix and demand; and (3) consider the broader set of benefits and beneficiaries of regional transmission facilities planned to meet those transmission needs.").

[5] ACEG, ANOPR Reply Comments, Appendix A (Nov. 30, 2021). Similarly, on August 16, 2022, a group of 30 diverse stakeholders, including utilities; consumers; NGOs; think tanks; labor groups; national trade associations; equipment providers; clean energy buyers; transmission developers, builders, and operators; independent power producers; and environmental organizations, submitted a letter in this docket continuing to support a strong planning rule. *See,* Diverse Stakeholder Letter (Accession No. 20220816-5129) *available at* https://elibrary.ferc.gov/eLibrary/filedownload?fileid=99297FAD-F5CC-C0DE-8491-82A83EE00000

Moreover, the ANOPR record includes extensive evidence supporting the need for large-scale high-capacity[6] transmission development.[7] Indeed, independent estimates indicate that high-capacity transmission will need to double by 2030 and triple by 2050 at a cost of $360 billion through 2030 and $2.2 trillion by 2050 in order to achieve a zero-carbon future by 2050.[8] Policies and incentives that support transmission buildout have the potential to deliver huge benefits for America. For example, between 2012 and 2014, in SPP $3.4 billion was invested in transmission expansion projects to better integrate the power system's eastern and western regions and reduce overall congestion on the SPP grid, with a net present value of all quantified benefits expected to total over $10 billion over the next 40 years.[9] Similarly, the MISO Multi-Value Project (MVP) portfolio, consisting of 17 transmission projects distributed across the MISO footprint, is estimated to generate $12.1 to $52.6 billion in net benefits over the next 20 to 40 years and will enable $52.8 million MWh of wind energy to meet renewable energy goals and mandates through 2031.[10] The benefits generated by MISO's MVPs and SPP's Priority Projects

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[6] ACEG encourages the Commission to use the term "high capacity" instead of "high voltage" to recognize that new technologies can enable transmission lines to carry more electricity at lower voltage levels.

[7] ACEG, ANOPR Reply Comments, at 1-2 and Appendix A.

[8] Americans for a Clean Energy Grid, *Planning for the Future, FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* (Jan. 2021) at 37, 90 and Appendix A, *available at* https://cleanenergygrid.org/wp-content/uploads/2021/09/ACEG_Planning-for-the-Future1.pdf (referencing Eric Larson *et. al.,* Net-Zero America: Potential Pathways, Infrastructure, and Impacts, at 77, Dec. 15, 2020), provided as Appendix C to ACEG's ANOPR Comments in Docket No. RM21-17-000 (Oct. 12, 2021).

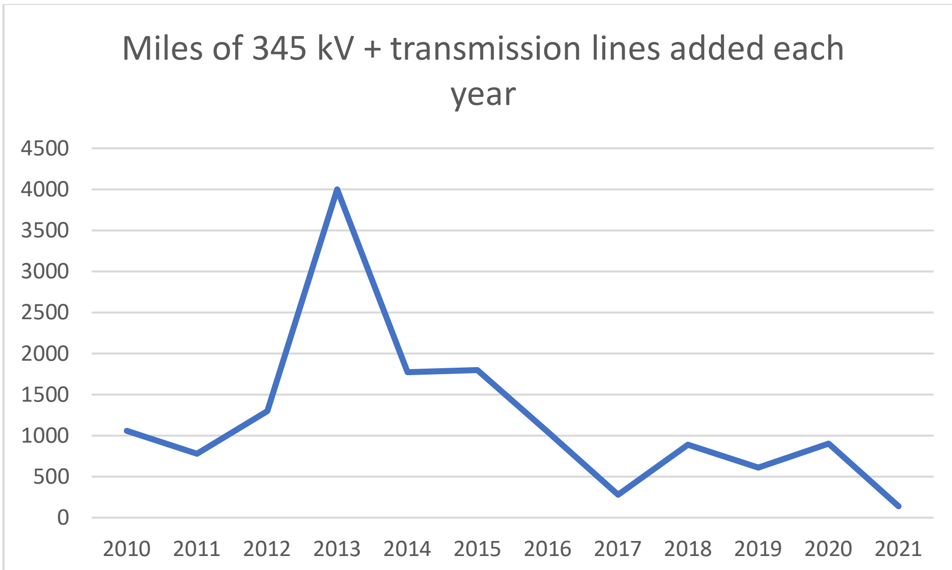
[9] ACEG Comments on the Department of Energy's Notice of Intent and Request for Information Regarding the Establishment of a Transmission Facilitation Program at 2, Ref. No. 2022-10137 (June 13, 2022) *available at* https://cleanenergygrid.org/wp-content/uploads/2022/06/ACEG-Comments-on-TFP_6.13.22.pdf; SPP, *The Value of Transmission,* at 5 (Jan. 2016) available at https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf

[10] MISO, *Regionally Cost Allocated Project Reporting Analysis* (Jan. 2021); MISO, MTEP17 MVP Triennial Review at 4 (Sept. 2017) https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf

exceeded the costs by 2.2 to 3.5 times and means that every dollar spent on transmission will enable access to generation that is $3 to $4 cheaper than would otherwise be available.[11]

Despite the demonstrated need and value, investment in high-capacity transmission development has fallen in the country over the last decade. The chart below shows this drop-off.

Figure 1: Declining investment in large scale transmission[12]



The current lack of proactive long-term regional transmission planning and high-capacity transmission development has led to a host of issues:

- Failure to fully appreciate the benefits of transmission upgrades, either through the transmission planning process or through the interconnection queue, leads to a much too narrow set of customers paying the costs and a host of free-riders that benefit from such

[11] ACEG Comments on the Department of Energy's Notice of Intent and Request for Information Regarding the Establishment of a Transmission Facilitation Program at 2, Ref. No. 2022-10137 (June 13, 2022) *available at* https://cleanenergygrid.org/wp-content/uploads/2022/06/ACEG-Comments-on-TFP_6.13.22.pdf (citing Larson et al, Princeton University, Net-Zero America: Potential Pathways, Infrastructure, and Impacts at 108 (October 29, 2021) *available at* https://netzeroamerica.princeton.edu/the-report); DOE*, DOE Launches New Initiative From President Biden's Bipartisan Infrastructure Law To Modernize National Grid* (Jan. 12, 2022).

[12] Grid Strategies, Fewer New Miles: The US Transmission Grid in the 2010s (Aug. 2022) *available at* https://gridprogress.files.wordpress.com/2022/08/grid-strategies_fewer-new-miles.pdf

facilities but do not share in the cost.[13] To ensure the identification of more efficient or cost effective transmission solutions, cost allocation should follow the accepted beneficiaries pays principles, which require appropriate identification and measurement of both the benefits and beneficiaries of new transmission facilities over a minimum of a 20-year time horizon to a potential 40-year time horizon to match the expected life of the assets.[14]

- "Re-active" and "siloed" planning processes lead to higher costs and may not lead to the identification of comprehensive transmission solutions. The current approach of siloed reliability/economic/public policy benefits fails to select projects and allocate the costs roughly commensurate with the benefits. All projects have reliability, economic, and public policy benefits, thus, except for near-term reliability projects, transmission cannot and should not be planned in silos. Beneficiaries experience all three types of benefits, and should be assigned costs accordingly.

- The inefficiency between interconnection needs and transmission planning is the root cause of resource adequacy issues that have been identified in many regions and that affect the reliability of the Bulk Electric System by slowing the transition that is already occurring in the generation resource mix.[15] Transmission planning that accounts for future generation development can significantly reduce interconnection costs and delays.

- A lack of interregional planning has led to higher costs. Severe weather events are estimated to cost Americans between $25-70 billion each year.[16] Proactive planning, which includes integrating extreme event scenarios, can have substantial economic value. Strengthening the transmission grid and increasing interregional ties are essential for preventing future outages. Stronger transmission ties to neighboring regions can be a lifeline to prevent power outages by cancelling out local fluctuations in the weather that affect electricity demand.[17] The grid of the future will facilitate multiple and diverse markets, resources, and kinds of energy demands.

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[13] *See, e.g.*, ICF, *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators are Delivering System-Wide Benefits*, at 9, Sept. 8, 2021. https://acore.org/wp-content/uploads/2021/10/Just_and_Reasonable.pdf; *see also* ANOPR at P 86.

[14] *Planning for the Future, FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* (Jan. 2021) at 21, 28-30, *available at* https://cleanenergygrid.org/wp-content/uploads/2021/09/ACEG_Planning-for-the-Future1.pdf

[15] Gramlich, Caspary, Goggin, Schneider, *Disconnected: The Need for New Generator Interconnection Policy*, at 7-8 (Jan. 2021) *available at* https://cleanenergygrid.org/portfolio/disconnected/

[16] Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather,* at 1-3, *available at* https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf (citing Executive Office of the President, *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages* at 3 (August 2013) *available at* https://www.energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf).

[17] ACEG Comments, Reliability Technical Conference, Docket No. AD21-11 at 2 (Feb. 22, 2022); *see also Grid Strategies, Fleetwide Failures: How Interregional Transmission Tends to Keep the Lights on*

- Without a large-scale transmission buildout, it will be impossible to achieve climate policies and bring on the lower-cost and cleaner resources for which utilities, states, and consumers have been calling. A timely, and well-planned, large-scale build out can save billions in energy costs.[18]

Policies and incentives that support transmission buildout have the potential to deliver huge benefits for America. The Commission's findings regarding the need for reform are real and must be addressed now, especially as both the need for transmission expansion and the investment needed to achieve that goal, are significant. ACEG encourages the Commission to act quickly to remedy deficiencies in the current transmission planning and cost allocation processes to address the issues discussed above and ensure that jurisdictional rates are just and reasonable, and in particular to address the areas of regional and interregional planning and cost allocation.

Long-Term Regional Transmission Planning

ACEG supports the pro-active, long-term, multi-benefit planning approach that the Commission is proposing through the requirement that transmission providers conduct Long-Term Regional Transmission Planning on a sufficiently forward-looking basis to meet transmission needs driven by changes in the resource mix and demand. Specifically, ACEG supports the proposal to require transmission providers to develop and plan on the basis of Long-Term Scenarios and to improve coordination of local and regional investments because such actions will lead to "right-sizing" transmission facilities. A 20-year planning horizon is appropriate as a minimum time frame for the Long-Term Regional Transmission Planning, and the Commission should consider a longer planning horizon of up to 40-years, to match the

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When There is a Loss of Generation, at 1 (2021) *available at* https://gridprogress.files.wordpress.com/2021/11/fleetwide-failures-how-interregional-transmission-tends-to-keep-the-lights-on-when-there-is-a-loss-of-generation.pdf

[18] Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather,* at 1-3, *available at* https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

expected asset life. A three to five-year frequency for Long-Term Scenarios is appropriate to balance the costs and the benefits of updating the inputs.

The Commission should require a common set of data inputs using best available data as defined in the NOPR. ACEG supports the Commission's proposal to require inclusion in the Long-Term Scenarios the identified categories of factors listed in the NOPR. However, the Commission should ensure that these factors are ***incorporated,*** not just ***considered***, in the scenarios. To provide flexibility, the Commission should also allow Long-Term Scenarios to select projects that demonstrate benefits even if they do not demonstrate them under all of the Long Term Scenarios. Finally, except for near-term reliability projects, the Commission should require multi-value assessments for planning processes to de-silo the planning processes as much as possible.

The Commission should require a minimum set of benefits that transmission providers must incorporate into Long-Term Regional Transmission Planning processes. Transmission providers should be required to include all twelve benefits that are listed and described in the NOPR. Just and reasonable rates require a balanced, unbiased analysis of both benefits and costs, both for planning purposes and for cost allocation principles under the Federal Power Act (FPA). Because a benefits analysis can be resource intensive given the complexity of power systems, ACEG recommends a screening approach, where benefit categories are initially screened for significance before investing staff resources and modeling work to provide a detailed quantification. A screening approach is preferable to allowing regions to explicitly ignore categories of benefits.

Additional benefits, such as carbon benefits, economic development, jobs, and local public health are often associated with transmission, and should be encouraged to be part of the transmission planning analysis.[19] Load diversity and its effect on reducing expensive generation capacity costs is a major, under-appreciated benefit of large-scale interregional transmission that should be included. Because different regions experience peak demand at different times, mostly due to variations in climate and weather, transmission allows peak electricity demand to be met with less generating capacity. As renewable energy resources are developed throughout the country, the total output of renewables will also likely vary by geographic area, such that "net load" (load minus generation) variability will be lower when transmission connects different areas.[20]

The final rule should adopt enhanced transparency requirements for local transmission planning and improve coordination between regional and local transmission planning with the goal of identifying opportunities to "right-size" replacement transmission facilities. Much of the nation's transmission facilities are over 50 years old.[21] To avoid creating a suboptimal transmission infrastructure network, a broader view of transmission planning is necessary in terms of replacement of existing, aging transmission facilities, coupled with a changing generation mix. ACEG supports the Commission's proposal to require transmission providers to consider "right-sizing" of existing facilities to strengthen the grid, with the incremental cost

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[19] *See generally*, ACEG, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.* (2020) *available at* https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf

[20] *Id.* at 19. *See also, e.g.*, Energy Systems Integration Group's Transmission Benefits Valuation Task Force, *Multi-Value Transmission Planning for a Clean Energy Future*, at 9, 28, 47 (2022) *available at* https://www.esig.energy/multi-value-transmission-planning-report/

[21] American Society of Civil Engineers, *Policy Statement 484 - Electricity Generation and Transmission Infrastructure* (July 13, 2019) *available at* https://www.asce.org/advocacy/policy-statements/ps484---electricity-generation-and-transmission-infrastructure; The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* at ii, 94 (2021) *available at* https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf

eligible for regional cost allocation. Without such a requirement, a large amount of new transmission investment – directed solely at replacement facilities – will be outside the Long-Term Regional Transmission Planning and thus not given an opportunity to contribute to the grid's overall efficiency and cost-effectiveness.

Transparent selection processes are the key to reducing conflict, developing legally sustainable long-term regional plans and transmission investments, and maximizing benefits over time to consumers without over-building transmission facilities. As ACEG noted in its comments to the ANOPR, "a rule relaxing the broad requirement for a competitive process is appropriate and upholds the Commission's duties under Sections 205 and 206 of the Federal Power Act." [22] As the Commission has proposed in the NOPR, there is also an opportunity to evaluate joint ownership models, which have long been a priority of the public power sector.[23] By taking a region-by-region or even context-specific approach to rights of first refusal, the Commission may achieve better results across all regions.

Cost Allocation

ACEG supports requiring transmission providers to fully identify benefits in the Long-Term Regional Transmission Planning process and account for the full list of benefits identified in the NOPR. This can help provide evidentiary support for cost allocation of Long-Term Regional Transmission Planning facilities and can aid in cost allocation decisions, particularly as to whether they adhere to the "beneficiary pays" and "roughly commensurate" requirements in the *Illinois Commerce Commission v. FERC* line of cases and their progeny.

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[22] ACEG, ANOPR Initial Comments at 9.

[23] NOPR at PP 351-358.

The Commission's finding that the current grid constraints are unjust and unreasonable is amply supported by the facts. First, there has been minimal construction of large regional or interregional projects in the past decade, despite the need for such facilities and Commission's clear direction that regional planning and construction is needed. Second, current planning processes do not secure all the resilience and reliability benefits that interregional connections and capacity transfers would provide. Finally, the existing transmission grid does not support access to sufficient clean energy resources to meet state public policies or national clean energy goals, and the markets' evolution. The final rule in this docket can expand upon the regulatory approach adopted in Order No. 1000, and foreshadowed by Order Nos. 888, 2000, and 890, based on a demonstrated need for the consumer benefits of larger power markets, enhanced reliability capabilities, and lower-cost decarbonized generation that interregional planning and cost allocation should produce.

Interregional Transmission Planning

ACEG supports major additional Commission action on interregional planning, so that Long-Term Regional Transmission Planning extends beyond current market structures, ISO/RTO territories, and bilateral planning areas. The developments of the last decade since Order No. 1000 was issued have made clear that the Commission must actively promote (if not require) interregional transmission planning and development. Accordingly, proactive interregional planning and cost allocation should be the next step for the Commission's electricity policy. Disparate regional priorities and increasing numbers of stakeholders that were unaligned have made interregional projects more difficult. Because interregional transmission capacity has not increased, the U.S. electrical grid has remained a patchwork quilt operationally, despite the fact that regional planning was mandated for transmission throughout the country.

The tragic suffering and loss that Texas (the ERCOT system) experienced during Winter Storm Uri in February 2021 because of a lack of access to diverse resources outside the state is ample demonstration of the risks posed by a lack of transfer capability between markets or regions, and among the RTOs. Moreover, the importance of broadening the geographical diversity of variable resources, which has become well understood in many regional processes, is just as applicable in the interregional construct. The Commission should move forward with policies on the interregional level that reflect the requirements established for regional planning.

II. NEED FOR REFORM

A. The Commission Has Properly Identified a Need for Reform of the Current Regional Transmission Planning and Cost Allocation Processes.

Current transmission planning and cost allocation processes are leading to investments in transmission infrastructure that are not efficient or cost effective. Consequently, the Commission has correctly concluded that continuing with the status quo "may result in transmission customers paying more than necessary to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof—either or both of which could potentially render Commission-jurisdictional rates unjust and unreasonable or unduly discriminatory or preferential."[24] ACEG agrees with the Commission's general findings of the need for reform and concurs that the Commission has an obligation under the FPA to remedy deficiencies in the currently transmission planning and cost allocation processes to ensure that jurisdictional rates are just and reasonable.

