UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric	**)**	
Regional Transmission Planning and Cost	**)**	**Docket Nos. RM21-17-000**
Allocation and Generator Interconnection	**)**	

COMMENTS OF THE LARGE PUBLIC POWER COUNCIL

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The Large Public Power Council ("LPPC") submits these comments in conditional support of the proposals contained in the Notice of Proposed Rulemaking issued in this docket by the Federal Energy Regulatory Commission ("FERC" or "the Commission") on April 21, 2022.[1] This support is conditioned on the Commission's recognition that cost and risk management practices are essential in assuring that the proposed Long-Term Regional Transmission Planning ("LTRTP") protocols proposed in the NOPR result in just and reasonable rates. The support is further conditioned on the assurance that state and municipal utilities have a role equivalent to what is contemplated for other state entities in the processes for selecting regional facilities and determining cost allocation.

LPPC is an association of 27 of the nation's largest municipal and state-owned utilities.[2] LPPC's members are located throughout the nation, both within and outside the boundaries of

[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022) ("NOPR" or "Proposed Rule"). *See* Notice on Requests for Extension of Time (issued May 25, 2022) (extending the deadline to submit initial comments in response to the NOPR to August 17, 2022, and extending the deadline to submit reply comments to September 19, 2022.

[2] LPPC's members are: American Municipal Power, Inc. (AMP), Austin Energy, Chelan County Public Utility District No. 1, Clark Public Utilities, Colorado Springs Utilities, CPS Energy (San Antonio), ElectriCities of North Carolina, Grand River Dam Authority, Grant County Public Utility District, IID Energy (Imperial Irrigation District), JEA (Jacksonville, FL), Long Island Power Authority, Los Angeles Department of Water and Power, Lower Colorado River Authority, MEAG Power, Nebraska Public Power District, New York Power Authority, Omaha Public Power District, Orlando Utilities Commission, Platte River Power Authority, Puerto Rico Electric Power Authority, Sacramento Municipal Utility District, Salt River Project, Santee Cooper, Seattle City Light,

regional transmission organizations ("RTOs") and independent system operators ("ISOs"). The members comprise the larger, asset-owning utilities in the public power community, owning approximately 90 percent of the transmission assets owned by non-federal public power entities.

I. BACKGROUND, SUMMARY OF POSITION AND ORGANIZATION OF COMMENTS

A. The NOPR

The core proposal advanced in the NOPR would require public utility transmission providers to conduct Long-Term Transmission Planning. Specifically, the Commission proposes to require that public utility transmission providers in each transmission planning region:

(1) Identify transmission needs driven by changes in the resource mix and demand through the development of Long-Term Scenarios that satisfy the requirements set forth in the NOPR;

(2) Evaluate the benefits of regional transmission facilities to meet these needs over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities; and

(3) Establish transparent and not unduly discriminatory criteria to select transmission facilities in the regional transmission plan for purposes of cost allocation that more efficiently or cost-effectively address these transmission needs in collaboration with states and other stakeholders. [3]

The NOPR builds on the framework established in Orders Nos. 1000, *et seq.*[4] The Commission says that the passage of time, along with the addition (and anticipated addition) of new generating resources to the grid, calls for a fresh look at the Order No. 1000 framework and the Commission's approach to planning and cost allocation for generation interconnection.

Snohomish County Public Utility District No. 1, and Tacoma Public Utilities. LPPC's members are also members of the American Public Power Association ("APPA").

[3] NOPR at P 69.

[4] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014) (together referred to here as "Order No. 1000").

B. LPPC Background and Mission

Representing the larger, asset-owning members of the public power community, LPPC is fully committed to the public power mission, while its members are mindful of their responsibility to serve as stewards of the significant investment in resources that their sponsoring communities have funded. LPPC members are all publicly owned, with some owned by municipal entities and some by the states in which they do business. Governing structures vary, with some boards standing for election, and some appointed by elected officials. In all cases, community ownership of these enterprises ensures their dedication to a public service mission, and that the organizations reflect the energy policy and environmental goals of their communities.

LPPC members are committed to:

- Providing safe and reliable service at the lowest reasonable cost;
- Being responsive and directly accountable to the communities they serve; and
- Developing and integrating renewable resources, a commitment that expresses public policy priorities of the communities that support, own and control LPPC members.

These commitments inform LPPC's reaction to the questions posed in the NOPR. As public power entities, LPPC members have no financial incentive to promote the use of any particular set of assets in advancing the public policy objectives their communities have adopted. LPPC members' connection to ratepayers and their policy goals is immediate and critical to their business model.

LPPC members are not "public utilities," as that term is defined in section 201(e) of the Federal Power Act ("FPA"),[5] and are generally excluded from Commission regulation under subchapter II of the FPA by section 201(f) of the FPA.[6] LPPC members are engaged in Order No.

[5] 16 U.S.C. § 824(e).

[6] 16 U.S.C. § 824(f) ("No provision in this subchapter shall apply to or be deemed to include, the United States, a state or any political subdivision of a State…or instrumentality of any one or more of the foregoing, or any

1000 processes around the nation, within and outside ISOs/RTOs, reflecting their commitment to transparent transmission planning and the open access framework, and their interest in participating in the markets in each of the regions in which they do business.

C. Summary of Comments

LPPC is dedicated simultaneously to meeting member policy objectives that call for increasingly far-reaching regional planning for the purpose of improving grid reliability and reducing carbon output, while maintaining service at the lowest reasonable cost. With those objectives in mind, LPPC embraces the Commission's forward-looking planning initiative, but believes the Commission has so far pulled up short in failing to incorporate important cost and risk management features into the proposed rule. Discussed below, such features would include periodic oversight of approved projects through the date they are placed in service, enabling stakeholders and the Commission to be assured that the cost-benefit parameters upon which projects are approved remain applicable, and that the perceived need for the facilities has not been undermined by changing assumptions regarding load needs and an evolving picture of needed resources.

It seems obvious that the longer the planning term, the greater will be the risk that the parameters upon which projects are planned and approved will change. Assuming the Commission adheres to its tentative decision directing the industry to consider planning for a 20-year term, the Commission has a companion responsibility to provide a framework for enabling industry participants to track developing costs, and to change course when changing circumstances make it clear this would be prudent. LPPC is aware that the NOPR makes an effort to assist in risk

corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing…unless such provision makes specific reference thereto.").

management by providing that the identification of geographic regions for purposes of targeting planned transmission facilities is optional only, and that the Commission proposes to eliminate the recovery of financing for Construction Work in Progress ("CWIP"). LPPC supports both of those features of the proposed rule, but believes more must be done.

Also at the top of LPPC's list for modifications of the proposed rule is an assurance that the public power community has a place at the table with other state entities on which the Commission would rest authority in selecting regional facilities and setting cost allocation parameters for approved regional facilities. As self-regulating entities invested by state legislatures and municipal codes with the authority to carry out legislative policy and set rates, municipal utilities (with few exceptions) are not represented by state public service commissions, and cannot reasonably be asked to abide by their decisions in connection with matters before FERC.

Focusing on the details of regional planning, LPPC supports the Commission's non-prescriptive approach to the identification of benefits, but also believes that any list of benefits approved by the Commission must prominently feature actual use of the proposed facilities (measured by flow studies) as the most objective and measurable of benefits. As to the factors the Commission proposes that transmission providers consider in evaluating long-term planning scenarios and the identification of needed facilities, LPPC believes that the terms of the FPA and good policy counsel that the needs of load serving entities ("LSEs") be placed at the top of the list.

Further, LPPC believes the Commission's proposal to require transmission providers to consider Dynamic Line Ratings and Advanced Power Controls is premature, pending the consideration of these issues in Docket No. AD22-5-000, and the ongoing evaluation of only recently-mandated Ambient Adjusted Line Ratings technology.

Finally, as to interregional planning, LPPC sees room for improvement in interregional coordination, but would oppose any protocols for mandatory interregional cost allocation. LPPC fears that laying interregional cost disputes on top of the nascent regional planning framework may severely handicap any potential progress regarding regional planning and consensus on needed facilities and cost allocation.

D. Organization of Comments

LPPC comments below on some but not all of the proposals and questions advanced in the NOPR. Where possible, text references are provided in order to track the NOPR.

II. COMMENTS

A. Regional Transmission Planning – Long-Term Regional Transmission Planning

1. General Comment: LPPC Supports the Commission's Proposed Planning Reforms So Long as They Are Accompanied by a Robust Cost Control Framework.

LPPC sees value in the Commission's directive to Transmission Providers to develop LTRTPs in order to identify transmission needs driven by changes in resource mix and demand over a long-term (20 year) period. LPPC members are dedicated to meeting policy objectives that call for increasingly far-reaching regional planning for the purpose of improving grid reliability and reducing carbon output. For that reason, LPPC embraces the Commission's forward-looking planning initiative.

