UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

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

MOTION TO INTERVENE AND COMMENTS OF THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

Pursuant to Rule 214 of the Federal Energy Regulatory Commission ("FERC" or "Commission") Rules of Practice and Procedure,[1] the National Association of Regulatory Utility Commissioners ("NARUC") submits these comments in response to the Commission's July 15, 2021 Advance Notice of Proposed Rulemaking ("ANOPR") and the September 3, 2021 Notice of Extension of Time in the above-captioned proceeding.[2] In the ANOPR, the Commission "is considering the potential need for reforms or revisions to existing regulations to improve the electric regional transmission planning and cost allocation and generator interconnection processes."[3]

I. COMMUNICATIONS

All pleadings, correspondence, and other communications related to this proceeding should be addressed to the following person:

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1 18 C.F.R. § 385.214 (2020).

2 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (2021) ("ANOPR").

3 ANOPR at P 1.

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II. MOTION TO INTERVENE

NARUC is the national organization of the state commissions responsible for economic and safety regulation of the retail operations of utilities. NARUC's members have the obligation under state law to ensure the establishment and maintenance of such energy utility services as may be required by the public convenience and necessity, as well as ensuring that those services are provided at just and reasonable rates. NARUC's members include the government agencies in the fifty states, the District of Columbia, Puerto Rico, and the Virgin Islands charged with regulating the rates, terms, and conditions of service associated with the intrastate operations of electric, natural gas, water, and telephone utilities. Both Congress[4] and the federal courts[5] have long recognized NARUC as the proper party to represent the collective interests of state regulatory commissions.

NARUC member state commissions and FERC have regulatory authority over and oversight of regional and local transmission facilities. Among the many questions that this

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4 *See* 47 U.S.C. § 410(c) (1971) (Congress designated NARUC to nominate members of Federal-State Joint Boards to consider issues of concern to both the Federal Communications Commission and State regulators with respect to universal service, separations, and related concerns); Cf., 47 U.S.C. § 254 (1996) (describing functions of the Joint Federal-State Board on Universal Service). *Cf. NARUC, et al. v. ICC*, 41 F.3d 721 (D.C. Cir. 1994) (where the Court explains "[c]arriers, to get the cards, applied to . . . [NARUC], an interstate umbrella organization that, as envisioned by Congress, played a role in drafting the regulations that the ICC issued to create the 'bingo card' system").

5 *See United States v. Southern Motor Carrier Rate Conference, Inc.*, 467 F. Supp. 471 (N.D. Ga. 1979), *aff'd* 672 F.2d 469 (5th Cir. 1982), *aff'd en banc on reh'g*, 702 F.2d 532 (5th Cir. 1983), *rev'd on other grounds*, 471 U.S. 48 (1985).

ANOPR asks are whether it is necessary to more clearly define those lines of authority and how the Commission should do so.[6] Additionally, for example, the ANOPR seeks to address issues concerning Public Policy Requirements, which by definition include requirements established by local and state laws or regulations.[7] Given such questions and topics, this proceeding will have an impact on NARUC member state commissions and, thus, NARUC has a direct interest in it.

III. INTRODUCTION

The Commission opened this proceeding pursuant to its authority under section 206 of the Federal Power Act ("FPA")[8] because it believed that after more than a decade since it issued Order No. 1000 and given all the changes in the electric sector that have taken place during that period, it was time to review that order and other transmission-related regulations.[9] The Commission also recently established a Joint Federal-State Task Force on Electric Transmission ("Task Force") to confer with state commissions on many of the same transmission-related topics.[10] NARUC commends the Commission for undertaking a comprehensive examination of the important issues concerning electric transmission and the need for reform. NARUC also welcomes the opportunity to participate in the Joint Task Force on Electric Transmission and looks forward to sharing the experiences of the states with the Commission and working collaboratively to find solutions. Ideally, the Task Force would have been able to meet and begin its process of opening up the dialogue between the states and the Commission prior to the

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6 ANOPR at P 5.
7 ANOPR at P 5 & N.7.
8 16 U.S.C. § 824e.
9 ANOPR at P 3.
10 *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (2021).

launch of such a comprehensive examination, but we understand the need to move quickly on these issues.

NARUC has endeavored to review the questions and address the issues raised in the ANOPR thoughtfully, but we note that with the breadth of the ANOPR, NARUC and its member states are still developing our thinking on some of these matters. Below, we offer our initial thoughts and questions on the issues raised in the ANOPR and we anticipate developing these further as this proceeding and the Task Force move forward.

We have organized our comments around the topics of transmission planning, cost allocation and generator interconnection. In addition to the inevitable overlap between these topic areas, we provide comments on the issue of cost containment that cuts across all three topics because, as state regulators, we have a responsibility always to be mindful of the financial impacts regulations and policies have on state citizens and electricity customers.

IV. COMMENTS

A. Regional Transmission Planning

NARUC appreciates the Commission's continued attention to transmission planning. While the primary drivers for transmission needs—ensuring reliability, providing economic benefits, and achieving legal and public policy requirements—remain constant, continued monitoring of the processes used to plan for and invest in these assets is important because the broader landscape in which they are built and used constantly evolves. Indeed, with Order No. 1000, the Commission sought to "remedy deficiencies in the existing requirements"[11] and,

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[11] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011) at P 12, *order on reh'g*, Order

among other things, required transmission providers to develop regional transmission planning processes to "expand opportunities for more efficient and cost-effective transmission solutions."[12] Much has changed in the decade since Order No. 1000 was issued. Not only have there been significant technical advances, states' energy laws and policies have evolved, with many states strengthening or expanding requirements related to clean energy generation.[13] With this in mind, the states agree with the Commission that it is timely to review the transmission planning processes established as a result of Order No. 1000. While the tenets established by the Commission in Order No. 890[14] and affirmed in Order No.1000 remain important,[15] NARUC identifies opportunities for reforms that may result in more efficient transmission planning and investment to the benefit of consumers, all while preserving jurisdictional authorities.

Along those lines, it is important to note that the transmission development process is comprised of transmission planning—in which the Commission, the regional system operators, transmission owners, utilities and other planning organizations have broad authority to explore and bring about improvements and reforms—and transmission siting—in which states determine whether the proposed transmission facilities meet state law, requirements, and criteria for approval of a certificate to construct. NARUC is not suggesting a change in these authorities, but rather, supports exploring reforms that will better align regional transmission planning with

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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).

[12] Order No. 1000 at P 146.

[13] *See* National Regulatory Research Institute's Clean Energy Policy Tracker at https://www.naruc.org/nrri/nrri-activities/clean-energy-tracker/.

[14] *Preventing Undue Discrimination and Preference in Transmission Service*, (Order No. 890), FERC Stats. & Regs. ¶ 31,241 (2007).

[15] Order No. 1000 at P 146 (requiring transmission providers to participate in a regional transmission planning process that produces a regional transmission plan and that complies with the transmission planning principles of Order No. 890).

state needs and ensure meaningful opportunities for the states to provide direction and input or otherwise have their laws and policies appropriately reflected throughout the transmission planning process – all while benefitting electricity customers. First, NARUC supports the development of a long-term planning process to allow stakeholders to evaluate transmission system needs and conditions as the system integrates resources that states want to develop in the future. In some cases, states' energy laws and policies look well beyond the ten-to-fifteen-year timeframe typical for transmission planning studies.[16] A long-term planning approach may well prove more efficient and less costly than continuing with incremental transmission upgrades. Similarly, NARUC supports the integration of various existing planning processes, including regional transmission plans and generation interconnection studies, to provide for more cost-effective transmission development. In considering such an approach, the Commission should consider how current interconnection queue practices—which the ANOPR identifies as fostering the potential for speculative projects[17]—could have implications for system planning to meet reliability needs. Some states view that the intersection of generator interconnection queues and regional planning may better lend itself to longer-term scenario planning than needs assessments for system reliability. It is also critical that any final rule allow for regional flexibility in meeting transmission needs. FERC should refrain from establishing overly prescriptive rules, particularly around the inputs into planning studies and analyses, so that planning processes will be able to accommodate evolving technology, state laws, regulatory structures, and policy preferences.

[16] It is not uncommon for state energy requirements and goals to look out 20 to 30 years, particularly for those requiring ambitious changes. *See* National Regulatory Research Institute's Clean Energy Policy Tracker at https://www.naruc.org/nrri/nrri-activities/clean-energy-tracker/.

[17] ANOPR at PP 41, 135, 138, 153.

Each region has unique attributes and that will require flexibility to develop an approach tailored to its needs.

In this section, NARUC provides specific comments on the following topics: improving the existing transmission planning process; achieving greater transparency in the planning process; renewing the focus on interregional transmission planning; and considering the need for and design of an independent transmission monitor.

1. Improving the Transmission Planning Process

The ANOPR identifies a need to reform existing transmission planning processes in the areas of planning, cost allocation, and coordinating and co-optimizing transmission planning and generator interconnection.[18] NARUC shares the Commission's perspective on the need to reform existing planning processes and is eager to explore many of the potential transmission planning enhancements the ANOPR presents. However, NARUC emphasizes that in undertaking this important task the Commission should not lose sight of the need to ensure that all potential transmission planning reforms explicitly recognize the essential role states, and state laws, play in this process.[19] Regional transmission planning processes must be designed to recognize the key role states play in implementing their individual legal requirements and policies and afford states the ability to craft transmission solutions that comply with those requirements. Some states believe that the Commission can best ensure this occurs by mandating the adoption of broad regional transmission planning principles that allow for flexible

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[18] *See*, ANOPR at P 4.

[19] Comments of the National Association of Regulatory Utility Commissioners, Transmission Planning and Cost Allocation by Transmission Owning and Operating Utilities, FERC Docket No. RM10-23-000 (September 29, 2010) at 4-5.

application of planning mechanisms to accommodate regional diversity while ensuring meaningful participation by states.

NARUC identifies the following set of reforms that are designed to better align transmission planning practices with the states' planning visions and urges the Commission to adopt them as best practices for use in both jurisdictional and non-jurisdictional planning regions.

1. **Increase transparency in the planning process**. Transparency and access to information is indispensable to facilitating meaningful participation by state officials and other stakeholders, including affected communities. Having timely access to planning assumptions, analyses, and results should instill greater confidence in the soundness of the planning process and the basis for recommended solutions. Consistent with NARUC's recommendation below, this material should be presented in a way that is understandable to affected communities. The planning process should provide needed transmission system planning information to the states and region, including high-level cost estimates and initial cost allocation estimates. Likewise, the planning process should share system planning information on an interregional level whenever appropriate.
2. **Assess project viability**. Any transmission planning process should recognize state laws on land use and use of eminent domain in considering constructible project proposals. The planning process should include appropriate opportunities for stakeholders to identify, assess, and evaluate project constructability concerns when planners evaluate potential project locations and alternate routes. To the extent possible, the planning process should include examination of siting

considerations and consider the siting risks to project feasibility, particularly with alternatives that use “greenfield” construction. Transmission planners and developers should be familiar with respective state laws and zoning and land use requirements and should reflect such issues throughout the project development and evaluation process.

