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

COMMENTS OF THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

The National Association of Regulatory Utility Commissioners ("NARUC") submits these comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") April 21, 2022 Notice of Proposed Rulemaking ("NOPR")[1] and the Notice on Requests for Extension of Time issued on May 25, 2022, in the above-captioned proceeding. The Commission is seeking comment on its proposals to reform its electric regional transmission planning and cost allocation requirements.[2]

I. INTRODUCTION

Pursuant to 16 U.S.C. § 824e,[3] the Commission is proposing reforms in the NOPR that "are intended to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential."[4] The Commission began this process with an Advance Notice of Proposed Rulemaking ("ANOPR"),[5] in response to which

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

2 NORP at P 1.

3 16 U.S.C. § 824e (2012).

4 NOPR at P 1.

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

NARUC filed comments.[6] The Commission also 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.[7] NARUC appreciates both the NOPR processes and the Task Force meetings as opportunities for state commissions to offer their views on these proposed reforms and others.

NARUC has organized its comments around five of the NOPR topics: Long-Term Regional Transmission Planning; Regional Transmission Cost Allocation for Long-Term Regional Transmission Facilities; Construction Work in Progress Initiative; Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process; and Interregional Transmission Coordination and Cost Allocation.

II. COMMENTS

A. LONG-TERM REGIONAL TRANSMISSION PLANNING

i. Introduction

NARUC values FERC's ongoing commitment to transmission planning reform. As NARUC stated in its ANOPR comments, the primary drivers of transmission needs – ensuring reliability, providing economic benefits, and achieving legal and public policy requirements – remain constant. However, it is important to continue to monitor transmission planning processes to keep up with evolving technology and changes in state energy laws and policies.[8] NARUC appreciates the Commission's efforts to consider and implement reforms that may facilitate more efficient and effective transmission planning, while recognizing the critical and

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[6] Motion to Intervene and Comments of the National Association of Regulatory Utility Commissioners, Docket No. RM21-17-000 (October 12, 2021) ("NARUC ANOPR Comments").

[7] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (2021).

[8] NARUC ANOPR Comments at 4.

key role of the states and preserving jurisdictional authorities. Any reforms that are reflected in a final rule must account for the states' need to ensure that planning processes appropriately accommodate their laws and policy preferences.

NARUC agrees that Regional Transmission Organizations and Independent System Operators ("RTOs/ISOs"), public utility transmission providers, and regional transmission planning entities in non-RTO/ISO regions should be required to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.[9] As described in more detail in these comments, NARUC largely supports the proposed reforms to the transmission planning process, and agrees with FERC's statement in the NOPR that the reforms do not and should not mandate any particular substantive outcome that may result from the process.[10] Further, the requirement to participate in Long-Term Regional Transmission Planning should generally continue to incorporate compliance with the transmission planning principles of Order Nos. 890 and 1000, as their core tenets have remained sound over the years. A regional transmission planning process that includes Long-Term Regional Transmission Planning must also accommodate the key role of states in implementing their individual legal requirements and public policies, while recognizing that each region has unique attributes and will require flexibility to develop an approach tailored to its needs.

Additionally, in its ANOPR comments, NARUC emphasized the importance of reforming existing transmission planning processes to integrate values of justice and equity. NARUC indicated that "[p]rocesses must provide for opportunities to consider the interests of historically disadvantaged communities and should provide flexibility for states to devise

9 NOPR at P 77.
10 *See e.g.*, NOPR at PP 9, 246.

mechanisms as needed to advance equity and environmental justice."[11] While this issue was not addressed expressly in the NOPR, NARUC would emphasize that it remains important and merits consideration.

ii. Development of Long-Term Scenarios for Use in Long-Term Regional Transmission Planning

The NOPR seeks comment on whether, in order to identify more efficient or cost-effective transmission facilities, transmission providers should be required to incorporate some form of scenario analysis into their existing reliability and economic regional transmission planning processes.[12] NARUC broadly supports FERC's findings to incorporate scenario analysis in long-term regional transmission planning. NARUC agrees that developing and utilizing Long-Term Scenarios[13] in the regional transmission planning process offers an appropriately flexible planning tool for addressing the uncertainty involved in identifying transmission needs driven by changes in the resource mix and demand, and ensure that transmission providers adequately assess the potential benefits of regional transmission facilities.[14] While NARUC supports scenario-based long-term regional transmission planning as a useful tool to manage the transition to a grid with more clean energy and changing electrification-driven loads, NARUC suggests that FERC not similarly prescribe specific scenario-based changes to long-established and successful reliability and economic regional transmission planning processes. Rather, NARUC recommends that FERC establish a principle

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11 NARUC ANOPR Comments at 16.

12 NOPR at P 90.

13 The NOPR defines Long-Term Scenarios as "a tool to identify transmission needs driven by changes in the resource mix and demand and enable the evaluation of transmission facilities to meet such needs, across multiple scenarios that incorporate different assumptions about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon." NOPR at n.129.

14 *See*, NOPR at P 86, 88.

requiring transmission providers to consider applying scenario-based planning to existing reliability and economic planning processes, while allowing them the flexibility to propose solutions to accommodate this goal through existing planning processes. By way of example, FERC could require transmission providers to demonstrate that they have a process in place to consider how reliability or economic projects might be "right-sized" to account for public-policy driven transmission needs. NARUC recommends that FERC allow for states to play a central role in assessing right-sizing opportunities and emphasizes that FERC should not mandate that such a process result in projects being "right-sized."

1. Transmission Planning Horizon and Frequency

The NOPR seeks comment on whether a 20-year transmission planning horizon for Long-Term Scenarios is appropriate to allow public utility transmission providers to identify transmission needs driven by changes in the resource mix and demand and to evaluate regional transmission facilities to meet such transmission needs more efficiently or cost-effectively.[15] NARUC views 20 years as a reasonable planning horizon to accommodate the reforms proposed in the NOPR, subject to the understanding that with a 20-year planning horizon, the Long-Term Regional Transmission Planning process is to be used as a planning tool and not a construction requirement.

A 20-year horizon balances the need to reflect well-documented policy-driven changes in load from transportation and building electrification and the long-term "swap" of generation assets (*e.g.*, a region transitioning from fossil-based resources to offshore wind) with increasing uncertainty as forecast horizons expand. NARUC recommends, however, that FERC not mandate 20 years as a fixed or minimum planning horizon. Rather, transmission planners should

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[15] NOPR at P 100.

be allowed independent entity variations to deviate above or below a 20-year horizon for planning or benefits analysis.[16] FERC should allow regions the flexibility to tailor the requirement for a long-term planning horizon to their respective regional planning processes. This flexibility should apply both to existing processes and new processes. Regional planning processes that achieve the overall objective of instilling an appropriate long-term planning horizon are already underway. In New England, for example, ISO-NE is conducting the 2050 Transmission Study at the request of the New England states to better understand the amount of electric transmission investment needed to meet future loads.[17]

The NOPR also seeks comment on the appropriateness of a three-year frequency for reassessing and revising data inputs and other factors incorporated in previously developed Long-Term Scenarios, as well as whether a three-year frequency requirement allows sufficient time for transmission providers to update assumptions.[18] The NOPR specifically seeks comment on whether this requirement helps balance the risks of under-building or over-building regional transmission facilities.[19] As a general guideline, NARUC considers three-years to be a reasonable frequency for reassessing and revising the data inputs and factors incorporated in Long-Term Scenarios. Once again, NARUC recommends that FERC should afford regions the flexibility to accommodate existing or proposed new long-term planning processes, or state IRPs, that largely satisfy the goal of timely revision of data inputs and other factors used in Long-Term Scenarios but that might not adhere strictly to a three-year schedule. FERC could structure this

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[16] *See, e.g.*, Order No. 2003, 104 FERC P 61,103 at PP 822-827 (allowing RTOs/ISOs to seek "independent entity variations" from the Final Rule pricing and non-pricing provisions at the time of their compliance filings); Order No. 2006, 111 FERC P 61,220 at PP 546-550.

[17] *See* ISO-NE Longer-Term Studies, available at https://www.iso-ne.com/system-planning/transmission-planning/longer-term-transmission-studies/ (last visited Aug. 16, 2022).

[18] NOPR at P 100.

[19] NOPR at P 100.

as a requirement that transmission providers conduct regular and frequent updates of long-term transmission plans with an interval of three years as a guideline. NARUC strongly supports FERC's focus on seeking ways to help balance the risks of under-building or over-building regional transmission facilities and suggests that Independent Transmission Monitors ("ITMs") could potentially play a role in assisting federal and state regulators in this important effort by developing information and assessing the data inputs and other factors that transmission providers incorporate in Long-Term Scenarios. However, the specific scope and responsibilities of ITMs would require development.

The NOPR also seeks comment on whether to require transmission providers to complete the development of Long-Term Scenarios within three years, and whether this proposed requirement prevents the overlap of the three-year assessments.[20] Consistent with its broad support for FERC's findings and proposed reforms to incorporate scenarios in long term regional transmission planning, NARUC views three years as an appropriate amount of time within which to require transmission providers to develop and complete scenarios to avoid overlap of the three-year assessments.

2. Factors

In its ANOPR comments, NARUC recognized that some states found benefit in FERC providing high-level federal planning policy, which could include consistent national interregional planning standards.[21] In the NOPR, FERC has proposed to require, at a minimum, a list of seven categories of factors for the development of Long-Term Scenarios as part of Long-Term Regional Transmission Planning: (1) federal, state, and local laws and regulations that affect the future resource mix and demand; (2) federal, state, and local laws and regulations on decarbonization and

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[20] NOPR at P 100.

[21] NARUC ANOPR Comments at 16.

electrification; (3) state-approved utility integrated resource plans and expected supply obligations for load serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator interconnection requests and withdrawals; (7) utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand.[22] The Commission seeks comment on whether and how these categories adequately capture factors expected to drive changes in the resource mix and demand.[23]

NARUC appreciates FERC's efforts in compiling this list and believes it to be a fairly comprehensive iteration of the factors that may influence transmission planning. However, as NARUC asserted in the ANOPR comments, individual regions should have flexibility in determining planning parameters in coordination with the regions' stakeholder communities.[24] This will further ensure that state regulators and siting authorities can comply with dynamic applicable local and state requirements and adapt to generation-resource trends and policies. Holistic transmission planning that incorporates a well-rounded list of regulations, policies, and other market realities is essential to ensuring the resilience and reliability of the grid. But there must be flexibility for each region to accomplish efficient, adaptable transmission planning. To this point, NARUC strongly emphasizes that, as the timeframe for long-term planning increases, the factors above will likewise change and evolve.