Having said this, LPPC also believes the Commission has so far failed to incorporate important cost and risk management features into the proposed rule. The scope of transmission planning contemplated by the proposed rule is novel and expansive, and the potential cost associated with 20-year transmission plans in order to accommodate new resources is unprecedented. The concerns underlying LPPC's recommendation are twofold: First, that costs

may escalate substantially beyond what was contemplated when regional facilities were selected; and second, that the need for the facilities (and associated benefits) may change.

These concerns are more than hypothetical. As to the level of costs, the electric industry's experience with large scale transmission projects strongly suggests that actual costs can vary widely from estimates, while the estimates themselves may change dramatically over time.[7]

As to the need for planned facilities and their associated benefits, there is every reason to believe that preliminary analyses will change, before or even after a project has been undertaken. This may occur for a number of foreseeable reasons. Developments that may cause actual demand in the future for particular long-line transmission facilities to depart substantially from the currently perceived need include: (1) changes in LSE resource plans following the development of local resources, including renewable and distributed energy resources; (2) technological developments affecting the nature of renewable resources and their location; (3) changes in the economics of expected generating resources vis-à-vis alternatives; and (4) changes in load forecast.

Further underscoring the risk of long-term planning and the associated investment, it bears remembering that when Order No. 1000 was promulgated, wind energy was by far and away the predominant form of renewable energy. Preceding Order No. 1000 and substantially animating it, ambitious proposals to build "transmission superhighways" rested on plans to link regions thought to be advantageous to wind production to population centers. In the intervening years, solar

[7] The Brattle Group's April, 2019 Report ("Cost Savings Offered by Competition in Electric Transmission; Experience to Date and the Potential Additional Value") offers an illustrative survey of the delta between initial estimates for transmission projects and actual costs, ranging as high as an escalation of 70% in ISO-NE during the study period *See* https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf, Figures 21, 22, 24 and 25. To be sure, Brattle's figures were disputed (*see* Concentric Energy Advisors' "Building New Transmission; Experience To-Date Does Not Support Expanding Solicitations," June, 2019 (https://ceadvisors.com/building-new-transmission/). Yet, the significant potential for substantial cost overruns seems indisputable, and likely greater than has historically been the case the further out the planning horizon is extended, and investment shifted to ambitious regional plans.

development proceeded apace, including both utility-scale solar and distributed energy resources. Underscoring this dramatic shift in emphasis, the Solar Futures Study released by the Department of Energy's Office of Energy Efficiency and Renewable Energy in September 2021 highlights massive anticipated reliance on solar development. The point is not that some of these resources may not ultimately materialize, and that infrastructure will not be needed in order to integrate them, but rather that there is a substantial level of uncertainly regarding generation mix and infrastructure needs.

LPPC acknowledges that the Commission has taken some steps to help manage the risk of its contemplated LTRTPs. Under the NOPR, plans to site transmission facilities based solely on the identification of geographic regions thought to be amenable to generating resource development are to be considered at each region's option, and will not be mandated. Further, the Commission proposes to eliminate an allowance for CWIP in rates for projects that are approved pursuant to the Order No. 1000 framework. The approach to each of these issues is helpful and endorsed by LPPC below. However, the risk of potentially out-of-control costs, and a mismatch between costs and benefits over time, remains.

As to projects geared strictly to geographic regions (those LPPC would consider the riskiest), the Commission's proposal would *permit* regions to move in that direction. Should they do so, the potential that the high cost of such projects may balloon over time seems quite real, as does the possibility that evolving LSE needs and associated benefits may undermine the cost-benefit equation that supported the project initially. Nor is the financial risk of ambitious transmission projects limited to those aimed strictly at geographic locations. The LTRTP process the Commission proposes to mandate requires regions to look twenty years into the future. In

anything approaching that time frame, estimates of resource needs and load are of an inevitably speculative nature.

Eliminating CWIP in this setting will surely be of value in helping to manage risk. The assurance of investment recovery through the inclusion of CWIP in rates even before facilities go on line would add to the risk of the plans supporting them, and its elimination is useful. Yet, eliminating CWIP does not wholly manage risk and cost, since that change alone does not avert the potential of an approved and ultimately unneeded project (with its accumulated Allowance for Funds Used During Construction) entering rates. Rather, following approval of a project and at periodic intervals throughout the process prior to its energization, stakeholders should be provided an opportunity to revisit their support, and petition the Commission to have the project cancelled should changes in circumstances so justify.

Nor does the Commission's proposal for regions to revisit and revise their Long-Term Scenarios every three years (as would be required under revised Attachment K) account for these risks, since the proposed tariff does not appear to contemplate a transparent process in which developing costs for approved projects are evaluated in the context of evolving market needs in order to enable stakeholders and the Commission to adjust the scope of planned projects and associated expenditures, and to cancel them if need be. If the history of the electric industry over the past 50 years teaches anything, it is that mistakes can be made with the best of intentions regarding enormous capital intensive projects, and that clear-eyed, ongoing analysis is required at all stages of project development in order to assure that costs and benefits remain within anticipated values.[8]

[8] The nuclear industry in the 1970s and 1980s offers an object lesson on this point. *See* Richard J. Pierce, *The Regulatory Treatment of Mistakes in Retrospect: Cancelled Plants and Excess Capacity*, 132 U. Pa. L. Rev. 497 (1984); Joseph P. Tomain and Constance Dowd Burton, *Nuclear Transition: From Three Mile Island to Chernobyl*, 28 Wm. & Mary L. Rev. 363 (1987).

While the approach to regional planning adopted by FERC in Order No. 1000 was upheld by the D.C. Circuit in in *S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014), the Commission's proposed regulations take a substantially more aggressive step toward directing investment, following the conclusion that existing planning and cost allocation processes "may not be planning transmission on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand . . . [and] may not be identifying the more efficient or cost-effective transmission facilities."[9] The Commission's proposed solution lies in revisions to Attachment K to the *pro forma* Open Access Transmission Tariff ("OATT") that will (1) identify transmission needs driven by changes in the resource mix and demand through the development of Long-Term Scenarios; (2) evaluate the benefits of regional transmission facilities to meet transmission needs driven by changes in the resource mix and demand over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities; and (3) establish criteria for the selection of transmission facilities in the regional transmission plan for purposes of cost allocation.[10]

These provisions contemplate a more active role in advancing the buildout of the transmission grid than ever the Commission has assumed. While the proposed changes pull up short of expressly directing transmission investment, they come close, mandating that transmission providers establish transmission plans and selection criteria for the designation of transmission projects whose costs will be recoverable on a mandatory basis from all regional participants.

Crossing this line would certainly be impermissible. FPA sections 205 and 206 are cited by the Commission in support of action taken in order to remedy "unjust, unreasonable, unduly

[9] NOPR at PP 24-25.

[10] NOPR, Appendix B at p. 10.

discriminatory, and preferential jurisdictional rates,"[11] but the FPA contains no authority authorizing the Commission to direct the development of transmission facilities. To the contrary, FPA section 215(i)(2) presumes the opposite, stating that "[t]his section does not authorize…the Commission to order the construction of additional generation or transmission capacity…." While FPA section 215 expressly governs electric reliability, the statutory savings clause appears plainly to contemplate that authority for FERC to compel the construction of additional transmission capacity does not exist elsewhere in the statute either.

LPPC's level of comfort with the proposal will be substantially influenced by the Commission's willingness to adopt a cost and risk management framework assuring that costs will remain just and reasonable. For these reasons, LPPC recommends that as part of a final rule in this docket, the Commission direct each Transmission Provider to develop and implement protocols providing for cost management and critical decision-making throughout the period leading to a project's in-service date meeting specified minimal criteria. These protocols would provide that any allocation of costs must be contingent on ongoing milestone and development review, overseen by FERC, including the following features:

- Sponsors of all projects approved by a region for cost allocation will be required to file reports at periodic intervals with FERC tracking anticipated project costs against projections upon which projects were approved, and updated information on the benefits of the projects (where projects have been approved on the basis of a benefit-cost ratio).

- Where periodic reports indicate that costs have exceeded an identified threshold percentage, or the benefit-cost ratio upon which a project has been approved declines by an identified threshold percentage, remedial action may be considered by regional stakeholders.[12]

[11] NOPR at P 34.

[12] LPPC suggests that the threshold for review would be triggered by variance from the cost basis upon which a project was approved for cost allocation purposes by 25% or more (consistent with a Variance Analysis in MISO's Tariff (Attachment FF, Section IX.C). Where projects have been approved on the basis of a benefit-cost ratio, it is also suggested that a 25% variance would be an appropriate threshold for review.

- Sponsors of identified projects which have exceeded identified thresholds will be permitted to present regional stakeholders with mitigation plans. Should there be no consensus on such plans, stakeholders may petition FERC to cancel regional cost allocation for the project. The Commission will grant such petitions unless it determines that the public interest is adversely affected.

- Review and remedial action will be available under these procedures until construction of the relevant project begins (i.e., the physical site for the proposed project has been altered).

- Where a project has been cancelled pursuant to these procedures, the project sponsors will be eligible for abandoned cost recovery consistent with FERC policy, absent a showing of imprudence.