3. **Consider transmission alternatives**. Technology and market innovation are major factors driving the introduction of new grid investments and approaches to grid operations that hold the potential to displace traditional transmission investments, unlock untapped existing capacity, and/or enhance grid operations. An effective transmission planning process should maximize the use of existing transmission and build new transmission only where necessary or economic. The planning process needs a clear pathway for consideration of alternative transmission solutions, including grid enhancing technologies, non-transmission technologies, and hybrid programs for efficiency, load control, distributed generation, and storage in the regional planning process.[20] Evaluation of storage resources should also be enhanced to appropriately consider their flexible role as supply and demand that may be uniquely positioned to mitigate the need to develop new transmission assets.[21] Studies used to evaluate storage and other alternative transmission solutions should reflect reasonable operating assumptions, such as charging during off-peak hours.

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20 ANOPR at PP 158, 171, 177.

21 Storage can also be considered as a transmission asset.

4. **Adopt scenario analysis**. The planning process should require detailed analyses for specific scenarios, with the objective being to provide insight into potential future conditions and the types of transmission solutions that can address them. Planning scenarios need to be flexible to reflect the unique characteristics and needs of each region, including: (a) onshore system upgrades, including specific areas that need strengthening; (b) offshore systems that may be needed to support offshore wind resources; (c) the impact of distributed energy resources ("DERs"), both distributed generation and flexible load sources, on transmission needs; (d) availability and siting of new generation, including wind, solar, storage, advanced nuclear, and hydrogen; and (e) the need for transmission upgrades or changes as a result of existing resource retirements. Where feasible and cost-effective, further consideration should be given to expanding transmission planning to include analytic approaches, including probabilistic approaches, that are better able to support multiple risks and planning objectives. Deterministic analysis, which has been historically used in transmission planning, identifies a single outcome for a given set of assumptions. Deterministic analysis can provide important information and is a relatively straightforward analysis to conduct. However, it does not consider the *likelihood* of the outcome—which could be an important factor for assessing need in transmission planning. To the extent that deterministic analyses can be modified to better support multiple risks and planning objectives, these enhancements should be considered. In addition, probabilistic analysis should be used, where feasible without significantly burdening the planning process, to incorporate randomness and uncertainty in

assumptions to produce a probability distribution. That is, where a deterministic analysis will identify a consequence, a probabilistic analysis will identify both the consequences and their likelihood of occurrence, which may allow for a more meaningful, quantitative risk assessment. Incorporating probabilistic approaches can augment existing planning processes by providing more insight into the benefits and risks of different decisions, and the importance and relationship between various uncertainties.[22] This type of information may be particularly relevant for transmission planning that includes anticipated future generation and longer time horizons, both of which will increase the complexity and uncertainty in transmission planning, particularly in the out years.

5. **Integrate interconnection with transmission planning**. Planning processes should seek to align generator interconnection and other needs assessments with broader regional transmission planning processes addressing reliability, economic, and public policy needs. Such alignment may include examination of the need for establishing standardized modeling assumptions. Assessing transmission needs through a more holistic, and less "siloed," process should optimize planning outcomes, result in more cost-efficient investment, and create opportunities to more equitably assign costs.

6. **Identify and quantify benefits**. A sound planning process should ensure all realistic benefits are identified and quantified, where possible. The Commission

[22] EPRI, "Case Studies on Probabilistic Assessment for Transmission and Other Planning Resources." February 23, 2015; Li, Wenyuan, "Probabilistic Power System Planning," Probabilistic Planning Conference of the U.S. Department of Energy, NARUC and Eastern Interconnection States' Planning Council on September 7, 2012.

should require a regular regional planning process that considers the reliability, economic, and policy benefits of every transmission project, including those transmission enhancements and replacements currently planned through individual transmission owners' planning processes that are currently not required for compliance with various regional transmission organization ("RTO") and independent system operator ("ISO") criteria and, therefore, not subject to regional cost allocation and other transmission planning principles expressed in FERC Order Nos. 890 and 1000. Regions should retain flexibility to define and weigh the benefits, allowing planning processes to account for regional differences rather than mandating a "one-size-fits-all" approach that may vary in effectiveness given regional differences.

7. **Enhance the project selection process**. Project selection should strive to provide the highest benefit to cost comparison to the region. Transmission planners should focus on identifying multiple cost-effective possibilities to solve a need and should consider a portfolio of transmission projects, as well as non-wires alternatives to new transmission, to optimize efficiencies, facilitate interconnections, and promote cost containment over a long-term planning horizon. State siting authorities can then consider, in addition to their mandated statutory duties under applicable state law, how those alternatives address state and local considerations like land use, zoning, state law, areas of special concern, equity, environmental justice, and disadvantaged communities. Further, in cases where building new transmission is determined to be the optimal solution,

processes should ensure that planning incorporates long-term state planning strategies and avoids building duplicative facilities.[23]

8. **Recognize and promote cost control efforts**. The planning process should recognize that states and utilities, including distribution utilities, are taking steps to better manage loads and other transmission cost drivers.[24] These efforts should be included in transmission planning to better control costs. For example, the management of emerging loads for transportation and building heating can inform whether new transmission investments are needed. Planners should also use competitive processes to minimize costs to consumers. Further, the planning process should provide regions the flexibility to consider whether mechanisms should be established to ensure that transmission facilities planned for anticipated future generation will be used and useful once constructed and not otherwise subject to abandonment charges. Finally, the planning process should provide regions the flexibility to consider whether participant funding serves as a meaningful mechanism to minimize costs as part of a more holistic transmission planning process that addresses free ridership and other related challenges.

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[23] Some states, such as Mississippi, have periodic transmission plans and associated capital investments that must be reviewed and approved by the state regulator, or, in the case of the public utilities, their board of directors. Many transmission owners' proposed transmission projects are designed to serve multiple purposes; their functionality often cannot be substituted by a regional transmission project proposed by the RTO. A regional project may not be used as a substitute for a transmission owner proposed project unless it satisfies each of the purposes driving the project; otherwise, the result will be multiple projects with duplicate wasteful investment.

[24] *See Investigation by the Department of Public Utilities On Its Own Motion Into Electric Distribution Companies' (1) Distributed Energy Resource Planning and (2) Assignment and Recovery of Costs for the Interconnection of Distributed Generation* (Docket D.P.U. 20-75), Massachusetts Department of Public Utilities.

Additionally, NARUC suggests, when planning processes identify possible projects within properly established "national interest electric transmission corridors,"[25] that federally owned land or grants of right-of-way be made available, when reasonable, for construction of transmission lines determined to be in the national interest. Further, NARUC suggests that legislative or administrative consideration be given to establishing a federal permit coordinator responsible for granting associated federal permits with reasonable time limits. Any such efforts must be focused on improving coordination of the regional transmission planning process with states and state processes, while continuing to recognize that states are usually the ultimate arbiters of what gets built, where it gets built, and how it gets built in accordance with applicable state siting law requirements.

2. Greater Transparency in Transmission Planning

The ANOPR seeks comment on whether current transmission planning processes provide sufficient transparency for stakeholders to understand how best to obtain information about, and fully participate in, the various processes.[26] Current transmission planning processes may not be sufficiently transparent in every region, and NARUC supports the Commission's efforts to enhance transparency for stakeholders participating in such processes. This includes presenting material in a way that is accessible to, and understandable by, affected communities. Greater transparency is particularly important for states in determining how transmission planning processes recognize, account for, and complement state laws and policies. State laws and policies that advance technologies and measures such as renewable portfolio standards,

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[25] 16 U.S.C. § 824p(a).
[26] ANOPR at P 109.

distributed energy resources, demand response, energy efficiency, and energy storage, both drive and depend on effective transmission development. This is one reason why the ANOPR generally recognizes the special role that states play in transmission planning. Absent greater transparency, states cannot effectively fulfill this role and ensure that planning processes properly account for state laws and policies.

As an example, the Commission should further examine how to buttress the way in which local transmission or supplemental transmission projects and regional generation or reliability needs are interwoven. Current methods, such as “do no harm” assessments, are not always sufficient in this regard. In the PJM Interconnection (“PJM”), the models that transmission owners develop to conduct “do no harm” assessments for local and supplemental projects are not subject to regulatory approval and often are at lower transmission voltages to integrate renewables into the grid. Additionally, the generation dispatches and load profiles for such models often differ from those incorporated into PJM’s Regional Transmission Expansion Plan. Improving transparency and oversight would better align these and similar processes.

Moreover, where feasible and cost-effective, transmission planners should provide greater transparency by periodically reviewing proposed projects to verify how likely they are to realize their forecasted benefits. This extends to processes for periodically evaluating aging transmission infrastructure. Such processes must better inform states about the most cost-effective solutions for replacing aging transmission, including whether regional transmission solutions that are equally—or more—robust could be developed alongside other long-term transmission solutions needed for reliability.

Further, NARUC emphasizes the importance of reforming existing transmission planning processes to integrate values of justice and equity. Processes must provide for opportunities to consider the interests of historically disadvantaged communities and should provide flexibility for states to devise mechanisms as needed to advance equity and environmental justice. Planning processes should explore the development of clear metrics to assess impacts on disadvantaged communities and mechanisms to ensure sufficient benefits flow to those communities.

More generally, if the Commission considers additional layers of review—such as an independent transmission monitor—the value of these structures can only be fully realized if they promote transparency. NARUC discusses the prospect of an independent transmission monitor below.

3. Renewed Focus on Interregional Planning

In the ANOPR, FERC seeks comment on potential reforms to the current interregional transmission coordination process and whether such reforms have relevance to the other potential reforms.[27] Although this did not appear to be a primary focus of the ANOPR, NARUC believes enhanced interregional transmission planning may be essential to meet demand for a large-scale clean energy transition, while ensuring rates remain just and reasonable. Substantial interregional transmission investment has not materialized in the years following Order No. 1000 on the scale necessary to support demand for a large-scale clean energy transition. Therefore, some states suggest now may be the time for FERC to provide new clear, high-level federal planning policy, which may include consistent national interregional planning standards. While

[27] ANOPR at PP 62-63.

the individual regions should decide the planning parameters (*e.g.*, requirements, standards, metrics, benefits) applicable to individual regional planning processes, some states suggest there may be a need for FERC to provide guidance and direction in defining interregional planning parameters. NARUC identifies the following areas where such guidance and direction may prove helpful.