Given the constant changes in technology, state laws, regulatory structures, and policy preferences, any final rule must allow for regional flexibility to determine the applicable categories of factors for the development of Long-Term Scenarios. Some states may prefer that certain

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22 NOPR at P 104.
23 NOPR at P 112.
24 NARUC ANOPR Comments at 16-17.

favored policy objectives, such as the advancement of distributed energy resources, are particularly incorporated in their region's transmission planning process. Some states also suggest that, while there should be some degree of regional flexibility, FERC should establish minimum planning parameters. FERC should, however, refrain from establishing an overly prescriptive final rule. As NARUC stated in its ANOPR comments, the Commission should allow planning processes to account for regional differences and avoid mandating a "one-size-fits-all" approach that may vary in effectiveness by region.[25]

3. Number and Range of Scenarios

The Commission's NOPR proposes that public utility transmission providers develop at least four distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning.[26] Those Long-Term Scenarios must be consistent with federal, state, and local laws and regulations that affect the future resource mix; federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans. The NOPR provides that the Long-Term Scenarios must be plausible, meaning that they must reasonably capture probable future outcomes, and they must be diverse, in the sense that public utility transmission providers can distinguish distinct transmission facilities or distinct benefits of similar transmission facilities in each scenario.[27] Additionally, the NOPR proposes that at least one of the four distinct Long-Term Scenarios must account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events.[28]

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25 NARUC ANOPR Comments at 12.
26 NOPR at P 121.
27 NOPR at P 123.
28 NOPR at P 124.

Subject to applicable confidentiality protections, the NOPR proposes that public utility transmission providers publicly disclose information and data inputs they use to create each Long-Term Scenario. Additionally, the NOPR proposes to require that public utility transmission providers give stakeholders the opportunity to provide timely and meaningful input into the identification of which Long-Term Scenarios are developed.

NARUC supports the Commission's proposal that public utility transmission providers develop multiple, distinct Long-Term Scenarios as part of their Long-Term Regional Transmission Planning. Long-Term Scenarios that are consistent with federal, state, and local laws and regulations that affect the future resource mix; federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans can serve as an important part of the process in identifying efficient or cost-effective regional transmission facilities.

NARUC also supports the NOPR's proposed transparency requirements and provisions for ensuring stakeholder input. Transparency about the factors that will be considered in the identification and development of Long-Term Scenarios[29] not only allows stakeholders to understand the assumptions and assessments, but also provides meaningful feedback to the planning organization as it constructs the scenarios.

4. Development of Sensitivities for Long-Term Scenarios

The NOPR seeks comment on whether public utility transmission providers should be required to develop sensitivities for each Long-Term Scenario to identify more efficient or cost-effective transmission facilities for selection in the regional transmission plan for purposes of

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[29] *See* NOPR at PP 109-110.

cost allocation as part of Long-Term Regional Transmission Planning.[30] NARUC agrees with the Commission that studying multiple scenarios could provide beneficial information, but comments that the scenarios and inputs should be considered in a manner that can distinguish what is expected to occur with a reasonable degree of certainty from what is speculation.[31] Where uncertainty exists, sensitivity studies should be performed.[32] A sensitivity analysis should identify how sensitive model outputs are to changes in inputs and how that sensitivity might affect decisions. A good sensitivity analysis can increase overall confidence in a long-range planning assessment, which should prove valuable when information from the plan is relied upon to select projects for cost allocation.

NARUC asserts that scenarios associated with public policy *goals* should be distinct from scenarios that reflect established *legislation or regulation*. In this way, if a project that includes public policy *goals* is selected for cost allocation, this approach provides transparency with regard to the justification as to why it is a reasonable selection.

NARUC does not object to the proposal that at least one of the Long-Term Scenarios used in Long-Term Regional Transmission Planning must account for uncertain operational outcomes that determine the benefits of, or need for, transmission facilities during high-impact, low-frequency events. However, given that this scenario would be a low frequency event, it is not clear how transmission project selection would proceed unless consideration of some risk factor is reflected in the selection process. Alternatively, if the scenario is constructed in a manner that facilitates comparisons to other scenarios, output from this scenario may serve to better inform project selection decision-making. Doing so may demonstrate that pursuing certain

[30] NOPR at P 126.
[31] *See* NOPR at P 114.
[32] *See* NOPR at P 114.

actions both addresses a need in one of the other scenarios and mitigates the impact of the low-frequency event. NARUC agrees with the Commission that public utility transmission providers should determine which high-impact, low-frequency event should be modeled in this Long-Term Scenario as part of Long-Term Regional Transmission Planning. Given states' involvement with responding to the consequences of such events, it is important that transmission providers consider the states' input in developing such a scenario.

5. Best Available Data Inputs

The NOPR proposes to require public utility transmission providers to use "best available data inputs" when developing Long-Term Scenarios, which would require the use of best practices in developing data input.[33] Specifically, the NOPR proposes to require data inputs that are developed using diverse and expert perspectives, adopted via a process that satisfies the transparency planning principle provided in the NOPR[34] and that reflect the list of factors[35] that public utility transmission providers must incorporate into Long-Term Scenarios. Additionally, the NOPR proposes to require that public utility transmission providers update all data inputs each time they reassess and revise, as necessary, their Long-Term Scenarios, which the Commission has proposed would be required at least every three years.

NARUC believes that using reasonable data inputs is essential to effective Long-Term Regional Transmission Planning because data inputs drive the results of transmission planning

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33 NOPR at PP 130-31.

34 The transparency transmission planning principle "requires public utility transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Public utility transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies." *See* NOPR at P 123, n.226.

35 *See* comments *supra* regarding the need for regional flexibility with respect to the use of these factors

models, including the identification of transmission needs as well as the identification of more efficient or cost-effective transmission facilities to address those needs. As such, NARUC supports the NOPR's definition of "best available data inputs."[36] With regard to the quality and source of data, the National Laboratories (*e.g.*, the National Renewable Energy Laboratory, the Pacific Northwest National Laboratory, and Lawrence Berkeley National Laboratory) may be good sources of data, including the data that informs trends in technologies and their operational efficiencies and costs. As the NOPR indicates, RTOs/ISOs could be essential in developing data inputs such as long-term load forecasts of demand.[37] However, the acquisition of best available data should not be relegated to just these traditional sources, but should also include any reasonable, credible sources.[38] These data should be examined for synergies and impacts to ensure that they are appropriately applied. For example, future growth in electric vehicle ("EV") sales projected by reliable sources in the automotive sector could inform the load forecast of demand and factor into Long-Term Scenarios that may suggest consideration of transmission expansion. However, prior to relying on this information for data input, the transmission planner should also examine the reasons for the projected EV sales for applicability to the load forecast. If sales are attributed to projected advancements in efficient and low-cost EV battery (electrical energy storage) technology, and if a similar technology can also be employed behind customers' meters paired with rooftop solar, then perhaps the load forecast data input may be significantly

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[36] The NOPR proposes to define "best available data inputs" as "data inputs that are timely and developed using diverse and expert perspectives, adopted via a process that satisfies the transparency planning principle . . . ." (internal footnotes omitted). NOPR at P 131.

[37] NOPR at P 131.

[38] For example, the Western Electric Coordinating Council ("WECC") collects data on projected demand and capacity forecasts for the Western Interconnection and for different regions in the Western Interconnection. *See* WECC's Western Resource Adequacy Assessment, available at https://www.wecc.org/ResourceAdequacy/Pages/default.aspx (last visited Aug. 16, 2022).

lower. This would be an important factor when developing scenarios that may influence the consideration of transmission project selection.

The NOPR notes NARUC's comments in response to the ANOPR stating that better sharing of data between states and RTOs/ISOs would be beneficial.[39] Those entities should also be attuned to state policies that could help define the data inputs. As the NOPR recognizes, "assumed dates of generation retirements can be a critical factor."[40] Even without revealing confidential information, RTOs/ISOs and regional planning organizations in non-RTO/ISO regions should be able to rely on these factors and information from other reliable sources to determine this critical data input. Neglecting this information has the potential to expose ratepayers to significant cost impacts.

The importance of timely, accurate data has been demonstrated in recent applications for Reliability Must-Run ("RMR") contracts, which have been requested to delay generator retirements in order to provide sufficient time for the RTOs to make needed transmission upgrades. For example, NRG Power Marketing LLC recently filed an application for approval of an RMR rate schedule for its Indian River Unit 4, a 410 MW coal-fired generation unit, after PJM found that the unit's retirement would necessitate transmission system upgrades to address reliability impacts that would take up to five years to complete.[41] Given the age of the transmission facilities, much of the identified upgrades may have been needed soon in any event. The purported need for the RMR is lamentable for various reasons, including that the plant has been uneconomic for years, its significant air emissions are inconsistent with numerous state

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[39] NOPR at P 129.

[40] NOPR at P 127.

[41] *See NRG Power Marketing LLC*, Docket No. ER22-1539. This case is currently contested and has been set for settlement judge proceedings. 179 FERC ¶ 61,156 (2022).

policies, and its continued use may impose additional costs upon ratepayers of up to several hundred million dollars over the life of the RMR. Better data input in long-term planning may have resulted in accelerated work on necessary transmission upgrades, thus obviating the need for consideration of an RMR. Both the generator retirement date and the aging transmission system upgrade date appear to be data inputs that could be considered in Long-Term Regional Transmission Planning. While this may seem to be an isolated example, as the generation mix continues to evolve and the transmission system continues to age, the importance of such data inputs becomes only more pronounced.