Large-scale transmission buildout is vital to achieving appropriate resource adequacy and resiliency in certain regions and bringing on the lower-cost and cleaner

[24] *Id.* at P 25.

resources that utilities, states, and consumers are pursuing. Independent estimates indicate that high-capacity transmission will need to double by 2030 and triple by 2050 at a cost of $360 billion through 2030 and $2.2 trillion by 2050 in order to achieve a zero-carbon future by 2050.[25] Updated policies and incentives are necessary to support the needed transmission expansion. Such policies can deliver huge benefits to consumers. For example, as discussed further below, the cost savings of effective, efficient and consistent transmission expansion can be in the billions.

B. The Commission Has the Authority and Responsibility to Remedy the Deficiencies in the Existing Regional Transmission Planning and Cost Allocation Processes.

FPA Section 206 allows the Commission to initiate a proceeding to revise any "rate, charge or classification" related to the transmission or sale of electricity that it determines is "unjust, unreasonable, unduly discriminatory or preferential."[26] Section 206 also allows the Commission to set aside wholesale rates and practices that are "unjust, unreasonable, unduly discriminatory or preferential."[27] The Commission may itself establish the just and reasonable rate under Section 206, provided that it *first* determines that the rate is unjust, unreasonable, or unduly discriminatory.[28] A finding that an existing rate or practice is unjust and unreasonable is

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[25] Americans for a Clean Energy Grid, *Planning for the Future, FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* (Jan. 2021) at 37, 90 and Appendix A, *available at* https://cleanenergygrid.org/wp-content/uploads/2021/09/ACEG_Planning-for-the-Future1.pdf (referencing Eric Larson *et. al.,* Net-Zero America: Potential Pathways, Infrastructure, and Impacts at 77, Dec. 15, 2020).

[26] 16 U.S.C. § 824e.

[27] *E.g.*, *S. Carolina Public Service Authority v. FERC*, 762 F.3d 41, 49 (D.C. Cir. 2014) ("To regulate a practice affecting rates pursuant to Section 206, the Commission must find that the existing practice is 'unjust, unreasonable, unduly discriminatory or preferential,' and the remedial practice it imposes is 'just and reasonable.'") (citing 16 U.S.C. 824e(a)).

[28] *E.g. Cities of Bethany v. FERC*, 727 F.2d 1131, 1143-1144 (D.C. Cir. 1984) (emphasis added) (citing 16 U.S.C. § 824e(a)). "The Commission has undoubted power under section 206" to change existing

the "condition precedent" to the Commission's exercise of its Section 206 authority to change that rate or practice.[29] Section 206(a) also allows the Commission to remedy any practice that *affects rates* for transmission if such practice is deemed to be unjust, unreasonable, unduly discriminatory or preferential.[30]

In several key rulemakings, the Commission successfully invoked its Section 206 authority to establish new and significant regulatory policy.[31] Courts have consistently upheld the Commission's authority to implement broad changes based on circumstances, specific factual findings, data, reports, or policy conclusions that are associated with the existence of unjust and unreasonable rates, terms or conditions, undue discrimination, limitations on competition, and industry developments.

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rates "*whenever it determines such rates to be unlawful*." *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956) (emphasis added).

[29] *Sierra Pacific Power*, 350 U.S. at 353. Without a showing that an existing rate is "unjust, unreasonable, unduly discriminatory or preferential," FERC is not authorized to impose a new rate. *See Fla. Gas Transmission Co. v. FERC*, 604 F.3d 636, 640-41 (D.C. Cir. 2010) (examining parallel requirement under the Natural Gas Act); *Sea Robin Pipeline Co. v. FERC*, 795 F.2d 182, 187 (D.C. Cir. 1986) (same).

[30] *S. Carolina Public Service Authority v. FERC*, 762 F.3d at 55-57 ("The text does not define 'practice' although use of the word 'any' amplifies the breadth of the delegation to the Commission.").

[31] For example, the Commission issued Order No. 888 to remove barriers to competition in the wholesale market and thereby increase efficiency and lower costs. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 FERC ¶ 61,080 (1996) [hereinafter Order No. 888]. The Commission relied on "general findings of systemic monopoly conditions and the resulting potential for anti-competitive behavior, rather than evidence of monopoly and undue discrimination on the part of individual utilities." The D.C. Circuit upheld Order No. 888, reasoning that the Commission's factual findings were sufficient under Section 206 and the Commission was not required to make specific findings. *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 688 (D.C. Cir. 2000), *aff'd sub nom.*, *New York v. FERC*, 535 U.S. 1 (2002). On appeal, the Supreme Court, in *New York v. FERC*, affirmed the D.C. Circuit and Order No. 888 on the grounds that the Commission met that test by finding "that electric utilities were discriminating in the 'bulk power markets,' in violation of § 205 of the FPA, by providing either inferior access to their transmission networks or no access at all to third-party wholesalers of power." *New York v. FERC*, 535 U.S. at 11.

Courts have also upheld the Commission's determination that existing transmission planning processes have a "direct and discernable" effect on rates for Section 206 purposes.[32] Beginning with Order No. 2000, the Commission established a framework for the development of RTOs by outlining four minimum characteristics and eight minimum functions that an organization must meet in order to become an RTO.[33] The Commission found that, since the passage of Order Nos. 888 and 889, there had been rapid growth in generation resources in the wholesale market, and that such resources were serving increasingly large areas, highlighting the importance of regional solutions.[34] The Commission cited a North American Electric Reliability Council (NERC) report that found that "the adequacy of the bulk transmission system has been challenged to support the movement of power in unprecedented amounts and in unexpected directions" and that these shifts "will test the electric industry's ability to maintain system security in operating the transmission system under conditions for which it was not planned or designed."[35]

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[32] *S. Carolina Public Service Authority v. FERC*, 762 F.3d at 57 (noting that a failure to act qualifies as a practice under Section 206 that FERC must remedy when the failure to act is unjust, unreasonable, unduly discriminatory or preferential and "directly affects or is closely related to jurisdictional rates.").

[33] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999) (cross-referenced at 89 FERC ¶ 61,285, at pp. 5, 151), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000) (cross-referenced at 90 FERC ¶ 61,201), *aff'd sub nom.*, *Pub. Util. Dist. No. 1 of Snohomish Cty. v. FERC*, 272 F.3d 607 (D.C. Cir. 2001); *La. Pub. Serv. Comm'n v. Entergy Corp.*, Opinion No. 519-A, 153 FERC ¶ 61,188 (2015) (Order No. 2000); 18 C.F.R. § 35.34. Order No. 2000 determined that RTOs should be independent, have a regional scope, possess operational authority, and be responsible for maintaining short term reliability of the grid in addition to having the following capabilities: (1) tariff administration and design; (2) congestion management; (3) parallel path flow; (4) ancillary services; (5) OASIS and total transmission capability and available transmission capability; (6) market monitoring; (7) planning and expansion; and (8) interregional coordination. The Commission anticipated that Order No. 2000 would create a future where all transmission facilities were under the control of RTOs, but it made RTO participation voluntary. 89 FERC ¶ 61,285 at pp. 151, 323.

[34] 89 FERC ¶ 61,285 at pp. 13-14.

[35] *Id.* at pp. 16-18 The Commission also cited a FERC Staff report that concluded that increased regional coordination was necessary to meet reliability concerns. *Id.* at p. 19. These findings were echoed in the final report of the Secretary of Energy Advisory Board Task Force which found that "the traditional reliability institutions and processes that have served the Nation well in the past need to be modified to

Additionally, the Commission cited "unprecedented high spot market prices" in the wholesale electric market as evidence of a developing problem.[36] The Commission noted a decline in investments in planned transmission, without which regional planning would further undermine the capacity to address complex issues. Finally, with respect to undue discrimination, the Commission found that "when utilities control monopoly transmission facilities and also have power marketing interests, they have poor incentives to provide equal quality transmission service to their power marketing competitors."[37] In light of these factors, the Commission determined that increased regional planning was necessary to maintain reliability and prevent undue discrimination. Order No. 2000 was designed to remedy these issues by strongly encouraging the development and participation in RTOs.

The Commission addressed comments that the evidence of undue discrimination was insufficient to justify generically mandating RTO participation as a remedy or that the record on undue discrimination was insufficient to impose a generic, industry-wide solution. The Commission concluded that continuing opportunities for undue discrimination exist in the electric transmission industry, but a voluntary approach to eliminating such opportunities through RTO formation represents a "measured and appropriate response to the significant undue discrimination and other competitive impediments identified in the record."[38]

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ensure that reliability is maintained in a competitively neutral fashion;" that "grid reliability depends heavily on system operators who monitor and control the grid in real time;" and that "because bulk power systems are regional in nature, they can and should be operated more reliably and efficiently when coordinated over large geographic areas." *Id*. at pp. 20-21.

[36] *Id.* at pp. 18-19.

[37] *Id*. at p. 35.

[38] *Id*. at p. 144. S*ee also* Order No. 2000-A, 90 FERC ¶ 61,201 at p. 13.

Order No. 890 implemented a number of reforms to remedy undue discrimination in transmission service, including requiring "coordinated, open, and transparent transmission planning."[39] The Commission found that the "economic self-interest of transmission monopolists" incentivized transmission owners to deny or offer inferior transmission to third parties. These incentives then led to discriminatory behavior.[40] Under Section 206, and in line with *Associated Gas Distributors v. FERC*[41], the Commission determined it had a responsibility to correct undue discrimination. The Commission relied on commenters that had experienced or perceived discriminatory conduct by transmission providers as evidence, noting that the "courts have made clear that the Commission need not make specific factual findings of discrimination in order to promulgate a generic rule to eliminate undue discrimination."[42] The Commission noted that specific factual findings were not required and that it had "ample grounds to act as necessary to limit opportunities for undue discrimination that continue to exist under the *pro forma* open access transmission tariff (OATT)."[43]

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[39] *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), 118 FERC ¶ 61,119, P 418, *order on reh'g*, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) [hereinafter Order No. 890].

[40] Order No. 890, 118 FERC ¶ 61,119 at PP 39, 423, 523.

[41] 824 F.2d 981 (D.C. Cir. 1987), "Courts reviewing an agency's selection of means are not entitled to insist on empirical data for every proposition on which the selection depends" and "[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." *Id.* at 1008.

[42] Order No. 890 at P 41. The Commission determined that "the existing *pro forma* OATT continued to allow transmission providers substantial discretion in implementing some of its basic requirements. This discretion, in turn, created substantial opportunities for undue discrimination. " *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890-A, 121 FERC ¶ 61,297 at P 7 (2007).

[43] Order No. 890-A at P 8. The Commission invoked prior legal precedent, including *Associated Gas Distributors v. FERC*, to support its analysis. *Id.* at P 14 (discussing *Associated Gas Distributors v. FERC*, 824 F.2d 981 (D.C. Cir. 1987)).

Order No. 1000 made several sweeping reforms to transmission planning and cost allocation. Specifically, it: (1) requires public utilities to participate in a regional planning process, (2) eliminates the federal right of first refusal ("ROFR"), (3) requires transmission providers to "improve coordination across regional transmission planning processes" by developing and implementing procedures for joint evaluation and information sharing, and (4) requires transmission providers to have cost allocation methodologies in place for new transmission facilities selected as part of the regional transmission plan.[44] The Commission promulgated Order No. 1000 to improve transmission planning and cost allocation processes under the OATT to ensure that the rates, terms and conditions of service provided by transmission providers are just and reasonable and not unduly discriminatory or preferential.[45]

The Commission found that Order No. 890 was inadequate and that the siting, permitting, and cost allocation of transmission facilities continued to face substantial challenges, evidenced, in part, by congestion costs.[46] In addition, the Commission discussed existing deficiencies in the electric power industry that justified the timing of Order No. 1000: (1) not having a regional transmission plan could hinder the construction of new transmission facilities; (2) new transmission needs driven by public policy, such as renewable portfolio standards, were not accounted for existing transmission planning mechanisms; (3) obstacles hindered the development of nonincumbent transmission projects; (4) lack of coordination between

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

[45] *Id.*

[46] Order No. 1000, 136 FERC ¶ 61,051 at P 3; *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, NOPR, 131 FERC ¶ 61,253 (2010) (discussing increased capacity prices in transmission-constrained areas).

transmission planning regions; and (5) challenges associated with allocating the cost of transmission that have "become more acute as the need for transmission infrastructure has grown."[47] The Commission determined these deficiencies were creating inequitable circumstances that could be characterized as unjust and unreasonable or unduly discriminatory.

In response to arguments that the Commission did not provide sufficient evidence to support Section 206 action, the Commission noted that the substantial evidence test in Section 313(b) of the FPA "makes Commission findings of fact conclusive if they are supported by substantial evidence . . . [and] [w]hen applied in a rulemaking context, the substantial evidence test is identical to the familiar arbitrary and capricious standard."[48] Therefore, the Commission need only show "that a reasonable mind might accept that the evidentiary record here is adequate to support a conclusion . . . that this Final Rule is needed to correct deficiencies in transmission planning and cost allocation processes[.]"[49] Additionally, the Commission relied on prior court precedent that it stated has "made clear that the Commission need not make specific factual findings of discrimination to promulgate a generic rule to ensure just and reasonable rates or eliminate undue discrimination."[50] The Commission received numerous comments from commenters that experienced unjust and unreasonable or discriminatory practices in the transmission service provided by transmission providers. It therefore found that was sufficient to sustain its obligation under Section 206.

On appeal to the D.C. Circuit, Petitioners challenged the Commission's Section 206 authority in a variety of ways. First, Petitioners argued that FPA Sections 205 and 206 only

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[47] Order No. 1000, 136 FERC ¶ 61,051 at P 485.

[48] *Id.* at P 48 (internal quotations omitted).

[49] *Id.* (internal quotations omitted).

[50] *Id.* at P 58 (internal quotations omitted).

allow the Commission to regulate existing commercial relationships and that a lack of regional transmission planning does not qualify as an existing practice and therefore the Commission did not have the requisite authority. The court was not persuaded by this and noted the broad authority given to the Commission under Section 206.[51] Second, Petitioners argued that the "theoretical threat"[52] outlined by the Commission was insufficient to meet the evidentiary burden under Section 206. In holding the "theoretical threat" was sufficient, the court reaffirmed that it has consistently held that substantial evidence does not mean empirical evidence and "[s]o long as a prediction is at least likely enough to be within the Commission's authority and it is based on reasonable economic propositions, the court will uphold it."[53] In finding that the Commission met this standard, the Court discussed a report from The Brattle Group as well as comments to the rulemaking that described similar problems.[54]

Third, the D.C. Circuit also rejected arguments under FPA Section 202(a) that the Commission exceeded its voluntary planning arrangement authority. Section 202(a) of the Federal Power Act "empower[s] and direct[s]" the Commission "to divide the country into regional districts for the voluntary interconnection and coordination of facilities."[55] The Court agreed with the Commission that Section 202(a)'s reference to voluntary coordination does not preclude mandatory planning activities. Rather, the voluntary coordination referred to in Section

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[51] *S. Carolina Public Service Authority v. FERC*, 762 F.3d 41, 71, 91 (D.C. Cir. 2014).

[52] *Id.* at 65; *See Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 839-41 (D.C. Cir. 2006) (upholding the Commission when it demonstrated both a theoretical threat and evidence or examples that the threat was occurring).

[53] *S. Carolina Public Service Authority v. FERC*, 762 F.3d at 65 (internal quotations omitted).

[54] *Id.*

[55] 16 U.S.C. § 824a(a) (emphasis added).

202(a) applies only to the operation of existing facilities, not to the planning of new facilities, which "'occurs before [facilities] can be interconnected.'"[56]

Finally, the Court noted that "[b]ased on its expertise and experience, the Commission's determination that the current planning and cost allocation practices were unjust or unreasonable warrants substantial deference from this court."[57]

C. Consistent With Prior Orders, the Commission has Authority Under Section 206 to Require the Transmission Planning Reforms Proposed in the NOPR.

In the decade since Order No. 1000 was issued, the Commission finds that "there is mounting evidence that the Commission's regional transmission planning and cost allocation requirements may be inadequate to ensure Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential."[58] In the NOPR, the Commission stated that it was concerned that the Order No. 1000 processes "may not be planning transmission on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand" and, as a result, the Order No. 1000 regional transmission planning and cost allocation processes "may not be identifying the more efficient or cost-effective transmission facilities."[59]

> We are concerned that continuing with the status quo approach may cause public utility transmission providers to undertake relatively inefficient investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. That dynamic may result in transmission customers paying more than necessary to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof—either or both of which could potentially render Commission-jurisdictional rates unjust and

[56] *S. Carolina Public Service Authority v. FERC*, 762 F.3d at 59 (D.C. Cir. 2014) (quoting Order No. 1000 at P 124, 77 Fed. Reg. at 32,206).

[57] *Id.* at 67 (internal quotations omitted).

[58] NOPR at PP 24-25.

[59] *Id.*

> unreasonable or unduly discriminatory or preferential. As the Commission has an obligation under the FPA to ensure that those rates are just and reasonable and not unduly discriminatory or preferential, we are proposing reforms to remedy these potential deficiencies in the Commission's existing regional transmission planning and cost allocation requirements.[60]

As the Commission noted, continuing with the status quo for many regions will result in short-term, piecemeal transmission expansion to meet needs driven by changes in the resource mix and demand.[61] Such short-term piecemeal transmission expansion will be unlikely to identify the more efficient or cost-effective solutions to transmission needs driven by changes in the resource mix and demand and thus will result in unjust and unreasonable transmission rates. The Commission therefore correctly concluded that the reforms in the NOPR to promote long-term transmission planning are necessary to ensure that transmission rates are just and reasonable. Such findings are consistent with previous orders on transmission planning that have been upheld in other rulemakings.