These provisions would provide meaningfully more protection for customers than the limited post-project approval review contemplated by Order No. 1000, which called for regions to determine whether delays in the development of transmission facilities selected in a regional transmission plan for purposes of cost allocation would require the evaluation of alternative solutions.[13] LPPC envisions that its recommended procedures would work together with the Commission's suggestion at P 248 of the NOPR that Public Utility transmission providers include in their selection criteria how they will address the status of previously selected transmission facilities if and when it is determined in the LTRTP planning process that facilities are no longer needed.

LPPC's recommendations are somewhat similar to, but more expansive than the provisions calling for "Variance Analysis" in MISO's tariff.[14] MISO's Variance Analysis is useful in calling for the reevaluation of approved projects after their selection but prior to project construction

[13] See Order No. 1000 at PP, 7, 263, 329.

[14] Attachment FF to MISO's OATT, initially approved by the Commission in *Midwest Independent Transmission System Operator,* 142 FERC ¶ 61,215 ((2013); *Order on Reh'g and Compliance Filing*, 147 FERC ¶ 61,127 (2014). The trigger provisions of MISO's variance analysis were later revised in Docket Nos. ER16-469 and ER20-740. *See Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,074 (2016); *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER16-469-001 (Ltr. Order dated Mar. 1, 2016); *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER20-740-000 (Ltr. Order dated Feb. 2. 2020).

where costs exceed an identified threshold above approved levels. But this analysis notably is limited to projects driven by economic benefits, while the approach calls for review only for variations in cost, schedule delays and deviation from the transmission developers' characteristics or qualifications. No analysis of the anticipated and potentially changing need for the project is contemplated.[15]

Going to the core of its statutory responsibility, the Commission has an affirmative obligation under FPA section 205 to assure that "all rates and charges…in connection with the [jurisdictional] transmission or sale of electric energy…shall be just and reasonable." Section 206 of the Act provides that "*Whenever* the Commission…shall find that any rate [or] charge….is unjust an unreasonable" it "shall determine the just and reasonable rate [or] charge…(emphasis added)" Following information that rates have exceeded just and reasonable levels, the Commission has in the past recognized its responsibility to investigate and address them.[16] *A fortiori,* when (as here) the Commission affirmatively mandates a program with an obvious cost impact, it has a commensurate obligation to review the cost impact of the program and its anticipated benefits. The provisions LPPC has recommended would enable the Commission to do this.

Finally, LPPC is certainly aware that the Commission has made plans in Docket No. AD22-8-000 for a technical conference in order to discuss cost oversight in connection with the

[15] 142 FERC ¶ 61,215 at P 358; *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,074 (2016); *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER16-469-001 (Ltr. Order dated Mar. 1, 2016); *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER20-740-000 (Ltr. Order dated Feb. 2. 2020).

[16] *See, e.g., ISO New England Inc.*, 164 FERC ¶ 61,003, at P 2 (2018) (instituting a proceeding under section 206 of the FPA finding that the ISO-NE's Tariff maybe unjust and unreasonable). FERC has acted similarly under the Natural Gas Act. *See, e.g., Natural Gas Pipeline Co. of America LLC.*, 158 FERC ¶ 61,044, at P 1 (2017) (initiating an investigation pursuant to section 5 of the Natural Gas Act to determine whether the rates currently charged by Natural are just and reasonable).

implementation of any rule in the instant docket.[17] To the extent it is determined that a proposal such as the one LPPC has advanced here calls for separate notice and comment, LPPC strongly urges the Commission to combine these proceedings, assuring full consideration of the cost management procedures that LPPC believes must accompany a final rule in this docket if the entire package is to be considered just and reasonable.

B. Existing Planning Programs and Implementation of the Proposed Long Term Regional Transmission Planning Process (NOPR at PP. 72 – 74, 253-255).

1. Existing Public Policy Planning Programs Should Be Presumed to Meet the Requirements of a Final Rule in this Case.

The Commission states that "public utility transmission providers may continue to rely on their existing regional transmission planning and cost allocation processes to comply with Order No. 1000's requirements related to transmission needs driven by *reliability concerns or economic considerations*"[18] but does not offer the same deference to existing planning processes furthering public policy goals. Instead, the Commission places an affirmative burden on transmission providers that have *already* developed processes to consider transmission needs driven by Public Policy Requirements through existing Order 1000 processes – and who "wish to retain" them – "to demonstrate that continued use of any such processes does not interfere or otherwise undermine the Long-Term Regional Transmission Planning" process.[19]

LPPC supports the Commission's proposed treatment of economic and reliability projects, but believes the less deferential approach to existing planning for public policy purposes risks

[17] *See Transmission Planning and Cost Management,* Notice of Technical Conference, issued April 21, 2022; Supplemental Notice of Technical Conference, issued July 22, 2022.

[18] NOPR at P 72 (emphasis added).

[19] *Id*., P 74.

unduly interfering with programs that advance important state-supported programs and thereby the Commission's own objectives.

As to existing planning for economic and reliability purposes, LPPC agrees with the Commission's implicit conclusion that these processes do not call for the Commission's further assistance, and that there is no need to enmesh them in this new framework, though it offers regions the option to do so.[20] In his concurring opinion, Commissioner Christie gives full voice to this thinking:

> Reliability and Economic projects are the meat and potatoes of regional transmission planning. These categories of projects are, by definition, integral to the primary duty of utilities to serve retail customers (load). Reliability projects are essential to keep the lights on. Economic projects are constructed to reduce quantifiable and definable congestion costs. When these projects are needed, they should be expeditiously built. The NOPR wisely does not disturb existing criteria for timely planning, constructing and paying for these two categories of projects.[21]

As to public policy projects, the Commission says it "understand[s] that public utility transmission providers in some transmission planning regions have developed processes to consider transmission needs driven by Public Policy Requirements through their regional transmission planning processes that they may wish to retain." Nonetheless, the Commission proposes to hold that such projects "would not supplant public utility transmission providers' obligations to comply with the Long-Term Regional Transmission Planning requirements," and further that transmission providers "seeking to retain existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements . . . would have to demonstrate that continued use of any such processes does not interfere or otherwise undermine the Long-Term Regional Transmission Planning . . . ."[22]

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[20] NOPR at P 75.

[21] Concurring Opinion of Commissioner Christie at P 8 (fn. omitted).

[22] NOPR at P 74.

Yet there is no reason to believe that regional planning processes compliant with Order No. 1000's requirements governing public policy considerations are any more likely to "supplant" the proposed rule's LTRTP processes than similarly compliant processes governing reliability and economic transmission projects. Further, the Commission does not explain what showing would be required to make the necessary demonstration that these processes will not interfere with the LTRTP process. Given those shortcomings, and because LPPC members see significant value in existing planning programs furthering public policy objectives, it asks the Commission not to risk their disruption. To that end, LPPC urges the Commission to establish a presumption of reasonableness for regions that have already implemented planning processes for public policy projects. The LTRTP processes may then be layered on top of, and integrated with, existing processes, as seems most efficacious to each region.

LPPC emphasizes that without the benefit of a presumption favoring existing programs, the Commission's proposal may have the unintended effect of retarding, rather than accelerating, the development of needed regional transmission projects. This could easily mire transmission planning regions in disputes about whether an existing FERC-approved regional planning process for consideration of public policy projects would "supplant" LTRTP processes.

The interrelationship between the New York ISO's planning processes and the 2019 New York State Climate Leadership and Community Protection Act ("CLCPA")[23] and the state's Accelerated Renewable Energy Growth and Community Benefit Act[24] illustrate these concerns,

[23] Climate Leadership and Community Protection Act, Chapter 106 of the laws of 2019. The CLCPA requires 70 percent of all of New York's electricity to come from renewable sources by 2030 ("70 x 30"), a 100 percent reduction in greenhouse gas emission from the electricity sector by 2040 ("100 x 40"), and 9,000 MW of offshore wind generation ("OSW") by 2035.

[24] Accelerated Renewable Energy Growth and Community Benefit Act, 2020 N.Y. Sess. Laws, ch. 58, Part JJJ (McKinney 2020) ("Accelerated Renewables Act"). The Accelerated Renewables Act requires the NYPSC to establish distribution and local transmission capital plans "for each utility in whose service territory the power grid study identified distribution upgrades and local transmission upgrades" that are determined "necessary or appropriate" to achieve New York's climate mandates. Likewise, the Accelerated Renewables Act requires the

demonstrating the importance of ensuring that existing programs are not in jeopardy. Working under the guidance of those Acts and the oversight of New York's Public Service Commission and the New York State Energy Research and Development Authority ("NYSERDA"), the state's principal transmission providers, including LPPC members New York Power Authority ("NYPA") and Long Island Power Authority ("LIPA"), developed a voluntary agreement on behalf of their customers to share the costs of local transmission projects developed to meet CLCPA targets and to allocate the costs according to each utility's volumetric load-ratio share.[25] The agreement would govern the allocation of the costs of major transmission projects necessary to allow new clean energy resources to be delivered into and throughout New York, consistent with New York public policy goals under CLCPA.[26]

The New York entities' 2021 proposal included a series of procedural checks to ensure their reasonableness. First, they would be required to obtain approval from the state commission to proceed with a local transmission project and to apply the return on equity and capital structure determined by the state commission. Second, they would work with the New York ISO to develop a conforming amendment to the New York ISO tariff, which would then be submitted to FERC for cost recovery consistent with any state commission orders approving the project(s) and

State-Regulated TOs and LIPA to "make local transmission upgrades in accordance with a schedule approved by the NYPSC or, in the case of LIPA, the LIPA Board of Trustees."