First, NARUC believes a forward-looking planning approach should seek to identify resource-rich areas and evaluate the most cost-effective methods of transporting energy from such areas to load centers on a multi-regional level, with possible minimum planning standards or requirements. Regions should be able to craft their own reforms and decide a best course for their stakeholder communities, but there should be guardrails that establish common planning principles to avoid conflicts in interregional planning. FERC, working together with states, should develop such long-term planning principles to help facilitate integration of optimal resources and transmission infrastructure found needed by states to deliver to loads. Examples could be common planning models, minimum standards or requirements for reliability, economic, and public policy projects, cost allocation methodologies that allocate cost to beneficiaries in multiple regions, identification of resource-rich areas, and common market models. While proactive planning is needed, it will also be essential to create consumer protection mechanisms ensuring new transmission investments will be used and useful, if and when they are built.

Maximizing the use of existing rights-of-way could also be a planning principle for interregional or interstate projects. Because certain clean energy resources are diffuse by nature, meaning the resources exist at disparate locations and cannot simply be placed near existing load centers, new transmission facilities may need to be developed to gather and transport energy from generation-rich areas to load. Recognizing state and local siting authority, any prospective interregional transmission project should consider any affected state's preference for maximizing the use of existing rights-of-way, while ensuring that state siting authorities can comply with their legal requirements and fully consider local perspectives.

NARUC also sees a potential for coordination of RTO planning processes in terms of time frames and modeling to achieve better results across the seams through planning studies. FERC seeks comment on whether, because an interregional project must first be selected in each of the neighboring regions' regional planning processes before being selected in the interregional process, this challenge to the current interregional coordination process is impeding the selection and development of efficient, cost-effective interregional projects and, if so, what revisions are necessary to address that barrier. The Southwest Power Pool ("SPP") has experienced this very issue in seams/interregional planning with Midcontinent Independent System Operator ("MISO") regarding their different transmission planning processes and resulting lack of approved seams/interregional projects. The multiple studies and approvals from the different RTO planning processes may have impeded the selection and development of efficient, cost-effective interregional projects. These differences include timeframes for planning studies, modeling, metrics, cost allocation methodologies, how RTOs charge for transmission service, and how the different markets operate. As stated previously, regions should be able to craft their own reforms and decide a best course for their stakeholder communities. However, some states suggest that FERC should investigate creating guardrails that establish common planning principles to avoid conflicts in interregional planning, and potentially including common planning models and timeframes, common standards, requirements, or metrics, common cost allocation methodologies, and common market mechanisms to help address this interregional barrier.

In addition to economic and public policy benefits of interregional transmission, NARUC maintains that reliability benefits may be gained through enhancing interregional import and export capabilities. For example, during Winter Storm Uri in February 2021, SPP relied heavily on imports from MISO and the PJM Interconnection due mainly to lack of available generation in the SPP footprint. Key observation number four in SPP's Comprehensive Review of SPP's Response to the February 2021 Winter Storm states that "[r]elationships and interconnections with neighboring systems were critical. Usually a net exporter of energy, SPP relied significantly on imported energy to serve load during the winter event, with net amounts exceeding 6,000 megawatts (MW) at times. This emphasizes the value these relationships and robust transmission interconnections provide during emergency events and the opportunity to further strengthen them."[28] Effective planning should strive to quantify benefits associated with enhancing interregional import and export capabilities, given the likelihood of future extreme weather events and related energy shortages. Further analysis and process improvements in interregional transmission development and imports and exports capability will be necessary, not only to accommodate demand for a clean energy transition, but also for reliability and defined resiliency benefits.

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[28] Southwest Power Pool, *A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations*, V. 1.0 (July 19, 2021) at 9, https://spp.org/Documents/65037/Comprehensive%20Review%20of%20SPP's%20Response%20to%20the%20Feb.%202021%20Winter%20Storm%202021%2007%2019.pdf.

4. Independent Transmission Monitor

The ANOPR seeks comment on whether it would be appropriate for the Commission to institute reforms that would require, among other possibilities, that transmission providers in each RTO/ISO establish an independent entity to monitor the planning and cost of transmission facilities in each region.[29] NARUC recognizes that it may be beneficial for the Commission to further develop these proposed reforms and establish independent transmission monitors. NARUC is interested in the allocation of resources to assist the Commission in its role overseeing transmission costs. NARUC looks forward to learning more about whether and how this proposal could assist the Commission in serving end-use consumers as a cost containment mechanism. The concept and role that the Commission envisions for transmission monitors is, at this time, unclear. NARUC has several questions about this role, including whether an independent transmission monitor would assume the current role of, or provide a check on, RTO/ISOs in the following areas: (1) recommending improvements to the planning process; (2) evaluating competitive transmission proposals and alternatives; (3) analyzing cost overruns; (4) providing planning and cost information to stakeholders; (5) verifying prudency, costs, and benefits of proposed projects; and (6) validating the physical constructability of proposed projects. In no case, though, should an independent transmission monitor be empowered to replace or oppose state decisions on approval or siting of any project.

The ANOPR also proposes that an independent transmission monitor could make referrals to the Commission in certain situations, and that the Commission could then conduct a review of referred transmission planning processes and/or transmission facility costs under

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[29] ANOPR, at PP 110-117.

section 206 of the FPA.[30] NARUC encourages the Commission to provide additional details on this proposed process, including how the internal transmission monitor's authority may differ from that retained by ISO/RTOs, whether the internal transmission monitor itself would have filing rights under section 206 of the FPA, and governance and structural relationships between existing entities and the independent transmission monitor.

Finally, NARUC questions whether the Commission has the authority to order an independent transmission monitor in areas that do not fall under the purview of the seven ISO/RTOs currently operating in the United States, and if the Commission has the authority, the role of the independent monitor in reviewing the work of regional planning organizations.

B. Cost Allocation

1. Cost causation and beneficiary pays principles

NARUC acknowledges FERC's concern that during the decade since the Commission issued Order No. 1000, the electricity sector resource mix has continued to evolve and that the differing characteristics of those resources are creating new demands on the electric transmission system. NARUC agrees that ensuring just and reasonable rates as the resource mix changes, while maintaining grid reliability, remains the priority of its member states. As FERC reviews the efficacy of Order No. 1000, NARUC urges the Commission to retain the foundational principle that transmission costs should be allocated commensurate with benefits.[31]

Order No. 1000 adopted the following six regional cost allocation principles that have been implemented by RTOs/ISOs and regional transmission planning organizations across the

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30 ANOPR at P 111.

31 Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 639.

country in a way that accommodates the regional, operational, and policy considerations of the transmission planners' members:

1. Costs of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits;
2. Those that receive no benefit from transmission facilities must not be involuntarily allocated any of the costs of those transmission facilities;
3. A benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1;
4. Costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs;
5. The method for determining benefits and identifying beneficiaries must be transparent; and
6. There may be different methods for different types of transmission facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.[32]

These regional cost allocation principles grounded in a beneficiary pays methodology have withstood judicial scrutiny[33] and resulted in an increased involvement by various stakeholders in regional transmission planning processes. The beneficiary pays principle has been adopted in the various RTOs/ISOs, as implemented in MISO's Multi-Value Projects ("MVPs"), PJM's Multi-Driver and State Agreement Approach options, and SPP's Balanced Portfolio process, to name a few. Rather than being siloed, the different approaches to implementation of the beneficiary pays principle reflect variations in each region with respect to the relative weight and consideration given to different drivers by the regions' respective stakeholders. They also reflect the regional transmission planners' consideration and adoption of Order No. 1000 planning principles 2, 5, and 6 in a way that has achieved crucial stakeholder support. The Commission

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32 Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 637, 646, 657, 668, 685.

33 *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

should not lightly revise the six foundational cost allocation principles embodied in Order No. 1000 absent clear evidence that they have failed to achieve just and reasonable rates.

NARUC also urges the Commission to retain its foundational cost causation principle applicable to network upgrades resulting from generator interconnections absent an overwhelming agreement by stakeholders to approve variations to currently applicable rules. Rather than embark on a full-scale revision to the rule, FERC should retain the core tenet of participant funding, while exploring the as yet untapped potential economies of scale that could result from increased coordination among participants. For example, the Commission may encourage improvements to the participant funding model that allow for the development of network upgrades and the sharing of their costs in "clusters" by similarly situated interconnecting generators in the interconnection queue and in geographical proximity. Regional transmission planners are especially well-situated in identifying appropriate "interconnection cluster zones" and notifying potential developers of the opportunity to explore joint funding arrangements. Such arrangements would also lessen the incentive to submit multiple generator interconnection requests by a single developer and result in more streamlined and efficient operations by the regional transmission planner. As explained more fully below, the Commission should explore further improvements to the participant funding model instead of directing its removal.

2. Cost responsibility for public policy requirements

The implementation of Order No. 1000 in the different regions has resulted in slight variations of cost allocation methodologies for projects driven by state public policy requirements, but such variations reflect the reasoned agreement by the regions' stakeholders, as well as different levels of the states' participation in regional transmission planning. For example, MISO's MVP methodology is not only the product of its stakeholders' agreement, but also that of the Organization of MISO States' ("OMS") active participation in the regional transmission planning process as voting members. The initial round of MVPs was approved 10 years ago in 2011, with a portfolio of transmission projects in every OMS state, with a benefit-to-cost ratio of 1.0, and an energy-based postage stamp cost allocation. By contrast, the PJM states are not voting members of PJM, but the majority have reached an equally valid agreement that the burden for costs driven by public policy requirements of one state should not be placed on customers of load serving entities in non-participating states. This agreement, called the State Agreement Approach ("SAA"),[34] does not preclude cost sharing where there are multiple drivers for a project, such as economic, reliability, or public policy, and allows for pro-rata cost allocation incrementally.[35]

Also, to alleviate dramatic customer rate impact to participants, planners could provide a platform for multi-state planning for states with complimentary or mutual requirements or goals to allow for cost allocation among states with similar public policy goals. Where states have enacted such individual state policy standards, the SAA,[36] embedded within the PJM Operating Agreement, provides an example of how state goals can be timely accommodated within the context of transmission planning and cost allocation.

[34] PJM Operating Agreement, Schedule 6 Sec. 1.5.9.

[35] *See* PJM Operating Agreement, Schedule 6 Sec. 1.5.10.

[36] "State governmental entities authorized by their respective states, individually or jointly, may agree voluntarily to be responsible for the allocation of all costs of a proposed transmission expansion or enhancement that addresses state Public Policy Requirements identified or accepted by the state(s) in the PJM Region. . . . All costs . . . shall be recovered from customers in a state(s) in the PJM Region that agrees to be responsible for the projects. No such costs shall be recovered from customers in a state that did not agree to be responsible for such cost allocation. . . ." PJM Operating Agreement, Schedule 6, Sec. 1.5.9.

