UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

REQUEST FOR REHEARING AND CLARIFICATION OF PUBLIC INTEREST ORGANIZATIONS

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Pursuant to section 313(a) of the Federal Power Act,[1] and Rule 713 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure,[2] Appalachian Voices, Energy Alabama, Environmental Defense Fund, Environmental Law & Policy Center, Natural Resources Defense Council, North Carolina Sustainable Energy Association, Sierra Club, South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Southern Renewable Energy Association, and Sustainable FERC Project (together "Public Interest Organizations" or "PIOs") submit this request for rehearing and clarification of the Commission's Order in the above-mentioned docket.[3]

I. Background

Since the Commission's issuance of its July 15, 2021 Advanced Notice of Proposed Rulemaking ("ANOPR") in Docket No. RM21-17-000,[4] PIOs and their respective members have been extensively engaged in the Commission's multi-year effort to comprehensively assess and

[1] 16 U.S.C. § 825l (2018).
[2] 18 C.F.R. § 385.713 (2023).
[3] *Bldg. for the Future Through Elec. Reg'l Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 (2024) ("Order No. 1920").
[4] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation and Generator Interconnection*, 86 Fed. Reg. 40,266 (July 15, 2021), 176 FERC ¶ 61,024 (2021) ("ANOPR").

address nation-wide transmission planning practices and procedures that have led to a systemic lack of transmission development necessary to adapt to a transitioning energy supply, readily interconnect new resources, meet rising demand, and maintain reliability at just and reasonable rates.[5] PIOs' ANOPR Comments provided comprehensive evidence of unjust, unreasonable, and unduly discriminatory transmission rates, planning practices, and procedures across the nation's transmission providers and expert analysis on potential reforms. Along with hundreds of other stakeholders, PIOs also provided comments on the Commission's April 21, 2022 Notice of Proposed Rulemaking ("NOPR") on long-term regional transmission planning and cost allocation requirements,[6] indicating their general support for the Commission's efforts while providing explanation on why further refinements to the Commission's proposal would be necessary to effectuate its aim of just and reasonable rates.[7] Since long-term planning and buildout of the regional transmission system is necessary to address the root cause of systemic interconnection queue delays, regional congestion, and grid resilience in the face of increasingly extreme weather, Order No. 1920's transmission planning reforms represent the lynchpin of the Commission's multi-proceeding reform effort, and PIOs applaud the Commission's extensive stakeholder engagement and thoughtful consideration of the nearly 17,000 pages of comments from nearly 200 diverse parties.[8]

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[5] *See, e.g.*, *Comments of Pub. Int. Orgs., Bldg. for the Future Through Elec. Reg'l Transmission Planning and Cost Allocation and Generator Interconnection*, Docket No. RM21-17-000 (Oct. 12, 2021), Accession No. 20211012-5519 ("PIOs ANOPR Comments") and *Reply Comments of Pub. Int. Orgs., Bldg. for the Future Through Elec. Reg'l Transmission Planning and Cost Allocation and Generator Interconnection*, Docket No. RM21-17-000 (Nov. 30, 2021), Accession No. 20211130-5284; *Comments of Public Interest Organizations*, Docket No. RM21-17-000 (Aug. 17, 2022) ("PIOs NOPR Comments"), Accession No. 20220817-5270; *Reply Comments of Public Interest Organizations*, Docket No. RM21-17-000 (Sept. 19, 2022) ("PIOs NOPR Reply"), Accession No. 20220919-5156.
[6] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 87 Fed. Reg. 26,504 (May 4, 2022), 179 FERC ¶ 61,028 (2022) ("NOPR").
[7] *See generally* PIOs NOPR Comments and PIOs NOPR Reply.
[8] Order No. 1920 at P 36.

PIOs continue to agree with the Commission's conclusion that there is substantial evidence demonstrating that existing regional transmission planning and cost allocation practices and procedures across the United States are systemically unjust, unreasonable, and unduly discriminatory or preferential, and believe that the regulations set forth in Order Nos. 888,[9] 890,[10] and 1000[11] need to be updated to close gaps and set minimum, common-sense requirements to ensure that the transmission and sale of electricity meet the Federal Power Act's foundational mandate to serve the public interest.[12] In particular, PIOs agree that the absence of sufficiently long-term, forward-looking, and comprehensive transmission planning requirements is causing transmission providers to fail to adequately anticipate and plan for current and future system conditions.[13] PIOs agree that transmission planners routinely fail to appropriately evaluate the benefits of transmission infrastructure, which leads them to undertake insufficient and inefficient investments that lock out cheaper competitors and require consumers to pay more than necessary or appropriate to meet their energy needs.[14] PIOs also continue to support the Commission's proposed framework of reforms, including its mandates that all transmission providers: (1) conduct scenario-based analysis of transmission needs over at least a 20-year period based on a common set of required factors that use best available data to estimate the future supply and demand needs, including meeting legal requirements pertaining to generation and electrification; (2) use and measure a mandatory set of benefits to evaluate the full value of

[9] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21,540 (May 10, 1996) ("Order No. 888").
[10] Preventing Undue Discrimination and Preference in Transmission Service, 72 Fed. Reg. 19,112 (Apr. 17, 2007) ("Order No. 890").
[11] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 76 Fed. Reg. 49,842 (Aug. 11, 2011) ("Order No. 1000").
[12] *See* 16. U.S.C. § 824; *see also* 16 U.S.C. §§ 824d(a)–(b) (rates and any rules and regulations pertaining to such rates must be just, reasonable, and may not be unduly preferential).
[13] NOPR at P 85.
[14] *Id.*

potential transmission solutions over at least a 20-year minimum period; (3) establish transparent and fair evaluation criteria to be used during the facility selection process; (4) establish default cost allocation methodologies to pay for selected transmission facilities that provide greater transparency and participation by all stakeholders; (5) consider less expensive grid-enhancing technologies as part of the project evaluation and selection process; (6) improve the local transmission planning process to increase transparency and stakeholder participation, and ensure that larger projects are properly sized and incorporated into the regional planning process; and (7) improve the interregional planning process by incorporating the results of these regional planning reforms and requiring greater coordination. Order No. 1920 establishes critical baseline requirements that are necessary to remedy systemic failures to properly plan, build, and pay for transmission across the entire grid while preserving needed flexibility to account for regional differences, and represents a logical regulatory progression based on lessons learned from the implementation of Order Nos. 888, 890, and 1000.

While PIOs believe that the Commission has largely struck an appropriate balance between mandates and flexibility, PIOs seek rehearing and clarification of a number of discrete findings to provide clarity for all stakeholders and ensure that Order No. 1920 achieves its aim of ensuring that all transmission providers comply with baseline requirements necessary to ensure open access to a reliable, affordable, and just transmission system. PIOs' request is guided by the consistent experience from over a century of Commission efforts to regulate transmission providers under the Federal Power Act demonstrating that while flexibility is important to accommodate regional differences, firm mandates are essential to counter the inherent economic incentives of the nation's transmission providers (and their generator affiliates) to avoid building or providing access to large-scale transmission that threatens their market power and profits.[15] While Order No. 1920 marks a significant step toward addressing the systemic injustices of current transmission planning practices, there are a number of ways in which the Commission's reforms are overly discretionary and, unless strengthened, will fail to remedy the acknowledged issues central to achieving just, reasonable, and not unduly discriminatory transmission rates, practices, and procedures.

As one example, PIOs request that the Commission reconsider its decision not to require transmission providers to assess the full list of benefits proposed in the NOPR when evaluating potential transmission solutions to identified long-term transmission needs, especially with regard to cost savings that would come with access to reduced-cost generation and increased competition. The failure to properly assess the full benefits provided by a proposed transmission solution is at the heart of the failure to build it or ensure that beneficiaries pay their fair share. Properly evaluating the full suite of benefits associated with transmission, such as savings from opening access to reduced-cost generation and increased competition, is already part of best transmission planning practices in some regions and has demonstrated how a holistic analysis of benefits routinely reveals savings that more than offset the cost of associated transmission.[16] For example, the Midcontinent Independent System Operator ("MISO") estimated that the consumer savings from access to cheaper generation alone would exceed the $14–17 billion cost of the entire portfolio of Tranche 1 transmission projects selected as part of its 2022 Long Range

[15] *See, e.g.*, Ari Peskoe, *Is the Utility Syndicate Forever?*, 42 Energy L.J. 1, 56–57 (2021); ANOPR Comments at 7–12, 61–65; NOPR Comments at 8–9, 52–53.
[16] *See, e.g.*, Christopher Clack et al., Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the U.S., Americans for a Clean Energy Grid (Oct. 2020), at 9–10, https://cleanenergygrid.org/wp-content/uploads/2020/11/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S.pdf.

Transmission Planning process.[17] Given that access to cheaper generation is a readily quantifiable benefit of such magnitude available to all consumers, transmission providers must assess it in order to ensure both that the most beneficial and efficient solutions to energy system needs are selected and that costs of those solutions are allocated commensurate with the benefits provided. PIOs discuss this and other similar requests for rehearing and clarification below.

PIOs also note that while they believe their proposed changes are necessary to fully address the harms caused by current transmission planning practices and procedures, given the long lead time for compliance with Order No. 1920, PIOs do not believe that any of its requests require delay of implementation of Order No. 1920 as currently issued and can be addressed in a supplemental order.

II. Statement of Issues and Specification of Error

Pursuant to Rules 203(a)(7) and 713(c),[18] PIOs provide the following specifications of errors:

1. The Commission's decision to expand the planning cycle from three years to five years lacked support in the record, did not make a rational connection between the findings and the choice made, and was arbitrary and capricious given the urgency of the problem.[19]

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[17] *See* Am. Council on Renewable Energy ("ACORE"), Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis: A Case Study Of Miso's Long Range Transmission Planning, at 15 (Aug. 2022), https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf.

[18] 18 C.F.R. §§ 385.203(a)(7), 385.713.

[19] 5 U.S.C. § 706(2)(E); 16 U.S.C. § 825*l*; *see, e.g.*, *Port of Seattle v. FERC*, 499 F.3d 1016 (9th Cir. 2007) (An agency must "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'") (*citation omitted*); *Emera Maine v. FERC*, 854 F.3d 9, 28 (D.C. Cir. 2017) (reversing FERC order for "fail[ing] to establish a 'rational connection' between the record evidence and its decision."); *Ctr. for Auto Safety v. Fed. Hwy Admin.*, 956 F.2d 309, 314 (D.C. Cir. 1992) ("An agency action is arbitrary and capricious if it rests upon a factual premise that is unsupported by substantial evidence.") (citation omitted); *Cal. Pub. Utils. Comm'n v. FERC*, 20 F.4th 795, 800 (D.C. Cir. 2021) (FERC orders will be upheld under the arbitrary and capricious standard only "if they are supported by substantial evidence") (citation omitted).

2. The Commission's failure to align the methodologies for conducting planning under Order No. 1000 or clarify the relationship between Order Nos. 1000 and 1920 was arbitrary and capricious and will perpetuate the unjust, unreasonable, and unduly discriminatory practices the Commission seeks to reform.[20]

3. The Commission's choice to exclude certain benefits, including access to lower cost generation and increased competition, is not supported in the record and will fail to establish just and reasonable rates.[21]

4. The Commission's refusal to establish clear modeling and transparency requirements for the categories of factors in scenario development process does not make a rational connection between the findings and the choice made and will fail to establish just and reasonable rates.[22]

5. The Commission's omission of energy storage from the enumerated alternative transmission technologies that transmission providers must consider in Long-Term Regional Transmission Planning failed to engage meaningfully with the record and was arbitrary and capricious.[23]

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[20] 16 U.S. Code § 824e; *Riverkeeper Network v. FERC*, 753 F.3d 1304, 1313 (D.C. Cir. 2014) (holding that decisions that "run[] counter to the evidence before the agency" are arbitrary and capricious) (quoting *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins.,* 463 U.S. 29, 43 (1983)); *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028, 1055 (D.C. Cir. 2022) (finding that FERC's holding that FERC's failure to provide an intelligible explanation for its decision was not reasoned decisionmaking; court found that "an order with apparent contradictions as to a dispositive issue is not reasoned decisionmaking and requires remand for clarification.") (citation omitted); *Pub. Serv. Elec. and Gas Co. v. FERC*, 989 F.3d 10, 17 (D.C. Cir. 2021) (FERC's orders will not stand if they are "either unreasonable or inadequately explained.") (internal quotes and citations omitted); *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 277, 136 S. Ct. 760, 774, 193 L. Ed. 2d 661 (2016), as revised (Jan. 28, 2016). (When FERC exercises its authority under FPA Section 206 then the Commission "shall determine the just and reasonable rate, charge[,] rule, regulation, practice or contract" and impose "the same by order.").

[21] 5 U.S.C. § 706(2)(E); 16 U.S. Code § 824e; 16 U.S.C. § 825*l*; *Emera Maine v. FERC*, 854 F.3d 9, 28 (D.C. Cir. 2017); *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 54 (D.C. Cir. 2014) (quoting *Motor Vehicles Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983)) (FERC must "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made.").

[22] 5 U.S.C. § 706(2)(E); 16 U.S. Code § 824e; 16 U.S.C. § 825*l*; *Del. Div. of Pub. Advoc. v. FERC*, 3 F.4th 461, 469 (D.C. Cir. 2021) (Commission acts arbitrarily if it "fail[s] to consider an important aspect of the problem . . . ."); *Port of Seattle v. FERC*, 499 F.3d 1016 (9th Cir. 2007) (An agency must "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'") (citing *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43); *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1303–04 (D.C. Cir. 1992) (For an agency order to pass scrutiny under the arbitrary and capricious standard, a reviewing court must be able to "discern a reasoned path . . . to the decision [the Commission] reached."); *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 277, 136 S. Ct. 760, 774, 193 L. Ed. 2d 661 (2016), as revised (Jan. 28, 2016). (When FERC exercises its authority under FPA Section 206 then the Commission "shall determine the just and reasonable rate, charge[,] rule, regulation, practice or contract" and impose "the same by order.").