[25] NYPSC Case 20-E-0197 - Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act. LIPA and NYPA are non-jurisdictional transmission owner signatories to the agreement; as such, the agreement and rate schedule contain provisions particular to them. Review and approval of LIPA rates and charges are governed by Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Under this authority, LIPA's Board of Trustees, after consultation with the New York State Department of Public Service ("DPS"), reviews and sets LIPA's rates and charges "at the lowest level consistent with sound fiscal and operating practices of the authority and which provide for safe and adequate service." FERC applies a comparability review standard to the incorporation of LIPA's rates and charges into the NYISO OATT. While NYPA is a party to the agreement, it does not have a local transmission and distribution system. It would be will be allocated costs under the proposed Rate Schedule 19 NYISO has filed with FERC.

[26] See Order Accepting Compliance Filings, NYPSC Case 20-E-0197, issued May 12, 2022, at p. 3 ("State Authorizing Order").

identifying an associated return on equity and capital structure.[27] The state commission has since approved the agreement,[28] New York ISO has filed a conforming addition to its tariff (Rate Schedule 19) with FERC,[29] and a Commission ruling on the filing is expected by August 22, 2022.

In seeking approval of its June 2022 tariff filing, the New York ISO asserts:

> The Commission's acceptance of proposed Rate Schedule 19 will advance New York's public policies relating to clean electricity supply across the state. Pursuant to Rate Schedule 19, the NYTOs will recover and allocate across New York to electricity consumers the costs of certain local transmission upgrades selected and approved under state law and policy as necessary to allow existing and new clean energy resources to be delivered into and throughout New York.[30]

Efforts like New York's should not face the additional burden, presented by the proposed rule, essentially to prove their reasonableness twice. The New York utilities' agreement has been integrated into New York ISO's tariff filing and is already subject to Commission review and approval. That should be enough.

C. Development of Long-Term Scenarios for Use in Long-Term Regional Transmission Planning – Factors (NOPR at PP 104-112).

1. While LPPC Does Not Oppose the Factors Identified by the Commission for Evaluating Long-Term Scenarios, Primary Consideration Must Be Given to The Ability of Load-Serving Entities to Satisfy Their Service Obligations.

The Commission proposes to require transmission providers to incorporate a minimum of seven identified "categories of factors" in their development of Long-Term Scenarios. The listed minimum factors are: (1) federal, state, and local laws and regulations that affect the future resource mix and demand; (2) federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and expected supply obligations

[27] *See* NYPSC Case 20-E-0197.

[28] Order Accepting Compliance Filings, NYPSC Case 20-E-0197 (May 12, 2022).

[29] New York ISO, Docket No. ER22-2154 (filed June 21, 2022).

[30] *Id*., Transmittal Letter, p. 1.

for load serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand.[31] According to the Commission, these categories of factors affect the future resource mix and demand, and are needed in Long-Term Scenarios to identify transmission needs driven by changes in the resource mix and demand through long-term regional planning.[32]

While the factors detailed by the Commission are not in themselves objectionable, they elide the Commission's fundamental responsibility to facilitate planning in order to meet the needs of LSEs, and Congress' recognition that LSEs themselves have a fundamental obligation to build transmission in order to meet their load. Indeed, the *only* express reference in the FPA to the Commission's responsibility when it comes to transmission planning is that it must facilitate the reasonable needs of LSEs. FPA section 217 ("Native Load Service Obligation") reinforces this in two important respects. FPA section 217(e), 16 U.S.C. § 824q(e) ("Obligation to Build"), specifies:

> Nothing in this chapter relieves a load-serving entity from any obligation under State or local law to build transmission or distribution facilities adequate to meet the service obligations of the load-serving entity.

Addressing the Commission's affirmative responsibility, FPA section 217(b)(4), 16 U.S.C. § 824q(b)(4), specifies:

> The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities…

[31] NOPR at P 104.

[32] *Id*., P 105.

With these provisions in mind, the list of planning factors offered by the Commission seems not so much wrong as mistaken in emphasis. While the factors the Commission has listed may be relevant to LSE needs, the Commission's primary touchstone for planning within its authority must be the load needs *identified by LSEs.* The FPA plainly contemplates that planning be done in a manner that facilitates the ability of LSEs to meet their service obligations first and foremost. Consideration of any other factor in the development of Long-Term Scenarios therefore should be secondary to the determinations made by LSEs regarding needed resources to satisfy their service obligations, and the Commission must do nothing to impede the ability of LSEs to discharge their obligation to meet these service obligations. Accordingly, the needs of LSEs must be at the top of any list of factors considered in connection with planning scenarios.

This approach aligns with the very purpose of the FPA, which is to protect *consumers*: it is well settled that "[t]he purpose behind [FPA] section 205(b) is the protection of the *consumer's* interest" (emphasis added),[33] and the intent of the statute's undue discrimination protections "is to protect consumers [ ] from being placed at a competitive disadvantage."[34] Further, LSEs, by virtue of their state-based franchises, are legally bound by a duty to serve and step into the shoes of their customers for purposes of planning, constructing and maintaining facilities necessary to render reliable, cost-effective service to customers in their service territories. Accordingly, consideration in the development of Long-Term Scenarios must be given first and foremost to the needs of LSEs, and LPPC is concerned that the Commission's proposal to establish a series of factors that look

[33] *Pub. Service Co. of Ind., Inc. v. FERC*, 575 F.2d 1204, 1213 (7th Cir. 1978) ("*Indiana*"); *see St. Michaels Util. Comm'n v. FPC*, 377 F.2d 912, 915 (4th Cir. 1967) ("*St. Michaels*").

[34] *Indiana*, 575 F.2d at 1212 (emphasis added); s*ee City of Frankfort, Ind. v. FERC*, 678 F.2d 699, 707 (7th Cir. 1982) ("*City of Frankfort*"); *Towns of Alexandria, Minn. v. FPC*, 555 F.2d 1020, 1028 (D.C. Cir. 1977) ("*Towns of Alexandria*"); *St. Michaels*, 377 F.2d at 915.

more broadly than this core obligation under the FPA threatens to undermine the needs of LSEs and their customers.

D. Identification of Geographic Zones (NOPR at PP 145-153)

1. LPPC Agrees That the Identification of Geographic Zones Should Be an Option that Regions May Consider but FERC will not Mandate. LPPC Further Urges the Commission to Address Potential Costs and Risks Associated with Building Lines to Remote Geographic Zones in Regions that Choose this Option.

At PP 145 of the NOPR, the Commission proposes to require transmission providers as part of the regional transmission process "*to consider whether to*: (1) identify, with stakeholder input, specific geographic zones within the transmission planning region that have the potential for development of large amounts of new generation; (2) assess generation developers' commercial interest in developing generation within the identified geographic zones; and (3) incorporate designated zones, and the identified commercial interest in each zone, into Long-Term Scenarios (emphasis added)." Identifying a three-step process for this consideration, the Commission further says that "we propose to require that public utility transmission providers *consider* whether to establish and include in the regional transmission planning process outlined in their OATTs the method that they will use to identify geographic zones within the transmission planning region (emphasis added)."[35] And the Commission says that after any draft geographic zones have been identified, stakeholders must be permitted to comment. In a second step of this process, the Commission says that it proposes to require public utility transmission providers in each planning region to assess generation developers' commercial interest in developing generation within the proposed geographic zones, following a set of listed criteria.[36] And in a third

[35] NOPR at P 147.

[36] *Id*., P 148.

proposed step, the Commission says it "propose[s] to require that public utility transmission providers in each transmission planning region incorporate the information from step one and step two regarding the designated geographic zones into their Long-Term Scenarios."

LPPC does not object to the Commission's proposals on this point to the extent the obligation imposed on transmission provides is only to *consider* whether to identify geographic zones, to assess generators' commercial interest in such zones and to incorporate them into an LTRTP. Based on LPPC's reading of the proposal on its face, it is our understanding that the decision whether to study transmission to identified geographic regions is *strictly within the transmission providers' discretion.*

If LPPC's reading is incorrect -- and if the Commission's proposal would require transmission providers to identify transmission to geographic regions when they choose not to, or call for Commission oversight of the process by which such determinations would be made -- LPPC would object vigorously. As LPPC commented when the proposal to build transmission to geographic regions was first suggested in the Advance Notice of Proposed Rulemaking ("ANOPR") in this proceeding,[37] a mandatory approach would be fraught with financial risk to the entities that would be called upon to fund transmission development, arising from the significant potential that the planned transmission facilities may ultimately go underutilized or altogether unused. This may occur for a number of foreseeable reasons. Developments that may cause actual demand in the future for particular long-line transmission facilities to depart substantially from projections include: (1) changes in LSE resource plans following the development of local renewable resources, including DER; (2) technological developments

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

affecting the nature of renewable resources and their location; (3) changes in the economics of expected generating resources vis-à-vis alternatives; and (4) changes in load forecast.