The SAA is based on the principle that the cost of one state's public policy projects should not be paid by customers in non-participating states. The SAA was supported by the Organization of PJM States, Inc. ("OPSI") and, while not unanimous, by the majority of the PJM states.[37] New Jersey is the first state within the PJM footprint to request that PJM initiate project solicitations under the SAA. There is no evidence that the SAA cannot successfully implement construction of the transmission needed to effectuate the public policies of a single or like-minded states. Rather than abandon this planning tool, most states urge that more should be done to encourage and incent states with similar public policy profiles to use the SAA. The SAA has the benefit of being a stakeholder-driven product that enjoys significant state support.[38] PJM's SAA and multi-driver options, as well as MISO's multi-value process offer examples of just and reasonable mechanisms for states to fund and construct their public policy driven transmission projects. Such widely supported agreements should continue to be used rather than abandoned.[39]

3. Maintaining regional flexibility of transmission planners

Transmission planners should be provided with the flexibility to establish appropriate definitions of benefits and beneficiaries that make sense for their respective regions. This flexibility would allow planners to accommodate the unique policies, topology, and generation types that exist and encourage innovation in this space. As the electric system evolves, so too

Motion to Intervene and Comments of the Organization of PJM States, Inc., Docket No. ER13-198 (December 10, 2012). Maryland and the District of Columbia filed protests to the SAA.

38 Resolution # OPSI-2012-1, Organization of PJM States, Inc. (January 5, 2012), https://opsi.us/wp-content/uploads/2018/08/OPSI-2012-1.pdf.

39 *See* Compliance Filing of PJM Interconnection, LLC, Docket No. RM10-23-000 (October 25, 2012); Compliance Filing of PJM Interconnection, LLC, Docket No. ER13-198-002 (July 22, 2013).

will the demands customers place on it and the benefits received by those customers. Regions should retain the flexibility to develop innovative approaches to allocating the costs associated with projects needed to maintain reliability and maximize benefits throughout this period of evolution. Attempting to prescribe these benefits in a one-size-fits-all approach would preclude this type of creativity, limit innovation in this area, and restrict the development of new approaches.

While overly specific requirements are not appropriate, it may be appropriate for the Commission to provide broad guidelines that would assist transmission planners to identify the types of benefits and methods of assessment the Commission would find acceptable. These types of guardrails can lend certainty to the stakeholder process and ensure some level of similarity between regions, which could help alleviate potential conflicts with interregional project cost allocation.

4. Importance of quantifiable or verifiable benefits

As stated above, NARUC urges the Commission to retain the foundational principle that transmission costs should be allocated commensurate with benefits and to maintain the six cost allocation principles. Using these cost allocation principles, customers of load-serving entities should only be required to pay the costs of regional transmission facilities that provide them with quantifiable or verifiable benefits. In this vein, NARUC further urges the Commission to heed the holding of the United States Court of Appeals for the Seventh Circuit that the costs of transmission projects must be allocated *at a minimum* in a way that is "roughly commensurate" with the benefits to the party bearing the costs, based on record evidence.[40] The Commission

[40] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009); *see also Ill. Commerce Comm'n v. FERC*, 756 F.3d 556, 559 (7th Cir. 2014).

must establish guidelines or a methodology to ensure transmission planning organizations or RTOs/ISOs engage in some form of cost-benefit analysis so that the transmission project's costs are allocated proportionally to the benefits of the project. A claim of generalized system benefits unsupported by evidence of the quantity or existence of the benefit is too speculative to meet the current standard.[41] Transmission facilities built to benefit primarily one region should not be allowed to shift a disproportionate share of their costs to another region's utilities' customers on which the transmission project will confer only future, speculative, or limited benefits.[42] To do otherwise violates established cost causation and cost allocation principles resulting in unjust and unreasonable rates. Additionally, if the Commission permits planners to stray from these well-established principles, the risk increases of both unneeded transmission and unjust and unreasonable costs of transmission.

NARUC cautions the Commission that any move away from the six regional cost allocation principles adopted in Order No. 1000, where costs of transmission facilities are allocated roughly commensurate with estimated, verifiable benefits may lead to less transmission being built. The siting of transmission facilities, with the exception of FERC's limited backstop siting authority, is within the states' jurisdiction. Under most states' laws, to obtain siting approval for a transmission line, the developer must obtain a certificate of public convenience and necessity from the state utility regulatory agency, and accordingly must prove that the transmission project, and its costs, is in the state's public interest. In other words, states may be reluctant to site transmission where the applicant has not articulated quantifiable, verifiable benefits.

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41 *Id.* at 476, citing *Transcontinental Gas Pipe Line Corp.*, 112 F.E.R.C. P 61,170, 61,924-61,925 (2005).

42 *Id.* at 565; *Ill. Commerce Comm'n v. FERC*, 756 F.3d 556, 565 (7th Cir. 2014).

For instance, in 2018, Transource Pennsylvania LLC ("Transource") applied to the Pennsylvania Public Utility Commission ("PAPUC") to build high-voltage lines across Pennsylvania as part of a market efficiency project approved by PJM to alleviate congestion outside of Pennsylvania. The Office of the Consumer Advocate presented evidence, using Transource's own projections, that between higher projected wholesale prices and the costs to construct, operate, and maintain the line, Pennsylvania's ratepayers received little benefit from the project.[43] The evidence also showed that from the time the project was approved by PJM to the time it was presented for adjudication to the PAPUC, the level of congestion that the project was designed to reduce had dramatically decreased while the project's costs had almost doubled. In upholding the denial of the certificate of convenience, the PAPUC considered the negative impact on Pennsylvania consumers along with the regional need for the project, and found that Transource had not met its burden of proof.[44] In contrast, where the regional benefits of a proposed transmission project have been demonstrated to exist, states have supported the accomplishment of the regional planning goals in the course of their state siting reviews, as demonstrated by the approval of the Trans Allegheny Interstate Line by Pennsylvania, Virginia, and West Virginia.[45]

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[43] Opinion and Order, *Applications of Transource Pennsylvania, LLC for approval of the Siting and Construction of the 230 kV Transmission Line Associated with the Independence Energy Connection – East and West Projects in portions of York and Franklin Counties, Pennsylvania*, A-2017-2640195, A-2017-2640200, at 36-39 (Pa. PUC May 24, 2021).

[44] *Id*. at 52-64.

[45] *See In re: Application of Trans-Allegheny Interstate Line Co.,* Docket No. A-110172 (Pa. PUC December 12, 2008); 2008 SCC Ann Rep't 366, JOINT APPLICATION OF VIRGINIA ELECTRIC AND POWER COMPANY D/B/A DOMINION VIRGINIA POWER, and TRANS-ALLEGHENY INTERSTATE LINE COMPANY; APPLICATION OF TRANS-ALLEGHENY INTERSTATE LINE COMPANY, Case No. PUE-2007-00031, 2008 WL 4572266, 2088 SCC Ann. Rep't 366 (Oct. 7, 2008); TRANS-ALLEGHENY INTERSTATE LINE COMPANY Application for a Certificate of Convenience and Necessity authorizing the construction and operation of the West Virginia segments of a 500 kV electric transmission line and related

5. Protection from broad estimates of transmission benefits

As previously mentioned, planning transmission facilities to meet the needs of anticipated future generation is complex; with the type, size. and final location of generation resources being subject to several variables, including state siting processes, technology costs, system hosting capacity, proximity to demand, and resource capacity factors. In fact, states observe that integrated resource plans ("IRPs") that plan resources for 5, 10, and 15 years out often change considerably in intervening years. If the Commission considers establishing a framework that requires transmission providers to consider the transmission needs of anticipated future generation, it should ensure that mechanisms are in place to protect ratepayers from transmission cost assignments that are based on the benefits of transmission projects driven by anticipated future generation resources that never materialize. To mitigate the likelihood that such projects are planned, state regulators specifically should be involved in developing futures scenarios to ensure that reasonable assumptions are made for key scenario-planning inputs such as generation siting and load forecasts. The Commission should also consider requiring periodic project benefit reviews and ensure that cost allocation frameworks are as dynamic as the electric system itself.

The Commission should further ensure that electricity customers are protected from broad, indirect, or generalized cost allocation methodologies or transmission costs driven by non-national public policy goals of other states or utilities. State regulators are concerned these methods can potentially create out-of-state resource subsidies and cost shifting to ratepayers who will not receive roughly commensurate benefits with their assigned costs, as well as potentially

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facilities in Monongalia, Preston, Tucker, Grant, Hardy, and Hampshire Counties, and for related relief, CASE NO. 07-0508-E-CN (Aug. 1, 2008).

incentivizing the buildout of uneconomic or otherwise less beneficial generation resources. Given the diversity in resource needs and preferences and future resource plans of states, it is important that the costs and benefits of transmission are considered in conjunction with the costs of future generation to ensure all-in costs are just and reasonable. However, NARUC also recognizes that a distinction exists between projects advanced to achieve specific non-national public policy goals, and those projects needed to maintain system-wide reliability during a period of resource transition, much of which is being driven not by public policy objectives, but because of advances in technology, reductions in cost, and customer demand. In working to limit one state subsidizing another, the Commission should avoid an overly broad definition of non-national public policy goals that would place additional barriers in the way of those projects that are simply reflecting the broader resource shift that is well underway, including projects needed to maintain the reliability of the grid as older and/or more expensive generation assets are retired and replaced by newer and/or less expensive alternatives.

6. Importance of participant funding model

As noted previously, NARUC urges the Commission to retain the participant funding model applicable to network upgrades resulting from generator interconnections. The participant funding model allocates the cost of transmission network upgrades required to interconnect a new generation asset based on the principle that the cost-causer should pay for transmission system upgrades that would not be required "but for" its interconnection on the power grid. The participant funding "but for" model recognizes that interconnection costs should be part of the generator's cost of doing business to align costs with the party best positioned to control those costs and benefit from them.

NARUC recommends the Commission refer to Order No. 2003, in which the Commission reasoned that "a well-designed and independently administered participant funding policy for Network Upgrades offers the potential to provide more efficient price signals and more equitable allocation of costs than the crediting approach."[46] With participant funding, the generator has the incentive to locate the project where it can interconnect most efficiently. The Commission reaffirmed this position when it approved PJM's Order No. 2003 compliance filing, holding that "the 'but for' method [PJM] uses to determine what payments must be made by an Interconnection Customer provides incentives to locate new generation in an efficient fashion."[47]

Contrary to the apparent presumption in the ANOPR, some state commissions' experience is that the network upgrades needed to allow generation interconnection do not provide benefits to transmission customers as a whole. As the National Rural Electric Cooperative Association and the American Public Power Association commented in the docket in which Order No. 2003 was issued, if generators are not required to pay for network upgrades, then the costs are "borne by transmission customers even in instances where reliability is not enhanced by the new transmission facilities, or where no Network Customers have contracted for power that requires such facilities."[48]

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[46] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 104 FERC ¶ 61,103 (2003) at P 695, *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

[47] Order Accepting Compliance Filing Subject to the Filing of Certain Revised Tariff Sheets, 108 FERC ¶ 61,025, at 19 (July 8, 2004).