6. Identification of Geographic Zones

In its ANOPR, the Commission sought comment on whether it should require public utility transmission providers to establish, as part of their regional transmission planning processes, a process that identifies geographic zones that have the potential for the development of large amounts of new generation, particularly renewable resources.[42] In its NOPR, the Commission preliminarily finds that requiring the consideration and potential identification of geographic zones within Long-Term Scenarios will assist public utility transmission providers, transmission developers, and generation developers to coordinate their activities.[43] The Commission asserts that considering geographic zones that have the potential for the development of large amounts of new generation will enable public utility transmission providers to plan transmission facilities that will serve large concentrations of new generation in a more efficient or cost-effective manner.[44] Accordingly, the Commission's NOPR proposes to require that public utility transmission providers consider whether to (i) identify with stakeholder input

[42] ANOPR at P 54.
[43] NOPR at P 146.
[44] NOPR at P 146.

geographic zones within the transmission planning region that have the potential for development of large amounts of new generation; (ii) assess generation developers' commercial interest in developing generation within each designated geographic zone; and (iii) incorporate designated zones, and the identified commercial interest in each zone, into Long-Term Scenarios.[45] Finally, the Commission seeks comment on how public utility transmission providers in multi-state transmission planning regions may reconcile or account for differing energy policy interests or preferences in implementing this proposed requirement, while respecting and not overriding state preferences.[46]

NARUC generally supports the proposal to require transmission providers to consider whether to identify geographic zones within the transmission planning region that have the potential for development of large amounts of new generation. If the Commission adopts this proposal in a final rule, it should account for the fact that states, and not the Commission, have jurisdiction over generating facilities[47] and that the "[n]eed for new power facilities, their economic feasibility, and rates and services, are areas that have been customarily governed by the States."[48] Thus, the proposal for transmission providers to consider in their long-term regional transmission planning processes geographic zones that are rich in generation resources is an area in which federal and state responsibility is shared. Accordingly, NARUC supports the Commission's proposal to require public utility transmission providers to provide all stakeholders, including applicable federal and state authorities, with a meaningful opportunity to provide input on the draft geographic zones. That stakeholder input will enable public utility

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[45] NOPR at P 145.
[46] NOPR at P 153.
[47] 16 USC § 824(b)(1).
[48] *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205, 103 S. Ct. 1713, 75 L. Ed. 2d 752 (1983).

transmission providers in each transmission planning region to identify known state law, state policy, siting, permitting, or other anticipated development challenges or opportunities associated with the draft geographic zones. Moreover, as with the other areas of planning for Long Term Regional Transmission Facilities, the Commission should not require any particular outcome, as geographic zones may not be suitable in every planning region.

Requiring transmission providers to consider and potentially identify geographic zones appears to support transmission system enhancements for the purpose of meeting demand from known areas abundant in wind and solar generation or other generation potential. Nevertheless, encouraging generation geographic zoning through transmission planning is a new, potentially transformative concept that needs to be examined and understood in terms of certainty of market entry by generation developers, including issues associated with developers' abilities to secure land rights, offshore leases, or power purchase agreements within an identified zone.

Other factors that may impact actual development of generation, such as state and local land use laws, financing, land costs and availability, must also be examined in the context of the consideration by public utility transmission providers of the identification of geographic zones. Nothing in this process should infringe upon or impair the expressly reserved powers of the states under the Federal Power Act to determine their choice of generation as well as their ability to exercise their transmission siting authority. Planning regions should have flexibility in defining the process(es) for considering and potentially identifying geographic zones.

Any process for the consideration of geographic zones should examine how measures relate to wholesale market competition and how prices affect market entry. Moreover, any requirement to establish processes for considering and potentially identifying geographic zones should require a significant demand by developers. Further, eligibility rules should be non-discriminatory as to the types of generation resources that can enter the market.

iii. Coordination of Regional Transmission Planning and Generator Interconnection Processes

FERC observes that there may be a need to improve coordination between the generator interconnection process and the regional transmission planning and cost allocation processes. FERC, therefore, proposes to require that public utility transmission providers consider, as part of their Long-Term Regional Transmission Planning, regional transmission facilities that address interconnection-related needs that were identified multiple times in the generator interconnection process, but that have not been constructed due to the withdrawal of the underlying interconnection requests.[49] The Commission also seeks comment on a number of specific issues, such as whether the proposal could delay the processing of existing interconnection queues and how it should interact with existing regional transmission planning processes.[50]

As stated in its ANOPR comments, NARUC believes that interconnection should be integrated with transmission planning and generally agrees that there should be better coordination between the regional transmission planning and cost allocation processes and the generator interconnection process.[51] As we noted, 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 generation interconnection agreements or that are well on their way toward achieving such agreements.[52] NARUC, therefore, recommended in its ANOPR comments that RTOs/ISOs should consider

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[49] NOPR at P 154.
[50] NOPR at P 174.
[51] NARUC ANOPR Comments at 11.
[52] NARUC ANOPR Comments at 42.

ways to integrate their transmission modeling efforts to evaluate multiple future scenarios for projected new generation resources beyond scenarios based purely on those projects that are currently in the queue.[53]

Although FERC intends to address interconnection reform more broadly in a separate proceeding, NARUC agrees that generator interconnection should be coordinated and co-optimized with transmission planning.[54] Through its proposed reform, the Commission reasonably states that it seeks to address a potential barrier to integrating new sources of generation that may otherwise continue to exist in the absence of the proposed requirements in the regional transmission planning process.[55] However, the Commission's transmission planning reform should not result in delay of existing interconnection queues or impede efforts already underway in several RTOs/ISOs and planning regions to implement measures to improve the interconnection queue process.

NARUC generally agrees that all transmission providers should consider, as part of their Long-Term Regional Transmission Planning, regional transmission facilities that address interconnection-related needs that were identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection requests. However, the meaning of the term "multiple times" should be informed by a process that also examines why those previous interconnection requests failed. Transmission facilities may not have been built because of generation developer land acquisition decisions or the identification of more economic transmission design alternatives. Because each

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53 NARUC ANOPR Comments at 43.

54 *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (2022); NARUC ANOPR Comments at 7.

55 NOPR at P 168.

region has unique attributes, flexibility should be afforded to RTOs/ISOs and public utility transmission providers in non-RTO/ISO regions, with input from the states and other stakeholders, to develop the specific criteria to identify interconnection-related needs to be considered in regional transmission planning processes. NARUC supports the integration of existing planning processes, including regional transmission plans and generation interconnection studies, to provide for more cost-effective transmission development.

iv. Evaluation of Benefits of Regional Transmission Facilities

1. Evaluations of Long-Term Regional Transmission Benefits

In its ANOPR comments, NARUC stated that it is "critical that any final rule allow for regional flexibility in meeting transmission needs."[56] This flexibility should extend to the consideration of the benefits identified in the NOPR and set out in Table 1 with the various RTOs/ISOs and the non-RTO planning areas retaining flexibility, in consultation with their states, to apply these identified benefits, or not, as appropriate to the resource mix, public policies, transmission topography, geography and economics of their respective planning areas. NARUC agrees with the NOPR's adoption of a proposed list of examples of benefits and measurement methodologies that may be useful in Long-Term Regional Transmission Planning.

In its ANOPR comments, NARUC also asserted that sound planning processes "should ensure all **realistic** benefits are identified and quantified, where possible."[57] Such processes should consider "the reliability, economic and policy benefits of every transmission project" and that each region "should retain flexibility to define and weigh the "benefits, allowing planning processes to account for regional differences[.]"[58] NARUC further submits that, where the states

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[56] NARUC ANOPR Comments at 6.
[57] NARUC ANOPR Comments at 11-12 (emphasis added).
[58] NARUC ANOPR Comments at 11-12.

in a planning region can agree upon the use of a set of planning benefits, that region's planning entity should use that set to enhance the chances of identifying a viable project. This volitional agreement among states is the essential basis of the NOPR's State Agreement Process but could be applied to the Long-Term Regional Transmission Planning *ex ante* allocation determination as well.

The set of identified Long-Term Regional Transmission Benefits identified in the NOPR may, as the Commission states, "be useful in evaluating transmission facilities for selection in the [long-term] regional plan for purposes of cost allocation."[59] Benefits 1-5 and 8-10 seem somewhat capable of quantification and thus, possible allocation among beneficiary states. The benefits of mitigation of extreme weather, weather events and system contingencies, while important, depending on the size of the region, may need to be more fully considered, as NARUC previously suggested, in interregional planning.[60] Projects intended to provide "increased competition and increased market liquidity" would seem to produce less tangible and more speculative "benefits," if any. Hence, NARUC believes that each planning region should have flexibility in considering the identified benefits in its planning processes. Even those benefits that may be allocable, however, come accompanied by corresponding risks that must also be considered during the planning and selection processes. Some of the identified benefits may be more capable of application in some planning areas than others, as well.

NARUC previously urged the Commission "to retain the foundational principle that transmission costs should be allocated commensurate with benefits . . . [and] customers of load-serving entities should only be required to pay the costs of regional transmission facilities that

[59] NOPR at P 185.
[60] NARUC ANOPR Comments at 19.

provide them with quantifiable or verifiable benefits."[61] NARUC reminded the Commission that movement away from these principles "may lead to less transmission being built."[62] States may be "reluctant to site transmission where the applicant has not articulated quantifiable, verifiable benefits."[63] Indeed, state law may preclude a state commission from permitting construction absent a definite showing of need. Thus, when the Commission asks whether "public utility transmission providers should be *required* to use some or all of the Long-Term Regional Transmission Benefits as a minimum set of benefits,"[64] NARUC submits that the answer is that system planners should be allowed to use benefits that, with the states' input, help identify a viable project. Projects that provide or maximize what might be considered "in-system benefits," *i.e.*, those that reduce customer costs, improve system reliability, or provide for achievement of state electric policy goals, are usually weighed and considered by state siting authorities in determining the need for a new project.

The first suggested benefit—avoided or deferred reliability facilities or deferred replacement of aging facilities—seems capable of calculation but carries with it a corresponding degree of risk if aging infrastructure continues to be operated. Some wildfires have been linked to deferred transmission maintenance of aging infrastructure, for instance. The 2003 Eastern Interconnect blackout also stemmed from, among other causes, deferred vegetation management along transmission lines in Ohio, for instance.[65]

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61 NARUC ANOPR Comments at 26.