These risks are real. As noted above, when Order No. 1000 was promulgated, wind energy was by far and away the predominant form of renewable energy.[38] Preceding Order No. 1000 and substantially animating it, ambitious proposals to build "transmission superhighways" rested on plans to link regions thought to be advantageous to wind production to population centers.[39] In the intervening years, solar development proceeded apace, including both utility-scale solar and distributed energy resources. Underscoring this dramatic shift in emphasis, the Solar Futures Study released by the Department of Energy's Office of Energy Efficiency and Renewable Energy in September 2021 highlights massive anticipated reliance on solar development.[40] The point is not that some of these resources may not ultimately materialize, and that infrastructure will not be needed in order to integrate them, but rather that there is a substantial level of uncertainly regarding generation mix and infrastructure needs, and that building transmission on a "Field of Dreams"[41] philosophy would be poor policy.

As a legal matter, it is most unlikely that the Commission could satisfy the standard in *ICC v. FERC* where costs are allocated to customers for transmission facilities planned solely to access geographic areas in which favorable conditions may be found for certain types of generation, but where no generation has yet been planned or contracted for. Costs must be allocated in a manner

[38] Order No. 1000 at P 29, citing at fn. 22 Department of Energy, 20% Wind Energy by 2030, at 93 (July 2008); *See also* NERC 2009 Long-Term Reliability Assessment at 8.

[39] *See, e.g.*, AEP, Interstate Transmission Vision for Wind Integration White Paper, at 8 (2007), *available at* https://cleanenergygrid.org/uploads/AEP-WindTransmissionVisionWhitePaper.pdf.

[40] https://www.energy.gov/articles/doe-releases-solar-futures-study-providing-blueprint-zero-carbon-grid. The study predicts a future in which 30 TW of solar capacity per year is built between now and 2025, and 60 GW per year between 2025 and 2030.

[41] https://en.wikipedia.org/wiki/Field_of_Dreams.

"roughly commensurate with benefits," and no costs may be allocated to entities that stand to gain no benefit at all. And while the court in *ICC v. FERC* did not insist on precision in cost allocation, some rigor is indeed required. Faulting the Commission for failing even to attempt any empirical match of costs to benefits, and rather to rely on generalized statements regarding general benefits to the utility grid, the court had this to say:

> No doubt there will be *some* benefit to the Midwestern utilities just because the network is a network, and there have been outages in the Midwest. But enough of a benefit to justify the costs that FERC wants shifted to those utilities? Nothing in the Commission's opinions enables an answer to that question.[42]

The difficulty presented by a proposal to fund and allocate costs for transmission associated with future generation not yet planned, and certainly where only a geographic region for generation development is identified, is quite similar. Alleged benefits cannot be reasonably associated with any given customer or even a set of customers based on anticipated use of generating facilities that have not even been planned and may never be.

Adding to LPPC's concerns with a potential rule allocating the cost of transmission in specific regions for future, as yet unplanned, generation, is the recognition that many of LPPC's members have been called upon to invest in local renewable resources, some by law. Such requirements exist in California and New York,[43] and even where they are not codified, the pressure on state and municipally owned enterprises to employ local resources is substantial. State and local renewable and carbon reduction objectives can certainly be addressed at least in part by

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[42] 576 F.3d at 477 (emphasis in original).

[43] *See, e.g.*, California 100% Clean Energy Act, SB 100 (requiring California utilities to produce 100% carbon-free electricity by 2045), *available at* https://www.energy.ca.gov/sb100. SB 100 calls for 75% of the state's renewable energy to be sourced in California, or, if outside California, from a resource with a first point of interconnection with the California BA. *See also*, New York's Climate Leadership and Community Protection Act, which calls for 70% of load to be served by renewable energy by 2030 and 100% by 2040 (*available at* https://www.nysenate.gov/legislation/bills/2019/s6599.) The legislation specifies that the state will source 6,000 MW of distributed solar energy by 2025, and an additional 9,000 MW from off-shore wind contracted for by the New York State Energy and Research Development Authority and designated as a New York Resource.

local resources, and mandatory funding for regional and interregional transmission facilities that municipals choose not to (or cannot) use will make the total cost of renewable energy more expensive. If the Commission wishes to advance more regional and interregional transmission development, it must harmonize its policy with existing state and local mandates and preferences. No customer should be asked to pay twice for the same benefit.

Nor would concerns over potential "free ridership" in connection with transmission facilities justify a mandate to build facilities to identified geographic regions. Both the Commission in Order No. 1000 and the court in *SCPSA v. FERC* rested reliance on free ridership theory on the existence of *actual* benefits to the entities to which costs are assessed. Certainly, actual anticipated use of these facilities is the clearest means by which benefits may be established. Evidence that integrated facilities improve grid reliability for the benefit of all customers would be the clearest indication of such use. Further afield would be transmission built to access planned generation that will have a demonstrable impact on existing markets. Furthest yet – and we believe a bridge too far – would be transmission built to accommodate as-yet unplanned generation, based on nothing more than the idea that a geographic region may be advantageous for generation development. As to this, the Commission would be moving into an entirely speculative environment, one in which it cannot be determined (to use the language of the court in *ICC v. FERC*) that there is an "articulable and plausible reason to believe that the benefits are at least roughly commensurate with" allocated costs.[44]

LPPC adds that for regions that choose to head down this path (and LPPC members may well be in such regions), the tools for managing the associated risk must be made available. High

[44] *ICC v. FERC,* 576 F.3d at 477. We discuss in section II.B.2 of the comments, *infra.*, whether the definition of benefits may be so broadly construed as to encompass social benefits outside the economics and reliability of the grid, and demand for transmission driven by public policy. Binding Supreme Court precedent makes it clear the answer is "no."

on that list should be a region's ability to weigh cost sharing by generation developers interested in interconnecting with proposed new facilities. Similar to the Commission's proposal that transmission providers may assess the commercial interest in developing generation within a designated geographic zone,[45] enabling transmission providers to evaluate the feasibility of transmission proposals in light of generation developers' willingness to share the cost of a transmission buildout will provide keen insight into whether the proposed facilities are commercially supportable. LPPC envisions that the structure of these arrangements would call for developers to provide up front capital contribution for a specified portion of identified projects, subject to reimbursement when facilities are used. Certainly, knowing that generators would be willing to put themselves at financial risk in order to secure transmission facilities that are essential to their business plan would engender confidence that the planned transmission facilities will be useful. As well, it seems entirely equitable to call for developers standing to earn a return that depends on needed infrastructure to contribute some of the capital needed in order to advance their business plans. LPPC sees this proposal as conceptually similar to the Commission's tentative determination that state entities' willingness to step up to fund proposed transmission facilities will be a factor in determining whether to select such facilities for regional cost allocation purposes.[46]

In addition, LPPC encourages the Commission to permit regions to look to customer subscription to proposed transmission projects as a means of evaluating the need for facilities. That model seems appropriate where proposed facilities predominately serve to bring new generation to market, rather than serving as an integrated element of the transmission grid. In these circumstances, demonstrated subscription to the proposed transmission project, similar to

[45] NOPR at P 150.

[46] NOPR at P 252.

what is required of natural gas pipelines seeking NGA section 7 certificates, has merit. Commission policy calls for natural gas pipeline project developers seeking certification under section 7 of the NGA[47] to provide support for a finding of need for their projects with evidence that a threshold level of the proposed pipelines' capacity has been contracted for by subscribers.[48] The policy simultaneously ensures that existing pipeline customers will not be called upon to subsidize speculative investment, and minimizes the environmental impact of unnecessary facilities.[49] The application of this policy in conjunction with the proposals considered in the NOPR seems entirely justified. Indeed, LPPC submits that if FERC chooses not to apply the subscription-based approach it has taken in the natural gas pipeline environment in ascertaining the need for facilities to this setting, it will need to explain and rationalize the decision.[50]

[47] 15 U.S.C. § 717(f).

[48] *See* "Certificate Policy Statement," *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128 (2000), *further clarified*, 92 FERC ¶ 61,094 (2000).

[49] The Commission was recently faulted by the D.C. Circuit for effectively failing to take this policy seriously by permitting evidence of subscription by the pipeline-project developer's affiliate to satisfy the showing of market support. *See Environmental Defense Fund v. FERC.* Case No. 20-1015 (D.C. Cir. June 22, 2021).