[23] 5 U.S.C. § 706(2)(E); 16 U.S.C. § 825*l*; *Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 969 (D.C. Cir. 2005); *W. Deptford Energy, LLC v. FERC*, 766 F.3d 10, 20 (D.C. Cir. 2014) ("It is textbook administrative law that an agency must "provide[ ] a reasoned explanation for departing from precedent or treating similar situations

6. The Commission's decision to not require that transmission providers use a portfolio approach when evaluating the benefits of long-term regional transmission facilities failed to engage meaningfully with the record and was arbitrary and capricious.[24]

7. The Commission erred when it allowed transmission providers to set the benefit-to-cost ratio at 1.25:1.

8. The Commission's decision to continue applying a presumption of prudence to local planning failed to engage meaningfully with commenters, contradicts its own findings, and will fail to establish just and reasonable rates.[25]

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differently," and "because it has not adequately explained its decision to treat [entities] differently in a context where they appear similarly situated, we remand the case to the Commission for a fuller explanation.") (*citing ANR Pipeline Co. v. FERC*, 71 F.3d 897, 901 (D.C.Cir.1995) and *Colorado Interstate Gas Co. v. FERC*, 146 F.3d 889, 893 (D.C.Cir.1998)); *Del. Div. of Pub. Advoc. v. FERC*, 3 F.4th 461, 469 (D.C. Cir. 2021) (finding FERC's decision to be arbitrary and capricious when its response to contrary evidence was "little more than a hand wave.")

[24] 5 U.S.C. § 706(2)(E); *Del. Div. of Pub. Advoc. v. FERC*, 3 F.4th 461, 469 (D.C. Cir. 2021) (finding FERC's decision to be arbitrary and capricious when its response to contrary evidence was "little more than a hand wave.") *Consol. Edison Co. of NY, Inc. v. FERC*, 45 F.4th 265, 278 (D.C. Cir. 2022) ("FERC's ratemaking orders will not stand . . . if they are 'either unreasonable or inadequately explained.'"); *NorAm Gas Trans. Co. v. FERC*, 148 F.3d 1158, 1165 (D.C. Cir. 1998) (an agency will be reversed when it does not "engage with the arguments raised before it."); *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1303 (D.C. Cir. 1992) ([I]t remains the duty of the courts "to ensure that an agency engage the arguments raised before it—that it conduct a process of reasoned decisionmaking."); *Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 1312–13 (D.C. Cir. 1991).

[25] 16 U.S.C. § 824e; 16 U.S.C. § 825*l*; *Kentucky Mun. Energy Agency v. FERC*, 45 F.4th 162, 178 (D.C. Cir. 2022) (Holding that FERC engaged in "unreasoned, arbitrary, and capricious decisionmaking" by refusing to consider the material effects of its order on customer rates); *Env't Def. Fund v. FERC*, 2 F.4th 953, 975 (D.C. Cir. 2021) (FERC's "ostrich-like approach" in the face of plausible evidence of self-dealing was not reasoned decisionmaking and failed to adequately balance public benefits and adverse impacts); *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028, 1055 (D.C. Cir. 2022); *Del. Div. of Pub. Advoc. v. FERC*, 3 F.4th 461, 469 (D.C. Cir. 2021); *Riverkeeper Network v. FERC*, 753 F.3d 1304, 1313 (D.C. Cir. 2014); *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 277, 136 S. Ct. 760, 774, 193 L. Ed. 2d 661 (2016), as revised (Jan. 28, 2016). (When FERC exercises its authority under FPA Section 206 then the Commission "shall determine the just and reasonable rate, charge[,] rule, regulation, practice or contract" and impose "the same by order.")..

III. Request for Rehearing

A. The Commission's Decision to Expand the Planning Cycle from Three Years to Five Years Lacked Support in the Record, Did Not Make a Rational Connection Between the Findings and the Choice Made, and Was Arbitrary and Capricious Given the Urgency of the Problem.

1. Five-Year Planning Cycles Will Not Keep Pace with the Change in Factors Driving Transmission Needs.

The NOPR proposed to require transmission providers to reassess and revise Long-Term Scenarios every three years.[26] It justified this planning cycle length on the need to keep pace with rapidly changing "technology, markets, and policies," balanced against the administrative burden of developing Long-Term Scenarios.[27] Many commenters,[28] including PIOs,[29] supported this proposed timeline as essential to account for shifting conditions that drive transmission needs, like extreme weather, demand growth, and a changing resource mix. Yet Order No. 1920 extends this timeline by two years, directing transmission providers to conduct and complete a Long-Term Regional Transmission Planning cycle every five years instead of every three.[30]

At the same time, Order No. 1920 recognizes that the pace of change that supported the NOPR's proposed three-year cycle has only *accelerated* in the two years since its issuance. This recognition and the underlying record evidence do not support lengthening the Long-Term Regional Transmission Planning cycle and making it less responsive to these trends. First, Order No. 1920 notes that "the record shows that changing reliability needs are driving a significant shift in demand placed on the transmission system, and that because extreme weather events are occurring with greater frequency, transmission is increasingly critical to ensuring system

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[26] *See* NOPR at P 97.
[27] *Id*. at P 99.
[28] *See* Order No. 1920 at PP 354–360.
[29] *See* PIOs Initial Comments at 16–17.
[30] *See* Order No. 1920 at P 377.

reliability."[31] Indeed, in the years following the NOPR, three major winter storms—Elliot,[32] Gerri, and Heather[33]—have prompted the Commission to launch joint investigations with NERC to assess their effects on the bulk power system. Second, Order No. 1920 finds that "demand is changing" and highlights comments "substantiat[ing] the fact that, in many regions, large loads associated with new and emerging industrial needs, like data centers, are driving rapid load growth."[34] Order No. 1920 further notes that these trends have only intensified since the ANOPR and NOPR first recognized them[35] and cites numerous studies and reports postdating the NOPR that catalogue extreme load growth projections.[36] Finally, whereas the NOPR cited the growth in interconnection request capacity as of 2020,[37] Order No. 1920 references updated studies from the Lawrence Berkeley National Laboratory "indicat[ing] that the capacity of wind, solar, and storage in interconnection queues is still increasing."[38] The Commission further notes that the Inflation Reduction Act's passage, which occurred after the NOPR's issuance, may further hasten this shift.[39]

Taken together, this record evidence demonstrates that to the extent that conditions have changed since the Commission issued the NOPR, the pace at which transmission drivers are shifting has only escalated. The faster conditions shift, the more frequently Long-Term Scenarios

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[31] *Id*. at P 94.
[32] *See id*. at P 234, n.585 (citing FERC & North American Electric Reliability Corporation ("NERC"), Winter Storm Elliot Report: Inquiry into Bulk-Power System Operations During December 2022 (Nov. 2023), https://www ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022).
[33] FERC & NERC, System Performance Review of the January 2024 Arctic Storms (Apr. 25, 2024), https://www ferc.gov/sites/default/files/2024-04/24_System%20Performance%20Review%20of%20the%20January%202024%20Arctic%20Storms_0425.pdf.
[34] Order No. 1920 at P 95.
[35] *See id*. at n.214.
[36] *See id*. at nn.215, 216, 218.
[37] *See* NOPR at n.171.
[38] Order No. 1920 at n. 242 (citing Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2022* (Apr. 2023)).
[39] *See id*. at PP 96, 99.

should be updated. Only then can the transmission planning process act nimbly enough to meet fast-emerging needs with long-lead regional solutions. In taking the opposite approach and increasing the planning cycle's length, Order No. 1920 disregards record evidence without a rational basis for doing so.[40]

2. The Extended Planning Cycle Would Not Achieve Its Purported Aim.

The Commission states that it was "persuaded" to set a five year cycle timeline by some commenters asserting that the three year timeframe to conduct Long Term Regional Transmission Planning "could be administratively burdensome"—in what manner the Commission does not say—and that the benefit of a shorter timeframe "may not outweigh those additional burdens."[41] While the record does not support extending the three year planning cycle to five years given the urgency of regional transmission needs, Order No. 1920's detailed timeline itself demonstrates that a five-year cycle is not necessary. The Commission requires transmission providers to complete the entire substance of a Long-Term Regional Transmission Planning cycle within the first three years of the five-year cycle, which entails: (1) developing Long-Term Scenarios; (2) identifying Long-Term Transmission Needs; (3) identifying Long-Term Regional Transmission Facilities to meet those needs and measuring their benefits; and (4) evaluating and deciding whether to select Long-Term Regional Transmission Facilities, after which there is a fallow period of up to two years.[42] It is not apparent from the record cited that any commenters asked for the Commission's proposed planning cycle structure—in fact most

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[40] 5 U.S.C. § 706(2)(E); 16 U.S.C. § 825*l*; see*, e.g.*, *Port of Seattle v. FERC*, 499 F.3d 1016 (9th Cir. 2007) (An agency must "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'") (citation omitted); *Emera Maine v. FERC*, 854 F.3d 9, 28 (D.C. Cir. 2017) (reversing FERC order for "fail[ing] to establish a 'rational connection' between the record evidence and its decision."); *Ctr. for Auto Safety v. Fed. Highway Admin*., 956 F.2d 309, 314 (D.C. Cir. 1992) ("An agency action is arbitrary and capricious if it rests upon a factual premise that is unsupported by substantial evidence.") (citation omitted)

[41] *See id*. at P 379.

[42] *See id*. P 378–79.

commenters supported the original NOPR requirement.[43] Moreover, this structure both fails to alleviate the purported administrative burdens raised by a minority of commenters questioning whether three years was a sufficient amount of time to develop Long-Term Scenarios and conduct the required studies,[44] and undermines Order No. 1920's essential purpose of requiring transmission providers to expeditiously identify and address rapidly-shifting and critical regional transmission needs with the urgency cited by the Commission as a foundational concern.[45]

The Commission asserts that the two-year period between project selection and the beginning of the next cycle allows for greater planning accuracy as it permits transmission planners to update the Long-Term Scenarios in advance of the next planning cycle to reflect changes in the factors going into the scenario and system need calculations, such as changes in technology or load forecasts, as well as incorporation of projects that were approved for building in the prior cycle.[46] However, what the Commission describes are merely updated inputs into tasks (1) and (2) of the regular three-year planning cycle. Especially for those transmission providers planning to re-use models built in a previous cycle, entering these updates would logically take *less* time to do[47] and the Commission does not explain why planners would require

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[43] The vast majority of those commenting on this aspect of the NOPR favored a three-year period or less. Order No. 1920 at PP 354–74 (At least 38 parties across a widespread stakeholder group, including several utilities and transmission organizations, expressing support for the NOPR's three-year proposal or a shorter time frame). To the extent that there were concerns, a smaller number of parties wanted more flexibility to set their own cycles to be either shorter or longer primarily because of cost or a desire to align with other processes such as a state IRP process and to make their own determinations on whether to start with a new scenario analysis or update the prior one. *Id.* at PP 361–69. Order No. 1920 only cites to 6 parties who asserted that a longer period was necessary, and these were generally vague assertions that three years would be too burdensome without explaining whether these burdens could be overcome and none of them appeared to propose the structure adopted by the Commission. *Id.* at 371–74).
[44] *See, e.g.*, Comments of International Transmission Company Initial Comments d/b/a/ ITC Transmission, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC, Docket No. RM21-17-000, at 10 (Oct. 12, 2021), Accession No. 20211012-5509; Indicated PJM TOs Initial Comments, Docket No. RM21-17-000 (Oct. 12, 2021), Accession No. 20211012-5612 at 11–12.
[45] Order No. 1920 at PP 94–100. As the Commission notes, many of the transmission needs include deadlines for built transmission to be in place by 2030 (*id.* at PP 93, 95–97), yet Order No. 1920's the first cycle of planning on what to build would not even be completed until 2030.
[46] Order No. 1920 at PP 380, 382.
[47] On this point, the Commission appears to agree. *See id.* at P 1779.

a total of five years to update the same information it initially assembled from scratch in three. Given that the Commission emphasizes that it does not believe the record supports a need for more than three years for transmission providers to conduct a full scenario analysis, needs assessment, benefits calculation, and project selection from scratch,[48] it defies logic to claim that transmission providers need two additional years at the end of each cycle to update inputs into those models to be ready for the next planning cycle when there is already an allotted period of time to do that within the three year time allotment.

3. The Implementation of a Five-Year Cycle is Unclear and Will Exclude Meaningful Stakeholder Participation.

To make matters worse, Order No. 1920 becomes increasingly unclear in detailing how this planning structure will work in practice. The Commission initially requires transmission providers to conduct all required analyses and "determine whether to select Long-Term Regional Transmission Facilities no later than three years" after the cycle begins.[49] But it then states that "nothing in this final rule prevents transmission providers from evaluating and selecting additional Long-Term Regional Transmission Facilities after year three" of the cycle and before the next cycle begins.[50] These statements very nearly contradict one another. The Commission attempts to clarify transmission providers' obligation by stating that "transmission providers must designate a point in the evaluation process at which transmission providers will determine whether to select or not select identified Long-Term Regional Transmission Facilities," but then repeats the inconsistency: (1) this point "must be no later than three years" after the cycle begins,[51] and (2) "transmission providers may evaluate and select additional Long-Term

[48] *Id.* at P 379.
[49] *Id.*
[50] *Id.* at P 381.
[51] *Id.* at P 955.

Regional Transmission Facilities . . . after this point and before the commencement of the next such cycle."[52] While these statements are facially irreconcilable, a conceivable interpretation would allow the transmission provider to make final selections decision on *any* Long-Term Regional Transmission Facilities up until the five-year cycle's end so long as it makes a selection decision on at least one Long-Term Regional Transmission Facility before the end of year three.