The extensive record developed in response to the ANOPR and the additional evidence likely to be presented in response to the NOPR, supports the conclusion that the lack of Long-Term Regional Transmission Planning is more than a theoretical threat. Indeed, studies have shown that considerable economic benefits can result from Long-Term Regional Transmission Planning that includes increased interregional transmission planning. Severe weather events alone are estimated to cost Americans between $25 and $70 billion each year.[62] Studies have

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[60] *Id.* at P 25 (internal footnotes omitted).

[61] *Id.* at P 27.

[62] Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather* at 1-3, 12, *available at* https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf (citing Executive Office of the President, *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages* (August 2013) *available at* https://www.energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf).

shown that additional transmission investment could have saved billions.[63] The fact that these costs can be avoided with improved regional and interregional planning is evidence that current processes are inefficient and result in higher costs.[64]

As with Order No. 1000, the Commission should act based on its expertise and experience and its determination that the current planning and cost allocation practices are unjust or unreasonable.[65] Commission action in this proceeding is sufficiently based on past experience and reasonable economic propositions.[66] Moreover, the record in this proceeding is stronger than in previous rulemakings because it contains empirical evidence in addition to reasonable predictions rooted in economic principles to support the Commission's findings.[67]

III. LONG TERM REGIONAL TRANSMISSION PLANNING

ACEG supports nearly all aspects of the Commission's proposed Long-Term Regional Transmission Planning requirements and recommends that the Commission require regions to plan based on reasonable future scenarios that use the best available data and forecasting

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[63] For example, Winter Storm Uri (February 2021) – An additional 1 gigawatt (GW) of transmission ties between ERCOT and the Southeastern U.S. could have saved nearly $1 billion and kept power flowing to hundreds of thousands of Texans. Each 1 GW of transmission ties could have saved an additional $100 million to consumers in the Great Plains (SPP region) and Gulf Coast States (MISO region). Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather,* at 1-3, 12, https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf; ACEG Comments, Reliability Technical Conference, Docket No. AD21-11 at 5 (Feb. 22, 2022).

[64] Goggin, Michael *et. al.*, *Fleetwide Failures: How Interregional Transmission Tends to Keep the Lights on When There Is a Loss of Generation* (Nov. 2021) *available at* https://gridprogress.files.wordpress.com/2021/11/fleetwide-failures-how-interregional-transmission-tends-to-keep-the-lights-on-when-there-is-a-loss-of-generation.pdf. *See also* GE International, Inc., *Potential Customer Benefits of Interregional Transmission* (Nov. 2021) *available at* https://acore.org/wp-content/uploads/2021/12/02-GEEnergyConsulting_ACORE_InterregionalTransmissionMemo_211129.pdf

[65] *S. Carolina Public Service Authority v. FERC*, 762 F.3d at 67 ("[b]ased on its expertise and experience, the Commission's determination that the current planning and cost allocation practices were unjust or unreasonable warrants substantial deference from this court.").

[66] *Id*. at 65 ("[s]o long as a prediction is at least likely enough to be within the Commission's authority and it is based on reasonable economic propositions, the court will uphold it.").

[67] *Id*.

methodologies. Long-Term Regional Transmission Planning requires the incorporation of resource cost curves, public policies, and corporate and utility procurement targets, among other things. These all fall under FERC's authority to require planning to be conducted using reasonably available information, just as FERC requires RTOs to establish capacity requirements based on their projections of load that is influenced by state energy efficiency policies and other factors.[68] The Commission is permitted to "recognize[] that state and federal policies might affect the transmission market" and require entities to plan accordingly.[69]

To ensure there is a pro-active, long-term, multi-benefit planning approach to planning, ACEG has a number of specific recommendations in response to the Commission's proposed requirements and request for comments, as discussed below.

A. Long Term Scenario Planning Will Support a Pro-Active, Long-Term, Multi-Benefit Planning Approach.

As proposed in the NOPR, transmission providers must identify transmission needs driven by changes in the resource mix and demand through the development of Long-Term Scenarios.[70] Specifically, the Commission proposes that transmission providers develop at least four Long Term Scenarios, with at least one of the four accounting for uncertain operational outcomes that determine the benefits of, or need for, transmission facilities during high-impact, low-frequency events (*e.g.*, extreme weather or cyber-attacks, etc.).[71] The Commission proposes that the Long-Term Scenarios be based on a 20-year planning horizon and must be reassessed at

[68] Americans for a Clean Energy Grid, *Planning for the Future, FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* at 82 (Jan. 2021) *available at* https://cleanenergygrid.org/wp-content/uploads/2021/09/ACEG_Planning-for-the-Future1.pdf

[69] *S. Carolina Public Service Authority v. FERC*, 762 F.3d at 89.

[70] NOPR at P 69.

[71] *Id.* at P 124. In the final rule, the Commission should require planners to identify plausible, potentially high impact weather-based and other scenarios relevant to their region.

least once every three years, with no overlapping assessments.[72] The Commission also proposes that the Long-Term Scenarios utilize "best available data" and include a set of Commission-identified categories of factors that may drive transmission needs driven by changes in resource mix and demand. Below, ACEG provides some recommendations on these requirements.

1. The Planning Horizon Should Be a Minimum of 20 Years and Potentially Longer.

The proposed 20-year planning horizon is appropriate as a minimum requirement given the long lead time required to construct new transmission facilities. A 40-year transmission planning horizon should also be considered because it will allow transmission providers to identify transmission needs driven by changes in the resource mix and demand over the expected life of most transmission assets. Standard regulatory practice for a benefit-cost analysis is typically the life of the asset. Importantly, a 40-year planning horizon will enable transmission providers to capture long-term benefits and thus more efficiently and/or cost-effectively meet such transmission needs and allocate costs in accordance with the beneficiary pays principle.

With respect to benefits, the Commission stated, "while we believe that 20 years may strike a reasonable balance, we also believe that a time horizon longer than 20 years for the evaluation of benefits may be consistent with the long life of transmission facilities—which generally exceeds 20 years by a substantial margin—and also consistent with the fact that transmission facilities provide significant benefits over their entire useful life."[73] ACEG's position is that the proper time horizon for evaluation of benefits is a minimum of 20 years and potentially longer to better match the life of the asset. The time horizon for planning and evaluation of benefits should be the same.

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[72] *Id.* at P 100.

[73] *Id.* at P 229.

2. A Three to Five-Year Frequency for Long-Term Scenario Updates is Appropriate.

A frequency of three to five years for reassessing and revising Long-Term Scenarios is appropriate. Updating the data inputs and factors incorporated in previously developed Long-Term Scenarios appropriately balances the benefits and burdens of such updates.[74] Reassessing and revising Long-Tern Scenarios is appropriate to reflect changes in technology, resource development and customer demand. If done too frequently, reassessing and revising Long-Term Scenarios may impose more costs than benefits, especially if the inputs have not changed much. A three-to-five-year frequency seems to strike the right balance.

3. A Common Set of Data Inputs Using Best Available Data is Essential.

The Commission requested comments on whether and how the categories of factors enumerated in the NOPR that may drive transmission needs adequately capture the factors expected to drive changes in the resource mix and demand.[75] Specifically, the NOPR proposed that the following identified categories of factors that may drive transmission needs driven by changes in resource mix and demand be incorporated in the Long-Term Scenarios;[76]

(1) federal, state, and local laws and regulations that affect the future resource mix and demand;
(2) federal, state, and local laws and regulations on decarbonization and electrification;
(3) state-approved utility integrated resource plans and expected supply obligations for load serving entities;
(4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation;
(5) resource retirements;
(6) generator interconnection requests and withdrawals (*i.e.*, needs that have been identified "multiple times" in the interconnection process but have never been constructed due to withdrawals); and

[74] *Id.* at P 100.

[75] *Id.* at P 112.

[76] *Id.* at P 104.

(7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand.[77]

The Commission also proposes to require that transmission providers use "best available data inputs" when developing Long-Term Scenarios. The Commission defines "best available data inputs" as those that are timely (*i.e.*, based on the most current information), developed using diverse and expert perspectives, adopted via a process that satisfies the transparency planning principle described in the NOPR, and that reflect the list of factors that public utility transmission providers must incorporate into Long-Term Scenarios.[78] Examples of best available data inputs could include the long-term load forecasts of demand that RTOs/ISOs currently use for predicting long-term resource adequacy and the most recent data on renewable energy potential and distributed energy resources developed by national labs.[79]

ACEG supports the Commission's proposal to require the identified categories of factors to be ***incorporated,*** not just ***considered***, in the Long-Term Scenarios. FPA Section 217(b)(4) supports the Commission's proposed requirement to plan based on the best available data and forecasting methodologies, and to include public policies and utility and corporate renewable procurement goals within planning scenarios.[80] Section 217(b)(4) requires the Commission to exercise its authority "in a manner that facilitates the planning and expansion of transmission

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[77] The NOPR also proposes that additional categories of factors can be incorporated if the Transmission Provider demonstrates that the incorporation of more than the minimum is consistent with or superior to the final rule. *Id.* at P 105.

[78] *Id.* at P 131. "By 'best available,' we do not imply that there is a single "best" value for each data input that public utility transmission providers must use, but rather that best practices are used to develop that data input." *Id.* at P 130.

[79] *Id.* at P 131 (citing US DOE Comments, Attach. B at 79, 94 (discussing NREL's Renewable Energy Potential Model and Distributed Generation Market Demand Model)).

[80] Americans for a Clean Energy Grid, *Planning for the Future, FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* at 83(Jan. 2021) *available at* https://cleanenergygrid.org/wp-content/uploads/2021/09/ACEG_Planning-for-the-Future1.pdf

facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of load-serving entities."[81] Load serving entities' service obligations will be more accurately predicted by the best available forecasting methodologies, and will naturally depend upon both public policies and the resource preferences of their customers.[82]

There is some confusion, however, in the Commission's proposal as to what exactly is required to be incorporated in the Long-Term Scenarios because, for many of the factors, the Commission proposes to allow transmission providers flexibility to discount those factors, and some are less binding than others. As a result, these factors are not really required to be incorporated and are instead only required to be considered. The Commission should apply a presumption that all of the listed factors are required to be incorporated unless the Commission approves a request from the transmission provider that a factor should not be included.

Factors (1), (2), and (3) are fairly straight forward and can be readily incorporated in transmission plans without the need for planners to exercise much discretion. Indeed, Order No. 1000 already requires that state laws and most other binding obligations be incorporated in transmission planning. Thus, it is appropriate for the final rule to require that these identified categories of factors continue to be incorporated in transmission plans. Factors (4), (5), (6) and (7) are new factors that the Commission acknowledges are flexible, voluntary, or require the exercise of some discretion. As a result, it does not appear that the Commission is proposing these factors as new ***requirements.***

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[81] 16 U.S.C. 824q(b)(4).

[82] Americans for a Clean Energy Grid, *Planning for the Future, FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* at 82 (Jan. 2021) *available at* https://cleanenergygrid.org/wp-content/uploads/2021/09/ACEG_Planning-for-the-Future1.pdf (citing Order No. 1000-A, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 139 FERC ¶ 61,132 at P 175 (2012)).

Specifically, the Commission states that with respect to factors (4), (5) and (6), transmission providers will have flexibility in how these factors are incorporated.[83] If not limited, providing flexibility could mean that these factors are not incorporated at all. Some transmission providers may be able to avoid incorporating some or all of these factors and essentially maintain the status quo. With respect to factor (7), the NOPR states that this factor is "less binding" and "more likely to change over time" and thus it may be appropriate to discount such goals and not assume that goals will be fully met.[84] It would be unfortunate if the information called for in factor (7) – utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand – were not requirements to be considered in the Long Term Scenarios. The focus of the NOPR is to ensure that transmission needs to accommodate future resource mix and demand are met. It would be a gaping hole in that mission if utility and corporate commitments and federal, state and local goals were excluded from or discounted in the analysis at the discretion of the transmission provider. Thus, there should be some limits on the flexibility and discretion allowed with respect to these factors, such as with a presumption of inclusion unless otherwise approved by the Commission.

In addition to the factors discussed above, utility and consumer stated resource mix targets should also be incorporated. The sources of information for estimating future generation type and location should include state policy, publicly stated utility resource plans (including SEC filings and public statements), integrated resource plans, known environmental regulations, expected retirements, and other publicly available information.[85] If resources are chosen by

[83] NOPR at P 107.

[84] *Id.* at P 108.

[85] For example, such information could come from SEC filings. The SEC's proposed rule would require registrants to provide certain climate-related information in their registration statements and annual

utilities in their resource plans for whatever reason, then planners should plan for them. All publicly stated load-serving entity decarbonization and/or resource plans and commitments should be included as inputs. To the extent retirements will be needed to meet these targets, these should be included in the future resource mix even if not specifically announced yet.

Stakeholder proposed corporate demand, including corporate buyer commitments, should also be incorporated. Plans should incorporate best available estimates based on best available data. Corporate demand is part of available data. Regional differences can be recognized where state public utility commissions develop scenarios without undermining the need for accurate Long-Term Regional Transmission Planning.

The Commission should also require an accurate estimate of the quantity and location of future generation based on load-serving entity expressed preferences. In requiring the best available inputs, the Commission should ensure that load-serving entities' expressed preferences for future resource commitments are taken into account. This ensures that planners are utilizing an accurate measure of the quantity and location of likely future generation. In doing so, the Commission would not be making any value judgment on particular resources or judging the nature or timing of resource commitments. Rather, the Commission would be requiring the use of best available data, where it exists, in this case in the form of future resource preferences or commitments.

Finally, ACEG supports a requirement to use "best available inputs" to transmission planning. "Best available inputs" is a standard and traditional regulatory requirement reflecting inherent uncertainty but the need to make investment decisions on behalf of consumers with the

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reports. The Enhancement and Standardization of Climate -Related Disclosures for Investors, Proposed Rule, File No. S7-10-22, *available at* https://www.sec.gov/rules/proposed/2022/33-11042.pdf best information possible. Uncertainty in transmission planning is inevitable and is present on both the demand side and the generation side, but it can be managed through sound forecasting and planning processes. The Commission should aid this process by identifying or standardizing the best available data inputs that meet this proposed requirement.[86] Using a common set of inputs and assumptions can support improved coordination of local and regional investments.

4. Projects Should Not Have to Be Beneficial Under All of the Long-Term Scenarios.

The Commission asserts that by utilizing multiple Long Term Scenarios, transmission providers "can also manage uncertainties about future system conditions and better identify more efficient or cost-effective regional transmission facilities by evaluating which transmission facilities are beneficial under multiple scenarios."[87] ACEG cautions that the phrase "evaluating which transmission facilities are beneficial under multiple scenarios" might allow those who disfavor transmission development to advocate for a policy under which only facilities that are beneficial under all of the Long-Term Scenarios can be built. Such a policy is unreasonable as a facility may only be beneficial under a few of the scenarios but is needed by the region. The Commission should ensure that projects are not required to be beneficial under all of the Long-Term Scenarios in order to get built.

5. The Commission Should Require Multi-Value Analyses for Economic Planning Processes.

The proposed rule maintains the reliability, economic and public policy "buckets" for transmission planning, which are near term. The Commission asked for comments on whether transmission providers should be required to incorporate some form of scenario analysis into

[86] NOPR at P 134.

[87] *Id.* at P 87.

their existing reliability and economic regional transmission planning processes to identify more efficient or cost-effective transmission facilities than are identified through those processes today.[88]

ACEG's response is yes. The Commission should change the current "siloed" approach to planning, with the exception of short-term reliability projects. The benefits of transmission facilities should be considered in a holistic manner, not in silos. Near-term reliability planning is driven by NERC requirements and should remain in its own sphere. However, the results of any separate processes should be reviewed to identify opportunities for optimization or "right-sizing." Further, where there should be opportunities for right-sizing of reliability projects and to the extent right-sizing of such projects can meet the reliability need on the required timeframe, such optimization and "right-sizing" must be considered.

Principles proposed for long term planning should also apply to nearer term economic and longer-term reliability planning. For example, if there is resilience value to a line that is not strictly required to comply with a reliability standard, that value should be taken into account. The Commission should also require use of comprehensive transmission network portfolios to address system needs more efficiently than the single project-by-project approach. In addition, the Commission should require planners to consider all technologies (DC, AC, advanced conductors, grid-enhancing technologies, and other new technologies that might arise), as they may improve the network's efficiency and reliability.

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[88] *Id.* at P 90.

B. The Commission Should Require a Minimum Set of Benefits that Transmission Providers Must Incorporate into Decision-Making.

In the NOPR, the Commission declined to prescribe any particular definition of benefits or beneficiaries or require use of any specific benefits. As with Order No. 1000, the NOPR proposes to allow for regional flexibility and to consider benefits on review of compliance proposals.[89] The Commission seeks comment on "whether public utility transmission providers should be required to use some or all of the Long-Term Regional Transmission Benefits as a minimum set of benefits for their Long-Term Regional Transmission Planning process."[90]

ACEG believes that transmission providers should be required to include all of the Long-Term Regional Transmission Benefits as a minimum set of benefits for their Long-Term Regional Transmission Planning process. Such a requirement will better facilitate both regional and interregional planning as a minimum set of benefits will help lay the foundation for joint planning across regions.

The list of benefits should include all twelve that are described in the NOPR. Just and reasonable rates require a balanced, unbiased analysis of both benefits and costs. Ensuring just and reasonable rates through an assessment of benefits should not vary significantly from one region to another. The minimum set of benefits should be implemented as universally as possible across RTOs/ISOs and non-RTO/ISO regions. Variance to the rule, if requested, should be demonstrated to allow flexibility, while the general rule stands as the backstop to preserve just and reasonable rates. In addition to the planning process, it is important in the cost allocation process to consider all benefits and all costs to achieve an outcome in which beneficiaries pay, consistent with cost allocation principles under the roughly commensurate principle.