[50] The NGA and FPA are appropriately read in *pari materia*, calling for the Commission to justify differences in policies adopted under the Acts. *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981). *See also, FPC v. Sierra Pacific Power Co*., 350 U.S. 348, 353 (1956); *Environmental Action, Inc. v. FERC*, 939 F.2d 1057, 1063 (D.C. Cir. 1991) ("Additionally, both of the Commission's reasons appear to be inconsistent with the position it has taken under the Natural Gas Act in the comparable situation.…"); *Mich. Consol. Gas. Co. v. FERC*, 883 F.2d 117, 121-23 (D.C. Cir. 1989) ("Without more support, and a distinction that justifies the seemingly different approaches that the FERC has taken under two very similar statutes, we cannot accept this footnote in full discharge of the agency's obligation to make a reasoned decision."); *see also*, *Transmission Access Policy Study Group v. FERC*, 225 F. 3d 667, 735 (D. C. Cir. 2000) (agency "conceded error" in failing to justify differing treatment of natural gas and electric transmission rights of first refusal.).

E. Evaluation of Benefits of Regional Transmission Facilities – Evaluation of Long-Term Regional Transmission Benefits (NOPR at PP 176-225).

1. LPPC Supports a Non-Prescriptive Approach to Evaluating Benefits of Regional Transmission Facilities, Provided That Any List of Benefits Approved by the Commission Prominently Feature Actual Use of Those Facilities.

At P 183 of the NOPR, the Commission "decline[s] to propose…any particular definition of 'benefits' or 'beneficiaries,' nor require use of any specific benefits." Instead, "acknowledge[ing] the benefits of regional flexibility…," the Commission offers a suggested list of benefits, and proposes to require transmission providers to identify their proposed list of benefits in compliance filings, along with proposals for their calculation.

LPPC supports the regional flexibility the Commission's proposal contemplates, but believes the Commission must be clear that any acceptable list of benefits detailed in compliance filings must emphasize actual use of the proposed transmission facilities by LSEs, which should be measured by anticipated power flows that occur across these facilities. As discussed above, the reasonable needs of LSEs to satisfy their service obligations must be a principal consideration in long-term planning, which necessarily follows from the responsibility and obligation for LSEs to meet their service obligations. This is critical to the function of LSEs, and it is central to the Commission's obligations under the FPA. Mindful of this obligation, actual use of proposed regional facilities by LSEs is an essential benefit which must be used by regions in evaluating regional transmission facilities for selection in their regional planning processes.

Of course, any number of ancillary benefits may flow from regional transmission facilities, which the Commission recognizes when it proposed a "common set of minimum benefits" that transmission providers "may consider in Long-Term Regional Transmission Planning and cost

allocation processes."[51] But these benefits should be considered by the Commission as secondary to what LPPC envisions to be the core benefit of any such facilities: whether those facilities are actually to be used by the LSEs whose service obligations and needs are to be served through these facilities. This approach is consistent with the native load service obligation articulated under FPA section 217 and the Commission's obligation thereunder to "exercise [its] authority...in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities."[52]

Above all else, the Commission must hew closely to the first two principles governing cost allocation articulated in Order No. 1000, which are: (1) that cost must be allocated in a way that is roughly commensurate with benefits; and (2) that there will be no involuntary allocation of costs to non-beneficiaries.[53] As the D.C. Circuit has made clear, the allocation of costs only to beneficiaries of the expenditures – *i.e.*, the "cost causation principle" – "add[s] flesh to [the] bare statutory bones" of the just-and-reasonable-rate requirement.[54] The cost causation principle is "one that ensures 'burden is matched with benefit.'"[55] Further, "all approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them."[56] It is on this basis that the Commission established the requirement in Order No. 1000 that costs must be allocated roughly commensurate with benefits, drawing as it did on precedent established by the Ninth

[51] NOPR at P 183.

[52] 16 U.S.C. § 824q(b)(4).

[53] Order No. 1000 at PP 10, 622, 637.

[54] *Old Dominion Elec. Coop. v. FERC*, 898 F. 3d 1254, 1255-56 (D. C. Cir. 2018).

[55] *BNP Paribas Energy Trading GP v. FERC*, 743 F.3d 264, 268 (D.C. Cir. 2014); *see Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368-69 (D.C. Cir. 2004).

[56] *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C.Cir.1992).

Circuit in *ICC v. FERC*.[57] This must remain the guiding principle underlying the evaluation of benefits and the allocation of costs of regional transmission facilities.

F. Selection of Regional Transmission Facilities (NOPR at PP 241-252).

1. The Selection of Regional Transmission Facilities Must Be Undertaken in Consultation with Municipal Utilities.

The NOPR proposes that transmission providers be required to work with "state entities" in developing selection criteria to be employed in choosing criteria for identifying transmission facilities that will be eligible for regional cost allocation. This proposed obligation is stated, variously, as a commitment to "coordinate with relevant state entities,"[58] to "seek support from relevant state entities,"[59] to develop selection criteria "in consultation with the relevant state entities in their transmission planning region's footprint."[60] Further, the NOPR provides that a state entity's decision voluntarily to fund the cost of a Long-Term Regional Transmission Facility may satisfy a transmission provider's selection criteria.[61]

LPPC does not object to this basic framework, but believes it is essential that municipal utilities be included as integrated participants in the consultative processes that the Commission envisions. For reasons argued by LPPC below (Section 3) in connection with the role that the Commission contemplates for state entities in the State Agreement Process that the Commission imagines may lead to consensus-based cost allocation decisions,[62] municipal utilities have

[57] 576 F.3d 470 (9th Cir. 2009).

[58] NOPR at P 241.

[59] *Id*., P 244.

[60] *Id*., P 246.

[61] NOPR at P 252.

[62] *Infra*. at 35-40.

statutorily conferred self-regulatory authority and represent their customers in ways that are fundamentally similar to state commissions.

2. Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices in Long-Term Regional Transmission Planning (NOPR at PP 272-277).

(a) LPPC Opposes the Commission's Proposal to Require Consideration of Dynamic Line Ratings in Long-Term Regional Transmission Planning.

The Commission proposes to require public utility transmission providers to "more fully consider in regional transmission planning and cost allocation processes" the "incorporation into transmission facilities of dynamic line ratings and advanced power flow control devices."[63] The Commission states that under its proposal, consideration of Dynamic Line Ratings ("DLRs") or advanced power flow control devices is to include first, "whether incorporating [these technologies] into *existing* transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other potential transmission facilities," and second, when evaluating potential *new* transmission facilities in regional plans, whether incorporating these technologies "as part of any potential regional transmission facility would be more efficient or cost-effective."[64] The Commission further proposes to require transmission providers to provide an evaluation of these considerations in sufficient detail to enable stakeholders to determine why the technologies were not adopted, if that is the transmission provider's decision.[65]

LPPC opposes the Commission's proposal to mandate that transmission providers consider incorporating of DLR and advanced power follow technologies at this time, though it has no objection to any individual transmission provider experimenting with these technologies, as indeed

[63] NOPR at P 272.

[64] *Id.*, P 274 (emphasis added).

[65] *Id.*, P 275.

have some LPPC members. As the Commission is aware, extensive comments were filed on April 25, 2022 in Docket No. AD22-5-000 in response to the same, if slightly narrower, inquiry regarding DLR (but not advanced power flow technology). In those comments, LPPC (jointly with APPA) and others asked the Commission to hold off in considering a requirement to utilize DLRs while the industry implements the closely related Ambient Adjusted Line Ratings ("AAR") requirement just mandated in Order No. 881.[66] As LPPC pointed out, AAR is an element of a DLR system that will test grid operations in similar if less complex ways, and promises to capture a significant portion of the benefits offered by substantially more involved and costly DLR systems.

LPPC's concerns here are procedural and substantive. The record in Docket No. AD22-5 is thick with technical input (including LPPC's) regarding the merit of a DLR requirement at this time. When LPPC filed its comments in that docket, it seemed reasonable to assume that FERC would digest the input and make a tentative decision reflected in a Notice of Proposed Rulemaking, if indeed it chose to proceed. Instead, with the NOPR in this docket, the Commission appears to side-step the extensive record in Docket No. AD22-5 without wrestling with the real technical and cybersecurity-related concerns previously raised. With that, the Commission interjects a proposal which has only a tangential relationship with the core (and already very complicated) issues presented in this docket.

Moving to the substance of the proposal, there is no substantial evidence of which LPPC is aware upon which to conclude at this time that there will be meaningful incremental benefits associated with DLR vis-à-vis AAR that justify the additional expense and complexity that would

[66] *Managing Transmission Line Ratings*, Order No. 881, *Fed. Reg.*, 87 Fed. Reg. 2244 (Jan. 13, 2022), 177 FERC ¶ 61,179, at P 7 (2021). The Commission provided for a three-year time frame for implementing AAR. *Id.* at P 360.

be associated with a generic requirement to implement DLRs. With the publication of Order No. 881 just over four months ago, the Commission put in place a three-year timetable for implementing AAR, following a 120-day time frame for the submission of compliance filings. That timetable responded to the Commission's acknowledgement of the "complexity of the proposed AAR requirements"[67] and the recognition that it will take several years to undertake work that will include

> developing and updating the transmission line rating methodologies, analyzing historical weather information, identifying limiting elements, developing a transmission line ratings database, updating the transmission management system, testing the transmission line ratings, and linking the transmission owners' transmission management system to the RTO/ISO EMS, all while maintaining cybersecurity standards.[68]

On top of this work will be placed the development and implementation of "software that communicates transmission line ratings" to transmission operators, along with the development and implementation of updates to EMS, SCADA and other operational software.[69]

The work of ascertaining what incremental benefits may be associated with the further implementation of DLR will be much facilitated by the development of reliable data associated with the operation of AAR. As the Electric Power Research Institute ("EPRI") commented in Docket No. RM20-16 (leading to Order No. 881), DLR is built on and incorporates AAR, promising more nuanced adjustments to ratings reflecting (in addition to ambient air temperatures), "wind cloud cover, solar irradiance intensity, precipitation, and/or transmission line conditions such as tension or sag."[70] With the Commission having required in Order No. 881 the

[67] Order No. 881 at P 349.