62 NARUC ANOPR Comments at 27.

63 NARUC ANOPR Comments at 27.

64 NOPR at P 188.

65 U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (April 2004) at 57-64, available at https://www.energy.gov/sites/default/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf.

Planners are likely already considering loss of load events to some degree in evaluation of system expansions. Whether such benefit, in isolation, is sufficient to recommend construction of a particular project is a question best left to the planning entities and their states. As the Commission seems to acknowledge, every investment in transmission produces some marginal quantum of this benefit simply by augmenting system transfer capability.[66] This quantum may also permit lowered system reserve margins, which, as the NOPR correctly recognizes, overlaps with the benefit of lowered loss of load probability.[67]

Reduction in transmission line losses can often be accomplished by upsizing a line or replacing some of its conductors. Certain advanced technologies may also be capable of providing this benefit and when possible, these should be preferred over new greenfield construction. Benefits associated with new construction to alleviate congestion is already a planning consideration.[68]

The listed benefits of mitigation of extreme events, system contingencies, weather and load uncertainties may, depending on the size of the region, be more appropriate to the issue of interregional planning, which the Commission has indicated will be examined separately. Mitigation of such contingencies seems likely to be among the soundest reasons for interregional transfer capability planning and construction. In regions with a large footprint, such as PJM and MISO, of course, it may be possible to assess these resiliency benefits in the regional transmission planning processes also.[69]

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[66] NOPR at P 195.

[67] NOPR at PP 196-197.

[68] NOPR at P 205.

[69] NOPR at P 207 (where the NOPR references ATC's production cost simulation analysis of insurance benefits for the ATC Paddock-Rockdale transmission line, located in the MISO); s*ee* 2021 Brattle Group Report at 61 (explaining that the "ATC study, which evaluated a wide

Another listed benefit is the capacity cost savings from "reduced peak energy losses," which the Commission believes "would reduce the need for new generation capacity installation or purchases."[70] This result appears to be either a subset of other previously listed benefits (*i.e.*, lowered system reserve margins) or unlikely to occur within organized, competitive generation markets because additional transmission will not serve as a "barrier to entry" to new generation under current federal open access policies. The benefit may be more attainable in areas in which vertically integrated utilities provide service, where transmission can or has been able historically to substitute for new generation construction. The same can be said to apply to the next listed benefit of deferred generation capacity investments. Hundreds of thousands of megawatts of generation currently await interconnection studies in the various RTOs/ISOs and non-RTO/ISO planning regions. It is difficult to see how construction of new transmission facilities can remove any of this demand for additional generator interconnection.

The Commission cites "access to lower cost generation" as another benefit.[71] This could indeed be deemed to be a benefit by the importing state but, under certain scenarios, it could also be deemed as a detriment or as the lack of a benefit by the state losing access to such resources.

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range of transmission-related benefits, found that while the 40-year present value of the project's customer benefits fell short of the project's revenue requirement in the 'Slow Growth' future, the present value of the potential benefits substantially exceeded the costs in other futures scenarios analyzed. *The other scenarios also showed that not investing in the project could leave customers as much as $700 million worse off*. Overall, the Paddock-Rockdale analysis showed that understanding the potential impact of projects across plausible futures is necessary for transmission planning under uncertainties *and for assessing the long-term risk mitigation benefit of a more robust, more flexible transmission grid*." (emphasis added)); s*ee* American Transmission Company's Paddock-Rockdale Project webpage, available at https://www.atc-projects.com/projects/paddock-rockdale-345-kilovolt-project/ ("While this project is largely driven by economics, *it also benefits electric consumers with a stronger, more stable electric system*." (emphasis added)).

[70] NOPR at P 211.

[71] NOPR at PP 216-219.

Indeed, the Arizona Public Service Commission withheld approval of that state's portion of the Devers-Palos Verde No. 2 line (referenced mistakenly in the NOPR as an interstate project approved by a California Public Utilities Commission Certificate of Public Convenience and Necessity in 2007)[72] for just this reason.

For the foregoing reasons, NARUC strongly urges the Commission to permit public utility transmission providers to consider flexibly any of the benefits, and their associated risks, set out in Table 1 of the NOPR during both the planning and project selection phases of long-term regional planning.

As stated above, transmission benefits must be verifiable and quantifiable to justify an allocation of associated costs to ratepayers. The definition of benefits beyond universally accepted benefit metrics that currently are used in transmission planning would necessitate rigorous analysis and regional flexibility.

NARUC agrees with the NOPR’s adoption of a proposed list of examples of benefits and measurement methodologies that may be useful in Long-Term Regional Transmission Planning. These examples will facilitate the rigorous stakeholder examination necessary to broaden the definition of benefits. The proposed list of benefits for consideration is a better way to accomplish the objectives of the NOPR than specification of benefits that must always be used in Long-Term Regional Transmission Planning.

Permitting states and regions to identify benefits that they see as sufficiently quantifiable to justify imposing costs on utility customers will provide data and create a framework for analysis for use by other states and regions as they also examine the benefits of Long-Term Regional Transmission Planning. The NOPR’s proposed benefits and measurement metrics

[72] NOPR at PP 207, 216, 221.

constitute a good starting point to promote rigorous examination of benefits and allows the states to be, as famously stated by Justice Brandeis, the laboratories of democracy.[73]

2. Evaluation of Transmission Benefits Over Longer Time Horizon

The Commission proposes to require that transmission providers in each planning region evaluate the benefits of regional transmission facilities over a time-horizon of at least 20 years.[74] It also notes that "for consistency and a matching comparison of benefits and costs over time, to the extent that public utility transmission providers estimate the costs of transmission facilities beyond the in-service date of the transmission facilities, we propose that they should estimate those future costs over the same time horizon as the estimated benefits."[75]

NARUC supports this proposal. Transmission planning must strike a reasonable balance between considering benefits only through the end of the planning horizon regardless of the facility's in-service date (which would undervalue the benefits of any facility coming on-line part-way through the planning horizon) and considering benefits for the full period of a facility's expected life of forty plus years (in which the value of benefits after 20 years would be more speculative and discounted than the value of the benefits in the first 20 years). A 20-year planning horizon is generally a reasonable one to capture the costs and benefits of new facilities.[76] It is therefore the planning horizon used in many states for purposes of Integrated

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73 *New State Ice Co. v. Liebmann*, 285 U.S. 262 (1932) (Brandeis, J., dissenting): "It is one of the happy incidents of the federal system that a single courageous state may, if its citizens choose, serve as a laboratory; and try novel social and economic experiments without risk to the rest of the country."

74 NOPR at P 227.

75 NOPR at P 228.

76 The NOPR provides an example where a project that is to become operational in year 10 of a 20-year plan would be evaluated for the next 20 years. This would effectively require a 30-year evaluation for the project. Recognizing how far into the future that would be, NARUC

Resource Planning, including in non-RTO states where local transmission planning is a component of those plans. Because FERC is proposing 20 years as a minimum time horizon, transmission providers would have flexibility to use a longer one where it is reasonable and can be justified (which might include where significant additions are expected part-way through the planning horizon); in that case, NARUC agrees with the Commission that costs and benefits should be considered over at least roughly the same time horizon so that an apples-to-apples comparison can be made.

3. Evaluations of the Benefits of Portfolios of Transmission Facilities

The Commission also seeks comment on whether transmission providers should evaluate the benefits of a transmission portfolio collectively rather than individual transmission projects independently. Its proposal is that transmission providers be given discretion to use a flexible approach but that a portfolio approach be encouraged.[77] NARUC supports this proposal and finds it appropriate for each transmission provider to elucidate and justify an approach appropriate for its own system and planning region in its Open Access Transmission Tariff ("OATT"). That allows for planning approaches to be adjusted as necessary for RTOs/ISOs and non-RTO/ISO regions, in addition to other relevant differences between regions. NARUC also supports the Commission's proposal that transmission providers that choose a portfolio approach describe their methodology for evaluating portfolio benefits in their OATT. In addition to ensuring transparency for stakeholders that are participating in planning processes, it is also critical to ensure that there is a clear methodology for how the benefits calculation will be fine-

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understands the NOPR to suggest that the evaluation would need to factor in the uncertainty inherent in this length timeline.

[77] NOPR at P 233.

tuned if one part of the portfolio is disallowed or altered during the planning stages; or if it becomes clear during transmission planning that one part of a larger portfolio may be an unnecessary addendum to the portfolio as a whole.

A portfolio approach to analyzing project benefits may serve to illustrate a more comprehensive and holistic view of the regional benefits of a set of projects when taken as a whole. Moreover, a portfolio approach may also create administrative efficiencies for system planners and reduce system study times. However, a portfolio approach could also run the risk of masking non-beneficial or unnecessary projects as the chaff gets mixed in with the grain. As such, a transmission provider utilizing a portfolio approach should clearly demonstrate that all elements of the portfolio, as a group, serve to capitalize on synergies and not double count or otherwise inflate the prospective benefits. Appropriate cost allocation[78] would need to be put in place to address portfolios with asymmetrical benefit distributions. "Cost allocation should be as granular and accurate as possible. Benefit-cost analysis should use metrics that are quantifiable, capable of replication, non-duplicative, and forward-looking."[79]

The last triennial review by MISO of its Multi-Value Projects ("MVPs") project portfolio demonstrated cost-benefit ratios ranging from 2.2 to 3.4, estimated to provide between $12 and $52 billion in benefits long-term, 20-40 years.[80] As evidenced by the success of MISO's MVP,

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78 NARUC supports FERC's proposal to require Long-Term Regional Transmission Planning cost allocation to comply with the six Order No. 1000 cost allocation principles and urges that the existing Order No. 1000 cost allocation principles also be extended to a portfolio cost-benefit analysis in the same way as they would apply to a single facility cost-benefit analysis.

79 Organization of MISO States, Inc. ANOPR Comments at 15; MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio (September 2017) at 4, available at https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf.

80 MISO ANOPR Comments at 9.

portfolio approaches can facilitate the construction of needed projects, but transmission providers' cost-benefit ratio accuracy will be dependent on utilizing reasonably firm inputs. It is also worth noting that the regional flexibility, which allowed MISO's stakeholder process to craft this innovative approach to long-term planning for the MISO region, should be retained.