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[89] *Id.* at P 183.

[90] *Id.* at P 188.

ACEG recognizes that a benefits analysis can be resource intensive given the complexity of power systems. For that reason, a screening approach, where benefit categories are initially screened for significance could be a useful approach. If a benefit category is estimated initially to have only small impacts on total benefits, then it could be prudent not to invest the staff resources and modeling work into a detailed quantification. A screening approach is better than allowing regions to explicitly ignore categories of benefits.

1. Specific Benefit Categories

The Commission provides a list of benefits that is not exhaustive and transmission providers have flexibility to propose what benefits to use.[91] This list includes:

(1) Avoided or deferred reliability transmission projects and aging infrastructure replacement;
(2) either reduced loss of load probability or reduced planning reserve margin;
(3) production cost savings;
(4) reduced transmission energy losses;
(5) reduced congestion due to transmission outages;
(6) mitigation of extreme events and system contingencies;
(7) mitigation of weather and load uncertainty;
(8) capacity cost benefits from reduced peak energy losses;
(9) deferred generation capacity investments;
(10) access to lower cost generation;
(11) increased competition;
(12) increased market liquidity.[92]

The Commission seeks comment on each of the Long-Term Regional Transmission Benefits, and how to ensure that each type of benefit is distinct such that the list of benefits does not "double count" benefits.[93] ACEG supports the specific list of benefits proposed in the NOPR. The list of 12 benefits are exclusive items. There is no double counting or redundancy between the 12 categories of benefits.

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[91] *Id.* at PP 184-186.

[92] *Id.* at P 185.

[93] *Id.* at P 187.

ACEG considers the list of 12 benefits in the NOPR to be a very modest set. ACEG notes that additional benefits, such as carbon benefits, economic development, jobs, and local public health are often associated with transmission, but the Commission does not include them in the enumerated list. While regional planning entities can incorporate those types of benefits if they choose and file them under Section 205 of the FPA, and the Commission can accept them in that context both for planning and cost allocation, we recognize the higher burden falling on the Commission in a Section 206 context in terms of determining what is just and reasonable. Thus, ACEG would support a final rule that does not include these additional benefits in a Section 206 context.

In addition, there are some other benefits that are not included in the enumerated list that can be very significant and yet are typically ignored in transmission planning today. In particular, load diversity and its effect on reducing very expensive generation capacity costs is a major, under-appreciated benefit of large-scale interregional transmission. Because different regions experience peak demand at different times, mostly due to variations in climate and weather, transmission allows peak electricity demand to be met with less generating capacity. As renewable energy expands, the total output of renewables will also likely vary by geographic area, such that "net load" (load minus generation) variability will be lower when transmission connects different areas.

Benefit (1) Avoided or deferred reliability transmission projects and aging infrastructure replacement[94]

ACEG supports inclusion of this benefit category and the definition provided in the NOPR. This benefit reflects that reliability considerations and replacing aging assets drive

[94] *Id.* at PP 190-193.

significant investment in transmission and account for almost all of the approximately $25 billion per year being spent nationally on transmission.[95] Economic considerations rarely enter those investments; rather they are undertaken if reliability standards say they are needed. The savings from more efficient transmission system designs are real savings that should be attributed to transmission plans that find more efficiency than this baseline. This benefit has been incorporated into a number of planning studies and plans.[96]

Benefit (2) Either reduced loss of load probability or reduced planning reserve margin[97]

ACEG supports this benefit category and the definition provided. ACEG agrees that the benefit can be included as either the value of reduced loss of load probability or reduced planning reserve margin, but not both.

Generation resource adequacy has often been a major source of benefit that has driven much of the development of interconnections between utilities throughout the industry's history. Looking forward, as renewable penetration increases, the resource adequacy benefit of

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[95] The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs,* at 2 (2021) *available at* https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Planning-for-the-21st-Century-Proven-Practices-that-Increase-Value-and-Reduce-Costs.pdf. *See also* Comments of ACEG, FERC Docket No. RM.21-17-000 (Oct. 12, 2021).

[96] Order No. 1000, 136 FERC ¶ 61,051 at P 81 (2011); *S.C. Elec. & Gas Co.*, 143 FERC ¶ 61,058 at P 232 (2013); The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs,* at 37 (2021) *available at* https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf; SPP, *SPP Benefit Metrics Manual* at 15 (Nov. 6, 2020); The Brattle Group, Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades at 114 (Sept. 15, 2015) *available at* https://www.brattle.com/wp-content/uploads/2017/10/5721_benefit-cost_analysis_of_proposed_new_york_ac_transmission_upgrades.pdf; MISO, *Proposed Multi Value Project Portfolio: Business Case Workshop* at 42-44 (2011) *available at* https://nocapx2020.info/wp-content/uploads/2014/04/20110919-MVP-Proposed-Portfolio-Business-Case.pdf; Australian Energy Market Operator, *2022 Integrated System Plan* at 64 (2022) *available at* https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en.

[97] NOPR at PP 194-197.

geographic diversification will be significant to capture the reliability benefit of renewables in different wind regimes, weather patterns, and time zones.

An aspect of wind and solar energy is that when their output is low in one place, it is often high in a neighboring area, and these output patterns can be measured over time and probabilistically estimated prospectively. Figure 1 shows that when wind output is at its lowest in the Great Lakes states, at 7 percent capacity factor, it is 3-6 times higher in neighboring areas, at 19-44 percent on the same day.[98] ***Attachment 1*** contains similar maps showing the least-windy day in each planning area from 2007 to 2013. Each map shows similar results: when it is not windy in one planning area, it is windy in other areas. Figure 2 shows the same is true for solar: on the least sunny day in one planning area, surrounding areas are sunny on that same day. ***Attachment 1*** also contains similar maps showing similar results for the least-sunny day in each planning area from 2007-2013.

[98] Attachment 1 at 10.

Figure 1: When wind is low in one area it is typically normal or high in neighboring areas.[99]

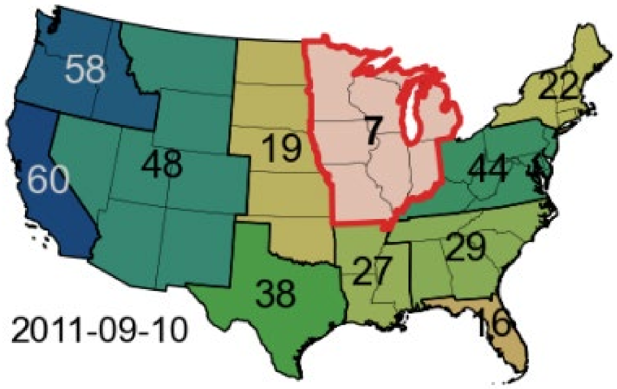
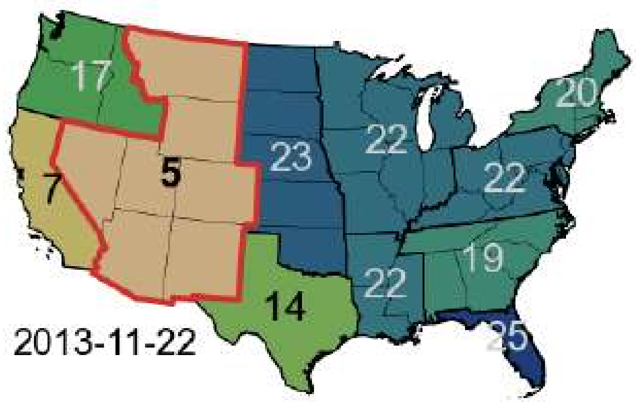


Figure 2: When the sun is not shining in one planning area, it is sunny in other planning areas.[100]



With properly measured capacity value that includes wind in different areas and the complementarity of wind and solar together, capacity values will reflect that in these instances, renewables will have capacity value that reduces loss of load expectation.

This geographic diversification results in higher capacity values for geographically diverse renewable resources. The effect was about 5% capacity value increase in the Eastern Wind Integration and Transmission Study, prepared for The National Renewable Energy

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[99] *Id*.

[100] *Id*. at 11.

Laboratory (U.S. Department of Energy).[101] As the Telos/ESIG report stated, referring to output at different times through the metric of "net load" (load minus renewable output), "[w]here resource adequacy and resilience benefits stand out, however, is in connecting systems with loosely correlated net load behavior."[102] This suggests significant and growing value in this category of transmission benefits.

One way to measure this benefit is through estimating the value of lost load; This has already been done in a number of cases.[103] Another way to measure this benefit, as the Commission's label for the category suggests, is in terms of generation capital cost savings from lower needed planning reserve margins achievable through transmission. This approach has also been used in multiple cases.[104] The Commission's categories suggest one or the other (but not both) are acceptable ways to measure this benefit. As MISO stated in its stakeholder process,

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[101] Enernex Corporation, Eastern Wind Integration and Transmission Study, NREL Report No. SR-550-47078, at 10-11 (Jan. 2010) *available at* https://nrel-primo.hosted.exlibrisgroup.com/permalink/f/1a440ct/NREL_ALMA5148117370003216.

[102] ESIG, *Multi-Value Transmission Planning for a Clean Energy Future* at 47 (2022) *available at* https://www.esig.energy/multi-value-transmission-planning-report/

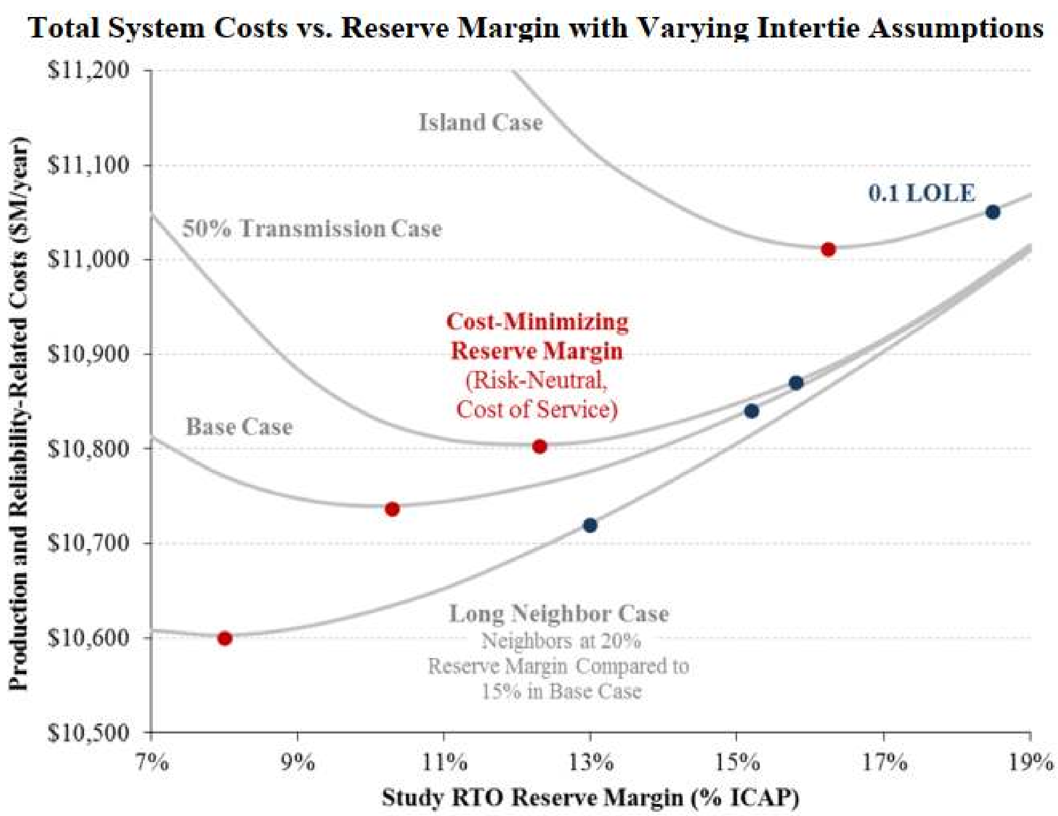
[103] SPP, Benefits for the 2013 Regional Cost Allocation Review at 25 (Sept. 13, 2012) *available at* https://www.spp.org/documents/18175/20120913%20mtf%20report_approved.pdf; J. Frayer, et al., *How Does Electric Transmission Benefit You?: Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investment*, (Jan. 8, 2018) *available at* https://www.remi.com/wp-content/uploads/2019/12/521-LEI-Electric-Transmission.pdf.

[104] MISO, Proposed Multi Value Project Portfolio: Business Case Workshop at 36-38 (2011) *available at* https://nocapx2020.info/wp-content/uploads/2014/04/20110919-MVP-Proposed-Portfolio-Business-Case.pdf; SPP, *Benefits for the 2013 Regional Cost Allocation Review* at Section 5.1 (Sept. 13, 2012). Public Service Commission of Wisconsin, *Order on Investigation on the Commission's Own Motion to Review the 18 Percent Planning Reserve Margin Requirement* at 5, Docket No.5-EI-141 (2008). SPP, *The Value of Transmission* at 16 (Jan. 16, 2016) *available at* https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf; MISO, *MISO Value Proposition 2020, Detailed Circulation Description* at 22 (2020). PJM, *Value Proposition* at 2 (2019). Australian Energy Market Operator, *2022 Integrated System Plan*, at 64 (2022) *available at* https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en.

"transmission is the enabler of reserve sharing for the MISO pool so that each load serving entity does not need to cover its own reserves but can share those resources when needed most."[105]

A report prepared for FERC staff by The Brattle Group and Astrape illustrates the lower cost to consumers from transmission interties. The lower lines in the graph below have more transmission, and lower costs for consumers.

Figure 3: Brattle/Astrape Illustration of Lower Generation Capacity Costs from Stronger Transmission Ties[106]



[105] MISO, *Planning Advisory Committee Summary of Review and Advice to Advisory Committee and Board of Directors MISO Transmission Expansion Plan (MTEP21), Addendum Appendix F* at 4 (May 20, 2022) *available at* https://cdn.misoenergy.org/20220527%20PAC%20Item%2002a%20MTEP21%20Addendum%20Appendix%20F%20-%20LRTP%20Tranche%201%20Substantive%20Comments624805.pdf.

[106] The Brattle Group, *Resource Adequacy Requirements: Reliability and Economic Implications* (Sept. 2013) *available at* https://www.brattle.com/wp-content/uploads/2017/10/6092_resource_adequacy_requirements_pfeifenberger_spees_ferc_sept_2013.pdf

The lower cost for consumers based on lower generation reserve margins that are enabled by stronger transmission ties should be evaluated by transmission planners and incorporated as a benefit.

Benefit (3)   Production cost savings[107]

ACEG supports inclusion of this benefit, with some improvements. Production cost savings is the most basic and widely used type of benefit. It can be studied relatively easily with standard production cost software and data. It has been used in a number of planning efforts.[108] The category includes fuel and variable operating cost savings, and adjustments for imports from neighboring regions. The category should also include ancillary service cost savings (unless that is treated as a separate category), which can include the reduced cost of cycling power plants, reduced amounts and costs of operating reserves and other ancillary services, and mitigation of reliability-must-run (RMR) conditions.

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[107] NOPR at PP 198-201.

[108] MISO Open Access Transmission Tariff, Attach. FF, Benefit Metrics Sec. (I)(A)(1). *See PJM Interconnection L.L.C.,*142 FERC ¶ 61,214, at P 416 (2013); *New York Independent System Operator Corp.,*143 FERC ¶ 61,059 at PP 268, 269, n. 516 (2013); NYISO, NYISO Tariffs, OATT, Attach. Y, § 31.5 (27.0.0), § 31.5.4.3.2. *Pub. Serv. Co. of Colo.,* 142 FERC ¶ 61,206, at P 314 (2013); ATC, Planning Analysis of the Paddock-Rockdale Project, Wis. Pub. Serv. Comm. Docket No. 137-CE-149, app. C, Ex. 1, at 35-38 (Apr. 5, 2007), *available at* https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=75598; SPP, *Regional Cost Allocation Review (RCAR II)* at 5 (Jul. 11, 2016), *available at* https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf; Australian Energy Market Operator, *2022 Integrated System Plan* at 64 (2022) *available at* https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en.

Benefit (4) Reduced transmission energy losses

ACEG supports inclusion of this benefit and the definition in the NOPR. The lower losses that result from greater transmission capacity produce real operational savings.[109] This has been calculated in various studies.[110]

Benefit (5) Reduced congestion due to transmission outages

ACEG supports inclusion of this benefit and the definition in the NOPR. A lot of expensive congestion that consumers pay for results from transmission outages.[111] Most planning models include planned, but not unplanned transmission outages and thus conceal this benefit.[112] Yet it has been done and can be used by any planning entity.[113]

One can see this effect in recent experiences. For example, in the NERC/FERC report about Winter Storm Uri, "the Event triggered numerous transmission facility outages, causing transmission owners to submit a large volume of manually-updated information (as with generator owners/generator operators, this information included causes of outages and estimates of restoration time)."[114] The NOPR on extreme weather notes that "concurrent outages occur nearly simultaneously in different planning areas due to the same extreme weather events, such

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[109] NOPR at P 202.

[110] ATC, Planning Analysis of the Paddock-Rockdale Project, App. C, Ex. 1 at 34-38 (Wisc. Pub. Serv. Docket No. 137-CE-149); SPP, *Regional Cost Allocation Review (RCAR II)*, at 5 (July 11, 2016) *available at* https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf.

[111] NOPR at P 205.