Such a structure also undermines logical concerns from stakeholders that the planning process not involve mid-stream changes requiring re-running an analysis.[53] It would also likely undo the careful political and economic bargains made as part of the planning process and in doing so, would encourage transmission providers to make decisions outside the context of that process when stakeholders are no longer at the table. This structure negates the progress Order No. 1920 makes on balancing power across all affected stakeholders to design an energy system that meets the needs of the system as a whole and which also serves as a critical check on the economic incentives of incumbent utilities to make decisions that prioritize their profits over the public interest.[54]

Given the systemic deficiencies in regional transmission and increasingly dire exigencies in addressing them identified by the Commission,[55] its decision to nearly double the time in which transmission providers may take to *formulate* a solution—on top of the Commission's acknowledgement that actually *completing* the chosen solution could take another decade[56]—is

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[52] *Id.* at n.2105.
[53] *See, e.g.*, *id.* at P 358.
[54] *See Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667, 689 (D.C. Cir. 2000) (finding that the record in Order No. 888 supported the Commission's general finding that open access requirement was justified by the discriminatory practices and anti-competitive behaviors dominating the industry).
[55] FERC, Chairman Phillips' and Commissioner Clements' Joint Concurrence on FERC Order No. 1920 (May 14, 2024), https://www.ferc.gov/news-events/news/chairman-phillips-and-commissioner-clements-joint-concurrence-ferc-order-no-1920#:~:text=Most%20significantly%2C%20we%20are%20requiring,%2C%20Long%2DTerm%20Transmission%20Facilities.
[56] Order No. 1920 at PP 116, 329.

irrational. While the Commission asserts that further time is necessary to ease the administrative burden on transmission providers, the Commission arrives at a solution that is neither justified by the record nor administratively workable.[57] Accordingly, PIOs respectfully submit that the Commission erred in expanding the planning cycle from three years to five years as its decision was not supported by the evidence in the record,[58] did not make a rational connection between the findings and the choice made,[59] and was arbitrary and capricious given the urgency of the problem.[60] The Commission can cure these infirmities by granting rehearing and adopting the NOPR's originally proposed and widely supported three-year planning cycle. The Commission can also allow for limited case-by-case extensions for the small minority of entities needing initial flexibility beyond the one year period all entities already have to file compliance filings in which they may need to assemble necessary resources or synchronize the long-term transmission planning process with other, related proceedings.

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[57] *Id.* at P 379.

[58] 5 U.S.C. § 706(2)(E); 16 U.S.C. § 825*l*; see*, e.g.*, *Port of Seattle v. FERC*, 499 F.3d 1016 (9th Cir. 2007) (An agency must "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'") (citation omitted); *Emera Maine v. FERC*, 854 F.3d 9, 28 (D.C. Cir. 2017) (reversing FERC order for "fail[ing] to establish a 'rational connection' between the record evidence and its decision."); *Ctr. for Auto Safety v. Fed. Highway Admin*., 956 F.2d 309, 314 (D.C. Cir. 1992) ("An agency action is arbitrary and capricious if it rests upon a factual premise that is unsupported by substantial evidence.") (citation omitted); *Cal. Pub. Utils. Comm'n v. FERC*, 20 F.4th 795, 800 (D.C. Cir. 2021) (FERC orders will be upheld under the arbitrary and capricious standard only "if they are supported by substantial evidence") (citation omitted).

[59] *Emera Maine v. FERC*, 854 F.3d 9, 28 (D.C. Cir. 2017) (reversing FERC order for "fail[ing] to establish a 'rational connection' between the record evidence and its decision.").

[60] *See Ctr. for Auto Safety v. Fed. Highway Admin*., 956 F.2d 309, 314 (D.C. Cir. 1992) ("An agency action is arbitrary and capricious if it rests upon a factual premise that is unsupported by substantial evidence.") (citation omitted); *Cal. Pub. Utils. Comm'n v. FERC*, 20 F.4th 795, 800 (D.C. Cir. 2021) (stating that the Commission's orders will be upheld under the arbitrary and capricious standard only "if they are supported by substantial evidence") (citation omitted).

B. The Commission Erred When It Failed to Align the Methodologies for Conducting Long-Term Regional Transmission Planning Under Order No. 1920 with Reliability and Economic Planning Under No. 1000, or Clarify the Relationship Between Order Nos. 1000 and 1920.

1. Order No. 1000's Siloed, Near-Term Planning Process is Unjust, Unreasonable, and Unduly Discriminatory.

Order No. 1920 highlights repeatedly that existing transmission planning practices and procedures under Order No. 1000 have led to threats to system reliability, the inability to meet governmental requirements, and unjust, unreasonable, and unduly discriminatory rates for consumers across the nation.[61] The Commission explains that existing transmission planning processes are failing to meet critical transmission needs that must be urgently addressed and finds that the typically near-term and siloed planning processes under Order No. 1000 fail to generate efficient and effective transmission infrastructure build out necessary to meet the comprehensive needs of regional transmission over the long term.[62] The Commission notes that shorter-term planning is ill-suited for planning regional transmission facilities that often take ten or more years to build, and that associated benefit analyses are too short to capture the many decades of benefits that such transmission projects can provide.[63] Moreover, the Commission finds that existing transmission planning requirements fail to require planners to adequately account for forward-looking system-wide transmission needs, such that:

> even following Order Nos. 890 and 1000, transmission providers have adopted widely divergent approaches to determining the factors that are relevant to identifying transmission needs within regional transmission planning. Specifically, . . . some existing regional transmission planning processes ignore trends in future generation and the impact of extreme weather [and] certain regional transmission planning processes ignore state laws or utility goals. In addition to failing to adequately account for factors that shape the resource mix, . . .current regional transmission planning processes fail to account for

[61] Order No. 1920 at PP 47–139.
[62] *See, e.g.*, *id.* at P 117.
[63] *Id.* at PP 117–18.

> factors that will shape future load, particularly new loads associated with electrification trends like, for example, electric vehicles and data centers.[64]

The Commission also acknowledges that much of the planning under Order No. 1000 has been siloed into separate economic, reliability, and public policy processes that fail to take into account future needs or analyze the multiple benefits that proposed projects provide and consequently forego transmission projects that would meet more than one of these needs at a time or where the combined benefits of a project would significantly outweigh costs, leading to inefficient, inadequate, and piecemeal transmission and unjust and unreasonable rates.[65]

As PIOs pointed out in our NOPR comments, economic and long-term reliability planning lend themselves both to a twenty-year planning horizon and proposed schedule of recurring three-year assessments. It would be grossly inefficient to evaluate proposed solutions on a project-by-project basis—especially if they were further siloed into reliability, economic, and public policy projects. Consequently, PIOs argued that expanding the NOPR proposal to require economic and long-term reliability planning would create planning efficiencies rather than extra burdens to transmission providers and will avoid creating the proverbial loophole that swallows the rule.[66]

As the Commission agrees, this currently near-term and siloed process also fails to allocate costs of projects that do go forward commensurate with benefits, leading to inefficient transmission and unjust and unreasonable rates.[67] Most perniciously, this process has allowed public utilities to conduct inefficient, reliability-only planning focused overwhelmingly on building highly lucrative local transmission facilities.[68] For these local projects, public utilities

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[64] *Id.* at P 118 (internal citations omitted).
[65] *See, e.g.*, *id.* at PP 122–23, 1474.
[66] PIOs' NOPR Comments at 34.
[67] *Id.* at PP 124–26, 1474.
[68] NOPR at PP 39–40.

can receive a right of first refusal with no competition for bidding, little to no oversight, and avoidance of regional cost allocation—which has also led to consumers being overcharged for transmission focused solely on local reliability needs that perpetuates regional congestion and thwarts the ability to identify or meet the pressing regional needs that would make the entire system more reliable, resilient, and affordable for customers.[69]

The Commission recognizes repeatedly throughout Order No. 1920 that current regional transmission planning processes under Order No. 1000 have led to systemically unjust and unreasonable rates. Order No. 1920 attempts to remedy these deficiencies by requiring that long-term transmission planning must be conducted to meet all reasonably anticipated transmission needs, account for the multiple benefits potential projects would provide, and allocate costs commensurate with benefits. Yet the Commission nevertheless inexplicably and arbitrarily permits transmission providers to continue to rely on their existing regional transmission planning and cost allocation processes under Order No. 1000 to identify and plan for transmission needs driven by reliability concerns or economic considerations—even, potentially over the long-term.[70] This is especially incongruous with regard to planning for local reliability projects which have guaranteed rates of return, no competition, little to no regulatory oversight, and which are central to the reason for the piecemeal transmission development that the Commission has found to be unjust and unreasonable.[71] Although Order No. 1920 makes modest improvements to transparency around the local planning process, apart from its right-sizing proposal, the Commission proposes to leave in place the lack of scrutiny over in-kind

[69] *See, e.g.,* Order No. 1920 at PP 109–12, 1569; PIOs ANOPR Comments at 31–44; PIOs NOPR Comments at 9.
[70] NOPR at P 242. *Ctr. for Auto Safety v. Fed. Hwy Admin*., 956 F.2d 309, 314 (D.C. Cir. 1992) ("An agency action is arbitrary and capricious if it rests upon a factual premise that is unsupported by substantial evidence.") (citation omitted); *Cal. Pub. Utils. Comm'n v. FERC*, 20 F.4th 795, 800 (D.C. Cir. 2021) (FERC orders will be upheld under the arbitrary and capricious standard only "if they are supported by substantial evidence") (citation omitted).
[71] Order No. 1920 at PP 1565–66, 1569–70.

transmission replacement facilities and a continued presumption of prudence of local transmission plans.[72]

2. In Order to Remedy Currently Unjust, Unreasonable, and Unduly Discriminatory Rates, the Commission Must Adjust the Order No. 1000 Planning Process to Complement the Order No. 1920 Process.

Given Order No. 1920's requirement that planners regularly conduct comprehensive long-term transmission planning cycles that identify, assess, and address all of the different transmission needs across the regional system, one would reasonably expect the Commission to limit the continued use of the Order No. 1000 planning process to only those few regional transmission needs that could not be reasonably anticipated or addressed within a long-term planning cycle (such as a truly unexpected facility failure whose immediate replacement is necessary for reliability reasons), yet the only boundary the Commission places on continued use of the Order No. 1000 process is to pre-empt its requirements when in conflict with Order No. 1920.[73] The Commission even goes so far as to require the continued use of the Order No. 1000 planning process to evaluate generator interconnection upgrades necessary to address the nation's systemic interconnection queue backlogs, despite its acknowledgment that the systemic failures of the current planning process is the root cause of those backlogs to begin with.[74] While it would appear that the Commission believes that eventually most transmission needs will be addressed through the long-term transmission planning process,[75] given that these two proceedings overlap significantly yet contain widely divergent approaches—neither of which includes a mandate to actually build selected projects— this belief is misplaced. In light of transmission providers' successful evasion of prior regional planning reform efforts through

[72] *Id.* at P 1737.
[73] *Id.* at P 244.
[74] *Id.* at PP 107, 1100–04, 1107, 1111.
[75] *See, e.g., id.* at PP 241, n.2371

exploitation of provisions that lacked clear mandates, without established limits on the application of Order No. 1000, it is far more likely that transmission providers will take advantage of its excessive flexibility to continue building reliability-only transmission in a manner that thwarts the ability to successfully plan for the system's comprehensive needs.

Evidence in the record is clear that the Commission's proposal to keep the Order No. 1000 planning process in place without boundaries or modifications to address its systemic inadequacies and align it with the proposed long-term transmission planning process is unworkable and will lead to continued unjust and unreasonable transmission procedures and rates.[76] Based on the Commission's determination that Order No. 1000's near-term, siloed, and non-transparent process has led to piecemeal transmission buildout that threatens grid reliability, thwarts competition, and overcharges consumers, the Commission is obliged to make adjustments to Order No. 1000 to ensure that it complements Order No. 1920 rather than conflicts with and undermines it.[77]

Evidence exists in the record that this can be done with three necessary reforms: (1) either combine all transmission planning into the Order No. 1920 process or require that the methodologies for conducting Long-Term Regional Planning under Order No. 1920 and economic and reliability planning under Order No. 1000 are aligned; (2) limit application of Order No. 1000 to urgent transmission needs that could not have been reasonably anticipated as part of the Order No. 1920 process (e.g., sudden transmission failure that could not have been planned for) and cannot be incorporated into the current long-term planning cycle nor wait until completion of the next one; and (3) require Order No. 1000 planners to use the same "base case" transmission needs scenario set in the prior long-term planning cycle.

[76] PIOs NOPR Comments at 44–49; *see also* Order No. 1920 at PP 166–68, 170.
[77] 16 U.S.C. § 824e.

a. *The Commission Must Combine all Long-Term Planning Into the Order 1920 Order Planning Process or Align and Clarify the Methodologies for Conducting Long-Term Regional Planning Under Order No. 1920 and Economic and Reliability Planning Under Order No. 1000.*

As noted by the Commission, PIOs and others advocated in the NOPR for a single combined transmission planning process under Order No. 1920 for all transmission planning.[78] While the Commission noted some of PIOs' objections and concerns about the continued application of the Order No. 1000 process, it acted arbitrarily when it largely dismissed these concerns without responding at all to the compelling issues raised by PIOs and other parties to explain how the inefficiencies and failures inherent to the very process the Commission found to be unjust, unreasonable, and unduly discriminatory in the long-term planning context are somehow just, reasonable, and not unduly discriminatory when used for a potentially shorter period of time.[79] In a brief paragraph addressing the requests from PIOs and others for regional transmission planning to occur in a single combined process, the Commission agrees that "a combined process has potential benefits" yet summarily concludes that "the benefits of requiring such a combined process on a generic basis *may be outweighed* by the difficulty of transitioning to such a process from existing regional transmission planning processes."[80] Yet the Commission fails to explain what that difficulty entails, especially in light of the potentially far greater difficulty and administrative burden of running two entirely different planning processes, one of which it has already found to be unjust and unreasonable.[81]

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[78] Order No. 1920 at PP 166–68.
[79] *Id.* at P 304; *Riverkeeper Network v. FERC*, 753 F.3d 1304, 1313 (D.C. Cir. 2014) (holding that decisions that "run[] counter to the evidence before the agency" are arbitrary and capricious) (quoting *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins.,* 463 U.S. 29, 43 (1983)).
[80] Order No. 1920 at P 245 (emphasis added).
[81] *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028, 1055 (D.C. Cir. 2022) (finding FERC's failure to respond meaningfully to objections raised by a party rendered its decision arbitrary and capricious and also stating

Understanding that there might be some merit to a separate process for immediate term needs that might continue under Order No. 1000, PIOs requested in their NOPR comments that the Commission require transmission planners to specify "when the results of one planning process [would be] incorporated into the other" and "require all reasonable effort[s] to avoid one process disrupting the other."[82] Considerable wasted effort is caused when the results of one transmission planning process change the assumptions used by another concurrent process. If Order No. 1000 processes and Long-Term Regional Transmission Planning are not fully aligned, one can easily imagine problems similar to those plaguing interconnection queues, where the Long-Term Regional Transmission Planning process would be repeatedly disrupted by projects built through the Order No. 1000 process altering the Long-Term Regional Transmission Planning's assumptions. PIOs requested that the Commission "direct transmission planners to establish study timing and procedures for how the results of one process are incorporated into others that prevents this from occurring."[83] However, the hands-off approach taken by the Commission fails to respond to these serious concerns and sets up the Order No. 1920 planning process to be mired in conflict out of the gate. Moreover, it is especially inconsistent with the Commission's emphatic acknowledgement of how important it is for the local and regional planning processes to align.[84] Accordingly, the Commission's failure to align the methodologies for conducting Long-Term Regional Transmission Planning under Order No. 1920 and economic

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that FERC had failed to engage in reasoned decision making when its decision introduced apparent contradictions on a dispositive issue and failed to provide an intelligible explanation for its decision (citing *FPL Energy Marcus Hook, L.P. v. FERC*, 430 F.3d 441, 448 (D.C. Cir. 2005)).