NARUC's support for allowing the optional use of a portfolio approach includes an understanding and expectation that this is a logistical planning tool for grid operators and relevant state entities, not a construction requirement. While NARUC is pleased that FERC has provided the states the opportunity to play a greater role in Long-Term Regional Transmission Planning and believes that state participation will better inform the construction of regional projects, NARUC highlights a potential jurisdictional issue and cautions that state participation in cost allocation for a portfolio of Long-Term Regional Transmission Planning projects does not require a state, in its individual role as a transmission siting authority, to approve any of the projects in the portfolio.

v. Selection of Regional Transmission Facilities

1. Selection of Regional Transmission Facilities (for Cost Allocation)

This NOPR builds on Order Nos. 888, 889, 890, and 1000 and should ensure that the significant transmission planning and cost allocation reforms of the past 25 years are reflected in FERC's transmission policies, rules, and procedures. It is extremely important that the Commission continue to encourage any relevant state opportunities for voluntary cost funding of Long-Term Regional Transmission Planning projects in RTOs/ISOs and non-RTO/ISO planning regions. State entities' involvement should occur at the earliest stage of the Long-Term Regional Transmission Planning process. Currently, some quasi-public/private state and federal entities participate in funding projects within RTOs/ISOs, most notably in the Southwest Power Pool

("SPP"), and nothing in this NOPR[81] should inhibit the states from permitting those types of arrangements or expanding them to other voluntary relevant state entities.

The idea of entertaining new or different funding mechanisms for transmission projects is reflective of the changing landscape of the bulk electric system and the evolution of RTOs/ISOs. On a challenge to the open access provisions of Orders 888 and 889, now considered foundational and the very essence of RTOs/ISOs, the D.C. Circuit stated

> Indeed, in 1935, when Congress enacted the [Federal Power Act], the networks of high-voltage, long-distance transmission lines which today crisscross the United States did not exist. Instead, vertically integrated utilities individually built facilities sufficient to meet the power needs of their customers. Over time, however, the landscape of the electric industry changed. Utilities decided to cover demand spikes by sharing power, rather than by building more generation capacity.[82]

Transmission development and planning are inherently long-term activities, (both in RTO/ISO and non-RTO/ISO regions). Public activity and especially potential public funding depend on well-documented and factually supported public policy goals in the form of statutes, regulations, and decisions by state regulatory commissions. The New Jersey Board of Public Utilities, for example, stated that FERC should facilitate, to the extent it is able, such state policy projects as an option for states, and this NOPR should help facilitate those goals for states that so choose:

> For example, regional transmission planning process do [sic] not typically quantify the value of facilitating state(s) public policies, even when achievement of those policies clearly has value to the state(s) with those policies. In large regions like PJM, not all states share the same public policy goals, particularly when it comes to achieving clean energy objectives. Traditional transmission expansion policies largely leave multi-state [RTOs/ISOs] in a quandary – how to recognize public policy "benefits" that may be of great value to one state, but have less value to an adjoining state

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81 NOPR at P 252.

82 *Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667, 691 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC,* 535 U.S. 1, 122 S. Ct. 1012, 152 L. Ed. 2d 47 (2002).

> with different policies. The Commission may wish to facilitate voluntarily [sic] agreements whereby some states ascribe additional "value" to the achievement of public policy goals, backed by a willingness to bear the costs associated with those benefits.[83]

This opportunity for relevant state entities[84] to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility should, in states that have this authority, also include interconnection customers if the state so chooses and if doing so is consistent with the state's already aforementioned policy goals. In short, any final rule adopted by the Commission should not attempt to limit a state's allocation of its portion of the costs of a selected project among the state's retail customers.

The Commission's proposal should not inhibit states' flexibility, to the extent possible, in their approaches to implement voluntary funding, or other "out of the box" commitments by relevant state entities under the proposed Long-Term Regional Transmission Planning process. For example, consider the currently existing iteration of the MISO-SPP Joint Targeted Interconnection Queue ("JTIQ") Study. This study originated in 2020 and is focused on

83 Comments of the New Jersey Board of Public Utilities, Docket No. AD21-15-000 (Apr. 1, 2022) at 4.

84 NARUC notes the NOPR's proposed definition of "Relevant State Entities," which the NOPR defines "for purposes of the Long-Term Regional Transmission Planning cost allocation requirements as any state entity responsible for utility regulation or siting electric transmission facilities within the state." NOPR at P 304. The NOPR finds that "providing relevant state entities an opportunity for involvement in establishing a cost allocation method, including through use of a State Agreement Process, would … increas[e] the likelihood that Long-Term Regional Transmission Facilities are actually developed, and without delay." NOPR at P 317. In some states, including the state regulatory commission having siting authority over transmission lines as part of the State Agreement Process may appear to create a conflict of interest or an appearance of a lack of impartiality if that body is also required to preside over the state's Certificate of Public Convenience and Necessity/Certificate of Convenience and Necessity proceeding in the same case. In that case, a potential remedy to this concern could be to include the state agency selected by the relevant state governor (such as a state division/department of energy, for example) among the "Relevant State Entities" in this definition.

interconnection. Through collaboration between MISO and SPP, the study aims at building transmission network upgrades along the MISO-SPP seams to enable new generator interconnections. This opportunity for voluntary funding, or other state commitments noted in this NOPR, raises the possibilities of state funding in transmission projects that could affect and benefit retail and end-user customers (a responsibility of regulation of the states) and would build on some of the same rationale JTIQ has been studied (*i.e.*, to identify issues and constraints on the bulk electric system as a whole), and as MISO acknowledges, in relation to JTIQ, "[t]his is achieved by identifying transmission constraints limiting new generator interconnection, comparing best solutions, and sharing costs among generators and load."[85] Separately, the exact mechanisms that would be appropriate to document agreement from the relevant state entities to "commit customers within the state to fund" the costs of a Long-Term Regional Transmission Planning Facility under the NOPR's proposed State Agreement process and applicable regulations to enable the selection of such facility should be as flexible as possible and account for the mix of varying state laws enabling such authority. FERC should grant the RTOs/ISOs or non-RTO/ISO planning entity and the state entity or entities flexibility on how to meet this requirement. It should be noted that for most states, public utility commissions are given broad latitude to implement just and reasonable electric rates for the benefit of the public in an overarching sense. Furthermore, most state public utility commissions' orders have the same effect as statutes.[86]

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85 MISO-SPP Joint Targeted Interconnection Queue Study's Mission Statement, available at https://www.misoenergy.org/stakeholder-engagement/committees/miso-spp-joint-targeted-interconnection-queue-study/ (last visited Aug. 16, 2022).

86 In *64 Am.Jur.2d, Public Utilities,* s 244, the general statement is made that: "Public utility rates filed pursuant to statute with a public service commission, or promulgated by order of the commission in accordance with the statute, have the same force and effect as if directly

2. Implementation of Long-Term Regional Transmission Planning

Because the NOPR requires that Long-Term Regional Transmission Planning must take place in addition to the regional transmission planning currently occurring,[87] the need for coordination between existing and new processes is intuitive. Each regional planning entity should have flexibility to develop that coordination based on the circumstances that exist in each planning region. For example, an RTO with cost allocation authority may be able to coordinate planning processes using existing processes, and to do so more quickly than a non-RTO transmission planning entity that has developed cost allocation methods, but that has not used those methods, or worked with state commissions to apply those methods.[88] As another example, the NorthernGrid regional transmission planning entity includes both FERC jurisdictional public utility transmission providers, and non-jurisdictional transmission providers, including consumer-owned utilities and Bonneville Power Administration, a federal Power Marketing Administration. Coordinating transmission planning where some entities would be subject to the provisions of the proposed rules, but other entities would not be, may result in significant time required for negotiation of new processes.

Long-Term Regional Transmission Planning must recognize that benefits inherently become more speculative as the planning horizon increases. Additionally, planning based on public policy objectives must be transparent about identifying projects that would not be selected

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prescribed by the legislature." *State ex rel. Jackson Cnty. v. Pub. Serv. Comm'n*, 532 S.W.2d 20, 28 (Mo. 1975). "A tariff is a document which lists a public utility services and the rates for those services. A tariff has the same force and effect as a statute, and it becomes state law." *State ex rel. Missouri Pipeline Co. v. Missouri Pub. Serv. Comm'n*, 307 S.W.3d 162, 178 (Mo. Ct. App. 2009), *as modified* (Feb. 2, 2010).

[87] NOPR at P 254.

[88] This unique circumstance in non-RTO regions also highlights one reason state entities should retain flexibility to define agreement among those entities. *See* NOPR at P 309.

but for those public policy objectives. Benefits assigned to projects must recognize these principles. Accordingly, the NOPR requirement for public utility transmission providers to explain how the timing of the proposed long-term regional planning process will interact with existing regional planning[89] will add transparency, both to the process generally and to the principles described in this paragraph.

The Commission's proposed periodic forum to coordinate best practices in implementing Long-Term Regional Transmission Planning should be a positive step to help evaluate and consider how the rule is being implemented in various regions.[90] NARUC supports the Commission's proposal to create these forums. They can be an opportunity to share best practices and to evaluate how the rules are being implemented in RTO/ISO areas compared to transmission planning entities in other areas. NARUC does not take any position on the frequency with which these forums should occur.

3. Consideration of Grid-Enhancing Technologies

In its ANOPR, the Commission sought comment on whether grid-enhancing technologies should be accounted for in determining whether and what transmission is needed.[91] In its NOPR, the Commission proposes to require that public utility transmission providers more fully consider in regional transmission planning and cost allocation processes the following two technologies: (i) the incorporation into transmission facilities of dynamic line ratings; and (ii) advanced power flow control devices.[92] In particular, the Commission proposes to require that public utility transmission providers consider for each identified regional transmission need whether selecting transmission facilities in the regional transmission plan for purposes of cost allocation that

[89] NOPR at P 253.
[90] NOPR at P 255.
[91] ANOPR at P 48.
[92] NOPR at P 272.

incorporate dynamic line ratings or advanced power flow control devices would be more efficient or cost-effective than transmission facilities that do not incorporate those technologies.[93] The Commission did not propose to require consideration of other grid-enhancing technologies at this time; however, the Commission did seek comment on whether there are other transmission technologies that should be considered in regional transmission planning and cost allocation processes.[94]

As NARUC stated in its ANOPR comments, an effective transmission planning process should maximize the use of existing transmission and allow for building of new transmission only where necessary or economic.[95] Additionally, the planning process should include 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.