[112] The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* at 79 (2021) *available at* https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf.

[113] SPP, *Regional Cost Allocation Review (RCAR II)*, at 51-52 (2016).

[114] FERC-NERC Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (2021) *available at* https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

as the unplanned generator outages associated with the major extreme heat and cold events discussed above."[115]

This issue has been noted by utilities in the MISO Long Range Transmission Planning process: "MidAmerican believes the production cost models used for this analysis provide conservative values for the congestion benefits because the transmission system is, for nearly all periods of time, in a state with more outages than the N-1 conditions assumed in MISO's models (*i.e.*, there is nearly always multiple planned and forced outages at any given point in time which can have significant impacts on congestion)."[116] MidAmerican Energy continues, "MISO states that the adjusted production cost value is understated because the model begins with a system intact state, which seldom is the case in MISO (*i.e.*, there is nearly always multiple planned and forced outages at any given point in time which can have significant impacts on congestion)."[117]

Benefit (6) Mitigation of extreme events and system contingencies

ACEG supports inclusion of this category and the definition in the NOPR with the suggested modifications below. Energy cost savings can be extremely high in very short time periods due to severe weather. Generation of all types is susceptible to extreme hot, extreme cold, and drought. The Commission defines this benefit as "reductions in production costs resulting from reduced high-cost generation and emergency procurements necessary to support the transmission system during extreme events (such as unusual weather conditions, fuel shortages, or multiple or sustained generation and transmission outages) and system

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[115] NOPR at P 68.

[116] MISO, *Planning Advisory Committee Summary of Review and Advice to Advisory Committee and Board of Directors MISO Transmission Expansion Plan (MTEP21) Addendum Appendix F*, at 3 (May 20, 2022) *available at* https://cdn.misoenergy.org/20220527%20PAC%20Item%2002a%20MTEP21%20Addendum%20Appendix%20F%20-%20LRTP%20Tranche%201%20Substantive%20Comments624805.pdf.

[117] *Id*.

contingencies."[118] This benefit is very evident looking backwards after the fact at the hundreds of millions of dollars that would have been saved if transmission capacity had been greater during a number of actual severe weather episodes.[119] Prospectively, one can assess this value probabilistically as has been done.[120]

The benefit should also include reduction in energy prices to consumers, not just production cost savings. Many regions have scarcity pricing where price is set administratively high during times of scarcity, and in the future, they may have prices set by actual demand side bids. These prices can be well above the generation production cost. Transmission that mitigates these prices produces real consumer benefits.

This category of benefit should also include increased storm hardening and wildfire resilience, increased fuel diversity and system flexibility. There are also operational benefits associated with HVDC lines that should be included in this category.[121]

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[118] NOPR at P 206.

[119] Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (Jul. 2021) *available at* https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.

[120] Grid Strategies, LLC, *Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis* (Aug. 9, 2022) (citing *Granting Certificate of Public Convenience and Necessity*, Cal. Pub. Util. Comm. Docket No. 05-04-015 (2007) *available* at https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf). ATC, *Planning Analysis of the Paddock-Rockdale Project*, app. C, Ex. 1, at 4, 50-53 (Wis. Pub. Serv. Comm. Docket No. 137-CE-149) (Apr. 5, 2007) *available at* https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=75598.

[121] PJM, *2008 RTEP — Reliability Analysis Update* at 8-10 (Oct. 15, 2008) *available at* https://www.pjm.com/~/media/committees-groups/committees/teac/20081015/20081015-reliability-analysis-update.ashx. L. P. Lazaridis, *Economic Comparison of HVAC and HVDC Solutions for Large Offshore Wind Farms under Special Consideration of Reliability*, Royal Institute of Technology Department of Electrical Engineering, at 34 (2005) *available at* https://www.diva-portal.org/smash/get/diva2:609080/FULLTEXT01.pdf; Institute of Electrical and Electronics Engineers Power & Energy Society, *HVDC Systems & Trans Bay Cable*, at 75 (Mar. 16, 2005) *available at* https://www.ewh.ieee.org/r6/san_francisco/pes/pes_pdf/Transbay_Cable.pdf. S. Wang, *et al.*, *Economic Assessment of HVDC Project in Deregulated Energy Markets*, Electric Utility Deregulation and Restructuring and Power Technologies (2008) *available at* https://ieeexplore.ieee.org/abstract/document/4523373.

Grid strength is also a reliability benefit that should go in this category, if not its own category. See, for example, the MISO RIIA study discussion of grid strength and the ability of transmission to support it.[122] Transmission can also support the concept that has been called "resilience," or "fuel security."[123] In ISO-NE where fuel security has been a major concern of the ISO and NERC, imports from other regions showed up as providing significant mitigation.[124]

Benefit (7) Mitigation of weather and load uncertainty

ACEG supports inclusion of this benefit category and the definition in the NOPR. This is an additional benefit stemming from the uncertainty associated with load and generation, and the value of transmission to integrate areas with load, generation, and "net load" diversity.[125] It has been incorporated in certain cases.[126]

Recent research suggests significant value from transmission when real world uncertainty is taken into account, as compared to deterministic modeling.[127] The Brattle-Grid Strategies report on transmission planning methods called this "[r]educed cost due to imperfect foresight of

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[122] MISO, *MISO's Renewable Integration Impact Assessment (RIIA)* (Feb 2021) *available at* https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

[123] V. Budhraja, *et al.*, Transmission Benefit Quantification, Cost Allocation and Cost Recovery at 43-44 (Jun. 2008) *available at* https://eta-publications.lbl.gov/sites/default/files/report-cost-allocation.pdf

[124] ISO-New England, *Operational Fuel Security Analysis*, at 33 (2018) *available at* https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

[125] NOPR at PP 208-209.

[126] ERCOT, *Economic Planning Criteria*, at 10 (Mar. 4, 2011) *available at* https://www.ercot.com/files/docs/2011/03/04/cmwg_plwg_question_1_recommendations_v03042011.ppt The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant Energy estimated probabilities for the same scenarios.

[127] Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System* (Oct. 14, 2020) *available at* https://open.bu.edu/handle/2144/41451.

real-time system conditions, including renewable forecasting errors and intra-hour variability."[128]

***Benefit (8)	Capacity cost benefits from reduced peak energy losses***

ACEG supports inclusion of this benefit category and the definition in the NOPR. This is also a distinct benefit category.[129] It has been measured before.[130]

***Benefit (9)	Deferred generation capacity investments***

ACEG supports inclusion of this benefit category and the definition in the NOPR. This benefit reflects the substitution of transmission for generation, which may result in savings.[131] These savings can be calculated and have been in various planning efforts.[132] The Commission defines this as transmission that "either defers or negates the need to invest in generation

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[128] The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* at 2, 34, 78, 85-86, 99 (2021) *available at* https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf.

[129] NOPR at PP 210-212.

[130] Grid Strategies, LLC, *Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis* (Aug. 9, 2022) (citing *ITC Holdings Co.*, Joint Application at Ex. ITC-600, 77-78, Docket No. EC12-145-000 (filed Sept. 24, 2012) (testimony of Pfeifenberger)) *available* at https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf; SPP, *SPP Priority Projects Phase II Report* at 26 (Apr. 27, 2010) *available at* https://www.spp.org/documents/11467/priority%20projects%20phase%20ii%20report.pdf; ATC, Planning Analysis of the Paddock-Rockdale Project at app. C, Ex. 1, at 4, 63 (Wis. Pub. Serv. Comm. Docket No. 137-CE-149) (Apr. 5, 2007) *available at* https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=75598; MISO, *Proposed Multi Value Project Portfolio: Business Case Workshop* at 25-27 (2011) *available at* https://nocapx2020.info/wp-content/uploads/2014/04/20110919-MVP-Proposed-Portfolio-Business-Case.pdf.

[131] NOPR at PP 212-214.

[132] *ITC Holdings Co.*, Joint Application at Ex. ITC-600, 77-78, Docket No. EC12-145-000 (filed Sept. 24, 2012) (testimony of Pfeifenberger) *available* at https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf; Australian Energy Market Operator, *2022 Integrated System Plan* at 64 (2022) *available at* https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en.

capacity resources within a transmission planning region by increasing import capability from neighboring regions into resource-constrained areas."[133] Thus it is a more localized concept, and separate from the system-wide resource adequacy benefit defined above. CAISO includes a "local capacity benefit" which "corresponds to a situation where a transmission solution leads to a reduction of local capacity requirement in a load area or accessing an otherwise inaccessible resource"[134] and is distinct from their "system resource adequacy" category.

Benefit (10) Access to lower-cost generation [135]

ACEG supports inclusion of this benefit category and the definition in the NOPR. This benefit is widely recognized though rarely actually incorporated. Generation capacity cost savings are separate from production cost savings described above. It has been included in a number of transmission valuation efforts.[136] There is often a tradeoff between more remote low-cost generation delivered with transmission, and more local higher cost generation that requires less transmission. Planners should assess this tradeoff. As available local sites are used up over

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[133] NOPR at P 214.

[134] CAISO, *CAISO 2021-2021 Transmission Plan* at 242 (Mar. 24, 2021) *available at* http://www.caiso.com/Documents/BoardApproved2020-2021TransmissionPlan.pdf

[135] NOPR at PP 216-218.

[136] Grid Strategies, LLC, *Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis* (Aug. 9, 2022) (citing Cal. Pub. Util. Comm. Opinion Granting Certificate of Public Convenience and Necessity, Cal. Pub. Util. Comm. Docket No. 05-04-015 (2007)), *available at* https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf; MISO, *Regional Generation Outlet Study* at 32, App. A (Nov. 19, 2010) *available at* https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf; ERCOT, *Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study* (Apr. 2, 2008) *available at* https://www.nrc.gov/docs/ML0914/ML091420467.pdf; Australian Energy Market Operator, *2022 Integrated System Plan* at 64 (2022) *available at* https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en; ATC, *Arrowhead-Weston Transmission Line: Benefits Report* at 7 (Feb. 2009) *available at* http://www.atc-projects.com/wp-content/uploads/2012/01/AW_FINAL.pdf.

time, it is reasonable to expect a greater need for and reliance on remote resources, justifying more transmission.

MISO's Regional Generation Outlet Study in 2010, and subsequent planning exercises explicitly analyzed and incorporated this tradeoff.[137] By accessing cheaper generation, MISO's initial analysis found that its MVP portfolio reduced the present value of wind generation investments by between $1.4 billion and $2.5 billion, offsetting approximately 15% of the transmission project costs.[138]

Benefit (11) Increased competition

ACEG supports inclusion of this benefit category and the definition in the NOPR. Generation market power has been a major concern and focus of the Commission's policy since the opening of competitive markets. Transmission can broaden the "geographic market," enabling more suppliers to compete, driving down prices. The Commission described a few ways to analyze this benefit.[139] It has been incorporated in some instances.[140]

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[137] MISO, *Regional Generation Outlet Study* at 32, App. A (Nov. 19, 2010) *available at* https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf.

[138] MISO, *Proposed Multi Value Project Portfolio: Business Case Workshop* at 25, 38-41 (2011) *available at* https://nocapx2020.info/wp-content/uploads/2014/04/20110919-MVP-Proposed-Portfolio-Business-Case.pdf.

[139] NOPR at PP 219-224 (citing The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* at 46-47 (2021) *available at* https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf; F. A. Wolak, *Managing Unilateral Market Power in Electricity*, World Bank Policy Research Working Paper, at 8 (Sept. 2005) *available at* https://openknowledge.worldbank.org/bitstream/handle/10986/8600/wps3691.pdf?sequence=1&isAllowed=y).

[140] Grid Strategies, LLC, *Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis* (Aug. 9, 2022) (citing Cal. Pub. Util. Comm. Opinion Granting Certificate of Public Convenience and Necessity, Cal. Pub. Util. Comm. Docket No. 05-04-015 (2007)), *available* at https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf; CAISO, *Transmission Economic Assessment Methodology* at Ch. 4 (Jun. 2004) *available at* https://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology.pdf; ATC, Planning Analysis of the Paddock-Rockdale Project at app. C, Ex. 1, at 44-49, Wis. Pub. Serv. Comm. Docket No.

Benefit (12) Increased market liquidity

ACEG supports inclusion of this benefit category and the definition in the NOPR. This distinct benefit relates to the increased number of transactions when more trade is possible, reducing the variation in prices and increasing the transparency of the market.[141]

2. Application to Non-RTO Areas

The Commission seeks comment on the application of the Long-Term Regional Transmission Benefits in non-RTO/ISO regions.[142] ACEG supports equivalent application of all requirements in the NOPR to RTO and non-RTO regions. The benefits apply equally, if not more so in allowing transmission providers outside RTOs to access resources and geographic diversity beyond their particular footprints. Additionally, as entities outside RTOs take steps towards greater cooperation and nascent markets, robust regional transmission is the basis on which such efforts will rest. Clear-eyed incorporation of the benefits of transmission in regional planning will provide greater insight as stakeholders consider which market mechanisms are most appropriate for their region.

3. The Final Rule Should Require Portfolio Plans.

The NOPR encourages but does not require portfolio planning. It states, "[w]e propose to afford public utility transmission providers in each transmission planning region the flexibility to propose to use a portfolio approach in the evaluation of benefits of regional transmission

137-CE-149 (Apr. 5, 2007), *available at* https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=75598.

141 NOPR at P 225; The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* at 50 (Oct. 2021) *available at* https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf

142 NOPR at P 187.

facilities through their Long-Term Regional Transmission Planning."[143] It seeks comment on whether there are certain circumstances for which the Commission should require the use of a portfolio approach.[144] In regions with a centralized market, the failure to plan on a system-wide basis means that the true benefit of the transmission additions and the way they work together may not be assessed. Portfolio planning more accurately evaluates the benefits new transmission provides to the system, including the portfolio, when determining how benefits are distributed.

ACEG believes portfolios of transmission lines should be the preferred planning approach. It is possible, but unlikely, that in a regional planning process, one single line will be found to maximize net benefits. It is almost always more efficient for consumers to have a portfolio of transmission lines and other assets working together to solve network needs.

4. The Final Rule Should Require Project Selections Based on Maximizing Net Benefits.

The NOPR does not require any particular selection criteria, but rather the filing of criteria that are transparent and non-discriminatory.[145] It does say the criteria "must aim to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand. Public utility transmission providers should seek to maximize benefits to consumers over time without over-building transmission facilities."[146]

ACEG agrees that selection criteria must ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan and that public utility

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[143] *Id.* at P 233.

[144] *Id.* at P 235.

[145] *Id.* at P 245.

[146] *Id.*

transmission providers should seek to maximize benefits to consumers over time without over-building transmission facilities. That means the decision rule should be to maximize net benefits. The Commission can require transmission providers to approve transmission plans that maximize net benefits using the same general authority it relied on in promulgating Order No. 1000. Such a requirement focuses on "process" and is "not intended to dictate substantive outcomes."[147]

Over-building would be avoided because once the benefits are saturated by an excessively large transmission option, the costs would begin to exceed the benefits, and that portfolio would have lower net benefits than a smaller plan. In contrast, a plan that is too small and at too low of a voltage level, would not achieve many benefits compared to one that captures the economies of scale in transmission. In these examples of too big, too small, and just right, the metric that consistently finds the "just right" option is the "maximize net benefits" decision rule. It is important to note that a benefit-cost option does NOT consistently find the right option. It is a standard economic policy principle in benefit-cost analysis that one should seek to maximize net benefits (benefits minus costs), not seek to maximize a benefit-cost ratio or other such metric.

5. Use of Benefits in Cost Allocation

The list of benefits adopted in the final rule for planning should also include the same minimum set of benefits for cost allocation purposes. ACEG agrees with the Organization of MISO States which advised MISO: "For fairness and equity, the benefits and attributes quantified should be the same for the planning process and the cost allocation process. The

[147] *S. Carolina Public Service Authority v. FERC*, 762 F.3d 41, 58 (D.C. Cir. 2014), (quoting Order No. 1000-A, at P 188, 77 Fed. Reg. at 32,215) (as with Order No. 1000, "[t]he substance of a regional transmission plan and any subsequent formation of agreements to construct or operate regional transmission facilities" would "remain within the discretion of the decision-makers in each planning region."). *See also* ACEG, *Planning for the Future, FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* at 83 (Jan. 2021).

processes must be symmetrical."[148] Likewise, as discussed above, the proper time horizon for evaluation of benefits should a minimum of 20 years or up to the life of the asset (*i.e.*, 40 years).

C. The Commission Should Ensure Coordination of Regional Transmission Planning and Generator Interconnection Processes.

The Commission proposes to require that transmission providers consider in the Long-Term Regional Transmission Planning regional facilities that address interconnection-related needs, where such facilities have been identified multiple times in the generator interconnection process but have not been constructed due to withdrawal of interconnection requests.[149] The Commission proposes these reforms to create more efficient and cost-effective transmission expansion. The Commission also suggests that these reforms would allow for cost allocation of such transmission facilities in a manner that is commensurate with estimated benefits, and eliminate a barrier to entry for new generation resources. The Commission proposes to require that to be considered in Long-Term Regional Transmission Planning, such upgrades must be identified in two interconnection queue cycles during the preceding 5 years, be at least 200 kV or higher and/or cost at least $30 million. The upgrades are limited to interconnection needs not already addressed in an executed generator interconnection agreement.[150]

ACEG supports the Commission's proposal to increase the coordination between regional transmission planning processes and generator interconnection processes. The significant and frequently increasing costs associated with interconnecting generation facilities to the

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[148] Regional Expansion Criteria and Benefits Working Group (RECBWG): Granular Benefits Identification and Cost Allocation, Response of Organization of MISO States Transmission Cost Allocation Working Group to RECBWG Feedback Request of Feb. 28, 2022 (submitted by Marcus Hawkins – OMS Sector on Mar. 25, 2022, posted March 30, 2022) *available at* https://www.misoenergy.org/stakeholder-engagement/stakeholder-feedback/recbwg-granular-benefits-identification-and-cost-allocation-20220228/

[149] NOPR at PP 166-173.