[48] Comments of the National Rural Electric Cooperative Association and the American Public Power Association on the Advance Notice of Proposed Rulemaking and January 11, 2002 Standard Generator Interconnection Operating Agreement and Procedures, Docket No. RM02-1-000 at 15 (Feb. 1, 2002).

The Commission also has recognized that participant funding for network upgrades is "part of a project's construction cost and business risk, and the Interconnection Customer must consider those cost[s] in determining whether the project is economically worthwhile."[49] "'But for' pricing is consistent with the Commission's policy of promoting competitive wholesale markets because it causes the Interconnection Customer to face the same marginal cost price signal that [ ] it would face in an efficient, competitive market."[50] If the generator does not expect to earn enough to cover the full all-in costs of the project, then the generation is not economical and should not be built.

When the Commission required public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to file standard agreements and procedures for interconnecting generators, it did so to "encourage needed investment in generator and transmission infrastructure."[51] In the current regulatory context, the participant funding model is the best way to ensure that new generation is needed.

In urging the Commission to retain the participant funding model, NARUC also advises that it may be appropriate for FERC to explore variations within the participant funding model. Currently, the first generator seeking interconnection that results in the need for a transmission network upgrade is allocated all of the transmission upgrade costs even though later-in-time interconnection customers may benefit from such network upgrades. Accordingly, it may be appropriate for FERC to explore revisions to this first-to-cause cost allocation within the participant funding model. Appropriate models that may allow for a more efficient and fair

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49 Order Accepting Compliance Filing Subject to the Filing of Certain Revised Tariff Sheets, 108 FERC ¶ 61,025, at 20 (July 8, 2004).

50 Order No. 2003 at P 702.

51 Order No. 2003 at P 12.

process could include, but are not limited to, the following: studying collectively all interconnections at a particular area on the grid; allocating the interconnection costs among the group; and modelling assignment of a portion of costs to later-in-time interconnection customers interconnecting in geographical proximity of the first interconnecting customer.

C. Generator Interconnection

The existing methods for interconnecting new resources to the transmission grid are inadequate and inefficient because of the time necessary to interconnect new resources and the corresponding network upgrade costs. The Commission should examine alternatives to current interconnection processes and seek just and reasonable solutions with regard to decreasing the timelines and avoiding excessive network upgrade costs for the interconnection of new resources.

According to analysis from Lawrence Berkeley National Laboratory ("LBNL") for the four RTOs/ISOs where data were available, the average approximate time projects spent in the Generation Interconnection Queues ("GIQs") increased from 1.9 years for projects built in 2000-2009 to 3.5 years for projects built from 2010 to 2020.[52] A near doubling of the time spent in the GIQs for projects demonstrates that the length of time of the queue process is a problem that merits study by this Commission. LBNL also found that the median project with an executed Generation Interconnection Agreement ("GIA"), but not yet built, has spent 1,387 days in the GIQ.[53]

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52 Joseph Rand, Mark Bolinger, Ryan Wiser, Seongeun Jeong for Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2020* (May 2021) at 3.

53 *Id.* at 16.

The cost to interconnect new resources to the transmission grid is similarly problematic. LBNL compared interconnections costs for already constructed projects with interconnection costs for proposed projects in MISO and PJM across various generation types.[54] The data demonstrate that new projects incur significantly higher interconnection costs than existing projects. LBNL sought to separate point of interconnection costs with bulk transmission system upgrade costs to separate costs related to insufficient transmission capacity from other interconnection costs. In a recent publication, Americans for a Clean Energy Grid[55] discussed the LBNL analysis and offered data from SPP, the New York Independent System Operator ("NYISO") and ISO New England Inc. ("ISO-NE"). As discussed, NARUC recommends the Commission review the costs of network upgrades for interconnections of new resources.

Interconnection problems are particularly challenging in the SPP footprint. As of June 17, 2021, the SPP Generator Interconnection ("GI") backlog of requests comprised seven Definitive Interconnection System Impact Study clusters representing 533 individual GI requests and over 100,000 MW of generation capacity. The quantity of capacity in the SPP GIQ far exceeds the amount of load within the SPP footprint. Without additional GIQ reforms, it is expected that it could take at least 8 years or more for SPP to complete all current and future backlogged interconnection studies.[56]

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[54] Will Gorman, Andrew Mills and Ryan Wiser for Lawrence Berkeley National Laboratory, *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy, at 10-12, October 2019.*

[55] Jay Caspary, Michael Goggin, Rob Gramlich and Jesse Schneider, Americans for a Clean Energy Grid, *Disconnected: The Need For A New Generator Interconnection Policy,* 13-18, January 2021.

[56] Southwest Power Pool, Strategic & Creative Engineering of Integrated Planning Team (Script): Report and Recommendations (Aug. 26, 2021) at 97. Available at: https://spp.org/Documents/65274/20210827%20SCRIPT%20Revised%20Combined%20Report%20DRAFT.docx.

SPP staff engaged stakeholders through the Strategic & Creative Re-engineering of Integrated Planning Team, the Generation Interconnection Users Forum, and ad hoc discussions with generation developers and various SPP members to create a process to address the GI backlog and a package of additional GI queue reforms to specifically target reducing, and ultimately clearing, the GI backlog. The proposed GI queue reforms that resulted from SPP's stakeholder process include:

1. Reduced restudies through development milestones;
2. Increased financial commitments; and
3. Simplified and reduced study timelines.

SPP members and the Board of Directors approved these additional reforms in July 2021 and the SPP members and board are expected to vote on GI procedures to implement the reforms in October 2021. As FERC studies improvement to the interconnection process, early data from SPP's most recent queue reform effort will be insightful.

At this stage of the ANOPR process, NARUC offers the following possible ideas to resolve the interconnection problem while acknowledging that consensus does not yet exist and these potential solutions require further study.[57]

1. NARUC supports the Commission investigating the option for an exception to the GIQ that would allow for "fast-track" interconnections to prioritize resources and locations that are consistent with and intend to advance state public policy goals. For example, the PJM SAA, discussed in the previous section, could be a foundation of "fast-tracking" interconnections to prioritize resources to advance state public policy

[57] NARUC offers these potential solutions in no particular order, *i.e.*, the order does not indicate priority or likelihood of reaching consensus.

goals.[58] The SAA has been approved by a majority of the states in PJM to support transmission projects driven by public policy requirements identified through PJM's Regional Transmission Expansion Planning process. Another example from PJM, but one that is not yet approved, would allow an individual state to request an RTO/ISO to fast track their resources through the GIQ when the RTO's/ISO's normal interconnection process cannot meet a state's required timeline. In this situation, PJM's Operating Agreement would allocate the corresponding network upgrades directly to the Interconnection Customers ("ICs") or to that state's transmission customers.

2. NARUC supports additional review of the fast-track option for an IC. Increasing the size of the generator on transmission lines greater than the current limits in the fast-track option may connect more resources to the Bulk Electric System ("BES"). The appropriate generation MW limits and transmission kilovolt limits for a fast-track approach should be determined after study and input from stakeholders.

3. NARUC supports instituting more site control requirements for ICs across the United States such as those in place in MISO and SPP. Under MISO's generator interconnection process ("GIP"), the IC must provide site control demonstration and attach it to the GIR, stating that it either (1) possesses site control for the project; or (2) is presently subject to regulatory restrictions that preclude the IC from obtaining site control for the project.[59] By contrast, ISO-NE and NYISO require demonstration

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[58] Amended and Restated Operating Agreement of PJM Interconnection, LLC (July 14, 2011) Schedule 6, Section 1.5.9 at 590.

[59] MISO FERC Electric Tariff, Attachment X, Site Control, Sections 7.2.1.1 and 7.2.1.2. https://www.misoenergy.org/legal/tariff/.

of Site Control, or an additional $10,000 deposit in lieu of demonstration of Site Control for their large generator interconnection requests ("GIRs"). Under such a process, by paying a flat fee of $10,000 instead of providing documentation of site control, the ICs can insert numerous projects in the GIQ, waiting it out through the definitive planning phases and system impact studies to determine which site has the lowest network upgrade costs. As this is not an effective method of managing a GIQ, NARUC recommends the Commission include more site control requirements.

4. NARUC supports the Commission considering whether a more uniform online GIR process is possible across all RTO/ISOs to make the GIR process simpler and more accessible. A review of GIR processes on RTO/ISO webpages (California ISO ("CAISO"),[60] MISO,[61] ISO-NE,[62] NYISO,[63] SPP, [64] and PJM[65]) highlights that they are all unique and different. Notably, the SPP GIR process includes an online checklist that steps the IC through the interconnection service request process, listing all the required documentation for the executed study agreement, demonstration of site control, financial requirements, other required information, and how to submit a GIR. Simplifying the GIR process and making the process electronic and more

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60 CAISO Generator Interconnection: A streamlined process for interconnecting generating facilities, http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx.

61 MISO Generator Interconnection, https://www.misoenergy.org/planning/generator-interconnection/.

62 ISO-NE Interconnection Service, https://www.iso-ne.com/system-planning/interconnection-service.

63 NYISO Interconnection Process, https://www.nyiso.com/interconnections.

64 SPP Generator Interconnection Submission Check List, https://opsportal.spp.org/documents/studies/SPPGIRCHECKLIST.pdf.

65 PJM Interconnection New Service Requests, https://www.pjm.com/planning/services-requests/new-service-requests.

accessible would help reduce the GIP timeline, as all the required documents, site control, and financial payments would be completed prior to entering the GIQ.

5. NARUC recommends that FERC encourage more cooperation, coordination, and communication between neighboring states and RTO/ISOs on all interregional seams to minimize the time of the affected system study results, require timelines for GIQs, and make additional process improvements as described previously. An example of effective cooperation, coordination, and communication between the neighbors on an interregional seam is the MISO-SPP Joint Study initiative, in which all parties are working conscientiously on GIQ coordination and communication through the Joint Targeted Interconnection Queue Study. [66]

6. NARUC recommends that FERC encourage the RTO/ISOs to better align the regional transmission planning process and the respective GIQs. As the Commission identified in the ANOPR, GIPs at RTO/ISOs across the county are delayed due to issues such as delayed affected system studies from a neighboring region, speculative projects in the GIQ, and expensive network upgrade costs for ICs, resulting in numerous projects dropping out of queues and RTO/ISOs rerunning the study. One way to address these issues is for the Commission to encourage RTO/ISOs to use the same modeling assumptions in their GIP as they do within their regional transmission planning process.

[66] SPP-MISO 2021 Joint Targeted Interconnection Queue Study: Scope of Work, Version 1 (Feb. 19, 2021), https://spp.org/documents/64101/spp-miso%20jtiq%20detailed%20scope%2002192021%20final.pdf.