[68] *Id.* at P 352.

[69] *Id.* at P 353.

[70] Comments of Electric Power Research Institute on Managing Transmission Line Ratings Notice of Proposed Rulemaking, Docket No. RM20-16 (filed March 22, 2021) ("EPRI Comments") available at: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=020C4113-66E2-5005-8110-C31FAFC91712.

implementation of AAR within this three-year time frame for *all* transmission facilities (not only those historically congested), the industry will now begin to amass data from which conclusions may be drawn.

The additional work that will be associated with the implementation of DLR is considerable. As described by the Department of Energy ("DOE") in its June 2019 Report to Congress, this work will include: (1) the installation of sensing and monitoring equipment; (2) the establishment of a communications link between that equipment and control rooms or other decision systems; (3) the installation of an analytics engine that will process the data collected by sensors and monitors; and (4) the integration of the information processed through these new systems into actionable information about system capabilities employed in utility controls (SCADA systems).[71]

As reported by DOE[72] (and the Commission in recounting the comments of parties in Docket No. RM20-16),[73] these systems are expensive, with estimates ranging from $500,000 for a 22-mile line[74] to over $1 million per line.[75] LPPC member New York Power Authority ("NYPA") reported a cost of $1.02 million for a 70.8-mile line associated with a pilot project undertaken by NYPA.[76] In Docket No. RM20-16, MISO Transmission Owners estimated a cost of $1.5 billion for the MISO system in aggregate.[77]

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[71] Department of Energy, Report to Congress on Dynamic Line Ratings, June 2019 ("DOE Report") at 15-21 available at https://www.energy.gov/sites/prod/files/2019/08/f66/Congressional_DLR_Report_June2019_final_508_0.pdf

[72] *Id.* at 22.

[73] Order No. 881 at PP 243, 246.

[74] DOE Report at 22.

[75] Order No. 881 at P 243.

[76] *See* Presentation of Charlie Xu, p. 7, filed in FERC Docket No. AD19-15 on September 17, 2019.

[77] *Id.*

LPPC recognizes that confidence in these cost estimates is low, substantially because information regarding appropriate placement and operation of relevant systems has not been fully developed and common assumptions established. In Docket No. RM20-16, EPRI only recently reported that *before* studies regarding the cost (and cost-effectiveness) of DLR systems and their appropriate placement can be developed, the following information is needed:

1. A technical basis on how to select the number, type, and location of field monitoring equipment.

2. Confidence in the accuracy of the installed monitoring systems and the potential benefits and inherent risks.

3. An understanding of the reliability of the installed monitoring systems and the associated maintenance costs.

4. Strategies on how to integrate the information from the monitoring systems into the energy management system (EMS) and procedures on how operators will use the information, including how to account for monitoring systems which are not reporting.[78]

Further relevant is the meaningful cybersecurity risk associated with the installation of the communications equipment that is an essential feature of a DLR system. New communications systems will be essential in enabling sensors placed throughout the grid to relay useful information to control centers or other information processing units. The installation of new communications equipment throughout a utility grid may involve hundreds or even thousands of routable devices, each of which may serve as a point of vulnerability to cyberattack. LPPC raised these concerns previously with the Commission in its comments filed in Docket No. AD22-5-000. The automation of DLR systems and the necessary communications links offer new vectors for cybersecurity attacks that the Commission must closely consider, and not overlook. The

[78] EPRI Comments at 4.

appropriate venue for consideration of such technical issues continues to be Docket No. AD22-5-000, in which a more thorough record of these issues has been assembled.

In any event, utilities should be vested with the discretion to decide for themselves whether or not to use DLRs or advanced power flow control devices on a case-specific basis, depending upon an individual utility's system characteristics and the impacts that integration of such technologies will have, depending upon, among other things, local dynamic conditions, costs and benefits.

With all of this in mind, LPPC strongly counsels the Commission to hold off in issuing any further requirement as to DLR at this time. Through the development and installation of AAR systems, the more widespread adoption of DLR pilot programs, and the analysis of data associated with both, FERC will be far better positioned to consider its policies concerning DLR deployment while helping the industry avoid a rush to further requirements that may not be as well conceived or tailored as they should be.

3. Regional Transmission Cost Allocation

(a) State Involvement in Cost Allocation for Long-Term Regional Transmission Facilities (NOPR at PP 302-324).

(i) Should the Commission Rely on "State Entities" to Establish Agreements on Regional Transmission Cost Allocation, Municipal Utilities Must Be Recognized as Equal Participants in Relevant Processes.

The Commission's proposed rule would give public utility transmission providers three options for tariff changes to comply with its directives concerning cost allocation methodologies for LTRTP facilities. They can either file (1) an ex ante "Long-Term Regional Cost Allocation Method," (2) "a State Agreement Process by which one or more relevant state entities may

voluntarily agree to a cost allocation method," or (3) a combination of the first two.[79] Under *any* of these three options, public utility transmission providers in each planning region would be required to secure the agreement of state entities, or explain to the Commission their "good faith" efforts to obtain such agreement.[80] The Commission proposes to define state entities to include "any state entity responsible for utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state."[81] The Commission further proposes that there would be only one such entity for each state in a region.[82] Though not clearly excluded from the definition of state entities (municipal utilities do have ratemaking authority), they are not plainly included either, and conversations with senior FERC Staff suggest that the initial contemplation is that municipal utilities are not considered state entities.

At first pass, this framework appears to involve the unlawful delegation of the Commission's statutory authority. Because LPPC's members appear not to be defined as state entities within the Commission's proposed framework, LPPC's concern is that they may be profoundly affected by this approach to ratemaking without representation. As discussed below, LPPC's concern may be ameliorated if the state entity construct were broadened to include public power entities, represented regionally on a load ratio share basis.

The Commission's tentative decision to turn transmission rate decisions over to state entities conflicts with its exclusive statutory authority over rates under the FPA.[83] While FERC

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[79] NOPR at P 302.

[80] *Id.*

[81] *Id.*, P 304.

[82] *Id.*

[83] The courts and the Commission itself have recognized that the Commission's statutory responsibilities are mandatory and non-delegable. *See, e.g., City of Tacoma, Washington v. FERC*, 331 F.3d 106, 115 (2003) (finding that FERC unlawfully delegated its responsibility to assess annual charges imposed under the FPA against

appears nominally to reserve backstop authority to review and approve cost allocation decisions by state entities, it also imposes on public utility transmission providers the obligation to secure the agreement of state entities or affirmatively explain why good faith efforts have failed. This framework strongly suggests that as a practical matter FERC contemplates the delegation of its rate authority to state entities, or at least extraordinary deference to state regulatory commission decision-making. Indeed, delegation of the Commission's ratemaking authority seems precisely what FERC has in mind in "preliminary find[ing] that a State Agreement Process by which one or more relevant state entities voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or portfolio of facilities) after it is selected in the regional transmission plan for purposes of cost allocation *may be a just and reasonable approach to cost allocation for such regional transmission facilities* (emphasis added)"

LPPC is sympathetic to the Commission's interest in cultivating input from state regulatory commissions in its decision-making process. While regulatory authority over unbundled interstate transmission rates belongs exclusively to FERC, the cost impact of transmission rates is of course felt at the state level through retail rates. This perspective is given full voice by Commissioner Christie, and LPPC certainly sympathizes with it.[84]

While LPPC respects this perspective, it nonetheless believes that more complete representation of relevant entities in the decision-making process would help assure that the Commission meets its statutory responsibilities. Grounds for granting LPPC members a place at this table are substantial. For one thing, LPPC members are self-regulating entities that possess

hydroelectric utilities licensed under the FPA to other federal agencies); *Entergy Servs., Inc.*, 120 FERC ¶ 61,020 at P 28 (2007) (denying Entergy's request that the Commission defer to a retail regulator the reasonableness of Entergy's wholesale rates, holding that "[t]he Commission's ratemaking obligations under the FPA cannot be delegated to a state commission"). *See also United States Telecom Ass'n v. FCC,* 359 F.3d 554, 565-568 (D.C. Cir. 2004) (rejecting FCC subdelegation of decisions within its statutory authority to state commissions).