[82] PIOs NOPR Comments at 48–49.

[83] *Id*. at 49.

[84] Order No. 1920 at PP 1569–70.

and reliability planning under Order No. 1000 or clarify the relationship between these two planning processes was arbitrary and capricious.[85]

b. *The Commission Must Limit the Scope and Time Frame of Order No. 1000 and Align the Timing with Order No. 1920 Cycles.*

As an initial matter, the Commission must place clear boundaries between the two planning processes. The Commission should also clarify the time horizon for Order No. 1000 planning, which looks forward between five and twenty years.[86] If left unchanged, this would result in both Order No. 1000 planning and Long-Term Regional Transmission Planning identifying solutions over the same time periods but with different planning assumptions, benefits assessments, and cost allocation. Order No. 1920 is ambiguous as to whether the Order No. 1000 process will be retained in its entirety or only for near-term planning, instead stating that where there is conflict between the two, Order 1920 prevails, but leaving it to transmission providers to provide any and all details about how this will work in practice.[87] Such conflicts can only be avoided if the Commission clarifies and narrowly limits the time period for which Order No. 1000 requirements regarding reliability and economic planning will continue to apply, such as for immediate near-term needs that must be addressed before the completion of the current long-term planning cycle (i.e., no more than five years).

The Commission must also ensure that the timing of these two transmission planning processes align and inform each other.[88] Order No. 1000 planning operates on its own cycles and planning windows which vary between planning regions. This creates a risk that the two planning processes operate on overlapping or otherwise unaligned schedules, which opens the

[85] *Pub. Serv. Elec. and Gas Co. v. FERC*, 989 F.3d 10, 17 (D.C. Cir. 2021) (FERC's orders will not stand if they are "either unreasonable or inadequately explained.") (internal quotes and citations omitted).
[86] PIOs NOPR Comments at 48.
[87] Order No. 1920 at P 244.
[88] PIOs NOPR Comments at 47–49.

door to inconsistent assumptions and uncoordinated project identification between the two processes. At the very least, operating two independent, unsynchronized planning processes creates confusion and administrative burden. Accordingly, PIOs request that transmission providers be required to synchronize assumptions with each Long-Term Regional Transmission Planning cycle.[89]

c. *The Commission Must Require Both Processes to Use the Same Base Case Assumptions About Transmission Needs.*

Foremost among PIOs' concerns is the fact that allowing two (or more) separate transmission processes risks creating two parallel but inconsistent system plans based on what the Commission acknowledges are "widely divergent" assumptions.[90] Unlike the scenario-based approach adopted for Long-Term Regional Transmission Planning under Order No. 1920, Order No. 1000 planning often uses a "base case" which is the planner's best assessment of future conditions, but unlike Order No. 1920, there is no requirement regarding what factors must considered in setting that scenario. Retaining both approaches risks planning based on inconsistent assumptions that could easily lead to redundant projects or failure to identify more efficient solutions that address emerging transmission needs—even in the near term. In particular, as noted repeatedly throughout Order No. 1920, current transmission planning under Order No. 1000 base cases identifies transmission solutions that are often inefficient and insufficient to meet critical needs, and if the resulting plans move forward in the near term, the opportunities for more efficient planning created by the long-term process will be lost.[91] Additionally, if transmission owners foresee different outcomes from the two planning processes, they may be motivated to undermine Long-Term Regional Transmission Planning if

[89] *Id*. at. 48.
[90] Order No. 1920 at P 118.
[91] *Id.* at PP 48, 85, 87.

they believe the Order No. 1000 planning will produce results more favorable to them, mirroring the dynamic currently playing out between the development of local and regional transmission.

In its NOPR Comments, PIOs recommended that the Commission avoid this outcome by mandating that Long-Term Scenarios and Order No. 1000 base cases are defined in the same process to ensure that all planning processes are working from the same set of future scenarios.[92] PIOs further recommended that the Commission require Order No. 1000 processes to include multi-value planning to address the inherent planning inefficiencies resulting from Order No. 1000's siloed planning process.[93] PIOs noted that there are a variety of approaches that would result in consistent planning assumptions between the two processes.[94] For example, MISO currently uses scenario planning in its Order No. 1000 process.[95] Planners could simply include Order No. 1000 assumptions as one scenario for the Long-Term Regional Transmission Planning, or the Long-Term Regional Transmission Planning process could include a "consensus scenario" that represents the near future for Order No. 1000 purposes.

C. The Commission Failed to Rationally Justify Its Decision to Exclude Certain Benefits, Which Will Result in Unjust and Unreasonable Rates.

While PIOs appreciate that Order No. 1920 requires transmission providers to measure and use seven enumerated benefits in Long-Term Regional Transmission Planning,[96] the Commission erred when it declined to require transmission providers to measure and use the five

[92] PIOs NOPR Comments at 45.
[93] *Id.* at 46.
[94] *Id.*
[95] *See* MISO, *Future Planning Scenarios*, https://www.misoenergy.org/planning/futures-development/.
[96] These benefits include avoided or deferred reliability and replacement transmission costs, reduced loss of load or planning reserve margin, production cost savings, reduced transmission losses, reduced congestion due to transmission outages, mitigation of extreme weather and unexpected system conditions, and capacity cost savings from reduced peak energy losses.

additional benefits identified in the NOPR, particularly benefits that result from lower generation costs.[97]

1. <u>The Narrowed List of Benefits is Not Sufficiently Broad to Capture the Value of Transmission.</u>

A central purpose of Order No. 1920 is to remedy the identified shortfalls of Order Nos. 1000 and 890. One of the specific shortfalls identified by the Commission is that transmission providers are not identifying the most efficient or cost-effective facilities, in part because the criteria that they use to plan long-term transmission fail to account for full benefits of these regional transmission facilities.[98] By requiring only a narrow list of benefits in Order No. 1920, the Commission risks perpetuating the status quo, where transmission providers use narrow benefits assessments that do not ensure the identification and evaluation of more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs, leading to unjust and unreasonable rates.

The Commission provides no explanation for requiring only seven of the twelve benefits it considered in the NOPR, simply stating "that the required set of benefits that we adopt herein is a sufficiently broad range of benefits to ensure that transmission providers are identifying, evaluating, and selecting Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs."[99] With respect to the other five benefits, the Commission states only that "the measurement and use of additional benefits in Long-Term Regional Transmission Planning is not necessary to ensure that rates remain just and

[97] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking*, 179 FERC ¶ 61,028 at P 185 (2022). The five benefits included in the NOPR but not included in Order No. 1920 include: mitigation of weather and load uncertainty, deferred generation capacity investments, access to lower-cost generation, increased competition, and increased market liquidity.
[98] Order No. 1920 at P 118.
[99] *Id.* at P 821.

reasonable."[100] In addition to providing no explanation for this narrowing of benefits that transmission providers must consider when evaluating and selecting Long-Term Regional Transmission Facilities, the Commission ignores its own evidence in the NOPR that the five additional proposed benefits—mitigation of weather and load uncertainty, deferred generation capacity investments, access to lower-cost generation, increased competition, and increased market liquidity—have a proven track record, can be discretely measured, and are unlikely to cause duplication.[101]

2. <u>The Benefits Excluded from Order No. 1920 are Quantifiable and Distinct from the Order's Chosen Minimum Benefits.</u>

The Commission should have mandated the consideration of access to lower-cost generation. As explained in the NOPR, "this refers to the value of savings that may accrue to consumers who, because of a new regional transmission facility or portfolio of facilities, are able to access lower cost generation resources that they would have been unable to [access] otherwise."[102] This benefit can be readily calculated "by comparing the status quo (i.e., higher-cost local generation) to a future (i.e., lower-cost distant generation) where the proposed new regional transmission facilities allow for the import of those lower-cost generation."[103] Moreover, the Commission acknowledged in the NOPR that while the method for calculating this benefit is similar to the methodologies for calculating production cost savings, the production cost savings methodologies fail to capture aspects that are considered when calculating this benefit.[104] Specifically, the access to lower-cost generation benefit would account for key aspects like "load variances during hotter or colder than normal weather

[100] *Id.*
[101] *See* NOPR at PP 208–209, 213–25.
[102] *Id.* at P 216.
[103] *Id.* at P 217 (emphasis omitted).
[104] *Id.* at P 218.

conditions," "transmission system outages or other situations where less than the full transfer capability of the transmission facility is available," "extreme events like multiple generator outages," and "operational issues such as forecasting errors or unexpected loop flows."[105] The Commission also acknowledged that "calculating access to lower-cost generation benefits . . . may require additional or separate analysis" by transmission providers since capturing this benefit "may require a different generation mix than specified in the production cost simulations."[106]

These cost savings are already part of best transmission planning practices and this benefit alone can often by itself pay for the cost of the transmission project.[107] For example, MISO estimated that the consumer savings from access to cheaper generation alone would exceed the entire $14–17 billion cost of the portfolio of transmission projects selected as part of its Tranche 1 of its 2022 Long Range Transmission Planning process.[108] Given that access to cheaper generation is a readily quantifiable benefit and is not captured by existing methodologies to calculate production cost savings, transmission providers should be required to assess it to ensure that the full benefits of Long-Term Regional Transmission Facilities are assessed in the Long-Term Regional Transmission Planning process.

The Commission also erred by excluding increased competition from the list of mandatory benefits. In the NOPR, the Commission refers to this benefit as "reduced bid prices in

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[105] *Id.*
[106] *Id.*
[107] *See, e.g.*, Christopher Clack et al., Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the U.S., Americans for a Clean Energy Grid, at 9–10 (Oct. 2020), at https://cleanenergygrid.org/wp-content/uploads/2020/11/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S.pdf.
[108] *See* ACORE, Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis: A Case Study Of MISO's Long Range Transmission Planning, at 8 (Aug. 2022), https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf.

wholesale electricity markets due to increased competition among generators and reduced overall market concentration."[109] To the extent that certain portions of a transmission planning region remain import-constrained, where a single resource or a small number of resources can significantly influence the energy prices paid by load through their pricing offers, additional transmission capacity may mitigate this influence. Consequently, this increased capacity can benefit transmission customers by reducing energy prices.[110] The Commission noted that several utility providers have considered this benefit for transmission facilities and that it can be calculated in at least three separate ways.[111] Because this benefit is readily measurable, has a proven track record, and there is no evidence in the record that it is duplicative of other benefits, FERC should require that transmission providers assess in the Long-Term Regional Transmission Planning process.

Further, the Commission should require consideration of the benefits derived from mitigation of weather and load uncertainty. Although the Commission notes that "elements" of this benefit are contained within Benefit 6,[112] these elements do not capture the entirety of the benefit, and thus the Commission should return to the separate framing in the NOPR. As explained in the NOPR, mitigation of weather and load uncertainty goes "beyond the effects of extreme weather described [in Benefit 6] and may account for, for example, regional and sub-regional load variances that will occur due to changing weather patterns."[113] Moreover, the calculability of this metric has already been demonstrated in ERCOT.[114] Using a weighted

[109] NOPR at P 219.
[110] *Id*. at PP 219–20.
[111] *Id*. at PP 221–24.
[112] Order No. 1920 at P 820, n.1820.
[113] NOPR at P 208.
[114] NOPR at P 209 (citing ERCOT, Economic Planning Criteria: Question 1: 1/7/2011 Joint CMWG/PLWG Meeting, at 10 (Mar. 4, 2011) (showing increased net benefits when using a probability-weighted average for three simulated load conditions).

average to account for this sort of load variation—which could be driven by extreme weather, but also other circumstances—adds a level of granularity that properly incorporates the unavoidable uncertainty in load forecasting and will therefore ensure more just and reasonable rates.

The Commission also erred in excluding the benefit of deferred generation capacity investments. As explained in the NOPR, "[d]eferred generation capacity investments benefits reflect the value of increased transfer capability, provided by new transmission facilities, that either defers or negates the need to invest in generation capacity resources within a transmission planning region by increasing import capability from neighboring regions into resource-constrained areas."[115] This benefit captures the way transmission can increase the capacity value of *existing* resources due to geographic diversity, thus deferring the need for additional investments into generation capacity.[116] Moreover, this benefit will only grow more important to capture in the face of growing load projections and lingering interconnection costs and backlogs, which can put pressure on the marginal cost of new capacity additions.