In certain applications, dynamic line rating devices may provide numerous benefits to the transmission system, including, as observed by the Commission, permitting greater power flows than would otherwise be allowed, aiding in the detection of situations where power flows should be reduced to maintain safe and reliable operations, and avoiding unnecessary wear on transmission equipment.[96] Other benefits may include strategic deployments and targeted applications where dynamic line ratings can increase the accuracy and power carrying capabilities of a line. While the NOPR discusses operational considerations, NARUC notes that another benefit may be the ability to capitalize on reduced congestion during certain hours with

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93 NOPR at P 274.
94 NOPR at P 277.
95 NARUC ANOPR Comments at 9.
96 *See Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179, at P 253 (2021).

the prospect of lowering costs to ratepayers in regions with competitive energy markets. Similarly, the ability of advanced power flow control devices to effectively control and route power to lines that have more capacity than others can benefit customers through a reduction in congestion and associated costs, and this can increase reliability of the transmission system.

NARUC further suggests that the Commission add storage as a transmission asset ("SATA") to its list of grid-enhancing technologies that public utility transmission providers should consider in regional transmission planning and cost allocation processes. SATA could help with avoided or deferred reliability – the very first benefit proposed by the NOPR.[97] Given this potential, the Commission should require regional transmission planning entities to develop and file a process in their OATTs to evaluate the use of SATA in transmission projects. NARUC also notes the Commission's finding that, "in certain situations, electric storage resources can function as a generating facility, a transmission asset, or both[,]"[98] but recognizes that the multi-usage issue is not a matter to be decided in this proceeding.

B. REGIONAL TRANSMISSION COST ALLOCATION FOR LONG-TERM REGIONAL TRANSMISSION FACILITIES

As described below, NARUC broadly supports the Commission's proposed reforms in the area of cost allocation for Long-Term Regional Transmission Facilities, particularly with respect to the regional flexibility provided and the level of involvement afforded state regulatory commissions.

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97 *See* NOPR at P 185.

98 Order No. 845, *Reform of Generator Interconnection Procedures and Agreements*, 163 FERC ¶ 61,043 (2018) at P 278. *See also* FERC 2017 Policy Statement PL-17-2, 1/19/2017; JB Twitchell et al., *Enabling Principles for Dual Participation by Energy Storage as a Transmission and Market Asset*, Pacific Northwest National Laboratory, (February 2022), available at https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-32196.pdf.

i. Identifying and Valuing the Benefits of Long-Term Regional Transmission Facilities

1. NARUC supports the Commission's proposal to allow for regional flexibility in defining "benefits."[99]

NARUC applauds the Commission for retaining the foundational principle that transmission costs should be allocated commensurate with benefits, or the beneficiary pays principle,[100] as the Commission reviews its rules and policies to ensure just and reasonable transmission rates to address changes in the generation resource mix and demand, while maintaining grid reliability.

As background, 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 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.[101]

These regional cost allocation principles grounded in a beneficiary pays methodology have withstood judicial scrutiny[102] and have resulted in increased involvement by various

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[99] NOPR at P 183-185.
[100] Order No. 1000, 136 FERC P 61,051 at PP 622, 639.
[101] Order No. 1000, 136 FERC P 61,051 at PP 622, 637, 646, 657, 668, 685.
[102] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

stakeholders in regional transmission planning processes. The beneficiary pays principle has been adopted in the various RTOs/ISOs, as implemented in MISO's 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.

With this background, and as stated above, NARUC supports the Commission's proposal to allow for regional flexibility in defining "benefits."[103] NARUC agrees that transmission planners should continue to 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 resource mix, public policies, transmission topography, geography and economics of their respective planning areas, and to encourage innovation in this space.

NARUC believes that sound planning processes should ensure that all realistic benefits are identified and quantified, where possible. Benefits should be quantifiable, verifiable, and reasonably certain in order to ensure that costs are appropriately allocated, and the inputs, assumptions, and data quantifying the benefits should be readily available for review by stakeholders and provided in a transparent manner. Such processes should allow for each region to retain flexibility to define and weigh the benefits, allowing planning processes to account for regional differences noted above. Of course, where the states in a planning region can agree[104]

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[103] NOPR, 87 FR 26504 at PP 183-185.

[104] FERC should respect the policy agreement of states within an RTO/ISO or planning region. *See ISO New England Inc.*, Docket No. ER22-1528 (May 27, 2022) (Christie concurring, P 4).

upon the use of a set of planning benefits, that region's planner should use that set as a way to enhance the chances of both identifying the most efficient and cost-effective transmission project and increasing the likelihood of such project's eventual construction.

2. NARUC supports the Commission's proposal to consider long-term planning across a 20-year time horizon, with the clear understanding and expectation that this is a planning tool, and not a construction requirement, for transmission providers and relevant state entities.[105]

In addition to the Commission's proposal "to require that public utility transmission providers develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon"[106] addressed above, the Commission proposes that the benefits of regional transmission facilities are evaluated at a time horizon that covers 20 years starting from the estimated in-service date of the transmission facilities.[107] By way of example, the Commission explains that a project coming into service at year 10 from the evaluation date would be evaluated to determine the benefits 20 years from that service date. The reasoning behind this is that transmission facilities have a long life and benefits should be evaluated to the best of the transmission planners' ability over the full life of the project.[108]

As stated above, NARUC agrees that the Commission's proposal to use a 20-year planning forecast is reasonable, provided that: (1) the Long-Term Regional Transmission Planning process is to be used as a planning tool and not a construction requirement, and (2) the 20-year planning period is only a starting point for determining the appropriate long-term planning period. After experience is gained with Long-Term Regional Transmission Planning,

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105 NOPR at P 227.
106 NOPR at P 97.
107 NOPR at P 227.
108 NOPR at P 227.

transmission planners should be allowed independent entity variations to deviate above or below a 20-year horizon for planning or benefits analysis.[109] These conditions are appropriately applied not just to the Commission's proposed 20-year Long-Term Regional Transmission Planning horizon, but also its proposed 20-year benefits analysis because costs[110] and benefits should be considered over at least roughly the same time horizon so that an apples-to-apples comparison can be made.

As we noted above, transmission planning must strike a reasonable balance between considering benefits only through the end of the planning horizon regardless of the facility's in-service date and considering benefits for the full period of a facility's expected life of forty or more years. As a 20-year planning horizon is generally a reasonable one to capture the costs and benefits of new facilities, many states use this planning horizon for purposes of Integrated Resource Planning, including in non-RTO states where local transmission planning is a component of those plans.[111] Because FERC is proposing 20 years as a minimum time horizon, transmission providers would have flexibility to use a longer one where it is reasonable and can be justified (which might include where significant additions are expected part-way through the planning horizon).

Yet, while the Commission's proposal that the 20-year benefits analysis may be appropriate at the start, flexibility should be built in if experience dictates that a 20-year forecast

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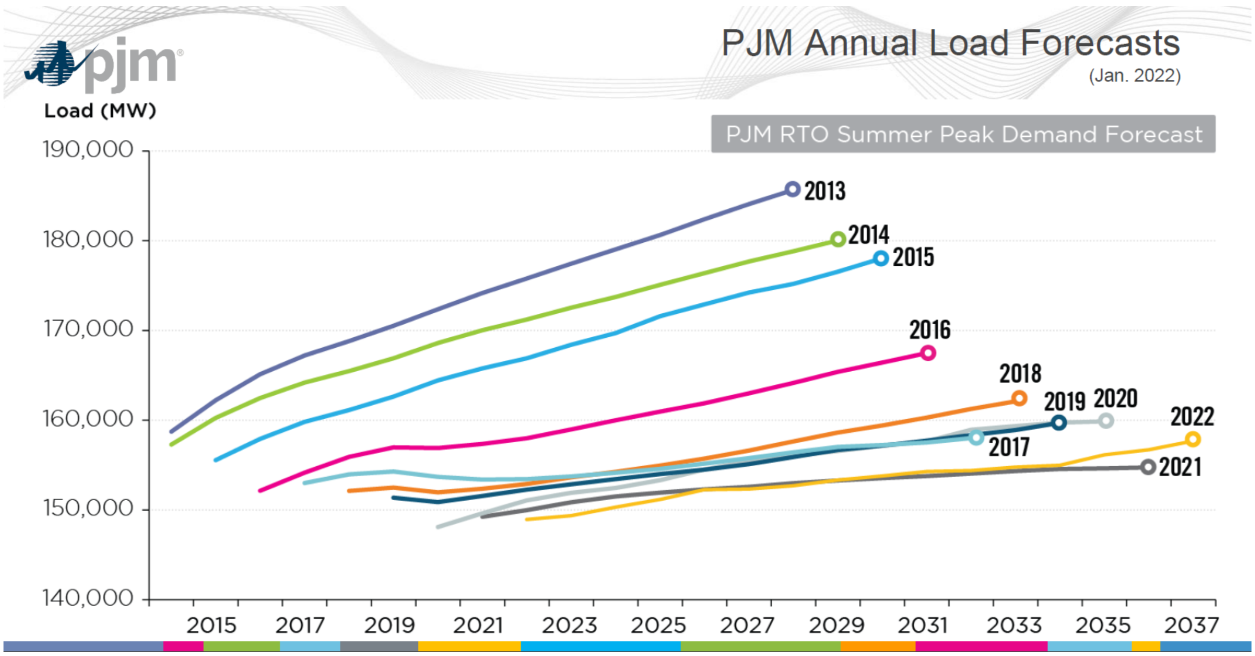
109 *See, e.g.,* Order No. 2003, 104 FERC P 61,103 at PP 822-827; Order No. 2006, 111 FERC P 61,220 at PP 546-550.

110 *See* NOPR at P 228 (applying the 20-year time horizon to the evaluation of costs as well as benefits).