[150] *Id.* at P 173.

transmission system is a known and apparent barrier to achieving greater system reliability and more affordable rates for consumers. Conversely, improved transmission planning and robust transmission build is the primary factor for reducing interconnection costs. A final rule that promotes robust, long term transmission planning that considers interconnection studies and processes would significantly aid in reducing the overall costs to interconnect new generation.

With the Commission's issuance of the notice of proposed rulemaking on *Improvements to Generator Interconnection Procedures and Agreements* on June 16, 2022 in Docket No. RM22-14-000, the Commission is taking a significant step toward reforming interconnection processes. Given the ongoing proceeding in that docket to address the need for improvement to the interconnection processes, ACEG will not provide detailed comments on the need for interconnection reform in this proceeding. However, the issues and challenges of interconnection processes and corresponding costs are evident and should be addressed. Changes to the transmission planning processes that would allow for certain transmission upgrades identified in the interconnection process to be addressed and ultimately constructed through the transmission planning process will only serve to increase the resiliency and reliability of the transmission system.

In the ANOPR proceeding, numerous commenters from many industry sectors indicated support for greater coordination between transmission planning and interconnection processes. There is a common call for interconnection process to be aligned with a broader regional transmission process.[151] For instance, transmission providers such as CAISO support "greater

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[151] *See* Comments of Acadia Center and Conservation Law Foundation, Docket No. RM21-17 (2021); Comments of Avangrid, Inc. at 17, Docket No. RM 21-17 (2021); Comments of NARUC at 38, Docket No. RM21-17 (2021); Comments of SOO Green HVDC, Docket No. RM21-17 (2021); Comments of Organization of MISO States at 11, Docket No. RM21-17 (2021).

integration between the transmission planning and generator interconnection processes."[152] Utilities also suggest that in order to promote efficiency, the Commission should consider permitting additional coordination between generation and transmission.[153] Many stakeholders believe that planning for interconnection upgrades should be better integrated into a more holistic transmission planning process.[154]

Requiring consideration of generator interconnection studies in transmission planning processes would ensure rates that are just and reasonable and not unduly discriminatory or preferential. Transmission planning that includes generator interconnection and associated network upgrades as an integrated part of the planning process would: (1) improve the evaluation and development of the future grid in a holistic manner that would result in more efficient planning than the current piecemeal upgrade process; (2) reduce reliance on generator interconnection network upgrades to accomplish grid expansion, and thereby speed up interconnection; and (3) reduce the need for changes and enhancements to the interconnection process. ACEG encourages the Commission to proceed with its proposed reforms in this regard.

D. The Commission Should Require Transmission Providers to Adopt Enhanced Transparency Requirements for Local Transmission Planning and Improve Coordination Between Regional and Local Transmission Planning with the Aim of Identifying Potential Opportunities to "Right-Size" Replacement Transmission Facilities.

Currently, there is no requirement that transmission providers provide information about potential in-kind replacements of existing transmission facilities in either their local or regional transmission planning processes. Indeed, even though some RTO/ISO transmission planning

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152 Comments of Cal. Indep. Sys. Operator at 69, Docket No. RM 21-17 (2022).

153 *E.g.* Comments of Dominion Energy Services at 24, Docket No. RM21-17 (2022).

154 *E.g.* Comments of Avangrid Inc. at 17, Docket No. RM21-17 (2021).

regions assess a planned in-kind replacement of an existing transmission facility for adverse reliability impacts, regional transmission planning processes generally do not evaluate whether the planned in-kind replacement transmission facility could be modified to more efficiently, or cost-effectively, address regional transmission needs.[155]

In the NOPR, the Commission determined that local transmission planning processes may lack mechanisms for transparency and meaningful stakeholder input, and that regional planning processes may not adequately coordinate with local planning processes.[156] Consequently, because in-kind replacement of existing transmission facilities is not subject to any transmission planning process, the Commission stated that it was concerned that there is a lack of coordination between regional transmission planning processes and in-kind replacement of existing transmission facilities to identify whether these replacement transmission facilities could be modified to more efficiently or cost-effectively address transmission needs identified through Long-Term Regional Transmission Planning. According to the Commission, this lack of coordination may result in a regional transmission planning process that does not identify opportunities to "right size" planned in-kind replacement transmission facilities and thus may result in the development of duplicative or unnecessary transmission facilities that increase costs to consumers and render Commission-jurisdictional rates unjust and unreasonable.[157]

To remedy the lack of coordination, the Commission proposes revisions to the OATT regional transmission planning process to enhance transparency of: (1) the criteria, models, and assumptions that transmission providers use in their local transmission planning process, (2) the

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[155] NOPR at P 385.

[156] *Id.* at P 398.

[157] *Id.* at P 399.

local transmission needs that they identify through that process, and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs. To ensure stakeholders have meaningful input, the Commission proposes to require transmission providers to establish an iterative process that gives stakeholders opportunities to participate and provide feedback on local transmission planning throughout the regional transmission planning process. The Commission also proposes that the regional transmission planning process include at least three stakeholder meetings (an Assumptions Meeting, a Needs Meeting and a Solutions Meeting), concerning the local transmission planning process of each transmission provider that is a member of the transmission planning region before each transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models.[158]

Further, the Commission also proposes that transmission providers in each transmission planning region evaluate whether 230 kV transmission facilities that an individual transmission owner anticipates replacing in-kind with a new transmission facility during the next 10 years can be "right-sized"[159] to more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Plans.[160]

Much of the nation's transmission facilities are over 50 years old.[161] To avoid creating a suboptimal transmission infrastructure network, a broader view of transmission planning is

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[158] *Id.* at P 401.

[159] *Id.* at P 403. By "right-sizing," ACEG means the process of modifying a public utility transmission provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability. "Right-sizing" could include, for example, increasing the transmission facility's capacity level, adding circuits to the existing towers (e.g., redesigning a single-circuit line as a double-circuit line), or incorporating advanced technologies (such as advanced conductor technologies).

[160] *Id.*

[161] American Society of Civil Engineers, *Policy Statement 484 - Electricity Generation and Transmission Infrastructure* (July 13, 2019) *available at* https://www.asce.org/advocacy/policy-statements/ps484---

necessary in terms of replacement of existing, aging transmission facilities, coupled with a changing generation mix and evolving customer needs.[162] ACEG supports the NOPR proposal and urges the Commission to ensure that transmission owners and transmission providers consider "right-sizing" and supply sufficient information. In-kind replacement of an existing transmission facility that does not incrementally increase that facility's capacity is not subject to Order No. 890 planning requirements and thus the existing process can fail to identify opportunities to improve transmission or to prevent development of duplicative or unnecessary transmission.[163]

Building on Order No. 890's transparency requirements, the Commission should require more specific minimum data transparency standards as part of the final rule, drawing on the examples set by MISO and SPP, for example, which "currently maintain . . . transparent cost recording and tracking processes for projects approved through their regional planning processes."[164] As The Brattle Group analysts have recommended, the Commission should require that regional planning entities at minimum "have a detailed project tracking mechanism

electricity-generation-and-transmission-infrastructure; The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* at ii, 94 (2021) *available at* https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf

[162] ACEG, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* at 18-24 (Jan. 2021), provided as Appendix C to ACEG's ANOPR Comments in Docket No. RM21-17-000 (Oct. 12, 2021).

[163] NOPR at P 385 (citing *S. Cal. Edison Co.*, 164 FERC ¶ 61,160 at P 31 (2018) ("While Order No. 890 does not explicitly define the scope of 'transmission planning,' the Commission adopted the transmission planning requirements in Order No. 890 to remedy opportunities for undue discrimination in *expansion* of the transmission grid." (citing Order No. 890, 118 FERC ¶ 61,119 at PP 57-58, 421-422)); *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161 at P 68 (2018); *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136 at PP 12, 89, *order on reh'g*, 173 FERC ¶ 61,225 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242 at P 54 (2020), *order on reh'g*, 176 FERC ¶ 61,053 (2021).

[164] Brattle Group, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value* at 26 (April 2019) *available at* https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf

that consistently document project cost estimates at various stages of the project, particularly when the project needs are first identified and at the completion of the projects."[165]

In addition, the Commission has the authority to evaluate replacement facility projects under Section 205 to ensure the same needs cannot be more cost-effectively met with regional and interregional transmission infrastructure, such as when considering the presumption of prudence in transmission rate cases.[166] For administrative efficiency in Section 205 proceedings, the Commission could issue policy guidance regarding its scope and process for review of new replacement facilities.[167]

ACEG agrees that, if opportunities for right-sizing replacement transmission facilities are not available, regional planning processes may not select the more efficient or cost-effective transmission facilities in the regional transmission plan for purposes of cost allocation to meet transmission needs identified through Long-Term Regional Transmission Planning. ACEG supports the Commission's proposal to require transmission providers to consider "right-sizing" of existing facilities to strengthen the grid, with the incremental cost eligible for regional cost allocation. Without such a requirement, a large amount of new transmission investment – directed solely at replacement facilities – will be outside the Long-Term Regional Transmission

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[165] *Id.* at 24.

[166] Existing Commission precedent applies a presumption of prudence to local transmission plans. *See Potomac-Appalachian Transmission Highline*, 158 FERC ¶ 61,050 at P 100 (2017); *Iroquois Gas Transmission System, L.P.*, 87 FERC ¶ 61,295 at 62,168 (1999). Nevertheless, the Commission could appropriately reason that such a presumption is not appropriate where evidence suggests that a regional transmission solution may more efficiently meet the same need. ACEG, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* at 88 (Jan. 2021), provided as Appendix C to ACEG's ANOPR Comments in Docket No. RM21-17-000 (Oct. 12, 2021).

[167] ACEG, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* at 88 (Jan. 2021).

Planning and thus not given an opportunity to contribute to the grid's overall efficiency and cost-effectiveness.

In addition, in-kind replacements need not be sited in the identical location as the facilities they replace.[168] The availability of "brownfields" rights-of-way (*i.e.*, existing transmission, highway, or railroad rights-of-way) and related land use, cost, and public impact considerations can be important factors in deciding how to serve specific resources or load or decide between alternative development plans at the regional or interregional level.

E. It is Crucial that Transmission Providers Establish Transparent and Not Unduly Discriminatory Criteria to Select Transmission Facilities in the Regional Transmission Plan for Purposes of Cost Allocation.

If transmission facilities are selected through opaque processes or processes that have the appearance of bias or discrimination, the inevitable result is protracted litigation which raises the end costs to consumers. Transparent selection processes are the key to reducing conflict, developing legally sustainable long-term regional plans and transmission investments, and maximizing benefits over time to consumers without over-building transmission facilities.

The NOPR proposes that transmission providers must include in their OATTs: (1) transparent and not unduly discriminatory criteria; and (2) a process to coordinate with the relevant state entities in developing such criteria.[169] It further proposes that "[s]ubject to certain minimum requirements . . . public utility transmission providers [will have] the flexibility to propose the selection criteria that they, in consultation with their stakeholders, believe will ensure that more efficient or cost-effective regional transmission facilities to address the region's

[168] Refer to NOPR Comments of Rail Electrification Council, Docket No. RM 21-17 (Aug. 17, 2022).
[169] NOPR at P 241.

transmission needs driven by changes in the resource mix and demand ultimately are selected in the regional transmission plan for purposes of cost allocation."[170]

ACEG supports the NOPR proposal, but encourages the Commission to include in the minimum requirements a directive that the transmission provider's selection criteria recognize and "maximize net benefits" based on the minimum benefits selected for consideration in long-range transmission planning. As discussed above, maximizing net benefits would be the most beneficial to consumers and the most just and reasonable result, and it would be unreasonable to ignore some of the benefits. If some benefits are eliminated from the equation, the analyses of many proposed transmission lines will be less likely to show benefits that exceed costs, and consumers will be denied cost saving opportunities. Moreover, a net benefits standard would also afford regions flexibility to weigh which criteria are more important to the integrity of their systems and their stakeholders.

ACEG further encourages the Commission to provide in the final rule suggestions for potential selection criteria in order to facilitate efficient compliance filing processes. For example, regions could choose selection criteria that consider whether the proposed solutions are in areas of significant existing rights-of-way, whether the proposed solutions contribute to equitable energy service or alleviate environmental justice concerns, or the job and economic development impacts of the selected transmission lines.

ACEG additionally supports the Commission's proposal to require planners to develop and select criteria in consultation with stakeholders and after coordination with relevant state entities. However, as transmission lines are regional in nature, planners should be careful to

[170] *Id.* at P 242.

ensure that the criteria selection maximizes net benefits to the region rather maximizing one state's interests over another's.

IV. COST ALLOCATION

ACEG supports the Commission's finding that reforms to regional cost allocation methods are necessary to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.[171] As discussed in ACEG's Reply Comments on the ANOPR, just and reasonable cost allocation may require customers in one state to pay more than customers in another state.[172] But it would not, for example, require one state to pay the full cost for Long-Term Regional Transmission Facilities and allow beneficiaries in other states to escape cost responsibility.

A. The Same Benefits Analysis Used in Long-Term Regional Transmission Planning Should be Used to Inform Cost Allocation Decisions.

The Commission proposes to require that transmission providers identify on compliance the benefits they will use in any *ex ante* cost allocation method associated with Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand.[173] It would be unjust and unreasonable to allocate costs in a manner that ignores certain benefits. Long-Term Regional Transmission Planning facilities must be assigned in a way that is "roughly commensurate" with

[171] *Id.* at P 278.

[172] ACEG Reply Comments at 15, Docket No. RM21-17-000 (Nov. 30, 2021).

[173] NOPR at P 326.

the benefits received, consistent with the *Illinois Commerce Commission v. FERC*[174] line of cases discussed below.

The Commission requested comments on whether it should require transmission providers to account for the full list of benefits identified in the NOPR, or whether no change to the benefits currently used in existing regional transmission planning processes is needed.[175] ACEG strongly supports requiring transmission providers to account for the full list of benefits identified in the NOPR.[176] Additionally, ACEG strongly supports implementing the minimum set of benefits as universally as possible across RTOs/ISOs and non-RTO/ISO regions. Requiring transmission providers to account for the full list of benefits identified in the NOPR will help provide evidentiary support for cost allocation of Long-Term Regional Transmission Planning facilities. Accounting for the full list of benefits will aid the Commission in its cost allocation decisions, particularly as to whether they adhere to the "beneficiary pays" and "roughly commensurate" requirements in the *Illinois Commerce Commission v. FERC* line of cases and their progeny.

The *Illinois Commerce Comm'n v. FERC* (*ICC*) line of cases are seminal precedent on the Commission's "beneficiary pays" and "roughly commensurate" cost allocation principles that require cost allocation to be "roughly commensurate" with the benefits provided to customers.[177]

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[174] *Illinois Commerce Comm'n v. FERC*, 576 F.3d 470 (7th Cir. 2009) (*ICC I*); *Illinois Commerce Comm'n v. FERC*, 756 F.3d 556 (7th Cir. 2014) (*ICC II*); *Illinois Commerce Comm'n v. FERC*, 721 F.3d 764 (7th Cir. 2013) (*ICC III*).

[175] NOPR at P 327.

[176] Refer to ACEG position on the importance of holistic benefits analysis, discussed above in Section III.

[177] *ICC I*, 576 F.3d 470 (7th Cir. 2009). PJM sought to allocate costs for new 500 kV transmission lines to all transmission-owning members of PJM on a *pro rata* basis regardless of the benefits each PJM member received and regardless of their location. The Seventh Circuit rejected the RTO-wide cost allocation stating that FERC must identify an "articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region[.]" *Id.* at 477.

In *ICC III* the court found that the Multi-Value Projects (MVPs) at issue promoted wind power, which in turn "reduc[ed] the nation's dependence on foreign oil and emissions of carbon dioxide," and that constituted a benefit that, along with other reliability and power flow benefits, justified the contested cost allocation at issue.[178] Key to the *ICC III* court's analysis was the finding that the benefits from the promotion of wind power would not be limited to one subregion of MISO.[179] Accordingly, the court upheld the region-wide cost allocation of MVPs based on the multi-benefit findings.

In *Old Dominion v. FERC*, the D.C. Circuit held that the Commission did not justify its approval of a tariff amendment that prohibited cost sharing for certain high-voltage transmission projects that provided significant regional benefits.[180] Specifically, the D.C. Circuit rejected the Commission's allocation of certain costs for high-voltage transmission projects to a single zone when the underlying transmission projects provided benefits to the entire PJM region. The D.C. Circuit reasoned that the narrow zonal cost allocation was a "severe misallocation of the costs of

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ICC II, 756 F.3d 556 (7th Cir. 2014). The Seventh Circuit again reviewed PJM's proposed RTO-wide cost allocation after FERC re-approved it with further explanation on remand. The court held that FERC's approval was based on assumed, but not articulated or demonstrated, benefits of the 500 kV transmission lines. The court stated that the benefits "may prove unquantifiable because they depend on the likelihood and magnitude of outages and other contingencies" but directed the Commission to engage in "*careful* consideration" and if the benefits cannot be quantified to use the utilities' estimates of benefits as a starting point. *Id.* at 564-65.