Finally, the Commission improperly excluded increased market liquidity from its mandatory benefits. Distinct from the proposed benefit of competition among generation, this benefit would focus on "enabling a larger number of entities, both buyers and sellers, to participate in a market."[117] Thus, the benefits of market liquidity include reduced transaction costs of bilateral transactions, increased pricing transparency, increased efficiency of risk

[115] NOPR at P 214.
[116] The Brattle Group and Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Cost, at 44-45 (Oct. 2021) ("Brattle-Grid Strategies Report"), https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Planning-for-the-21st-CenturyProven-Practices-that-Increase-Value-and-Reduce-Costs.pdf.
[117] NOPR at P 225.

management, improved contracting, and better clarity for long-term transmission planning and investment decisions—all of which will help drive down energy prices for consumers.[118]

PIOs respectfully seek rehearing of the Commission's decision to narrow the required list of benefits. The Commission fails to substantiate its reasoning that the list of benefits it adopted in Order No. 1920 "is a sufficiently broad range of benefits to ensure that transmission providers are identifying, evaluating, and selecting Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs."[119] As the Commission itself acknowledges, failure to consider the broad range of project benefits logically leads to the failure to "identify the more efficient or cost-effective regional transmission solution, resulting in relatively inefficient or less cost-effective transmission development."[120] Simply put, under the Commission's own logic, the list of seven benefits is too narrow to achieve the goals of Order No. 1920 and would render resulting rates unjust and unreasonable.[121] The Commission's decision to exclude these specific factors was thus arbitrary and capricious and not supported by the evidence in the record.[122]

Moreover, the Commission's decision to exclude from its mandate quantifiable benefits whose categorical value is undisputed in the record violates the long-standing cost causation principle that transmission costs be allocated according to the benefits parties receive from the

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[118] NOPR at P 255 (citing Brattle-Grid Strategies Report at 50).

[119] Order No. 1920 at P 821. The five benefits included in the NOPR but not included in Order No. 1920 include mitigation of weather and load uncertainty, deferred generation capacity investments, access to lower-cost generation, increased competition, and increased market liquidity.

[120] *Id*. at P 725.

[121] *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 277, 136 S. Ct. 760, 774, 193 L. Ed. 2d 661 (2016), as revised (Jan. 28, 2016). (When FERC exercises its authority under FPA Section 206 then the Commission "shall determine the just and reasonable rate, charge[,] rule, regulation, practice or contract" and impose "the same by order.").

[122] 5 U.S.C. § 706(2)(E); 16 U.S. Code § 824e; 16 U.S.C. § 825*l*; *Emera Maine v. FERC*, 854 F.3d 9, 28 (D.C. Cir. 2017); S*.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 54 (D.C. Cir. 2014) (quoting *Motor Vehicles Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983)) (FERC must "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made.").

facility and is unlawful under *Illinois Commerce Commission v. FERC*.[123] Especially where a project provides multiple benefits to multiple load centers across a region to varying degrees, if the full benefits of a project are not being assessed, then by definition one cannot know if its cost allocation is commensurate with those unknown benefits.

On rehearing, the Commission should require that transmission providers measure and use the five additional benefits in Long-Term Regional Transmission Planning set forth in the NOPR.

D. The Commission's Failure to Set Clear Modeling Standards for Categories of Factors for the Scenario Planning, or to Mandate Full Public Transparency of Inputs and Models Is an Irrational Decision That Will Undermine the Commission's Reform Efforts.

PIOs applaud the Commission's requirement that transmission providers conduct scenario-based transmission planning,[124] as well as the required incorporation of specific categories of factors to be used in scenario planning.[125] However, Order No. 1920 grants transmission providers excessive levels of discretion in designing the modeling and data inputs for each factor and scenario, without requiring the levels of information transparency and accountability necessary to ensure that there are no design flaws or biases hidden behind a black box that ultimately thwarts accurate identification of transmission needs or efficient buildout of needed transmission facilities. If the data and modeling used to build and analyze the scenarios are not representative of the future, then the transmission solutions identified will be inefficient, resulting in the unjust and unreasonable rates the Commission seeks to remedy. In order to ensure realistic scenario development, PIOs urge the Commission to provide limits and accountability mechanisms for the transmission provider's ability to "discount" the latter four

[123] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009).
[124] PIOs NOPR Comments at 14.
[125] *Id.* at 17–18.

categories of factors, revise its interpretation of best available data for pricing and trend categories, and strengthen the transparency requirements to ensure that the opportunity for stakeholder input is more meaningful.

1. <u>The Commission Must Provide Specific Guardrails for Two of the Seven Categories of Factors to Ensure that Transmission Needs are Accurately Assessed.</u>

The Commission grants transmission providers "additional discretion" in how they account for four of seven categories of factors: trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and electrification technologies; resource retirements; generator interconnection requests and withdrawals; and utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals.[126] The Commission dismisses concerns that this flexibility could allow transmission providers to functionally minimize these categories because the final rule requires incorporation of all the factors, and requires that each scenario be "plausible."[127] This dismissal is not substantiated by the evidence in the record. Given that the Commission found that each of these categories of factors is "essential" to properly assess transmission needs,[128] it must do more to ensure that the latter four factors are not so manipulated as to project inaccurate needs. In combination with the final rule's vague and process-oriented definition of "best available data," the Commission's decision to allow boundless discounting of these categories creates an opportunity for transmission providers to functionally ignore the Commission's mandate. PIOs narrow our request on rehearing to include specific guardrails for two of the four "flexible" categories in order to remedy this significant loophole, and PIOs explain how increasing the

[126] Order No. 1920 at P 516.
[127] *Id.* at P 518.
[128] *Id.* at P 410.

Open Access Same-Time Information System ("OASIS") reporting requirements is needed to ensure the meaningful opportunity for stakeholder participation that Order No. 1920 seeks.

Regarding the category of factors for trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and electrification technologies, PIOs urge the Commission to consider a limited version of our request to maintain a list of best available data.[129] The metrics within this category are particularly well suited for standardization from an entity like the U.S. Department of Energy ("DOE") or the National Renewable Energy Laboratory ("NREL")—and indeed, several comprehensive data sets for these precise metrics, which are regularly updated, already exist.[130] While the Commission expresses generally that data uniformity could be challenging given regional variation,[131] DOE and NREL are entirely capable of generating regional calculations. PIOs note that this should be a win-win solution for transmission providers as it would reduce their analysis burden and provide reliable inputs and standardization across regions, which would facilitate greater interregional planning. It would also ease the oversight burden on the Commission and other regulators responsible for ensuring that transmission providers are using independent, reliable data. Resistance to such suggestions is an indication of the types of motives that the Commission must ensure do not bias the resulting needs study results. Moreover, this data requirement could still provide for flexibility by allowing transmission providers to justify any deviations from these data sets.

With respect to the category for utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs, PIOs

[129] PIOs NOPR Comments at 19–20.
[130] *Id.* (For example, NREL ATB data, U.S. DOE's Annual Energy Outlook for fuel costs, and NREL's Electrification Futures Study for electrification trends).
[131] Order No. 1920 at P 639.

urge the Commission to limit the discounting of utility and corporate commitments. We emphasize these factors in particular because utility and corporate commitments are such a significant driver of the resource mix and will only continue to be so.[132] Though the Commission's concerns are reasonable that self-imposed commitments might not be met, granting full discretion to transmission providers to estimate this likelihood is not a tenable solution. On rehearing, the Commission should instead create a presumption that transmission providers' discounting cannot assume greater failure to reach utility and corporate commitments than has occurred in the previous ten years. This solution would increase the accuracy of these factors' weighting while allowing transmission providers the option to rebut the presumption in instances in which it has substantiated reasons to believe that achievement of the targets will not match historical achievement rates. Without such a limitation on the degree of potential discounting, the Commission would allow the functional discarding of an "essential" factor. The Commission's decision to allow boundless discounting would not enable just and reasonable rates and is arbitrary and capricious because it fails to consider an important part of the needs identification process.[133]

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[132] Comments of Advanced Energy Buyers Group, at 5–6, Docket No. RM21-17-000 (Aug. 17, 2022), Accession No. 20220817-5219 (citing Clean Energy Buyers Association, State of the Market 2022, https://cebuyers.org/state-of-the-market/ and Caitlin Marquis & Danny Waggoner, Adding it All Up for Voluntary Buyers of Renewable Energy, Advanced Energy United (Jan. 28, 2021), https://blog.advancedenergyunited.org/adding-it-all-up-for-voluntary-buyers-of-renewable-energy).

[133] *Del. Div. of Pub. Advoc. v. FERC*, 3 F.4th 461, 469 (D.C. Cir. 2021) (Commission acts arbitrarily if it "fail[s] to consider an important aspect of the problem . . . ."); *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 277, 136 S. Ct. 760, 774, 193 L. Ed. 2d 661 (2016), as revised (Jan. 28, 2016). (When FERC exercises its authority under FPA Section 206 then the Commission "shall determine the just and reasonable rate, charge[,] rule, regulation, practice or contract" and impose "the same by order.")..

2. The Commission Must Strengthen the Transparency Provisions of the Final Rule by Requiring More Detailed Explanations of Factors Used in Scenario Planning and by Requiring Transmission Providers to Justify Any Discounting of Factors Four through Seven.

Finally, in order to enhance the accuracy of needs identification more broadly, PIOs request that the Commission strengthen the transparency provisions of the final rule by requiring more detailed explanations of the factors to be used in scenario planning, as well as requiring transmission providers to justify any discounting. PIOs appreciate the Commission's efforts to explain what constitutes an opportunity for meaningful stakeholder input, including "the opportunity to propose factors, provide information" and suggest best available data, explain how a factor could be reflected, and provide input on potential discounting.[134] While we recognize that it is difficult to create standards that ensure transmission providers' processes meaningfully provide these opportunities, stronger reporting requirements will incentivize transmission providers to have more meaningful engagement processes. On rehearing, the Commission should remedy this accountability issue with two specific changes.

First, the Commission should strengthen the wording of the third item of the OASIS posting requirements from merely a "general statement explaining how they will account for each . . . factor" to "a detailed description of the reasoning and methodology used to account for each factor, as well as providing the actual data inputs when possible." PIOs note that making the information that goes into the planning process public is essential to allow stakeholders to validate data accuracy and methodology validity, without which the information asymmetry that would otherwise exist would enable transmission providers to use biased or inaccurate data and models that generate outcomes favoring their economic interests without any oversight.[135]

[134] Order No. 1920 at P 529.
[135] PIOs NOPR Comments at 20.

Giving transmission providers this kind of unfettered discretion over information central to the planning process would effectively undercut the Commission's effort to require transmission providers to open the planning process to meaningful participation by affected stakeholders. To the extent that the actual data cannot be made publicly available due to security or confidentiality issues, the transmission provider must be required to: (a) justify in detail why the data cannot be made publicly available; (b) provide data in a redacted or aggregated format that removes identifying information; and (c) take steps to share data with engaged stakeholders via a standardized, minimal-cost confidentiality agreement process. This type of detailed reporting will also be important for factors such as the inclusion of resource retirements, which may use more amorphous qualitative reasoning in addition to numerical data sets.[136]

Second, the Commission must reconsider its decision to not require transmission providers to justify their discounting of categories four through seven. The Commission stated that requiring transmission providers to do this sort of justification would be a "time-consuming administrative burden . . . not justified by the value of the additional information" to stakeholders.[137] However, this explanation ignores the way transparency measures also provide an *accountability* function. By requiring public posting of discounting justifications that might otherwise be disclosed only at non-recorded meetings or deep in technical documents, transmission providers would be better incentivized to make the most accurate discounting assumptions and resist pressure from self-interested stakeholders. Put frankly: if a transmission provider provided a truly meaningful opportunity for stakeholder input and discussion as

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[136] *Id.* at 21. The importance of transparency into the method used to consider retirements is heightened by the Commission's correct clarification that transmission providers must account for likely resource retirements beyond those publicly announced. *See* Order No. 1920 at P 464.
[137] Order No. 1920 at P 536.

required in the final rule, documenting the reasons for its decisions—including its discounting decisions—would not be a time-consuming administrative burden.

PIOs seek rehearing on these transparency measures because while the Commission claims that Order No. 1920 requires transmission providers to "provide meaningful opportunity for stakeholder input" and "make transparent the methodology, criteria, assumptions, and data used to develop each Long-Term Scenario,"[138] the final rule does not deliver on this promise. The Commission's decision to only require general descriptions and explanations rather than detailed explanations and the actual data underlying scenarios does not rationally flow from the Commission's more fundamental findings that the scenario process must be open, coordinated, and transparent and as such is arbitrary and capricious.[139]

E. The Commission's Omission of Storage as a Transmission Asset in Its List of Alternative Transmission Technologies That Transmission Providers Must Consider Is Arbitrary and Capricious.