111 *See* Oregon PUC Order No. 07-002, Appendix A, Guideline 1, available at https://apps.puc.state.or.us/orders/2007ords/07-002.pdf. Some states which no longer use Integrated Resource Planning have historically also used a 20-year planning horizon. *See* 66 Pa.C.S. § 524.

analysis of benefits and costs creates too much uncertainty. For example, the load stagnation that has progressed in many regions over just the last 10 years surprised many load forecasters. In PJM, in 2013, the summer peak demand forecast over 10 years turned out not only to be inaccurate, but it was directionally incorrect as well.[112] An accurate load forecast is a critical component to determine the benefits of a transmission line.



While load growth stagnation has been mostly the product of energy efficiency gains,[113] the rise in electrification provides new reasons to believe that load forecast uncertainty may

112 PJM, *2021 New Jersey State Infrastructure Report* (May 2022) at 26, available at https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2021/2021-new-jersey-state-infrastructure-report.ashx (note: while the report is state specific, the peak load forecast is PJM-wide).

113 *See e.g.*, Robert Walton, *Dealing with stagnant load growth, ISO-New England turns to gas, efficiency and DERs*, Utility Dive (Nov. 11, 2015), available at https://www.utilitydive.com/news/dealing-with-stagnant-load-growth-iso-new-england-turns-to-gas-efficiency/408985/; Stephanie Bouckaert and Timothy Goodson, Commentary, International

remain high. Because experience so far sows doubt on achievable levels of certainty in a long-term forecast, the Commission's proposal to set a fixed or minimum 20-year benefit analysis horizon should allow for independent entity variations to deviate above or below that horizon based on actual experience.[114] The Commission proposal to evaluate benefits 20 years from the projected in-service date, which the Commission recognizes could be 10 years from the date of evaluation[115] also increases the potential inaccuracy of the forecast.

In summary, NARUC agrees that transmission planners should be required to include in their tariffs a time horizon for evaluation of benefits and costs of no less than 20 years, aligned with Long-Term Regional Transmission Planning, and subject to reevaluation by transmission planners if not performing as expected.

3. NARUC supports FERC's Selection of Regional Transmission Facilities proposal that requires transmission planners to "consult with and seek support from the relevant state entities, as defined below, within their transmission planning region's footprint to develop the selection criteria."[116]

The Commission proposes to require transmission planners to "consult with and seek support from the relevant state entities, . . . within their transmission planning region's footprint to develop the selection criteria."[117] NARUC supports this proposal, which is consistent with NARUC's ANOPR comments regarding seeking reforms that would better align regional transmission planning with state needs and ensure meaningful opportunities for the states to

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Energy Agency, *The Mysterious Case of Disappearing Electricity Demand*, (Feb. 14, 2019), available at https://www.iea.org/commentaries/the-mysterious-case-of-disappearing-electricity-demand.

114 *See, e.g.*, Order No. 2003, 104 FERC P 61,103 at PP 822-827 (allowing RTOs/ISOs to seek "independent entity variations" from the Final Rule pricing and non-pricing provisions at the time of their compliance filings); Order No. 2006, 111 FERC P 61,220 at PP 546-550.

115 NOPR at P 227.

116 NOPR at PP 244-246.

117 NOPR at PP 244-246.

provide direction and input or otherwise have their laws and policies appropriately reflected throughout the transmission planning process.[118]

As previously noted, NARUC member commissions have regulatory authority over and oversight of regional and local transmission facilities, and are obligated under their respective state laws to ensure both the establishment and maintenance of such energy utility services as may be required by the public convenience and necessity and the provision of those services at just and reasonable rates.[119] The states and jurisdictions of NARUC's more than fifty members all have their own distinct laws and policies on energy usage. These state-specific laws, policies, and goals include not only policies that advance technologies and measures such as renewable portfolio standards, distributed energy resources, demand response, energy efficiency, and energy storage, but also measures to contain costs of transmission development and consideration of non-transmission alternatives and distribution level activities that avoid the need for new transmission.[120] NARUC appreciates that the Commission properly identifies and acknowledges that these state-specific policies may have an impact on the resource mix and demand, and, by extension, on regional long-term transmission needs.[121]

The reform proposed in paragraph 246 of the NOPR would ensure that more efficient or cost-effective regional transmission facilities to address a region's transmission needs driven by changes in the resource mix and demand ultimately are selected in the regional transmission plan for purposes of cost allocation.[122] Requiring that public utility transmission providers consult with and seek support from relevant state entities when establishing selection criteria for regional

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[118] NARUC ANOPR Comments at 5-6.
[119] NARUC ANOPR Comments at 2-3.
[120] NARUC ANOPR Comments at 14-15, 47.
[121] NOPR at P 244.
[122] NOPR at P 242.

transmission facilities results in two specific improvements in the existing process. First, this reform complies with Order Nos. 890 and 1000 transmission planning principles by reducing the risk of stakeholders being subject to determinations that fail to sufficiently explain why particular transmission projects were or were not selected. Second, it sufficiently balances individual state interests within each transmission planning region.[123]

However, NARUC recommends that the Commission provide general parameters for the steps public utility transmission providers in RTO/ISO regions must follow to comply with the proposed requirement to consult and seek support from relevant state entities pursuant to paragraph 244 of the NOPR. Public utility transmission providers must, at a minimum, (a) communicate with the relevant state entities promptly following issuance of a final rule, (b) in a manner reasonably calculated to be received by the relevant state entities, and (c) establish a forum for negotiation among the transmission providers and the relevant state entities that enables full and robust participation from each during the period allotted for making compliance filings. Even though RTOs/ISOs have established modes and institutions for communication with state commissions, sufficient guidance from the Commission will avert the potential for confusion amongst stakeholders as to whether public utility transmission providers have made adequate efforts to fulfill the proposed obligation when developing selection criteria for Long-Term Regional Transmission Planning. Transmission providers and some regional transmission planning organizations outside of RTOs either have established methods and institutions for communication with state commissions or understand the operations and policies of their state regulators and will follow the Commission’s guidance regarding consultation.

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[123] NOPR at PP 242, 244.

Further, NARUC seeks clarification as to what recourse will be available to state commissions, as relevant state entities under paragraph 304 of the NOPR, in the event that there is a breakdown in the process for establishing selection criteria or where the public utility transmission providers and relevant state entities cannot reach an accord. Given the Commission's stated goal of accommodating individual states' energy policies and goals into Long-Term Regional Transmission Planning, NARUC opposes any resolution that permits public utility transmission providers to override or ignore any selection criteria promulgated and supported by relevant state entities.

ii. State Involvement in Cost Allocation for Long-Term Regional Transmission Facilities

NARUC strongly supports the Commission's proposal to involve states in cost allocation for Long-Term Regional Transmission Facilities[124] and conversely explicitly rejects a requirement that public utility transmission providers include a Long-Term Regional Transmission Cost Allocation Method in their OATTs without being obligated to seek agreement from relevant state entities.[125] There are numerous reasons for FERC to formally offer state regulators a seat at the table. State regulators are eager to collaborate with the Commission and with transmission providers on the challenging and rewarding project of planning a bulk transmission system that meets the needs of our energy future.

FERC noted the general consensus that, given states' role in making state public interest determinations when siting transmission facilities, involving state regulators is particularly important.[126] FERC posited that early state involvement in cost allocation could minimize delays

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124 NOPR at PP 303-318.
125 NOPR at P 318.
126 NOPR at P 300.

and the associated costs, thus leading to just and reasonable Commission-jurisdictional rates.[127] NARUC concurs.

In many regions, state regulators are at the forefront of successful efforts to coordinate regional transmission, including what many understand to be the most challenging issue, cost allocation. For instance, in SPP, the Regional State Committee has the primary authority for setting the basis of any regional cost allocation. In both MISO and ISO-New England, state committees have the ability to propose alternative cost allocation methodologies under some circumstances.[128]

Moreover, since the projects under consideration in the Long-Term Regional Transmission Planning process are largely driven by state public policies, state regulators should have a key role in evaluating the benefits and allocating the costs. State regulators are attuned to the concerns of the local communities where the transmission will be sited[129] and the retail ratepayers who must, in many instances, foot a large fraction of the cost.[130] For instance, retail ratepayers in many states face significant energy burdens, but some regions face higher levels of household energy insecurity than others.[131] During the Federal-State Task Force Meeting on

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127 NOPR at PP 99, 301.

128 *See* MISO Transmission Owners Agreement, Appendix K, Article II, Section II.E.3.b (providing regional state committee with the opportunity to develop and request MISO file an alternative cost-allocation methodology under certain circumstances); ISO New England, Agreements and Contracts, Transmission Operating Agreement, § 3.04 (h)(vi)(A-C) (providing regional state committee with opportunity to provide alternative cost allocation proposal in connection with certain transmission cost allocation provisions in ISO-NE's tariff).

129 *Joint Fed.-State Task Force on Elec. Transmission*, Transcript of Feb. 16, 2022 Meeting, Docket No. AD21-15-000 ("Task Force Feb. Meeting Transcript"), at 116:21 (Chair Dutrieuille).

130 Task Force Feb. Meeting Transcript at 108:5-12 (Cmm'r Duffley).

131 U.S. Energy Information Administration, *In 2020, 27% of U.S. Households Had Difficulty Meeting Their Energy Needs* (April 11, 2022), available at https://www.eia.gov/todayinenergy/detail.php?id=51979&src=%E2%80%B9%20Consumption%20%20%20%20%20%20Residential%20Energy%20Consumption%20Survey%20(RECS)-b3.

regional transmission planning and cost allocation, a theme that emerged was the importance of accounting for the "human element" and meeting people where they are.[132]

NARUC agrees that involving state commissions in cost allocation for Long-Term Regional Transmission Facilities will facilitate state commissions' oversight of the reasonableness and prudence of associated costs.[133]

1. FERC should allow transmission providers and state entities wide latitude regarding the approach to cost allocation for Long-Term Regional Transmission Facilities.