7. NARUC recommends that the Commission continue to apply the participant funding model for network upgrades driven by ICs as provided in Order No. 2003.[67] Under that model, the IC pays for the network upgrade needed to maintain reliability, such as relieving a thermal or voltage violation, with the interconnection of its generation resource. The IC gets access to the BES at a nominal upgrade cost, and customers pay for the transmission service from the generation resource to the load. This rule has been in place for almost two decades, and has resulted in fair and reasonable impact to both ICs and ratepayers.
8. As noted in the sections on transmission planning and cost allocation, NARUC recommends streamlining the interconnection study process to conduct interconnection studies in batches or "clusters." Under this approach, generators that have filed GIRs in the same geographic area of the electric grid may be evaluated in the same study rather than on a first-come, first-served basis. This approach provides two tangible benefits.

   First, and most visibly, performing a single study for a batch of GIRs reduces the amount of time and resources for ICs, transmission operators, and RTOs/ISOs that would otherwise be spent performing sequential, project-by-project studies. Historically, RTOs/ISOs have faced both staffing and technological limitations that delay the completion of interconnection studies.[68] Grouping such studies in this

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67 Order No. 2003, 104 FERC ¶ 61,103 at P 679.

68 ISO/RTO Council Whitepaper on Interconnection Queue Management Process submitted as Comments of the ISO/RTO Council, *Interconnection Queuing Practices* (Docket No. AD08-2-000) (Jan. 10, 2008) at 11.

manner could help to streamline the process and optimize usage of those limited resources.

Second, using a "cluster" study approach may provide a mechanism to alleviate the cost burden placed on a single generator. The cost of network upgrades identified in a "cluster" study may be shared across multiple projects. As a result, a single project would not pay the disproportionate share of upgrade costs where multiple generators seeking to interconnect in the same general area of the electric grid might benefit from such upgrades. This could reduce the number of projects that drop out of the queue and refile later, which the Commission has noted exacerbates queue delays.

While the "cluster" study approach provides tangible benefits, there are also limits to these benefits. Such studies are only viable in locations where multiple generators are planning to interconnect in the same general area of the grid. Further, the ability to spread costs across projects may be limited by the number of projects seeking to interconnect in a particular geographic area, and such costs may still be too high for one generator to absorb. As such, this approach may reduce some of the interconnection queue burden, but likely will need to be paired with other potential solutions to maximize the benefit.

9. NARUC supports improvements in computational processes to improve the speed or efficiency of the conduct of system impact studies and increased staffing dedicated to performing interconnections studies. Notwithstanding the improvements to be gained through computing processes, if the barrier to increasing the efficiency of the GIQ meaningfully is not the inadequate speed of performing system impact studies, then it

could be a lack of dedicated staff to conduct the studies. Thus, NARUC supports FERC examining both the processes and personnel levels for such studies.

10. NARUC supports better coordination of projects in the GIQ with long-term planning forecasts to help evaluate viability. States across the country are enhancing their long-term planning models to better evaluate changes in the electric grid that will result in the development of new transmission and generation resources. The lessons learned and data that these planning exercises produce could be applied to the GIP when RTO/ISOs and regional planning organizations are assessing projects currently in the GIQ and to better plan for future GIRs.

    In particular, such information could help RTO/ISOs better assess the level of new generation resources that likely will be developed to meet reliability and economic requirements, as well as public policy goals. In turn, this information could help the RTO/ISOs determine whether additional modifications to the GIQ are needed to accommodate such future GIRs. Although this may provide limited benefit in the short-term because it will not clear out immediate GIQ backlogs, the true benefit likely will be realized in the long-term as such information may help RTO/ISOs plan for GIRs that could exacerbate existing GIQ delays.

    One source of such long-term planning data is utility IRPs. These documents are assessments of future or anticipated load shapes and generation needed to meet future load. They evaluate and model multiple future scenarios and provide a great level of detail regarding the addition of potential new generation resources as well as asset retirements that may be forthcoming. The IRPs also often model state policy requirements such as renewable portfolio standards or carbon-free energy requirements that may signal a state-level or regional buildout of significant new generation resources that may result in interconnection requests. While some utilities in RTO/ISO regions do not conduct IRPs, transmission planning in those regions could benefit from using such future-focused data to better evaluate and plan for what may be significant new interconnection requests in the coming years.

A potential vehicle for this information flow could be the "integrated" planning processes either being contemplated or already implemented by various states, which combine distribution level planning with transmission level planning, or variations of these processes that may directly integrate with RTO/ISO transmission planning.[69] Such comprehensive integrated planning processes could provide the necessary information to achieve the benefits described above. Integration of these data sources also would provide increased transparency between state resource planning and regional transmission planning.

Additionally, the GIP often proceeds separately and independently from the transmission planning process. The transmission planning process typically does not model transmission projects that could enable the interconnection of new generator resources, but typically evaluates only those projects that have received executed GIAs or are well on their way toward achieving such agreements. However, because GIQ delays impede projects from reaching the agreement stage, the number of new generator projects that are modeled may represent just a fraction of the number of projects that are projected in state level IRPs to meet reliability, economic, or other

69 *See* NARUC-NASEO Task Force activity on Comprehensive Electricity Planning, https://www.naruc.org/taskforce/.

> public policy considerations. As such, RTO/ISOs should consider ways to integrate their transmission modeling efforts to evaluate multiple future scenarios for projected new generation resources beyond those projects that are currently in the queue. This could help to streamline both the evaluation of future GIRs and the evaluation of needed transmission resources to accommodate such requests.

NARUC recognizes that these suggestions for how to improve GIQ constraints and delays will be of limited use without the addition of transmission lines to transfer the energy. As excess transmission capacity is depleted, the cost of interconnection begins to include the costs for transmission upgrades. The benefits of faster generation interconnection may be limited unless paired with efforts to facilitate energy imports and exports among regions, *i.e.*, transmission planning. Solving any single generator interconnection issue will not independently solve the larger dilemma of transmission planning and construction.

D. Cost Containment

As the Federal Power Act requires,[70] and the ANOPR emphasizes,[71] "the priority" for potential reforms to the regional transmission planning, cost allocation, and generator interconnection processes to accommodate resource mix changes while maintaining grid reliability must be to ensure that the resulting rates for transmission customers are just and reasonable. NARUC agrees that the potential influx of investment in the transmission system

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70 *See* ANOPR, Chairman Glick and Commissioner Clements concurrence at P 11 (citing *California ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1017 (9th Cir. 2004); *City of Chicago v. FPC*, 458 F.2d 731, 751 (D.C. Cir. 1971) ("[t]he Commission must vigorously oversee the rules governing how transmission projects are planned and paid for if we are to satisfy our responsibility to protect customers from excessive rates and charges.").

71 ANOPR at PP 3, 43. See also *id*. at PP 41, 84, 99, 122, 159.

"underscores the importance of ensuring that ratepayers are not saddled with costs for transmission facilities that are unneeded or imprudent."[72]

In this section, NARUC provides specific comments on the importance of containing transmission costs that address the following topics: the need for enhanced oversight of transmission, including adherence to a set of best practices to better contain transmission costs and consideration of the benefits of establishing Independent Transmission Monitors charged with oversight of transmission spending; the potential need for reform of Order No. 1000 competitive processes and transmission planning requirements; and the eligibility of projects for electric transmission incentives.

1. Need for Enhanced Oversight of Transmission Spending

a. Transmission Costs Already Significantly Contribute to Customers' Retail Bills.

As Commissioner Christie has previously emphasized, "transmission costs are *already* a significant and rising part of consumers' retail bills."[73] Over the past two decades, annual spending by major U.S. electric utilities on transmission investment has increased dramatically and the upward trajectory is projected to continue. According to an April 2019 report produced by The Brattle Group, U.S. investments in electric transmission facilities grew "from approximately $2 billion per year during the late 1990s to approximately $20 billion per year" between 2013 and 2017.[74] The Energy Information Administration reports that in 2019 major

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72 ANOPR at P 159.

73 *Supplemental Notice of Proposed Rulemaking Regarding the Commission's Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act,* 175 FERC ¶ 61,035 (April 15, 2021) ("Supplemental NOPR"), Commissioner Christie concurrence at 2.

74 Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission Experience to Date and the Potential for Additional Customer Value* (2019), at 14-15,

U.S. utilities spent $23.5 billion on new transmission investment,[75] and the Edison Electric Institute ("EEI") has reported that investor-owned utilities ("IOUs") and stand-alone transmission companies plan to invest $27.1 billion in 2021.[76]

These increases in transmission investments have generally resulted in substantial growth in transmission rates. For example, the total annual revenue requirement for transmission enhancements in PJM increased by 294.5 percent from 2011 to 2017.[77] More recently, transmission charges in PJM increased more than 15 percent between 2019 and 2020 alone.[78] CAISO's High Voltage Transmission Access Charge, which is a primary component of transmission charges on customers' bills, also increased by more than 355 percent from 2009 to 2021, whereas load decreased by 9.3 percent.[79] In New England, transmission charges under the

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https://brattlefiles.blob.core.windows.net/files/15987_brattle_competitive_transmission_report_final_with_data_tables_04-09-2019.pdf) ("Brattle Group Report").

75 "Utilities continue to increase spending on the electric transmission system," Energy Information Administration (March 26, 2021), https://www.eia.gov/todayinenergy/detail.php?id=47316.

76 "Historical and Projected Transmission Investment," Edison Electric Institute Business Analytics Group (November 2020), https://www.eei.org/resourcesandmedia/Documents/Historical%20and%20Projected%20Transmission%20Investment.pdf.

77 *See* American Municipal Power, Inc. analysis, Transmission Cost Drivers, https://www.amppartners.org/Assets/AMP_Rose_Transmission.pdf, at slide 30.

78 2020 State of the Market Report for PJM, Table 1-8, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-sec1.pdf (showing that transmission charges increased from $10.39/megawatt hours ("MWh") in 2019 to $11.98/MWh in 2020, an increase of 15.3 percent).

79 *Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1, California Public Utilities Commission*, May 2021, file:///C:/Users/jp8/Downloads/Senate%20Bill%20695%20Report%202021%20and%20En%20Banc%20whitepaper_final_04302021%20(2).pdf ("CPUC White Paper") at 41-42 (citation omitted) (explaining that the level of high-voltage Transmission Access Charge for 2021 is based on a forecast by Pacific Gas & Electric Company ("PG&E"), and that while rates increased from

Regional Network Service rates rose from $26.3 per kW-year in 2006 to $141.0 per kW-year in 2021, while regional loads declined over the same period.[80] The existing financial burden on transmission customers highlights the need for the Commission to adopt reforms to ensure that all investments in transmission infrastructure are necessary and provide "the most significant benefits for customers" at just and reasonable rates.[81]

b. States Will Need to Play a Central Role in Transmission Planning to Ensure Containment of Costs.