As part of the NOPR, the Commission found that since Order No. 1000 was issued, there was an influx of "commercially available technologies [that] make transmission systems operate more efficiently or cost-effectively" in ways that can "improve the operation of new and existing transmission facilities or defer new transmission investments."[140] The Commission found that consideration of such technologies as part of transmission planning "could help to ensure that these processes are identifying more efficient or cost-effective regional transmission facilities

[138] *Id.* at P 305.
[139] 5 U.S.C. § 706(2)(E); 16 U.S. Code § 824e; 16 U.S.C. § 825*l*; *Del. Div. of Pub. Advoc. v. FERC*, 3 F.4th 461, 469 (D.C. Cir. 2021) (Commission acts arbitrarily if it "fail[s] to consider an important aspect of the problem . . . ."); *Port of Seattle v. FERC*, 499 F.3d 1016 (9th Cir. 2007) (An agency must "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'") (citing *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43); *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1303–04 (D.C. Cir. 1992) (For an agency order to pass scrutiny under the arbitrary and capricious standard, a reviewing court must be able to "discern a reasoned path . . . to the decision [the Commission] reached.").
[140] NOPR at P 267.

and in turn, that Commission-jurisdictional rates are just and reasonable."[141] Accordingly, the NOPR proposed to require transmission providers to consider two of these technologies, namely dynamic line ratings and advanced power flow control devices, and sought "comment on whether there are other transmission technologies serving a transmission function that should be considered in regional transmission planning and cost allocation processes."[142]

In response, numerous commenters recommended that the Commission require transmission providers to consider storage as one of the enumerated alternative transmission technologies in the Long-Term Regional Transmission Planning process.[143] Storage, such as a battery electric storage system ("BESS"), can provide a flexible and cost-effective solution to transmission needs. Storage can improve transmission in numerous ways, including by providing voltage support, controlling the timing of power flows, and reducing peak loads.[144] Experience with storage as transmission is rapidly growing in the United States and has proven to be a cost-effective transmission solution. The California Independent System Operator ("CAISO"),[145] MISO,[146] Independent System Operator New England ("ISO-NE"),[147] and SPP[148] all have tariff provisions allowing for storage as transmission. One recent study of real-world deployments found that storage-as-transmission "is a viable alternative to transmission wire solutions because it reduces congestion and cost-effectively improves transfer capability."[149] Moreover, prices for

[141] *Id.*
[142] *Id.* at PP 276–77.
[143] Order No. 1920 at P 1230, n.2632 (listing commenters that supported storage as transmission).
[144] *See, generally,* Sw. Power Pool ("SPP"), Electric Storage Resources: White Paper (Jan. 7, 2020), https://spp.org/documents/61602/electric%20storage%20resource%20white%20paper.pdf.
[145] *See* CAISO, 2021–2022 Transmission Plan, at 31–36, https://www.caiso.com/Documents/ISOBoardApproved-2021-2022TransmissionPlan.pdf.
[146] *Midcontinent Indep. Sys. Operator, Inc.*, 172 FERC ¶ 61,132, *reh'g denied*, 173 FERC ¶ 62,022 (2020).
[147] *ISO New England, Inc.*, 185 FERC ¶ 61,044 (2023).
[148] *Sw. Power Pool, Inc.*, 183 FERC ¶ 61,153, at P 29 (2023).
[149] William Brown et al., Storage as Transmission Asset Market Study, Quanta Technology, at 4 (Jan. 2023), https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf.

batteries continue to rapidly decline, meaning that they will become increasingly cost-effective as transmission providers develop their Long-Term Regional Transmission Plans.[150]

In response to comments, the Commission required transmission operators to incorporate two additional technologies—transmission switching and advanced conductors—into long-term regional transmission planning.[151] The Commission explained it was adding these technologies because various transmission providers have experience with these technologies, which "sufficiently demonstrate[s] that transmission providers are capable of considering the enumerated alternative transmission technologies in Long-Term Regional Transmission Planning."[152] Despite extensive record evidence, Order No. 1920 omitted storage as an enumerated grid-enhancing technology. However, the final rule includes no findings suggesting that storage is difficult to incorporate into long-term planning or that storage is not a cost-effect transmission solution. Instead, in a brief paragraph, the Commission justifies its decision declining to include storage as an enumerated requirement solely on the basis that "the evaluation of whether an electric storage resource performs a transmission function requires a case-by-case analysis."[153]

While PIOs agree with the Commission that storage as a transmission solution requires a case-by-case analysis, this fact does not preclude *consideration* of storage in the Long-Term Regional Transmission Planning process. Indeed, *any* transmission solution requires a case-by-case analysis to determine whether it is the best approach given the various complex needs and challenges in each region. Even something as basic as the voltage of lines varies widely between

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[150] John Fitzgerald Weaver, *Battery Prices Collapsing, Grid-Tied Energy Storage Expanding*, PV Magazine (Mar. 6, 2024), https://pv-magazine-usa.com/2024/03/06/battery-prices-collapsing-grid-tied-energy-storage-expanding/.
[151] Order No. 1920 at P 1198.
[152] *Id.* at P 1206.
[153] *Id.* at P 1245.

and within regions, depending on the specific needs a particular project seeks to address. For example, MISO's long-range transmission plan relied on 345 kV lines for its first tranche of projects, but will use a mix of 765 kV and 345 kV lines for its second tranche.[154] In contrast, CAISO's 2022–23 transmission plan relies largely on 500 kV lines.[155] Moreover, as the Commission explains, Order No. 1920 does "not require the selection of any particular enumerated alternative transmission technology to address any particular transmission need."[156] No solution is universal.

The Commission appears to recognize this reality elsewhere in Order No. 1920. For example, in declining to "mandate further details on how transmission providers should evaluate the enumerated list of alternative transmission technologies," the Commission explains that "transmission providers are the appropriate entity to identify, evaluate, and select specific solutions to specific transmission needs."[157] This rationale applies equally to storage technology, just as it does to any other grid-enhancing technology. At this stage, the Commission need not dictate specifically *how* transmission providers evaluate storage-as-transmission, but can simply require transmission providers to consider storage as one of the tools that they must consider as an alternative transmission technology.

Finally, to the extent that the Commission's primary concern regarding including storage on the enumerated list is ensuring that a storage resource is actually performing as a transmission resource, the Commission makes reference to the fact that it has already "identified five considerations that, together, ensure that a selected storage resource will serve a transmission

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[154] Ethan Howland, *MISO Proposes Up to $23B Transmission Expansion With 765-kV*, Utility Dive (Mar. 7, 2024), https://www.utilitydive.com/news/miso-midcontinent-tranche-2-lrtp-transmission-expansion/709576/.
[155] CAISO, Press Release: CAISO 2022–2023 Transmission Plan Approved (May 18, 2023), https://www.caiso.com/Documents/caiso-2022-2023-transmission-plan-approved.pdf.
[156] Order No. 1920 at P 1209.
[157] *Id.* at P 1210.

function."[158] These factors are: (1) a storage as transmission-only asset ("SATOA") must be connected to the transmission system as a transmission facility solely to support the transmission system; (2) a proposed SATOA must be identified or selected in the transmission planning processes as the preferred solution to resolve a transmission issue; (3) there must be a need to resolve the transmission issue through the storage facility's function as a SATOA, as the transmission issue cannot be addressed by a market solution; (4) a SATOA's participation in the markets is limited to only charging from, and discharging to, the transmission system as necessary to provide the services for which the SATOA was constructed; and (5) the SATOA will be under the transmission provider's operational control.[159] Yet the Commission fails to explain why it did not simply note that the use of storage as a transmission asset will ultimately need to comply with these factors.

Given the substantial potential benefits of including storage as an alternative transmission technology in Long-Term Regional Transmission Planning as well as its established use as a transmission-only asset, the Commission's omission of storage as an alternative technology transmission planners are required to evaluate as part of regional planning was unreasonable and will likely result in unjust and unreasonable rates.[160] In addition to its high value, storage as transmission meets the same criteria used by the Commission as reasons to require the four other alternative transmission technologies as part of Order No. 1920's transmission planning requirements, yet the Commission arbitrarily excludes storage from the list of enumerated alternative transmission technologies and fails to engage meaningfully with commenters or

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[158] *See Improvements to Generator Interconnection Procedures and Agreements*, 88 Fed. Reg. 61,014, P 1599 (Sept. 6, 2023) ("Order No. 2023"); Order No. 1920 at P 1245, n.2671 (*citing to* Order No. 2023 at P 1599).
[159] *See Sw. Power Pool, Inc.,* 183 FERC ¶ 61,153 at P 29 (2023).
[160] 16 U.S. Code § 824e.

provide a reasoned explanation for its decision.[161] Consequently, PIOs urge the Commission to grant rehearing to require transmission operators to evaluate storage as transmission as part of the Long-Term Regional Transmission Planning Processes.

F. The Commission's Decision to Not Require That Transmission Providers Use a Portfolio Approach When Evaluating the Benefits of Long-Term Regional Transmission Facilities Failed to Engage Meaningfully with the Record and is Arbitrary and Capricious.

One of the core problems that Order No. 1920 seeks to address is how to shift from the siloed, uncoordinated, and piecemeal transmission infrastructure development that has resulted in unjust and unreasonable rates across the nation's grid to building well-planned transmission projects that solve multiple needs at once and create a resilient and reliable electric system at least cost.[162] The Commission emphasized that the solution to this problem lies with "[p]roactive, forward-looking" and "more comprehensive regional transmission planning and cost-allocation processes—like the process used to plan the MISO [Multi Value Process ("MVP")]—that [are] necessary to increase the likelihood that such highly beneficial transmission infrastructure is developed."[163] Achieving this requires planning for regional transmission as a holistic system of interlocking facilities that serve multiple needs at once—in other words, planners must look at the forest and not just the trees. Doing so requires switching from evaluating and building transmission on a facility-by-facility basis in isolation from each

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[161] 5 U.S.C. § 706(2)(E); 16 U.S.C. § 825*l*; *Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 969 (D.C. Cir. 2005); *W. Deptford Energy, LLC v. FERC*, 766 F.3d 10, 20 (D.C. Cir. 2014) ("It is textbook administrative law that an agency must 'provide[ ] a reasoned explanation for departing from precedent or treating similar situations differently,'" and "'[b]ecause it has not adequately explained its decision to treat [entities] differently in a context where they appear similarly situated, we remand the case to the Commission for a fuller explanation.'") (*citing ANR Pipeline Co. v. FERC*, 71 F.3d 897, 901 (D.C. Cir. 1995) and *Colorado Interstate Gas Co. v. FERC*, 146 F.3d 889, 893 (D.C. Cir. 1998)); *Del. Div. of Pub. Advoc. v. FERC*, 3 F.4th 461, 469 (D.C. Cir. 2021) (finding FERC's decision to be arbitrary and capricious when its response to contrary evidence was "little more than a hand wave.")
[162] NOPR at PP 25–26, 33, 40–43, 47, 55, 245.
[163] *Id*. at PP 28, 33.

other to planning for a suite of multiple transmission facilities that work together in an aggregated, integrated fashion through a portfolio approach—as the MISO MVP does.[164] This approach is not optional—a view shared by the Department of Energy[165]—because, as explained in expert testimony from Johannes Pfeifenberger of the Brattle Group:

> [P]ortfolio-based planning process will be necessary to address the broad range of long-term regional transmission needs in a cost-effective fashion. This is because long-term transmission needs are not a collection of separable needs that apply to individual locations on the grid so that they could be addressed cost-effectively through an individual transmission project. Rather the "needs" are defined by reliability, market-efficiency, and public policy requirements that occur simultaneously and tend to cover large geographic areas—such as entire sub-regional, regional, or multi-regional footprints. To identify transmission solutions that can cost-effectively address the multiple needs in a geographically-expansive footprint will necessarily require a portfolio of transmission projects that can work in unison to cost-effectively support the full set of needs of the long-term time horizon. To achieve the benefits (cost savings) offered by simultaneously addressing the full range of long-term needs will require the design of a portfolio of individual transmission projects that, as a group, offers significant synergies and cost savings. Quantifying the overall benefits offered by such a solution will similarly require quantifying the total benefits offered by the entire portfolio, because an individual project may not be able to yield the full benefit without the synergies provided through its interaction with other projects in the portfolio. Of course, a number of different portfolios and portfolio-configurations will need to be evaluated in order to design a portfolio of transmission projects that performs best across the range of uncertain long-term futures analyzed through the scenario planning effort.[166]

The record across this docket evinces substantial evidence (including expert reports) on the benefits of transmission providers evaluating transmission facilities on a portfolio basis and Order No. 1920 includes five pages detailing the widespread support for and numerous benefits of this approach.[167] These include administrative efficiencies related to economies of scale, the

[164] *Id*. at P 871.
[165] Comments of the United States Department of Energy to Notice of Proposed Rulemaking, at 34–35, Docket No. RM21-17-000 (Aug. 17, 2022), Accession No. 20220817-5010.
[166] PIOs NOPR Comments, Ex. A: Aff. of Johannes P. Pfeifenberger on Behalf of the Natural Resources Defense Council at 13.
[167] Order No. 1920 at PP 872-880; NOPR at PP 231–35. *See also* PIO ANOPR Comments at 87, Ex. A: The Brattle Group, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs at 64–66; PIO NOPR Comments at 28–37.

ability to capture synergistic benefits greater than the sum of the individual projects,[168] and a more stable and widely-dispersed distribution of benefits across sub-regions, which is likely to facilitate state agreement on regional cost allocation.**[169]** As the Commission noted, most commenters supported the use of a portfolio approach and several supplied reports and examples of existing processes to establish the benefits of a portfolio approach, including the MISO Multi-Value Project process, which has resulted in lower interconnection costs for generators as compared to transmission upgrades planned in response to interconnection requests.[170] The New Jersey Commission went so far as to state that failing to require a portfolio process is "*per se* unjust and unreasonable."[171]

A number of commenters called for adjustments to the portfolio planning process, including PIOs and a number of other commenters that called for the Commission to incorporate long-term reliability and economic needs and benefits in the long-term portfolio process, as it allows stakeholders to find the most efficient and cost-effective solutions to address all transmission needs that affect different jurisdictions simultaneously and would prevent balkanized and redundant planning efforts that have perpetuated overbuilding on the local level, clogged interconnection queues, and unjust and unreasonable rates.[172] While several commenters asked for flexibility to use individual project approvals in limited situations when a

[168] As PIOs pointed out, portfolio planning can help bring about solutions that not only increase benefits but also bring greater equity across the energy system such as when a transmission project that could open generation development to a traditionally underserved rural community that might not clear a cost-benefit threshold on its own is paired with another project that relieves congestion in a dense load pocket in an environmental justice community, the two projects together can create power flows across the system that would not be possible without both projects being evaluated together. PIO NOPR Comments at 31–32; Order No. 1920 at P 878.
[169] Order No. 1920 at PP 872–84, 890.
[170] *See e.g.* Order No. 1920 at P 873 n.1927; P 875.
[171] New Jersey Commission Initial Comments at 7.
[172] PIO NOPR Comments at 33-34; Order No. 1920 at PP 886–87.

portfolio process would be inapplicable, [173] the vast majority of commenters supported the portfolio approach in at least some circumstances.[174]

Opposition to the portfolio approach was minimal at best. Order No. 1920 includes a single paragraph summarizing comments from a handful of parties expressing vague concerns that the portfolio approach "*may* have downsides" which were unsupported by specifics or data, and only two of which fully opposed the portfolio approach.[175]

In light of the overwhelming support for and evidence that portfolio planning is not only beneficial but necessary to conduct long-term transmission planning, the Commission's decision "to allow, but not require, transmission providers … to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities" lacks substantial evidence in the record.[176] Moreover, while Order No. 1920 requires transmission providers using a portfolio approach to include such a provision in their tariffs, the Commission then incongruously declines to require such providers to provide any information on when or how they will use it on the supposed grounds that "[t]hese requirements could impede . . . consideration and development of portfolio approaches."[177] Even more inconsistent was the Commission's two sentence rationale dispensing with several pages of comments advocating for a portfolio requirement whereupon it

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[173] Order No. 1920 at PP 881–84.