[84] Concurring Opinion of Commissioner Christie at P 13-14.

many of the same regulatory characteristics as do state commissions. State and municipal utilities undertake retail ratemaking in a public setting, and are politically accountable to their customers in much the same way (if not more directly) as state regulatory commissions.[85] Further, State and municipal utilities are not represented by state commissions, and while state and municipal utility policies as to generation mix, carbon reduction and the like generally track policies applicable to regulated investor-owned utilities, state commissions generally have no obligation to concern themselves with rate impacts on state and municipal customers, a matter of great concern to LPPC members. Finally, it is worth noting that in certain states, municipal utilities collectively represent a market share larger than most individual investor-owned utilities. Further, many municipal and state-owned utilities are among the nation's largest utilities (public or private), while municipal utilities provide *all* of the state's utility service in Nebraska.

In his concurring opinion, Commissioner Christie comments that the states' special role under the proposed rule follows from the fact that the FPA "explicitly recognizes state authority."[86] So, he reasons, "it is perfectly fitting for state regulators to have the important roles proposed in this NOPR, without preempting the regional planning entities from seeking additional input through their existing stakeholder processes."[87] The FPA, however, also "explicitly recognizes" the authority of political subdivisions of a state through the exemptions given to them from most of Part II of the Act. They, too, must be given a say-so as "relevant sate entities" to ensure that LTRTPs will not be built and paid for by *their* consumers unless they have a voice in assuring that "such projects are indeed needed and wanted" by the consumers they represent.

[85] Specifically as to siting authority, some state and municipal entities possess this authority unilaterally, while others participate in a state regulatory framework.

[86] Concurring Opinion of Commissioner Christie at P 13.

[87] *Id*.

Commissioner Christie also correctly observes that the Order No. 1000 planning processes that would be supplemented by the proposed rule already require open, inclusive and non-discriminatory stakeholder participation. But just as the general stakeholder process must be non-discriminatory, so too must the Commission avoid discriminating between "relevant state entities" as defined in the proposed rule and political subdivisions of states (like LPPC's members).

In *Southwest Power Pool, Inc.*,[88] the Commission recently articulated the criteria essential to a non-discriminatory planning process for "zonal planning criteria" to be developed by the "facilitating transmission owner": "a defined process by which transmission owners and transmission customers in the zone can provide input on potential Zonal Planning Criteria, as well as comment and ultimately vote on draft Zonal Planning Criteria developed by the Facilitating Transmission Owner."[89] In rejecting the SPP's earlier filing the Commission found the previously-proposed voting mechanism unduly preferential because it would have given the "Facilitating Transmission Owner" the potential to select planning criteria that would "address only its own local reliability needs" or "foreclose SPP's consideration of local reliability needs of other transmission owners.[90]

While the *Southwest Power Pool, Inc.* case addressed the reasonableness of the stakeholder process within SPP, the non-discrimination concerns it addressed there apply equally to the Commission's proposed LTRTP reforms. Any final rule adopted by the Commission should provide an opportunity for municipal utilities serving a portion of a state's electric load to have a role in the state's vote. This would ensure that a state entity cannot limit its interests to those consumers served only by public utilities.

[88] 179 FERC ¶ 61,229 (2022).

[89] *Id.*, P 47.

[90] *Id.*, P 51.

The remedy for this shortcoming need not be complex. The most obvious fix would be for the Commission to grant municipal utilities representation on a load ratio share basis. In all regional cases where voting is involved, municipal utilities must have no less than one vote, in order to ensure that they have a voice. LPPC recognizes that this approach is slightly more involved than envisioned in the NOPR. But LPPC is convinced that the unique regulatory status of state and municipal entities calls for an adjustment to the proposed rule.

4. Construction Work in Progress Incentive.

(a) LPPC Supports the Commission's Proposal to Withhold the Construction Work in Progress Incentive for Regional Projects.

LPPC strongly supports the Commission's proposal not permit public utility transmission providers to take advantage of the CWIP Incentive for Long-Term Regional Transmission Facilities.[91] LPPC agrees with the Commission that "the CWIP Incentive, if made available for Long-Term Regional Transmission Facilities, may shift too much risk to consumers to the benefit of public utility transmission providers in a manner that renders Commission-jurisdictional rates unjust and unreasonable."[92] As Commissioner Christie explains in his concurring opinion:

> CWIP is the award of cost recovery of construction costs during the pre-construction and construction phases to the developer. CWIP is, of course, passed through as a cost to consumers, making consumers effectively an involuntary lender to the developer. By contrast, AFUDC is booked during the pre-service phases, but cannot be recovered from customers until the project is completed and actually serving customers, i.e., "used and useful." The NOPR proposal is simply in keeping with traditional good utility ratemaking principles.[93]

With that said, the elimination of CWIP for LTRTP projects reflects only a part of a necessary cost and risk management framework. LPPC has addressed above the additional

[91] NOPR at P 333.

[92] *Id*.

[93] Concurring Opinion of Commissioner Christie at P 15.

necessary components of an effective cost management program that LPPC believes the Commission must put in place in order to assure customers that costs are being managed throughout the process preceding the in-service dates of planned project, and that the anticipated benefits of these projects remain realistic.[94]

5. Interregional Transmission Coordination and Cost Allocation (NOPR at PP 426-429).

(a) LPPC is Open to Improvements in Interregional Coordination, But Opposed to Mandatory Interregional Cost Allocation.

LPPC does not object to the changes to the interregional protocols proposed in the NOPR and sees potential value in improved regional coordination and an approach that may facilitate interregional projects. As the Commission explains, it is proposing to require transmission providers to revise their existing interregional transmission coordination procedures and planning processes established in compliance with Order No. 1000 to reflect the LTRTP-related changes proposed in the NOPR.

Specifically, the NOPR proposes to require public utility transmission providers in neighboring planning regions to revise their existing interregional coordination procedures (and regional planning processes) to "provide for: (1) the sharing of information regarding the respective transmission needs identified in the Long-Term Regional Transmission Planning that we propose to require in that section above, as well as potential transmission facilities to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address transmission needs identified through Long-Term Regional Transmission Planning."[95] Further, the Commission

[94] *See supra*., at pp. 6-13.

[95] NOPR at PP 426-427.

proposes to "require that public utility transmission providers in neighboring transmission planning regions revise their interregional transmission coordination procedures (and regional transmission planning processes as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to transmission needs identified through Long-Term Regional Transmission Planning."[96] LPPC has no objection to these proposals.

LPPC *strongly* endorses the Commission's decision not to require any changes to existing interregional cost allocation methods for interregional transmission facilities.[97] As things now stand under the Order No. 1000 framework, any interregional cost allocation must be voluntarily assumed by each affected region. In Order No. 1000, the Commission steered clear of mandating interregional cost sharing. The decision was upheld in *SCPSA v. FERC,* with the court citing favorably the Commission's conclusion that "the resulting regional transmission planning processes would amount to interconnection-wide transmission planning with corresponding cost allocation, albeit conducted in a highly inefficient matter."[98]

The Commission's conclusion in Order No. 1000 was that mandatory interregional planning and cost allocation, with the daisy chain of adjacent regions all connected in some fashion in each interconnection, would collapse under its own weight. There is no reason to draw a different conclusion today. Transmission planning is time consuming and heavily process-oriented. Processes take place at the local level, and feed up to the regional level, with stakeholder input at all levels and inevitably contentious discussions regarding cost allocation. Regions are obligated to coordinate with one another today, but those discussions are not fraught with the

[96] *Id*., P 428.

[97] *Id*., PP 416, 426 (fn. 674).

[98] 762 F.3d at 87 (citing Order No. 1000 at P 660).

potential for one region to impose costs to another. With an overlay of mandatory interregional planning and cost allocation, it is hard not to envision these processes becoming overwhelmed, resulting not in better planning but more extended, contentious processes yielding little but controversy.

The balance struck by the Commission in Order No. 1000 calling for interregional coordination without mandatory cost allocation simultaneously respects regional differences in policy, while avoiding the enormous practical difficulty presented if one region chooses to insist on financial contribution from another. By contrast, mandatory interregional cost allocation holds the potential for enormous political controversy, to say nothing of the complexities of managing state siting and eminent domain processes. The allocation of costs associated with transmission projects driven by public policies specifically, should go no further than the region whose governmental authorities are responsible for the underlying policies.

LPPC is certainly not opposed to proposals to make interregional coordination more valuable, and interested in means by which interregional discussion may be enhanced and the possibility of mutually beneficial transmission projects discussed, optimizing regional plans. For example, the New York ISO is developing transmission plans to enable the delivery of offshore wind across coastal zones and into the New York bulk electric system. Neighboring states in ISO-New England and PJM are making similar plans. Should there be an interregional project that can minimize the joint cost of separate regional projects without sacrificing benefits, it would be worth pursuing. But if not undertaken consensually, interregional transmission may simply add costs without commensurate benefits. We can imagine FERC playing a valuable role in facilitating those discussions, and urge the Commission to move in that direction.

III. CONCLUSION

For the foregoing reasons, LPPC asks the Commission to issue any Final Rule in this proceeding consistent with the comments articulated herein.

Respectfully submitted,

Large Public Power Council

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