NARUC shares the Commission's focus on ensuring that oversight of transmission investments adequately protects customers from excessive costs.[82] The states agree that further reforms should enhance the Commission's oversight of transmission providers' spending on transmission facilities and should enhance the involvement of state officials through regional planning organizations and regional state committees in that oversight. While the "final determination on whether costs are prudently incurred remains with the Commission,"[83]

$3.83/MWh in 2009 to $13.60/MWh in 2021, load decreased from 216.7 million MWh in 2009 to 196.5 million MWh in 2021).

80 RNS Rate Effective June 1, 2021 and January 1, 2022, PTO-AC Rates Working Group presentation at the NEPOOL Transmission Committee Meeting (July 14, 2021) and RNS Rate Effective July 1, 2016, PTO-AC Rates Working Group presentation at the NEPOOL Reliability Committee and Transmission Committee Summer Meeting (August 8-9, 2016), https://www.iso-ne.com/search?query=rns%20rate.

81 ANOPR, Chairman Glick and Commissioner Clements concurrence at P 9 (stating "the *status quo* may be disproportionately producing transmission facilities that address a narrow set of needs, providing comparatively modest benefits, but at a still-substantial total cost instead of developing the type of transmission infrastructure that could provide the most significant benefits for customers").

82 ANOPR at PP 5, 64, 159, 176, 177.

83 *Id*. at P 173.

heightened state involvement would complement the Commission's oversight of costs and provide additional means of ensuring that rates are just and reasonable.

Cooperative planning between states, regional planning organizations, RTOs/ISOs, and transmission providers is especially important in the current era in which states are taking action on multiple policy fronts (*i.e.*, promoting a clean generation mix and electrification of transportation and heating) that will likely precipitate significant new transmission investments. States, through regional planning organizations and regional state committees, will need to play a central role in transmission analysis and planning to contain costs. In particular, state authorities provide a unique role in assessing costs for state public-policy driven projects as well as non-transmission alternatives ("NTAs") and distribution level activities that avoid the need for transmission. This state oversight role also ensures that one state's policy does not negatively impact transmission costs in another state.

Accordingly, NARUC supports reforms that recognize and integrate the supporting role that state engagement in planning efforts currently plays in cost containment today and allows greater involvement of state officials in the oversight of transmission planning processes and on matters related to the development and operation of the bulk electric transmission system. This includes supporting any necessary revisions to RTO/ISO tariffs or governance in other planning processes to establish state involvement and active participation as a permanent feature of the planning process.

c. Proper Application of Order No. 890's Transparency Planning Requirements to Utility Self-Approved Projects Would Increase Cost-Effective Investments in Forward-Looking Transmission Infrastructure.

In the ANOPR, the Commission asks whether increased federal and/or state regulatory oversight of local transmission facilities is needed,[84] and whether transmission provider practices regarding retirement and replacement of transmission facilities "sufficiently align" with the Commission's directive "to ensure evaluation of alternative transmission solutions" and the most cost-effective ways to serve future needs.[85] Increased oversight of utilities' planned replacements of assets that are then capitalized is critical.[86] The decision to undertake an asset replacement project, or whether a feasible alternative solution would be more cost-effective, involves a significant amount of discretion, yet is typically delegated to incumbent utilities with no scrutiny in regional transmission planning processes. These *utility self-approved projects*[87] currently comprise approximately half of IOUs' transmission spending in FERC-jurisdictional RTOs/ISOs.[88] These projects should be evaluated in regional transmission planning processes to ensure they are needed and are the most cost-effective alternative. As Commissioner Clements

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[84] ANOPR at P 161; see also *id*. at P 37.

[85] *Id*. at P 171.

[86] Planned replacements of transmission assets include upgrades to facilities such as substations, line remediation projects that may incidentally increase the capacity of the line, and projects to extend the useful life of facilities.

[87] Significantly, the referenced lack of federal or state regulatory oversight is not limited to locally cost allocated projects. The problem also applies to projects that are regionally cost allocated but not reviewed in regional transmission planning processes because they involve repair and/or replacement of utility assets. To refer to this important subset of capital projects, we use the umbrella term "utility self-approved projects."

[88] *See* Brattle Group Report at 6 (providing that for the five-year period spanning 2013-2017, roughly one-half ($35 billion) of the approximately $70 billion of total RTO/ISO transmission investments by FERC-jurisdictional transmission owners were not scrutinized in any detail within regional stakeholder planning processes).

astutely has suggested, reforms to Order No. 890 are necessary to ensure that the most cost-effective solutions for modernizing the grid are identified in regional transmission planning processes.[89] NARUC respectfully submits that the most critical reform needed at this time is to apply Order No. 890's transparent planning principles to utility self-approved projects.[90] This would eliminate incumbent utilities' incentive to overinvest in these projects and provide the appropriate regulatory scrutiny over investments that currently comprise approximately 50 percent of transmission costs.[91]

d. Transmission Planning and Oversight Should Adhere to Best Practices to Better Contain Transmission Costs.

As the ANOPR recognizes, all potential reforms to transmission planning, cost allocation, and generator interconnection must consider whether changes in the Commission's policies will result in just and reasonable rates.[92] NARUC identifies the following set of reforms and

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89 *Gridliance High Plains LLC*, 174 FERC ¶ 61078, Commissioner Clements concurrence at P 2 (2021) (emphasis added) (stating "the electricity grid has undergone significant transformation since the issuance of Order No. 890 almost 15 years ago. *Consideration of reform to local planning processes is appropriate as part of broader transmission planning reform*, to ensure that [transmission-dependent non-public utilities] are given fair and adequate service, *and more broadly to ensure that all transmission system plans - local, regional, and interregional - succeed in identifying cost-effective solutions to established system needs and thereby ensure that any new infrastructure is money well spent by customers.*")

90 *C.f., Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.,* 164 FERC ¶ 61,161 (2018).

91 *See e.g.*, 2020 State of the Market Report for PJM at 570 (explaining that "[t]he average number of supplemental projects in each expected in service year increased by 715.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 163 for years 2008 through 2020 (post Order 890)."); see CPUC White Paper at 41 (explaining "[i]n data reported by [the three major California IOUs—PG&E, Southern California Edison, and San Diego Gas & Electric Company]—to the CPUC in July 2020, capital additions between 2016 and 2019 for all three IOUs totaled over $7.5 billion. Approximately $4.5 billion (60 percent) of these capital additions were utility self-approved, while $3 billion were CAISO-approved.").

92 *See* note 70 *supra*.

principles to better contain transmission costs, protect consumers against excessive costs, and ensure just and reasonable transmission rates. NARUC urges the Commission to adopt them as best practices for use in both jurisdictional and non-jurisdictional planning regions.

i. Improved Project Cost Management

The Commission asks whether "in light of the significant potential costs of transmission . . . customers and other stakeholders might benefit from enhanced oversight over identification and costs of transmission facilities."[93] This is supported by data that indicate that many approved transmission projects experience cost escalations, *i.e.*, data for initial project cost estimates and final project costs show significant cost escalations.[94] To address these cost escalations, NARUC supports reforms that promote oversight processes that encourage greater project cost management and scrutiny of approved transmission projects. These oversight processes should be transparent, timely, and hold parties accountable to give public confidence in FERC and state oversight reviews.

Enhanced oversight of approved transmission projects should ensure confidence that reasonable project implementation cost estimates are being made, ensure estimates are just and reasonable, and ensure that transmission builds are appropriately managed to contain costs, consistent with initial cost estimates (*i.e.*, avoid cost overruns during project builds). Project cost

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[93] ANOPR at P 162.

[94] *See e.g.*, Brattle Group Report, Appendix A, at 52-53 (explaining that for the time periods analyzed by The Brattle Group for each RTO/ISO, on average "cost escalations ranged from 18 percent average cost escalations for the reported project types in MISO and SPP to 41 percent in CAISO and 70 percent in ISO-NE. The high average cost escalation in ISO-NE is due primarily to the cost escalations on three major projects—the Southwest Connecticut, Greater Springfield, and the Rhode Island Reliability Projects—each of which was completed at more than twice the initial cost estimate."); see *id*. at 54-57, Figures 21-25 (providing detailed cost escalation data for each U.S. FERC-jurisdictional RTO/ISO except the NYISO).

management across the state or regional level should: (1) ensure consistent approaches and cost data in the development of project cost estimates; (2) establish and implement consistent cost reporting requirements to facilitate better tracking of project costs and any cost increases; and (3) consider transmission developer-offered cost caps or other cost-containment commitments to reduce the risk of significant cost increases.

As an example, the Commission should continue to promote efforts by states, regional planning organizations, and RTOs/ISOs to implement planning procedures to contain costs, such as ISO-NE's Planning Procedure No. 4 or MISO's Transmission Cost Estimation Guide. These planning procedures provide guidance that specify the information and analysis that must be submitted to support a transmission project, the data and methodology to be used in developing project cost estimates (including a contingency adder), and timelines for project tracking and stakeholder review processes.

ii. Limits on the Presumption of Prudence

The Commission seeks comment on additional oversight approaches the Commission might take to ensure that wholesale transmission spending is cost effective.[95] To promote cost containment, NARUC suggests that the Commission consider a limit on the presumption of prudence for transmission costs that exceed estimates by a certain percent or other defined thresholds. Specifically, NARUC recommends that the Commission explore whether there is some limit at which the presumption of prudence no longer applies and ratepayers would benefit from an automatic review of the prudence of an expenditure. The intended goal is to promote cost discipline on the part of transmission providers.

95 ANOPR at P 180.

iii. Emphasis on Holistic Planning Approaches

The Commission seeks comment on whether developing plausible long-term scenarios would lead to the identification of more efficient or cost-effective transmission solutions and whether and how transmission providers should account for an array of different future scenarios when identifying more efficient or cost-effective transmission.[96] NARUC agrees that planning efforts should reflect a more holistic approach to better contain transmission costs. A more holistic planning framework creates opportunities to co-optimize multiple purposes for transmission. To contain costs, regional planning reforms should include a greater emphasis on probabilistic planning approaches and long-term scenario analysis.