[174] *See e.g.* Order No. 1920 at PP 881 (Duke explains situation in which portfolio approach better suited and asks for switching between portfolio and facility-by-facility approach), 882 (APPA and TANC ask for regional flexibility for portfolio approach).

[175] Order No. 1920 at PP 888–84. Most of the comments the Commission relied upon in this section did not in fact appear to express outright opposition to the portfolio approach but rather support flexibility. *Compare id.* at n.1966 (citing CAISO Reply Comments at 24, Duke Initial Comments at 25–26, and Idaho Commission Initial Comments at 4 as expressing apprehension about the portfolio approach) *with* Order No. 1920 at P 884 (CAISO agrees "that the portfolio planning should be optional."); Comments of Duke Energy Corporation, at 25–26, Docket No. RM21-17-000 (Aug. 17, 2022) Accession No. 20220817-5094 (encouraging flexibility); and Comments of the Idaho Public Utility Commission in Opposition of Docket No. RM21-17-000, at 4, Docket No. RM21-17-000 (Aug. 17, 2022) Accession No. 20220817-5245 (opposing requiring using portfolio due to ambiguity of circumstances it would be used).

[176] Order No. 1920 at P 889; 16 U.S.C. § 825*l*.

[177] Order No. 1920 at P 889.

first agreed that "there are numerous advantages to a portfolio approach" before stating that "these advantages must be balanced against other considerations, and we therefore find that providing . . . flexibility on whether to use a portfolio approach is appropriate."[178] Yet the Commission fails to explain what these "other considerations" are or why they outweigh so much evidence finding portfolio planning to be a necessity.[179]

The weight of evidence overwhelmingly supports the Commission requiring that transmission providers use the portfolio approach. that the Commission has stated repeatedly that a central purpose of Order No. 1920 is to address the grid's currently inefficient and piecemeal transmission infrastructure by planning for system-wide transmission needs on a comprehensive and regional basis.[180] Allowing transmission providers to continue to evaluate, build, and allocate costs for facilities on a project-by-project basis without restriction undermines this central goal and leaves in place the status quo of balkanized planning efforts, as well as clogged interconnection queues, a transmission grid that remains inadequate for the complex and interconnected needs of the future, and unjust and unreasonable rates for customers. The Commission's decision to not require such an approach, or to create a rebuttable presumption that projects be assessed on a portfolio basis, failed to engage meaningfully with the record and was arbitrary and capricious.[181]

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[178] *Id.* at P 890.
[179] *Id.*
[180] *See e.g.* Order No. 1920 at PP 87, 89.
[181] 5 U.S.C. § 706(2)(E); *Delaware Div. of Pub. Advoc. v. FERC*, 3 F.4th 461, 469 (D.C. Cir. 2021) (finding FERC's decision to be arbitrary and capricious when its response to contrary evidence was "little more than a hand wave.") Consol. Edison Co. of NY, Inc. v. FERC, 45 F.4th 265, 278 (D.C. Cir. 2022) ("FERC's ratemaking orders will not stand . . . if they are 'either unreasonable or inadequately explained.'"); *NorAm Gas Trans. Co.v. FERC*, 148 F.3d 1158, 1165 (D.C. Cir. 1998) (an agency will be reversed when it does not "engage with the arguments raised before it."); *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1303 (D.C. Cir. 1992) ([I]t remains the duty of the courts "to ensure that an agency engage the arguments raised before it—that it conduct a process of reasoned decisionmaking."); *Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 1312–13 (D.C. Cir. 1991).

The Commission can provide flexibility while meeting the goals of Order No. 1920 by establishing, as recommended by US DOE[182]— a *rebuttable presumption* that projects be assessed on a portfolio basis—in this way, the portfolio approach would be the standard, but transmission providers could rely on facility-by-facility or other approaches with Commission approval by demonstrating that the portfolio approach is inapplicable in some circumstances.

G. The Commission Erred When It Set the Benefit-to-Cost Ratio at 1.25 to 1.

PIOs request rehearing of the Commission's decision to adopt a benefit-cost ratio of 1.25 to 1 as the maximum benefit-cost ratio that transmission providers may use as a selection criterion in Long-Term Regional Transmission Planning process,[183] and recommend that the Commission lower the applicable benefit-cost ratio to 1 to 1.

First, as explained by the expert testimony provided by PIOs, the traditional 1.25 to 1 cost-benefit requirement simply does not work in the context of scenario-based planning using a portfolio approach.[184] As a most basic element, some projects may be below the cost-benefit threshold—or even below a 1 to 1 cost-benefit threshold—when viewed as an individual project in isolation, but when paired with other projects, can raise the value of the entire portfolio of projects beyond the applicable threshold.[185] Additionally, the value of different projects will change under different scenarios, especially with regard to projects that solve low-frequency, high risk scenarios, with some that may fall below a 1.25 to 1 threshold under a base-case

[182] US DOE Initial Comments at 34–35.
[183] Order No. 1920, 187 FERC ¶ 61,068 at P 958 ("Consistent with Order No. 1000 regional cost allocation principle (3) transmission providers may not impose as a selection criterion a minimum benefit-cost ratio that is higher than 1.25-to-1.00. We decline to reduce or increase the maximum benefit-cost ratio that transmission providers may use as a selection criterion in Long-Term Regional Transmission Planning. As the Commission found in Order No. 1000, requiring that a benefit-cost ratio, if adopted, not exceed 1.25-to-1.00 ensures that the ratio is not so high as to exclude Long-Term Regional Transmission Facilities with significant positive net benefits from selection.")
[184] *See* PIO NOPR Comments, Ex. A at 12–17.
[185] *Id.* at 12–13.

scenario but may exceed it considerably during a high-risk scenario.[186] Consequently, trying to apply a cost-benefit threshold to a project whose value is not fixed is of little use. While Order No. 1920 allows transmission providers to use other methodologies such as a least regrets or maximum net benefits model, the Commission must also make clear that a minimum cost-benefit ratio is not applicable in such situations. Because, as PIOs argue above, portfolio planning should be made mandatory, application of a 1.25 to 1 cost to benefit ratio to projects selected as part of portfolio planning would be unjust and unreasonable based on the record.[187]

H. In Order to Achieve the Aims of Order No. 1920, the Commission Must Require Local Transmission Providers to Meet Their Burden to Prove that Local Projects are Just, Reasonable, and Not Unduly Discriminatory.

The substantial improvements to regional planning and cost allocation processes required by Order No. 1920 are undercut by the Commission's decision not to address the unfettered deference transmission providers receive when constructing local transmission projects. In Order No. 1920, the Commission finds that there is substantial evidence in the record that current processes for developing local transmission projects are unjust, unreasonable, and unduly discriminatory as they lack transparency, meaningful input from stakeholders, and adequate coordination with regional planning processes.[188] The Commission goes on to require modest changes to the transparency of local transmission projects planning processes and a new process by which transmission providers must evaluate the ability to "right-size" certain local transmission projects to meet regional needs. While PIOs support these changes, they do not go far enough to fix the problem. Especially in light of the Commission's decision to leave Order No. 1000 transmission planning procedures in place, the Commission should adopt PIO's

[186] *Id.* at 13–17.
[187] 16 U.S.C. § 825*l*.
[188] Order No. 1920 at PP 1565–66, 1569–74.

proposal to eliminate the presumption that local projects are prudent unless the transmission provider demonstrates that the drivers of the project have been reviewed and not addressed in a regional planning process.

1. Substantial Evidence Exists in the Record that Local Projects Lack Sufficient Oversight and Result in Inefficient and Ineffective Build Out of Transmission.

Along with many others, PIOs submitted evidence in the ANOPR and NOPR comment period demonstrating that the combination of power financial incentives and a lack of oversight over and presumed prudence of local transmission projects has led to the piecemeal, reliability-focused local transmission projects dominating the transmission-investment landscape that are core to the problems Order No. 1920 seeks to address.[189] PIOs made several recommendations for reforms that would bring transparency, oversight, and coordination necessary to address the systemic the local planning process.[190] In Order No. 1920, the Commission sidesteps this evidence by stating that "suggestions for changes to local transmission planning processes were not proposed in the NOPR and therefore are outside the scope of this proceeding."[191] The Commission's determination, however, is both factually incorrect and at odds with the other changes made in response to NOPR comments that are reflected throughout Order No. 1920, including changes made to local transmission planning processes pertaining to transparency, new requirements for right-sizing local transmission projects, and a federal right of first refusal for such projects.[192]

[189] *See, e.g.*, PIO ANOPR Comments at 30–40, 45–46, 60–65, 72–75; PIO NOPR Comments at 49–60; *see also*, Order No. 1920 at 1565–75.
[190] *See* PIOs ANOPR Comments at 61–65; PIOs NOPR Comments at 49–60.
[191] Order No. 1920 at P 1632.
[192] *See* NOPR at PP 414–15 seeking comments on the requirements proposed in the NOPR, including whether the Commission should add substantive requirements; Order No. 1920 at PP 1625–48 (local planning requirements), 1677-92 (eligibility), 1702–09 (right of first refusal), 1716–22 (cost allocation).

Moreover, the request to remove the Commission's presumption of prudence for local projects does not involve a new substantive requirement on the part of the regulated community, as utilities already have the burden of proof to show that rates or charges are just and reasonable under Federal Power Act § 205(e). Rather, PIOs ask the Commission to rescind its own legally flawed abdication of oversight responsibility and return the burden of proof back to utilities who are already required to demonstrate prudence and should thus be able to show their work, rather than inappropriately forcing other stakeholders to prove "serious doubt[s]" about prudence before such a showing is required.[193] Moreover, serious doubts *have* been raised about the prudence of local transmission planning since, as the Commission admits, there is considerable evidence in the record demonstrating that local transmission planning and project spending on local projects (especially in-kind replacement projects) is a core reason for the inefficient and ineffective build out of transmission that has led to systemically unjust and unreasonable rates for consumers.[194]

2. <u>Order No. 1920's Reforms to the Local Planning Process Do Not Eliminate the Incentives for Transmission Providers to Construct Local Transmission Projects That Could Be More Efficiently Met by a Regional Solution, Leading to Unjust and Unreasonable Rates.</u>

Order No. 1920 acknowledges that because local transmission planning serves as a foundation for regional planning, it is critical that these two planning processes "be

[193] *See Minn. Power & Light Co*, 11 FERC ¶ 61,312, 61,644–45 (1980) ("As Section 205(e) of the Federal Power Act states, 'the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility.' As a matter of practice, utilities seeking a rate increase are not required to demonstrate in their cases-in-chief that all expenditures were prudent unless the Commission's filing requirements, policy or precedent otherwise require. However, where some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent.") (citations omitted); *Iroquois Gas Transmission Sys., L.P.*, 87 FERC ¶ 61,295, 62,168 (1999) ("As a matter of procedural practice to ensure that rate cases are manageable, the Commission does not require regulated entities to 'demonstrate in their cases-in-chief that all expenditures were prudent unless the Commission's filing requirements, policy, or precedent otherwise require.'") (*citing Minn. Power & Light Co.*).
[194] Order No. 1920 at PP 48, 85, 87, 109–10.

appropriately designed and aligned to ensure that transmission providers and stakeholders have the information needed . . . to conduct effective . . . transmission."[195] While Order No. 1920's proposed reforms take some steps in the right direction, it does not actually require the kind of comprehensive information transparency, scenario-based planning, multi-benefit analysis, and process coordination necessary for stakeholders to truly understand when proposed local transmission projects could be more efficiently met by a regional solution. As a result, there is little to no basis upon which stakeholders can verify whether local transmission projects are prudent or whether a regional solution is more appropriate.

Not only is this a short period in the context of transmission planning, but there is no obligation for local planners to arrange it to coincide with the development cycle of regional transmission projects and, since the Commission did not require such planning to operate from the same set of assumptions or benefits—there is little to no ability for local and regional transmission planning to meaningfully inform each other.[196] Further, there is no obligation on behalf of a transmission provider to decline to construct a local transmission project even if stakeholders identify a regional transmission project that would obviate the need for the local transmission project. And as PIOs noted, none of Order No. 1920's proposed reforms require information for stakeholders to really evaluate whether in-kind replacements below 200kv could be consolidated or right-sized into a regional solution—evidence and examples of which PIOs and the Union of Concerned Scientists outlined in detail.[197]

[195] *Id.* at P 1570.
[196] It is noteworthy that while the Commission says that it disagrees with stakeholders who argue that this time period is too short, it bases this disagreement on its view that the minimum time established "is just that, a minimum, and we expect that transmission providers and their stakeholders will, in practice, implement a schedule for the required stakeholder meetings that best meets the needs of their transmission planning region." Order No. 1920 at P 1639. However, without any requirement to do so or oversight if the ultimate timing does *not* meet those needs, the Commission's expectation is misplaced.
[197] PIO NOPR Comments at 53–60; PIOs' ANOPR Comments at 92–94; Comments of Union of Concerned Scientists, at 24–31, Docket No. RM21-17-000 (Oct. 12, 2021), Accession No. 20211012-5493.

While transparency is important and incorporating higher voltage local transmission projects into regional planning processes as early as possible will help develop regional projects, the Commission's proposed reforms are not enough to ensure just and reasonable rates. Without the same kind of mandates around local planning processes as are required of regional transmission planning, the Commission cannot simply expect transmission providers to voluntarily forgo the highly lucrative, risk-free capital projects in the form of local transmission projects simply because stakeholders might be able to identify regional projects that would do the same job better and less expensively. This is why the Commission *must* require transmission providers to meet their burden under FPA Section 205(e) to prove that their local transmission projects are the least-cost way to meet the needs of the grid. Without meaningful Commission oversight, the reforms the Commission has enacted will serve as suggestions incumbent utilities can simply ignore, serving as a strong disincentive for stakeholders to bother participating in the local planning process and leaving unchanged the strong incentives utilities have to continue using the local planning process to undermine effective regional planning that threatens their profits and market power—thus perpetuating the unjust and unreasonable rates and practices Order 1920 seeks to address.[198]

The Commission lacks the authority to grant transmission providers the ability to implement unjust and unreasonable rates by imprudently constructing local transmission projects without review. This is particularly true when regional projects are a more efficient, effective, and affordable solution that renders the underlying local project (or projects) clearly imprudent. In light of the extensive evidence in the record regarding the central role played by the largely

[198] *See South Carolina Public Service Authority v. FERC*, 762 F.3d 41, 57 (D.C. Cir. 2014) ("Reforming the practices of failing to engage in regional planning and *ex ante* cost allocation for development of new regional transmission facilities is not the kind of interpretive "leap" that concerned the court in *CAISO* but rather involves a *core reason underlying Congress' instruction* in Section 206") (emphasis added).

unfettered ability of transmission owners to develop piecemeal local transmission projects that displace more efficient and effective regional projects in contributing to unjust and unreasonable rates,[199] the Commission's refusal to require local transmission planning to demonstrate prudence as required by Section 205(e) of the FPA lacks support in the record and is an abuse of discretion.[200] The Commission should grant rehearing to ensure that transmission providers only construct local transmission projects when they are the best option for maintaining reliability at least cost to consumers.