ICC III, 721 F.3d 764 (7th Cir. 2013). MISO sought approval to charge its members to fund construction of new transmission lines for wind facilities. According to MISO, the whole RTO system would benefit several hundred million dollars from the switch to wind energy, but it was impossible to calculate the savings to individual members. The Seventh Circuit upheld that cost allocation, stating "FERC's attempt to match costs and benefits of the MVP program [might have been] crude; if crude is all that is possible, it will have to suffice." *Id.* at 775.

[178] *ICC III*, 721 F.3d at 774-75 ("The promotion of wind power by the MVP [transmission project] program deserves emphasis. . . . The use of wind power in lieu of power generated by burning fossil fuels reduces both the nation's dependence on foreign oil and emissions of carbon dioxide. . . . There is no reason to think these benefits will be denied to particular subregions of MISO.").

[179] *Id.*

[180] *Old Dominion Electric Coop. v. FERC*, 898 F.3d 1254 (D.C. Cir. 2018).

such projects" that amounted to a "wholesale departure from the cost-causation principle[.]"[181] The D.C. Circuit reasoned that the "cost-causation" principle is a longstanding and generally applicable rule that "prevents regionally beneficial projects from being arbitrarily excluded from cost sharing – a necessary corollary to ensuring that the costs of such projects are allocated commensurate with their benefits."[182]

Accordingly, holistic identification and analysis of benefits, such as those identified in the NOPR, will help transmission providers and the Commission support broad cost allocation of Long-Term Regional Transmission Planning facilities and avoid misallocation of costs due to a failure to account for all benefits.[183] Even transmission lines that address, in part, a state's climate goals, also invariably provide many other benefits.

In addition to holistic identification of benefits ACEG also supports cost allocation of Long-Term Regional Transmission Planning facilities based on a concrete voltage or capacity threshold where costs for facilities at or above that threshold are regionally allocated. As discussed above, the need to improve regional and interregional planning arises from the transformative changes occurring with respect to resource diversity, energy market efficiencies, technological changes, operational innovations and resiliency to withstand severe weather events. If transmission facilities are not constructed, these are all benefits that would otherwise be forfeited.

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[181] *Id.* at 1261.

[182] *Id.* at 1263. The D.C. Circuit stated that its opinion does not "limit the ability of PJM or FERC to assess whether individual projects are in fact appropriate under the governing planning or reliability criteria." *Id.*

[183] *See Long Island Power Authority v. FERC*, 27 F.4th 705, 709 (D.C. Cir. 2022) ("we have set aside cost allocations that ignored the regional benefits") (citing *Old Dominion Electric Coop. v. FERC*, 898 F.3d 1254).

B. Response to Additional Specific Requests for Comment on Cost Allocation

1. ACEG Supports the Commission's Proposal to Allow Transmission Providers to Resolve the Inability of Relevant Parties to Reach Agreement by Simply Explaining the Good Faith Efforts to Obtain Agreement from Relevant State Entities.

The Commission requested comments on "[h]ow to resolve the potential inability of the relevant parties to come to agreement."[184] ACEG agrees that states should be formally consulted and transmission providers' tariffs should describe the process for such formal consultation. However, when consensus cannot be reached it is important that transmission providers retain an avenue to nonetheless file a regional cost allocation method for transmission facilities selected through Long-Term Regional Transmission Planning, including over the objection of relevant state entities.

ACEG supports requiring transmission providers to establish a potential alternative Long-Term Regional Transmission Cost Allocation Method, including in circumstances where agreement from all relevant state entities cannot be obtained or when one or more relevant state entities oppose the Long-Term Regional Transmission Cost Allocation Method. ACEG does not support affording the opposing state entities additional time to reach agreement as this would inappropriately slow down the process. Establishing firm time frames will provide states with the flexibility to reach a different agreement, if they so choose, but will also increase the

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[184] NOPR at P 303. In so requesting, the Commission noted "that it will ultimately be necessary for Transmission Providers to have a cost allocation method on file with the Commission for transmission facilities selected through Long-Term Regional Transmission Planning, and recognizing a State Agreement Process or combination cost allocation method would not comply with this proposed rule unless the relevant Transmission Providers has obtained agreement from the relevant state entities." *Id.* The Commission also requested comment on "[t]he appropriate outcome when the relevant state entities fail to agree on a cost allocation method for all or a portion of Long Term Regional Transmission Facilities and whether in such circumstances the Transmission Providers should be required to establish a Long-Term Regional Transmission Cost Allocation Method, the relevant state entities should be afforded additional time to endeavor to reach agreement, or the Commission should instead have the responsibility to establish the Long-Term Regional Transmission Cost Allocation Method." *Id.* at P 310.

importance and urgency of initial cooperation by the relevant state entities. It will also prevent a relevant state entity from refusing to agree to a proposed cost allocation methodology or using delays in the process to block an appropriate filing.

In cases where agreement is not reached in the established timeframe, ACEG supports the Commission's proposal to allow transmission providers to simply explain the good faith efforts it undertook to seek agreement from relevant state entities in lieu of demonstrating that agreement was obtained. The Commission should clarify in the final rule that relevant state entities do not have the authority to block a Long-Term Regional Transmission Planning cost allocation proposal. Allowing an explanation of good faith efforts when relevant state entities cannot agree will allow transmission providers to continue to move transmission facilities forward from the planning stage towards construction and operation. Relatedly, the Commission should clarify that once a Long-Term Regional Transmission Planning cost allocation method is established it does not need to be reestablished in every planning cycle. This clarification will help move projects out of the planning stage towards construction and operation because reestablishing a cost allocation method can result in significant delays.

2. ACEG Supports the Proposed Definition of Relevant State Entities.

The Commission defines "relevant state entities" for purposes of Long-Term Regional Transmission Planning cost allocation requirements as "any state entity responsible for utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state."[185] ACEG supports this proposed definition. ACEG also supports the Commission's finding that each state should designate a single entity as the voting

[185] NOPR at P 304.

or representative entity to avoid confusion and over-representation by a single state in a multi-state voting process. ACEG also recommends that the requirement to designate a single entity as the voting representative should apply to each of the power marketing administrations and non-jurisdictional entities with a reciprocity tariff. To avoid disputes over which single state entity is the "relevant state entity" the Commission should clarify in the final rule that determining the relevant entity for each state should be consistent with or superior to existing processes. For example, existing processes in SPP's Regional State Committee, MISO's Organization of MISO States, and ISO-NE's New England States Committee should be used, or superior processes may be used if they can be demonstrated as such.

3. ACEG Supports the Proposal to Afford Flexibility in Defining What Constitutes "Agreement" Among the Relevant State Entities for Cost Allocation of Long-Term Regional Transmission Facilities.

ACEG supports the Commission's proposal to afford flexibility in determining what constitutes "agreement" among the relevant state entities for cost allocation of long-term regional transmission facilities. Given that several regions have existing processes and definitions of agreement among stakeholders or participating states, states and stakeholders are already familiar with how they operate in practice. Allowing the use of existing processes and definitions of agreement creates one less process to develop. However, the Commission should clarify in the final rule that flexibility to determine "agreement" should not result in providing states with veto power. With this clarification, the Commission's proposal to afford flexibility creates an opportunity for administrative efficiency.

C. ACEG Supports a Modified State Agreement Approach Whereby Load is Required to Pay its "Roughly Commensurate" Share of Costs and States or Interconnection Customers May Voluntarily Pay More Costs.

ACEG supports the modified state agreement approach advocated by the American Clean Power Association (ACP) in its ANOPR and NOPR Comments.[186] ACP proposes to allow two options for voluntary funding for transmission projects: the Transmission Alternative Right and the Transmission Expansion Right. ACP's proposal is an overlay to cost allocation for facilities identified in Long-Term Regional Transmission Planning that allows states and interconnection customers to voluntarily fund all or part of a facility identified in Long-Term Regional Transmission Planning.[187] Under this approach the costs of transmission projects that are identified in Long-Term Regional Transmission Planning should first be allocated to customers as the primary beneficiaries.[188] Second, the Commission should allow states and/or generation interconnection customers to voluntarily fund the cost of alternative or expanded transmission projects compared to projects identified in the regional transmission plan's base case on an incremental cost addition basis. ACP's proposal is overall consistent with the *ICC* line of cases above because it allocates costs to primary beneficiaries first and then allows entities to identify themselves as beneficiaries when they may not have otherwise been identified as such in the planning process, thereby creating a more precise cost allocation.

The voluntary agreement aspect of ACP's proposal is supported by Commission precedent. In 2021, the Commission issued a Policy Statement titled *State Voluntary Agreements to Plan and Pay for Transmission Facilities*[189] to clarify that Voluntary Agreements

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[186] Refer to ACP's NOPR Comments, Docket No. RM21-17-000 (Aug. 17, 2022).

[187] Refer to NOPR at P 252.

[188] ACP ANOPR Comments at 75-79, Docket No. RM21-17-000 (Oct. 23, 2021).

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

are not precluded by the Federal Power Act (FPA) or the Commission's regulations.[190] The Commission stated that Voluntary Agreements "may allow state-prioritized transmission facilities to be planned and built more quickly than would comparable facilities that are planned through the regional transmission planning process(es)."[191]

The aspects of ACP's proposal involving priority access rights to capacity is also supported by Commission precedent. The Commission's 2013 Policy Statement on allocation of capacity for new merchant transmission projects and new nonincumbent, cost-based, participant-funded transmission projects allows transmission developers to select a subset of customers and reach agreements for procuring up to the full amount of transmission capacity when certain conditions are met.[192] Both merchant projects and cost-based, participant-funded projects "involve willing customers assuming part of the risk of a transmission project in return for defined capacity rights[.]"[193] The reasoning in the 2013 Policy Statement provides support for ACP's "Transmission Expansion Right" proposal because the interconnection customer, like the participant-funder, would be a "willing customer[] assuming part of the risk of a transmission project in return for defined capacity rights"[194] in its portion of the "upsized" or incremental capacity. The Commission's goal of providing open access on a non-discriminatory basis would be met by making the underlying capacity (*i.e.*, the capacity identified to meet the regional need

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[190] *Id.* at P 1.

[191] *Id.* at P 2.

[192] *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects; Priority Rights to New Participant-Funded Transmission*, 142 FERC ¶ 61,038 (2013). The conditions include: "(1) broadly solicit interest in the project from potential customers, and (2) demonstrate to the Commission that the developer has satisfied the solicitation, selection, and negotiation process criteria in the policy statement." *Id.* at P 8.

[193] *Id.* at P 6.

[194] *Id.*

prior to inclusion of the upsized capacity) available for network service. As discussed in ACP's proposal, Order No. 807[195] also supports priority rights to capacity because there the Commission affirmed that "it is generally in the public interest . . . to allow an [owner of Interconnection Customer Interconnection Facilities (ICIF)] . . . to retain priority rights to the use of excess capacity on ICIF that it plans to use to interconnect its own or its affiliates' future generation projects."[196] Order No. 807's reasoning provides support for ACP's "Transmission Expansion Right" proposal because the interconnection customer (or a state) would "shoulder the extra expense" of the "upsized" incremental transmission capacity.[197]

Finally, ACP's proposal is consistent with PJM's State Agreement Approach whereby a state identifies its specific Public Policy Requirements to be included in PJM's Regional Transmission Expansion Plan (RTEP), PJM opens an RTEP competitive proposal window (at the state's request), and the State selects its preferred project which PJM will include in the RTEP.[198] Under the State Agreement Approach the state is allowed to assign capacity of the selected project for a limited amount of time, and future users of the selected project will be

[195] *Open Access and Priority Rights on Interconnection Customer's Interconnection Facilities*, Order 807, 150 FERC ¶ 61,211, *order on reh'g*, Order No. 807-A, 153 FERC ¶ 61,047 (2015).

[196] Order No. 807, 150 FERC ¶ 61,211 at P 109. In Order No. 807, the Commission established a safe harbor period of five years, starting at the commercial operation date wherein the ICIF owner would have priority over the facilities. The Commission reasoned that this allowed the "ICIF owner to be reasonably assured of being able to use that extra capacity, while also providing a mechanism for expansion. Without such reasonable assurance, there is no incentive for a developer to shoulder the extra expense of ICIF sized larger than their initial project." *Id.* at P 39.

[197] *Id.* at PP 14-15, 39; *Aero Energy LLC*, 116 FERC ¶ 61,149 at P 28 (2006); *Milford Wind Corridor, LLC*, 129 FERC ¶ 61,149 at PP 22, 24; *Terra-Gen Dixie Valley, LLC*, 132 FERC ¶ 61,215 at P 49 (2010).

[198] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 142 (2013) ("PJM's State Agreement Approach supplements, but does not conflict with or otherwise replace, PJM's process to consider transmission needs driven by public policy requirements as required by Order No. 1000[.]"), *order on reh'g and compliance*, 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance*, 150 FERC ¶ 61,038 (2015), *order on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).

required to pay a *pro rata* share of the total project costs.[199] ACEG requests that the Commission adopt ACP's Transmission Alternative Right and the Transmission Expansion Right proposals in the Final Rule.

V. INTERREGIONAL PLANNING

The NOPR proposes that transmission providers in neighboring transmission planning regions should be required to revise their existing interregional coordination procedures (and regional transmission planning processes as needed) to require (1) sharing of information regarding the respective transmission needs identified in the Long-Term Regional Transmission Planning, as well as potential transmission facilities to meet those needs; and (2) identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address transmission needs identified through Long-Term Regional Transmission Planning.[200] The Commission also proposes to require transmission providers in neighboring transmission planning regions to revise their interregional transmission coordination procedures (and regional transmission planning processes as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to transmission needs identified through Long-Term Regional Transmission Planning.[201]

The Commission states that it does not, at this time, propose changes to the existing interregional transmission cost allocation requirements of Order No. 1000.[202] The NOPR restates the requests for comment in the ANOPR, such as the need for more interregional

[199] *PJM Interconnection L.L.C.*, 179 FERC ¶ 61,024 at PP 20, 40-42 (2022).

[200] NOPR at P 427.

[201] *Id.* at P 428.

[202] *Id.* at P 416.

coordination, identification of geographic zones of concentrated new generation, the role of regional state committees or other officials in evaluating the coordination processes, and whether to require joint planning processes between neighboring planners. But the NOPR does not offer proposed responses to those issues.

ACEG therefore makes two observations. First, as discussed below, the NOPR's requirement for identification of interregional projects through the regional transmission planning process is just scratching the surface of the changes needed. It does not eliminate the siloes in planning nor resolve the "triple hurdle" that interregional projects must clear. Identification of interregional projects is simply the beginning. Second, the NOPR and ANOPR lay the groundwork for an additional inquiry about how to structure an efficient interregional planning process that may differ from regional planning and cost allocation in certain fundamental ways. ACEG looks forward to a constructive proceeding around these issues.

A. Need for Reform: The "Grid of the Future" is Interregional.

ACEG strongly supports major additional Commission action on interregional planning, so that Long-Term Regional Transmission Planning extends beyond current market structures, ISO/RTO territories, and bilateral planning areas. Proactive interregional planning and cost allocation is the next step for the Commission's electricity policy. Order Nos. 890 and 1000 developed compelling but flexible approaches to planning and cost allocation. In Order No. 1000, the Commission responded to the growing need for transmission across markets or regional grid "seams" by urging coordination and information sharing among regional planners. Interregional projects first had to be selected at the regional planning level and then be compared and coordinated with other relevant regions.[203] The process was, and remains, voluntary.

[203] *Id.* at PP 418-421.

ACEG contends that changes in the generation mix, grid operations, and regional integration since Order No. 1000's issuance in 2011 have made stronger interregional planning measures necessary. The developments of the last decade have made clear that the Commission must actively promote (if not require) interregional transmission planning and development. Disparate regional priorities and increasing numbers of stakeholders that were not aligned made interregional projects more difficult. As ACEG notes elsewhere, very few projects were planned with regional needs in mind in the years after Order No. 1000 and fewer if any projects were built based on assessment of multi-regional or multi-market needs.[204] Because interregional transmission capacity did not increase, the U.S. electrical grid has remained a patchwork quilt operationally, despite the fact that regional planning was mandated for transmission throughout the country.

The tragic suffering and loss that Texas (the ERCOT system) experienced during Winter Storm Uri in February 2021 because of a lack of access to diverse resources outside the state is ample demonstration of the risks posed by a lack of transfer capability between markets or regions, and among the RTOs. The Commission has received powerful confirmation of the critical importance of large-scale transmission to the reliability and resilience of the electric system, in part from the Federal-State Task Force on Electric Transmission and the Reliability Technical Conference. Several industry panelists and state energy regulators indicated that the benefits of capacity sharing were especially helpful during times of extreme weather that affects

[204] The Brattle Group, Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value at 4 (April 2019) ("Significant investments have been made but relatively little has been built to meet the broader regional and interregional economic and public policy needs envisioned when FERC issued Order No. 1000. Instead, most of these transmission investments addressed reliability and local needs.") *available at* https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf

demand.[205] Interconnecting large geographic areas can also save electricity consumers substantial money, often by eliminating the need to build new power plants.

The need to improve regional and related interregional planning arises from the transformative changes occurring or anticipated in the market with respect to the resource diversity, technological change, and the operational innovations driving change in the nation's electric system.