Long-term scenario analysis (greater than 10 years) that accounts for an array of different scenarios may reduce costs to ratepayers by identifying more efficient or cost-effective NTAs or transmission solutions. Planning scenarios can be flexible to reflect the unique characteristics and needs of each region, helping to further contain costs. Probabilistic planning approaches that allow for the analysis of multiple risks and planning objectives further aid the identification of more efficient or cost-effective solutions. Probabilistic analysis is particularly relevant when combined with long-term scenario analysis, which increases the complexity and uncertainty of the planning horizon.

iv. Recognize Management of Loads and Other Transmission Cost Drivers

Throughout the ANOPR, the Commission seeks comment on whether the existing regional transmission planning and cost allocation processes fail to adequately account for

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[96] ANOPR at P 48.

anticipated future generation and whether that failure causes customers to pay unjust and unreasonable rates for transmission service.[97] In addition to accounting for anticipated future generation, the transmission planning process should recognize that state and distribution utility policy efforts are being taken to better manage loads and other transmission cost drivers. These efforts should be included in transmission planning to better control costs. For example, the management of emerging loads for transportation and building heating can inform whether and how much new transmission investments are needed. To contain costs and avoid unnecessary transmission investments, NARUC recommends that the Commission examine reforms to effectively incorporate distribution utility load management efforts into the transmission planning process, including recognizing that these efforts will inform whether and how much new transmission investments are needed.

v. Sending Appropriate Price Signals

For certain cost recovery approaches, like postage stamp pricing used in connection with pool-funding of eligible transmission projects, the structure of transmission cost recovery should include consideration of efficient, forward-looking price signals consistent with well-established rate-making considerations routinely applied at the retail and distribution level. Efficient, forward-looking price signals help avoid unneeded transmission builds and help contain transmission costs.

Because future loads will likely be driven by state policies for clean energy and electrification of transportation and heating, it is important that wholesale transmission price signals match these load drivers. Distribution utilities have demonstrated that where there are

[97] ANOPR at PP 30-36, 44, 45, 68.

efficient wholesale price signals, they can respond appropriately to manage loads for the benefit of the system and their consumers (thereby reducing the future need for upgrades to major new bulk transmission builds). An example of effective regional price signals that encourage cost containment by distribution utilities are the load-ratio share framework that exists in New England and in some other RTO/ISO regions. Under this approach, transmission costs allocated by peak load encourage reductions in loads, thereby avoiding the need for future transmission builds.

Any future consideration of cost recovery should include an analysis of long-run marginal costs that will drive transmission costs and establish price signals that match those cost drivers. For example, future transmission costs may no longer be driven solely by peak loads, but instead by location-based clean energy, and costs should be allocated accordingly.

e. The Commission Should Consider the Benefits of Establishing Independent Transmission Monitors Charged with Oversight of Transmission Spending.

The ANOPR asks whether the Commission should "establish Independent Transmission Monitors ("ITMs") to monitor the planning and cost of transmission facilities in particular regions."[98] NARUC recommends the Commission consider the cost containment benefits that could be attained by ITMs in each RTO/ISO and non-RTO/ISO region focused on oversight of transmission spending, and, more broadly, ensuring that future buildout of the grid is cost-effective.

At this stage, NARUC recommends that the Commission focus on the essential questions related to the concept including: (1) where do gaps exist in the existing framework of cost

[98] *Id*. at PP 163-175.

oversight that would be addressed through an ITM; (2) what expertise and skill sets would be brought to bear to address such gaps; (3) what would be the nature of the ITM's responsibilities to the applicable states and the Commission; and (4) could the need be met more efficiently through an existing entity, such as by expanding the responsibilities of the existing market monitor?

NARUC suggests that ITMs in RTO/ISO regions could function like existing market monitors, though with specific expertise in permitting, construction, and financing of transmission projects. The Commission should further investigate this proposal accounting for state authority and the need for state involvement in oversight of the ITMs, *e.g.*, by requiring the ITMs to directly report to a state committee comprised, in part, of members of the applicable state commission(s).

2. Potential Need for Reform of Order No. 1000 Competitive Process and Transmission Planning Requirements

The Commission asks whether Order No. 1000 has resulted in "a relative increase in investment in local transmission facilities or [a lack of] diversity of projects resulting from competitive bidding processes."[99] The answer is yes: since the Commission issued Order No. 1000 in 2011, there has been a significant increase in the development of local transmission projects that are exempt from competitive bidding requirements.[100] This has contributed to

99 ANOPR at P 37.

100 Brattle Group Report at 25 (noting that "[t]he introduction of competitive processes [under Order 1000] coincide[d] with substantial increases in locally-planned transmission that are outside the full regional planning processes."); Ari Peskoe, "Is The Utility Transmission Syndicate Forever?," Energy Bar Association, May 5, 2021 at 51 (citations omitted) (explaining that, for example, in PJM, "IOUs have tripled spending on local non-competitive projects since Order No. 1000 went into effect while the value of PJM-approved regional projects has dropped by a third."); *id*. at 55-56 (citation omitted) (explaining that the Midcontinent Independent

significant, and potentially unwarranted, increases in transmission rates, and compromised effective regional transmission planning.[101] Thus, the Commission should investigate how to encourage the use of current competitive processes and discourage overinvestment in local transmission facilities where the development of more competitively priced projects will maximize regional (and interregional) benefits.

In the ANOPR, the Commission also asks whether reforms to Order No. 1000 processes could better facilitate the consideration of more efficient or cost-effective alternatives.[102] Although Order No. 1000 requires that "transmission and non-transmission alternatives must be comparably considered in the regional transmission planning process,"[103] "little to no progress

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System Operator ("MISO") has carved out projects from competition by changing cost allocation rules resulting in a significant decrease in regional projects, "from nearly $6 billion (total, 2010–2013) to just $300 million (total, 2014–2019).").

101 *See e.g.*, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, Americans for a Clean Energy Grid, January 2021, https://cleanenergygrid.org/planning-for-the-future/ (explaining that the concentration of transmission spending in local reliability upgrades "results in higher total energy bills for customers than would result from more forward-looking, holistic transmission planning."); *How are we going to build all that clean energy infrastructure? Considering Private Enterprise, Public Initiative, and Hybrid Approaches to the Challenge of Electricity Transmission*, Niskanen Center, Clean Air Task Force, August 2021, at 25, Appendix II, https://www.niskanencenter.org/wp-content/uploads/2021/08/CleanEnergyInfrastructure_Report_08.19.21.pdf (stating that "FERC's decision to exempt local reliability projects from competitive bidding altogether further incentivizes utilities to favor lower-voltage, intrastate transmission projects over interstate trunks. *That focus on short-haul transmission to the exclusion of broader concerns helps explain why some areas have seen transmission expenses rise as much as 40 percent without gaining any connections to geographically diverse sources*. [emphasis added]"); Brattle Group Report at 4.

102 ANOPR at P 171.

103 Order No. 1000 at P 148.

has been made to incorporate these technologies onto the bulk energy system."[104] The Commission should consider Order No. 1000 reforms to address this.

Specifically, the Commission should explore requiring regional planning organizations and RTOs/ISOs to consider alternative transmission solutions, including grid-enhancing technologies, and non-transmission technologies, in the transmission planning process to determine whether such technologies could more cost-effectively meet identified needs than capital-intensive transmission lines.[105]

The Commission should also investigate the use of a "sponsorship model" in which "the transmission planning region identifies regional transmission needs" and then bidders sponsor or propose transmission projects to meet the identified needs.[106] This could spur creativity, adoption of new technologies, and identify more cost-effective solutions than under the "competitive bidding model," where the transmission planning region identifies both the regional

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104 Kerinia Cusick, Jon Wellinghoff, and Lorenzo Kristov, *Transmission Planning Protocol: Leveraging Technology to Optimize Existing Infrastructure*, Center for Renewables Integration, August 2019 ("Cusick, *et al*.") at 1, [Transmission+Planning+Protocol+Aug+2019.pdf (squarespace.com)](Transmission+Planning+Protocol+Aug+2019.pdf).

105 *See e.g*., Burcin Unel, Ph.D., *A Path Forward for the Federal Energy Regulatory Commission: Near-Term Steps to Address Climate Change*, Institute for Policy Integrity, New York University School of Law, September 2020, at 16 (recommending, for example, that the Commission could require RTOs/ISOs "to consider a various-transmission-technologies alternative in the planning process," and that "FERC, as part of its prudence review, could also require a utility show that it has considered these alternatives in its decisionmaking.").

106 2017 Transmission Metrics, Staff Report, Federal Energy Regulatory Commission, October 2017 ("2017 FERC Transmission Metrics Report") at 8, https://www.ferc.gov/sites/default/files/2020-04/transmission-investment-metrics_0.pdf. *See* Brattle Group Report at 11 (recommending that "to maximize the value of competitive transmission development processes," transmission planning regions should adopt the sponsorship model because it requires developers to compete "on broader design ideas, which can yield significant additional cost benefits when innovative solutions can more cost-effectively meet identified system needs.").

transmission needs *and* the transmission solutions to meet those needs, and then solicits competitive proposals.[107] Some states believe that use of the sponsorship model would "yield significant benefits," through greater incorporation of alternative transmission and non-transmission alternatives, and more cost-effective solutions.[108]

Further, the Commission asks whether "given state regulatory authority over the approval of non-wires solutions," a regional state committee should "play a role" in identifying situations where a non-wires alternative would be the most cost-effective solution for solving an identified transmission need, "and facilitating a process by which the relevant state regulator could be given an opportunity to approve such a solution?"[109] NARUC supports the establishment of state committees, which would include representatives from the applicable state commission(s), charged with evaluating and approving bidders' proposals in response to competitive solicitations.

3. Eligibility for Electric Transmission Incentives

The ANOPR asks whether only projects that are selected in regional planning processes should be eligible for a return on equity ("ROE") adder incentive "that may be available for

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107 *Id*.

108 *See e.g.*, Cusick *et al*. at 23 (explaining that "[t]he benefit-cost analysis used by the ISO/RTO to evaluate solutions to economic-based transmission needs, combined with a return-on-equity (ROE) financial model *in the absence of competitive procurement processes* [emphasis added], motivates transmission owners to propose the highest capital cost solution with a cost-benefit ratio that just meets the ISO/RTOs threshold requirements since there is little competition in transmission development. *Additionally, many ISO/RTO transmission planning processes offer limited opportunity for non-incumbents to submit alternative proposals, or may lack transparent and effective criteria for comparing them*. Therefore, low capital cost solutions or options with an excellent benefit-cost ratio are often just never considered.")(emphasis added).

109 ANOPR at P 177.

RTO/ISO participation."[110] To promote competitive markets and help curtail the growing investment in utility-self approved projects, NARUC urges the Commission to clarify that projects planned outside of the regional transmission planning process are not eligible for *any* section 219 incentives,[111] including any ROE adder that may be available for RTO/ISO participation.

V. CONCLUSION

NARUC respectfully requests that Commission consider these comments. NARUC recognizes that a comprehensive review of planning, cost allocation and interconnection processes is necessary to address concerns about transmission availability and containing costs. Through these ANOPR comments and engagement in the Task Force, NARUC looks forward to working collaboratively with FERC in exploring such reforms.

Respectfully submitted,

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Dated: October 12, 2021

110 *Id.* at P 61.

111 *See* 16 U.S.C. § 824s.

CERTIFICATE OF SERVICE

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

Dated at Washington, DC: October 12, 2021

Respectfully submitted:

/s/ Jennifer M. Murphy