IV. Requests for Clarification

A. The Commission Should Clarify That Transmission Providers Filing Cost Allocation Tariffs Must Identify Any State Agreement and Must Explain How Any Failure to Follow That Agreement Is Just and Reasonable and Not Unduly Discriminatory or Preferential.

Order No. 1920 reasonably balances the value of state engagement and support in the transmission cost allocation process with the need for process certainty and to avoid allowing a single state to veto a project with regional benefits by requiring transmission providers to include in their Open Access Transmission Tariffs (OATTs) one or more Long-Term Regional Transmission Cost Allocation Methods for Long-Term Regional Transmission Facilities that are

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[199] *See, e.g.,* ANOPR Comments at 74; Monitoring Analytics, *2020 State of the market Report for PJM* (2021), p. 614; *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 277, 136 S. Ct. 760, 774, 193 L. Ed. 2d 661 (2016), as revised (Jan. 28, 2016). (When FERC exercises its authority under FPA Section 206 then the Commission "shall determine the just and reasonable rate, charge[,] rule, regulation, practice or contract" and impose "the same by order.").

[200] *Kentucky Mun. Energy Agency v. FERC*, 45 F.4th 162, 178 (D.C. Cir. 2022) (Holding that FERC engaged in "unreasoned, arbitrary, and capricious decisionmaking" by refusing to consider the material effects of its order on customer rates); *Env't Def. Fund v. FERC*, 2 F.4th 953, 975 (D.C. Cir. 2021) (FERC's "ostrich-like approach" in the face of plausible evidence of self-dealing was not reasoned decisionmaking and failed to adequately balance public benefits and adverse impacts); *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028, 1055 (D.C. Cir. 2022); *Del. Div. of Pub. Advoc. v. FERC*, 3 F.4th 461, 469 (D.C. Cir. 2021); *Riverkeeper Network v. FERC*, 753 F.3d 1304, 1313 (D.C. Cir. 2014).

selected, but also creating a process for States to identify their preferences.[201] States may identify their cost allocation preferences both through the Engagement Process for the development of the Long-Term Regional Cost Allocation Methods and through the potential inclusion of a State Agreement Process for defining the cost allocation of selected Long-Term Regional Transmission Facilities.[202] Order No. 1920 also finds that, in the absence of voluntary waiver, transmission providers will hold the ultimate filing rights to submit cost allocation methods, and therefore are not obligated to include in their tariffs a Long-Term Regional Cost Allocation Method developed by states, a State Agreement Process, or a cost allocation developed through a State Agreement Process.[203]

The Commission should clarify that in tariff filings regarding cost allocation, including in the context of the initial filing of *ex ante* Long-Term Regional Transmission Cost Allocation Methods and the filing of tariffs for selected Long-Term Regional Transmission Facilities, transmission providers must clearly disclose and explain the outcome of any Engagement Process, State Agreement Process, or other formal process for developing State consensus on cost allocation. The Commission should further clarify that in any case where a particular cost allocation methodology or related tariff provision garnered support by States in such process and the transmission provider elects not to include that methodology or provision in its tariff filing, the transmission provider must explain in its filing why that methodology or provision was not used and explain how the alternative chosen is just and reasonable and not unduly discriminatory or preferential. The Commission should also clarify that transmission providers may, in their Order No. 1920 compliance filing, voluntarily commit to a process that will ensure that, where a

[201] Order No. 1920 at PP 1291–95, 1354, 1362, 1408–09.
[202] *Id.*
[203] *Id.* at P 1412.

state agreement on cost allocation exists, the agreed cost allocation will be put before the Commission for approval.

These clarifications are important because engagement in transmission planning and cost allocation processes requires substantial effort on the part of states and because cost allocation agreements between states require serious negotiation and compromise. For states to commit to engagement in these processes and be willing to negotiate and compromise, they must be given reasonable assurances that those efforts will not be fruitless. If a transmission provider could ignore an agreement reached through such efforts without disclosing, explaining, and justifying its decision to do so, many states might be reasonably reluctant to commit resources to such a process. As Order No. 1920 explains, state engagement in these processes and the use of cost allocations reflecting state agreements creates a number of benefits, including greater confidence among states and other stakeholders that the cost allocation is a fair reflection of project benefits, reduced likelihood of opposition to and even litigation against selected projects, and potentially smoother state siting and permitting approval processes.[204] Clarifying that the Commission will be informed of and evaluate any decision by transmission providers to make filings inconsistent with a state agreement will offer states additional confidence that participation in engagement and state agreement processes will be meaningful.

Order No. 1920 acknowledges that a number of commenters argued that requiring transmission providers to include cost allocation reflecting state agreements in their tariff would be inconsistent with those providers' filing rights, absent voluntary waiver of those rights.[205]

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[204] *Id.* at P 1364.
[205] *Id.* at PP 1428–31; *see generally Atl. City Elec. Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002). PIOs do not take a position in this filing on the limits *Atlantic City Electric Company* and other relevant precedent impose on scope of the Commission's authority to direct the inclusion of particular provisions, including particular cost allocation methods, in transmission provider's tariff filings.

However, requiring that tariff filings disclose the results of any state agreement process and explain and justify any departure from those results does not create any potential legal issues. The Commission has broad discretion to determine what information must be included with tariff filings, to find that tariffs that do not meet information requirements are incomplete, and to request additional information that will support consideration of whether the tariff rate is just and reasonable and not unduly discriminatory or preferential.[206] Clarifying that transmission providers must file information regarding any state agreement process will ensure that both the Commission and stakeholders receive clear and transparent information relevant to evaluating the tariff. States and other stakeholders may then file comments or protests explaining their position on whether the filed tariff should be approved.

The Commission should also clarify that it will carefully evaluate the existence of a state agreement regarding cost allocation and any departure from that agreement in reviewing whether a tariff filed by a transmission provider is just and reasonable and not unduly discriminatory or preferential. The transmission provider filing a tariff has the burden of proving that the filed rate meets this standard.[207] The Commission has clear authority to consider both the existence of a state agreement and its details in determining whether the rate filed by the transmission provider based on alternate cost allocation is just and reasonable and not unduly discriminatory or preferential and such consideration will give state agreements appropriate weight without any possibility of infringing on transmission providers' filing rights. It is clearly established that the Commission can consider a variety of factors in determining whether a tariff meets the FPA

[206] 16 U.S.C. 824d(e)–(f); *see Ky. Utils. Co. v. FERC,* 689 F.2d 207, 211 (D.C. Cir. 1982) ("FERC 'retains broad discretion' to determine the adequacy of a filing to satisfy the objective of affording notice to the Commission and the public." (quoting *City of Groton v. FERC*, 584 F.2d 1067, 1070 (D.C. Cir. 1978)).
[207] 16 U.S.C. 824d(e).

standard, including the impact on ratepayers of the tariff and alternatives.[208] Indeed, the Commission may even consider the impact of the tariff on rates outside of its jurisdiction, such as retail rates.[209] Careful evaluation of the filed tariff, any alternative that was developed as part of a state agreement process, and the explanations offered by the transmission provider and any stakeholders that filed comments or protests will allow the Commission to determine whether the filed rate is just and reasonable.

The Commission should also clarify that transmission providers may, in their Order No. 1920 compliance filing, voluntarily commit to a process that will ensure that, where a state agreement on cost allocation exists, the agreed cost allocation is put before the Commission for approval, such as through a provision in the OATT requiring that where a specified state agreement standard has been met the agreed-upon cost allocation will be included in the tariff filing, or through a provision that allows an entity other than the transmission provider to file an alternative tariff under Section 205, akin to the "jump ball" provision in the ISO-NE Participants Agreement.[210] The voluntary inclusion of such a provision by a transmission provider is consistent with the Federal Power Act and precedent and would offer states the assurance that any cost allocation methodology or provisions they agree to will receive full consideration on at least the same level as any other proposal.

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[208] *See Fed. Power Comm'n v. Conway Corp.*, 426 U.S. 271, 281.
[209] *Id.* ("The rules, practices, or contracts 'affecting' the jurisdictional rate are not themselves limited to the jurisdictional context.").
[210] Participants Agreement Among ISO New England Inc. and the New England Power Pool and Individual Participants, Section 11.1.5, https://www.iso-ne.com/participate/governing-agreements/participants-nescoe-mou.

B. The Commission Should Clarify Using the Required Benefits to Identify Long-Term Transmission Needs.

PIOs request clarification related to Order No. 1920's requirement that transmission providers "must use th[e] same set of [seven required] benefits to help to inform their identification of Long-Term Transmission Needs."[211]

First, PIOs request clarification of what "help to inform" means in this context, in order to avoid an outcome in which these benefits are considered only superficially, rather than as meaningful determinants of Long-Term Transmission Needs. This clarification might parallel how the Commission described the requirement to incorporate the seven categories of transmission drivers into the Long-Term Scenarios, where Order No. 1920 "clarif[ied] that incorporating each category of factors into the development of Long-Term Scenarios means more than merely considering each category of factors in the development of Long-Term Scenarios."[212] As with the seven categories of drivers, incorporating a benefit into the needs-identification step "should have a measurable impact" on the set of identified Long-Term Transmission Needs, "compared to . . . if it had not incorporated" that benefit.[213]

The Commission should also clarify that a needs-identification step that relies on only one of the Order No. 1000 silos (e.g., reliability) to identify Long-Term Transmission Needs would fail to comply with the requirement that the seven required benefits "help to inform" the identification of needs.[214] This clarification would be in line with Order No. 1920's commitment

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[211] Order No. 1920 at P 301; *accord* Order No. 1920 at P 719 ("[T]hese same benefits should help to inform transmission providers' identification of Long-Term Transmission Needs.").
[212] *Id.* at P 413.
[213] *Id.*
[214] *See* PJM, Long-Term Regional Transmission Planning (LTRTP) Framework Update (Dec. 15, 2023), https://www.pjm.com/-/media/committees-groups/workshops/ltrtp/2023/20231215/20231215-item-02---ltrtp-framework-update.ashx (proposing to create a long-term planning process in PJM that identifies needs solely on the basis of thermal and voltage violations, and then using other benefits to compare proposed solutions).

to de-silo regional planning processes to ensure just and reasonable rates.[215] If a transmission provider were to identify Long-Term Transmission Needs solely on the basis of reliability, for example, and then use the seven required benefits only to compare potential solutions, the resulting set of needs would be incomplete and the resulting solutions would be inefficient.

Finally, FERC should clarify that the requirement to use the seven required benefits to help identify Long-Term Transmission Needs applies equally to (1) transmission providers that identify specific projects with clear parameters and then use a competitive bidding process to select a developer and (2) transmission providers that use a sponsorship model in which developers submit solution ideas to more general requests for solutions. Regarding the second model, PIOs further request clarification as to how FERC envisions the process by which a transmission provider could use the seven required benefits to help identify needs, without these needs being so granular that the transmission provider has effectively defined a specific project. For example, FERC could clarify whether it would be potentially compliant for a transmission provider to use a capacity expansion model with low granularity to minimize total system costs across a set of variables that monetizes the seven required benefits, and then rely on developers to propose specific projects that align with the needs identified by this modeling. This low-resolution modeling to identify general needs that could be satisfied by specific solutions would be comparable in many ways to the DOE's modeling in the National Transmission Planning Study, except limited in scope to a single planning region.[216]

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[215] *See* Order No. 1920 at P 1474 ("[T]ransmission providers may not establish reliability, economic, or public policy transmission facility types as part of Long-Term Regional Transmission Planning and, therefore, may not establish Long-Term Regional Transmission Cost Allocation Methods based on reliability, economic, or public policy transmission facility types . . . . [W]e find that reliability, economic, or public policy transmission facility types reflect a more siloed approach to regional transmission planning that is misaligned with our Long-Term Regional Transmission Planning reforms . . . .").

[216] *See* DOE Grid Deployment Office, August 1, 2023 National Transmission Planning Study Updates Webinar (July 24, 2023), https://www.energy.gov/gdo/articles/august-1-2023-national-transmission-planning-study-updates-webinar.

C. The Commission Should Clarify Whether Required Scenario Factors Include City and Consumer-Side Market Preferences.

As part of its scenario factors, Order No. 1920 requires transmission providers to incorporate "utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs."[217] The Commission justifies this factor on the basis that the "relevant commitments and goals represent known consumer preferences that have been, and will continue to be, key drivers of Long-Term Transmission Needs."[218] The Commission highlights as an example bilateral corporate contracts with energy suppliers. PIOs believe that this is one of several possible indications of consumer preferences and seek clarification on whether this would also include—as PIOs believe—the known preferences of residential and government consumers, such as government contracts with suppliers and consumer demand as reflected in participation in governmental, utility-sponsored, or other independent energy entity clean energy programs, such as energy choice, community solar projects, and private demand response programs.

[217] Order No. 1920 at P 481.
[218] *Id.*

V. Conclusion

PIOs respectfully request that the Commission grant their requests for rehearing, as well as their requests for clarification of Order No. 1920, for the reasons specified above.

Respectfully submitted this 12th day of June 2024,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing to be served upon each person designated on the official service list compiled by the Secretary in the captioned proceeding.

Dated: June 12, 2024

/s/ Danielle C. Fidler
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