These developments warrant more thorough reexamination of the need for major interregional transmission integration and a new approach to planning and paying for projects that are developed and shared between regions, whether to suit a common goal and purpose or diverse state goals and purposes in the aggregate. ACEG believes there is room for more innovative solutions such as a required minimum level of interregional transfer capability that addresses expected reliability challenges and concerns about system resilience. For instance, in the context of reliability deliberations during the second meeting of the Joint Federal-State Task Force on Electric Transmission, Commissioner Christie enquired about the possible need for a mandatory interregional capacity requirement: "I want to hear from the state regulators about that very specific type of project, inter-regional, to ensure a minimal level of power transfer

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[205] During the September 30, 2021 Reliability Technical Conference, the essential role of large-scale transmission for reliability was emphasized by multiple panelists. Jim Robb, NERC President and CEO, pointed out that "transmission infrastructure will be required to support reliability as the grid continues to transform. This includes infrastructure to support resilience, and to deliver renewable resources from remote areas to load centers." Reliability Technical Conference, Tr. at 19:20-24, Docket No. AD21-11-000 (Sept. 30, 2021). Former FERC Chairwoman Cheryl LaFleur stated that transmission "helps keep the lights on." *Id.* at 90:10-12. Debra Lew of the Energy Systems Integration Group recommended that it is "in our best interest as a country to take advantage of our huge geographic diversity to smooth the variability with increased large scale transmission that connects this diversity." *Id.* at 263:17-21. Mark Ahlstrom from NextEra expressed support for a national macro grid, stating that it is "the best answer to resilience you can find" and "has all kinds of economic benefits as well." *Id.* at 280:17-23. Refer to ACEG Comments the Reliability Technical Conference, Docket No. AD21-11-000 (Feb. 22, 2022).

capacity."[206] ACEG strongly supports this concept as a potential building block of interregional planning to maximize grid reliability and the full range of transmission benefits. If planning regions are required to use a uniform modeling approach with common assumptions, methods, and timelines, interregional planning will become more productive and feasible.

B. Requested Commission Action on Interregional Planning Beyond the NOPR

The NOPR envisions regional plans driven by long-term scenario planning analysis under its Long-Term Regional Transmission Planning. It would therefore require coordination procedures among neighboring planning regions to be updated for purposes of interregional transmission planning, to require:

- Sharing of information regarding the respective transmission needs identified in Long-Term Regional Transmission Planning, as well as potential transmission facilities to meet those needs;
- Identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address transmission needs identified through Long-Term Regional Transmission Planning; and
- Transmission providers in neighboring transmission planning regions to revise their interregional transmission coordination procedures (and regional transmission planning processes as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to transmission needs identified through Long-Term Regional Transmission Planning.[207]

ACEG applauds the NOPR's requirement for public utility transmission providers to revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms and include joint evaluation of interregional transmission facilities that will support more efficient and cost-effective options to meet regional needs. But

[206] Joint Federal-State Task Force on Electric Transmission, Tr. at 43:10-44:21, Docket No. AD21-15 (Feb. 16, 2022). Other regulator panelists discussed the reasons for maintaining a minimum level of connectivity as part of reconsideration of interregional planning.

[207] NOPR at PP 427-428.

fundamentally, the NOPR leaves existing interregional coordination and cost allocation requirements under Order No. 1000 largely undisturbed and focuses instead on improving regional planning. ACEG believes there are substantial costs and risks in not expanding interregional transmission planning, and approaching it as a version of regional planning.

The Commission appropriately seized upon the deficiencies that have become clear since Order No. 1000 was issued to propose a stronger planning process based on anticipated future policy, resource diversity, technological, and economic needs. Long-Term Regional Transmission Planning will be central to interregional as well as regional project planning. A robust, forward-looking, and proactive approach is called for. Transmission planning based on best available data and realistic scenario planning also requires unparalleled coordination among participating states and stakeholders but on terms that are both generally agreed to and necessary to preserve the vitality of the FPA. For example, a planning process that is designed to identify and maximize the net benefits to the system and to consumers must cast a broad net in terms of potential types of benefits to diverse beneficiaries of the system. This is uniquely challenging for interregional projects. But the Commission must be clear about how to identify relevant benefits across many parts of the grid nationally and determine how they can or should be calculated for purposes of assessing alternatives and assigning costs.

Because the NOPR does not make significant changes in interregional transmission capacity development, it is not a blueprint for a nationally integrated grid, which would ultimately offer the greatest potential economic and public policy benefits, not to mention a major new capacity transfer capability that will significantly increase system resilience at a time of increasingly likely extreme weather and a changing climate. ACEG believes that continuing with the same approach and expecting a different result will prove a lost opportunity to make genuine advances in grid integration and flexibility. While the application of the Long-Term Regional Transmission Planning reforms in the NOPR is a good start, ACEG strongly argues that it is the bare minimum for interregional planning. The Commission should do more to assess the most optimal way to foster interregional project development. Other potential elements of an effective, proactive planning regime include the following:

- Joint planning across multiple regional systems that is based on consideration of portfolios of transmission network facilities will also address the individual needs of affected constituent electrical systems and maximize the broadest array of calculable benefits overall. If undertaken jointly by two or more regional planners, or by a separately designated interregional planner, joint planning should employ common or negotiated assumptions, methods and timelines for action as well as agreed upon modelling approaches. This approach goes well beyond interregional coordination to a more dynamic holistic conception of how the grid of the future should be planned and developed.

- Interregional planning must be transparent to minimize distrust and delay. The Commission and planners should also seek to minimize the opportunities for any one state or stakeholder to essentially veto a multi-state project selected for cost allocation.

- Because the downside risk of sharing decision making with others, especially other government agencies or jurisdictions, is the risk of impasse, the Commission needs to be clear about its role under the FPA as the default decision maker if more than one planner, state, or other party threatens to delay or cease consideration of a project that represents a widely accepted solution with the broadest feasible interregional benefits.

- Interregional planning should include consideration of how to resolve disparities in state siting and permitting processes in the interest of achievable net benefits for all participants, including the benefits of advancing grid integration. Proactive planning should incorporate state and industry input that identifies potential opportunities to utilize existing longitudinal rights-of-way early in the planning process as a way to reduce the number and severity of land use problems and community impacts that can accompany large regional and interregional transmission projects. Such a process may also be vital to the Commission's eventual success in efficiently exercising its authority to site projects within (or which may constitute) National Interest Electric Transmission Corridors ("NIETC") under FPA Section 216(a).

C. Issues Raised in the ANOPR and NOPR Justify an Additional Proceeding on Interregional Planning and Cost Allocation.

The NOPR is an excellent start on reinvigorating regional transmission planning. ACEG believes that the scope of the NOPR and the record it is likely to generate will be insufficient to sustain, as a substantial evidence matter, a thorough reassessment of how interregional transmission is planned, built, and cost allocated. ACEG recommends that the Commission take action on the modest solutions to interregional planning in the captioned docket and then propose a separate procedure for the planning and developing of multi-state, multi-market transmission projects. The issues that must be confronted inter-regionally – cost allocation, siting, benefits calculations, coordination among regional planning and regulatory authorities, governance, environmental mitigation, and possibly ownership – are likely to be different than in the regional grid planning context and subject to new solutions.

The experiences and lessons derived from regional planning will be enormously valuable and will help improve all planning processes. However, the Commission needs to put options on the table that will enable transmission providers, customers, planners, and generators to find effective solutions capable of achieving high levels of grid integration, including perhaps a separate entity to administer interregional grid expansion above a specified voltage or capacity level, independent grid monitors, and new collaborative institutions. ACEG believes that a wholesale redesign of interregional planning procedures would be a challenging and lengthy process and probably beyond the scope of the Commission's current proposals. Interregional planning will nevertheless be informed by the Long-Term Regional Transmission Planning reforms, the experiences under Order No. 1000, and the wealth of studies that have been generated about the need for action.

ACEG therefore requests that the Commission issue a NOPR or NOI on interregional transmission planning and cost allocation. As with the NOPR, ACEG supports proactive, forward-looking planning, based on best available data, collaborative processes, and Long-Term Regional Transmission Planning. In the interregional context, the Commission should encourage identification and use of existing transportation rights-of-way (*e.g.*, railroads and highways) or existing transmission rights-of-way as a tool to accelerate development of large-scale high-capacity projects at scale. The Commission should further pursue coordination of interregional planning and the corridor designation process upon which the future of some interregional projects will depend. Because ACEG believes the Commission should already be developing procedures for handling project proposals that arise under its FPA Section 216 authority, such capabilities may have even broader application.

D. The Commission Should Support an Active State Role as Proposed.

The NOPR also proposes to incorporate state advice and decision making on cost allocation and planning and to allow states to use the Commission's planning processes to advance state public policy goals and to jointly identify and plan "regional" projects. They may utilize a Long-Term Regional Cost Allocation Methodology or seek state agreements, or a combination, to advance regional projects. While acknowledging that significant interregional transmission coordination is needed, the NOPR asks commenters to help clarify issues left unresolved with respect to how regional collaborative processes should be used at the interregional level.

The NOPR does not propose to change the requirement that interregional projects must be considered in regional planning procedures before a joint interregional process is employed. However, just as is the case for cost allocation, if states cannot agree on plans for a Long-Term

Regional Facility, the process can presumably be extended, the transmission provider can establish the Long-Term Regional Cost Allocation Methodology, or the Commission can decide the matter. The need for elaborate coordination procedures may be minimized by establishing minimum interregional transfer capacity requirements to address reliability challenges and concerns about system resilience.

Capacity sharing may ultimately lead to agreement about the need to construct new facilities that benefit two or more states or regions, or it may simply act as a stop-gap until additional interregional capacity can be built. Nevertheless, the state role in establishing such capacity sharing requirements will benefit from further clarification.

ACEG supports an active state role in regional and interregional planning and cost allocation. States should be given an opportunity to offer opinions as to important considerations from individual states and through the regional state committee processes. The pathway to the involvement of states in the planning process should not create delays in needed plans. The problem is magnified for interregional projects that will be required to align multiple states and stakeholder groups with differing public policies, economic circumstances, and vulnerabilities. ACEG notes that the involvement of the states in the SPP Regional State Committee and the MISO MVP process, which are frequently cited as a good examples of productive state engagement, is in the planning process itself and is not generally decisional. Rather, the role of the states in planning and cost allocation has been tied to the development of forward-looking cost allocation policy. This approach generally avoids the delays that might otherwise occur in the planning process, particularly since SPP relies on the highway/byway cost allocation methodology, which is a constant across planning cycles. ACEG recommends the final rule establish clear rules about what role states play and when decisions about joint planning with other jurisdictions or cost allocation must be finally settled by the Commission.

VI. CONCLUSION

In the NOPR, the Commission made the requisite findings under FPA Sections 205 and 206 that transmission planning needs to be conducted regionally and, furthermore, that the Commission's goals require changes to provide lower costs and greater reliability to consumers. FPA Sections 201, 216, and 309 further bolster the breadth of the Commission's authority to engage proactively in advancing the grid of the future, including the grid the nation will need for reliability, commercial and environmental purposes in the 2030s and 2040s. The analytical rationale and policy foundation in the NOPR and underlying record for long-term planning, both regionally and inter-regionally, will enable the Commission to take another step toward the clean energy future.

The challenges of the past decade following Order No. 1000 – the failure of large regional or interregional projects to materialize despite the demonstrated need and the Commission's clear policy goals, the inability for existing processes to secure all the resilience and reliability benefits that interregional connections and capacity transfers would provide, the continuing inability of the transmission grid to enable sufficient clean energy resources to meet state public policies or national clean energy goals, and the markets' evolution – also support a finding that the current grid constraints are unjust and unreasonable. Therefore, the final rule in this docket can expand upon the regulatory approach adopted in Order No. 1000 and foreshadowed by Order Nos. 888, 2000, and 890, based on a demonstrated need for the consumer benefits of larger power markets, enhanced reliability capabilities, and lower-cost decarbonized generation that multi-benefit, long-term planning and cost allocation should produce.

Respectfully submitted,

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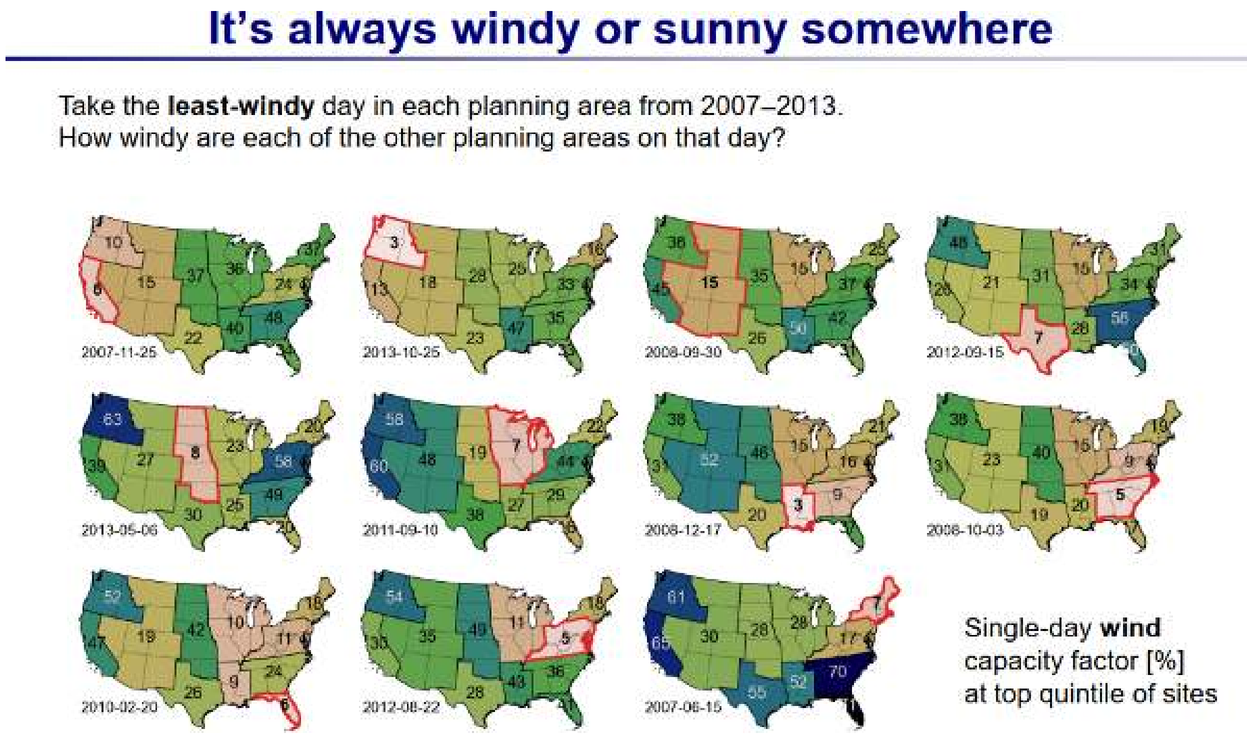
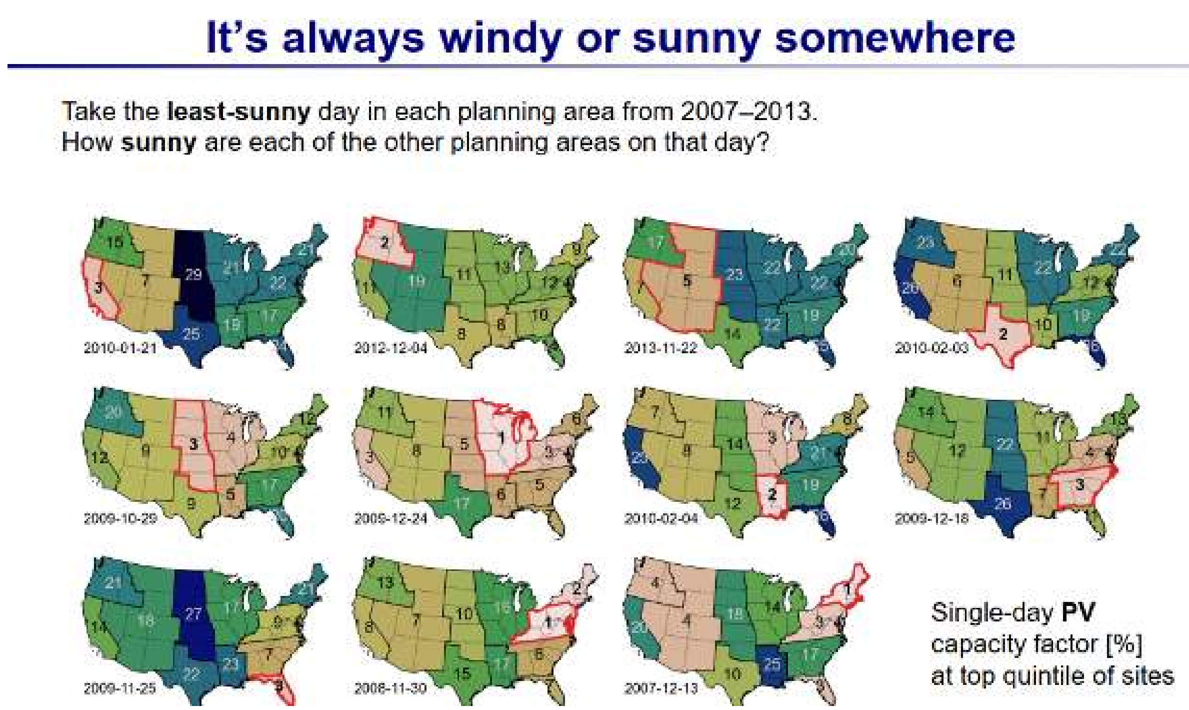
Dated: August 17, 2022

Attachment 1

These figures show that when it is not windy or sunny in one area, it often is in neighboring areas, suggesting that transmission would be valuable to serve load with a relatively steady aggregate supply of renewable energy.[1]





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[1] NARUC Task Force on Electric Transmission, Patrick R. Brown, The Value of Interregional Coordination and Transmission in Decarbonizing the US Electricity System (July 8, 2022) *available at* https://github.com/patrickbrown4/zephyr/blob/main/presentations/20220708-transmission_decarbonization/pbrown_20220708.pdf.