In proposing reforms regarding cost allocation for Long-Term Regional Transmission Facilities, the Commission has sought comment in several places regarding the amount of discretion that should be left to states and transmission providers. NARUC agrees with the opinion expressed by several state commissioner members of the Federal-State Task Force: FERC is well-advised to regulate in this arena with a light touch.[134]

In following this guidance, FERC should not adopt a specific definition of the agreement among state entities with respect to a planning region's cost allocation approach alternate proposal to define state agreement.[135] A FERC-defined "one size fits all" definition of "agreement" is less likely to advance the goals of the NOPR.

Specifically, NARUC agrees with FERC's proposal that public utility providers in each transmission planning region should be afforded flexibility in the process by which they seek agreement from the relevant state entities.[136] As noted above, RTOs/ISOs have established modes and institutions for communication with state commissions. Transmission providers and

132 Task Force Feb. Meeting Transcript at 85:12-14 (Chair Thomas).
133 NOPR at P 287.
134 Task Force Feb. Meeting Transcript at 94:24 (Chair LeVar); 107:24 (Comm'r Duffley).
135 *See* NOPR at P 309.
136 NOPR at P 306.

some regional transmission planning organizations outside of RTOs also understand the operations and policies of their state regulators. Similarly, NARUC supports FERC's proposal to provide the state entities with flexibility in defining what constitutes "agreement" among them for the purposes of determining an appropriate cost allocation approach for Long-Term Regional Transmission Facilities.[137] Within RTOs/ISOs, existing organizations of state regulatory commissions, such as the Organization of MISO States, Organization of PJM States, and the Regional State Committee – Southwest Power Pool, already have well-oiled working relationships and processes. Outside of organized markets, the state commissioners may need to forge new institutions or establish new processes, and accordingly flexibility is particularly important. Because each regional context holds unique challenges and opportunities, each planning region should be given ample room to build consensus. This path has the greatest promise of achieving FERC's goal of increasing the likelihood of beneficial Long-Term Regional Transmission Facilities being constructed efficiently and cost-effectively.

At the same time, as with seeking state agreement on the selection criteria for Long-Term Regional Transmission Facilities, the Commission should provide guideposts for transmission providers to ensure that they engage with the relevant state entities in a timely and appropriate way.

2. FERC should allow sufficient on-ramps to allow for meaningful participation by relevant state entities.

In the NOPR, the Commission acknowledges that it has no power to compel states to participate in cost allocation for Long-Term Regional Transmission Facilities[138] and accordingly

[137] NOPR at P 306.
[138] *See* NOPR at P 309.

seeks comment as to the appropriate outcome when states attempt to reach agreement on a cost allocation approach but are unable to do so.[139]

First, NARUC urges FERC to require transmission providers to file changes to their OATTs that reflect as much consensus as was reached. For example, if the relevant state entities reach agreement as to cost allocation for a portion of Long-Term Regional Transmission Facilities (*e.g.*, for projects under 230kV), but not others, the transmission providers should reflect that agreement in their compliance filings. Additionally, the cover letter to the filing must provide space for any state to express its position on the filing, without prejudice to the ability of the state to also file comments in any proceeding created by the filing.

Second, FERC should provide some mechanism for future review of cost allocation methodologies for Long-Term Regional Transmission Facilities as reflected in the transmission providers' OATTs. As the name suggests, these transmission facilities are expected to be planned over a longer period of time than projects built for reliability or economic reasons. States that do not currently have public polices requiring extensive transmission investments may forego an opportunity to participate in discussions regarding cost allocation, but their public policies may evolve over time. For the reforms proposed in this NOPR to be successful, the positions of relevant state entities should not be frozen in time. This is even more important in light of the fact that even an extended compliance period as proposed by FERC may not be sufficient to allow states to engage in the arduous task of reaching agreement over cost allocation methodologies, as discussed below. Accordingly, NARUC suggests that the Commission's final rule provide some mechanism for ensuring that transmission providers remain in compliance with the requirements to include relevant state entities in cost allocation for Long-Term Regional

[139] NOPR at P 310.

Transmission Facilities. One possibility is to require the transmission provider to open a new negotiation period with the relevant state entities periodically. Another possible reform is to require transmission providers to file a modification to their OATTs if states reach the requisite agreement on a different cost allocation methodology than reflected in the OATT then on file. NARUC recognizes that FERC must balance this need to accommodate changes in position with the need for a level of certainty and administrative efficiency and does not expect nor advise that a final rule provide for ceaseless negotiation.

3. NARUC supports an extended compliance period for any rule affording state entities a role in cost allocation for Long-Term Regional Transmission Facilities.

In the NOPR, the Commission has proposed an eight-month compliance period "in order to accommodate meaningful engagement with states with respect to this Long-Term Regional Planning cost allocation reform."[140] NARUC supports a compliance period of at least this long. In the experience of NARUC members, eight months is unlikely to allow sufficient time for state entities to meaningfully engage around these topics. For example, since MISO filed a cost allocation method that divided postage stamp rates between MISO Midwest and MISO South in February of 2022, the MISO cost allocation committee has been discussing a replacement cost allocation method and expects to continue these discussions until well into 2023. For planning regions outside of RTOs/ISOs, state commissions may not be conversant with various cost allocation methods and will face a learning curve on substantive issues in cost allocation. Further, state entities likely will have internal legal and procedural issues to sort through regarding a number of issues, including delegating negotiating authority, receiving stakeholder input at the state level, ensuring that their involvement in federal tariffs is not deemed to be

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[140] NOPR at P 306 n.513 and 430.

prejudging the outcomes of state proceedings, and coordinating with legislative and executive branch entities to ensure that the state regulatory entities have authority to negotiate on behalf of their states and retail ratepayers. Given their existing state retail regulatory duties, eight months will likely be insufficient to allow the relevant state entities to coordinate internally and externally on this consequential matter.

4. NARUC supports the Commission's proposed framework for transmission providers to engage with relevant state entities in arriving at a cost allocation method for Long-Term Regional Transmission Facilities.

NARUC supports FERC's proposal to require public utility transmission providers to establish a process for determining the appropriate cost allocation methodology for Long-Term Regional Transmission Facilities with multiple opportunities for participation by relevant state entities.

Initially, public utility transmission providers would be required to seek agreement from relevant state entities regarding the approach to cost allocation to be filed in the transmission provider's OATT, which may include a Long-Term Regional Transmission Cost Allocation Method, a State Agreement Process, or a combination of the two.[141] NARUC is particularly supportive of the State Agreement Process, which is similar to the PJM State Agreement Approach that has been approved by FERC and that NARUC and state commissions advocated to be included in the final rule.[142] A state agreement approach allows states to further their public policy goals without burdening the ratepayers of states that have different priorities.

Following selection of a Long-Term Regional Transmission project, the Commission proposes to provide states a time period in which to negotiate a cost allocation method that is

141 NOPR at P 305.
142 NOPR at P 289 (citing comments of NARUC, Ohio Commission, and Pennsylvania Commission).

different from the *ex ante* cost allocation method that would otherwise apply.[143] NARUC finds this to be a very constructive concept. Once a Long-Term Regional Transmission Facility has been modeled and selected through the transmission planning process, its benefits will be far easier for states to identify and value, and therefore, this "second bite at the apple" offers an opportunity for developing a cost allocation method that is more satisfying to a greater number of stakeholders.

As stated in its ANOPR comments, NARUC agrees that the six Order No. 1000 cornerstone cost allocation principles should apply to Long-Term Regional Transmission Facilities, and it agrees with the Commission that those principles should govern any *ex ante* state agreement process as well.[144]

However, there are some details of FERC's proposed reform with which NARUC does not agree. First, FERC proposes to prescribe a 90-day time period for a state-negotiated cost allocation to be memorialized in writing, reasoning that this is consistent with the period for state cost allocation negotiation that the Commission accepted in NYISO's filing.[145] Ninety days may have been a sufficient amount of time for a single-state planning region, but most regions are much larger than a single state. Additionally, state commissions may need to conduct state regulatory proceedings in order to meet state law obligations before obligating retail ratepayers, and ninety days likely is insufficient to allow for such proceedings. At the same time, NARUC understands the need for selected projects to move forward. Accordingly, NARUC suggests that FERC require public utility transmission providers add to their OATTs a six-month period for states to arrive at and document a state-negotiated alternate cost allocation method, but

[143] NOPR at PP 319-324.
[144] NOPR at P 312.
[145] NOPR at P 323.

transmission providers should be able to add a period of less than six months if they receive unanimous agreement of affected states.

Second, the Commission proposes that if the states in which a selected regional transmission facility will be located unanimously agree on a state-negotiated alternate cost allocation method, then the public utility transmission provider *may* elect to file it with the Commission under FPA section 205.[146] However, NARUC recommends that if such an agreement has been reached, the transmission provider be required to file it with FERC as part of its section 205 filing. If the transmission provider concludes that the state agreement process has yielded a cost allocation method that does not comply with the six cost allocation principles found in Order No. 1000 or is otherwise deficient, then the transmission provider may include in the filing the cost allocation method that would apply in the absence of state agreement. This procedure would not violate the public utility transmission provider's rights to make a Section 205 filing but would be a procedural rule establishing the filing requirements for Section 205 filings relating to cost allocation for Long-Term Regional Transmission Facilities.

5. NARUC supports the Commission's proposal to give states the option of voluntarily funding transmission facilities.

In a similar vein, NARUC supports the Commission's proposal to allow relevant state entities to agree, using the State Agreement process (or, where applicable, the PJM State Agreement Approach) to commit their customers to fund all or a portion of a Long-Term Regional Transmission Facility as a means of meeting a planning region's selection criteria.[147] In fact, NARUC suggests that the Commission make no effort to inhibit any type of public funding or, where state law permits, private entities' subscription to all or a part of a transmission

[146] NOPR at P 319.
[147] NOPR at P 252.

facility to ensure it is funded and constructed.[148] Significant ratepayer savings could be achieved in this manner. The Commission has sought guidance on how such an agreement would be documented in order to assure that the commitment is legally binding. Because that issue is deeply intertwined with state law, transmission providers should be given latitude in their compliance filings to account for applicable circumstances to demonstrate a legally binding commitment has occurred.

C. CONSTRUCTION WORK IN PROGRESS INCENTIVE

Construction work in Progress ("CWIP") is an accounting designation stated in the FERC Uniform System of Accounts.[149] Inclusion of CWIP in rate base is a regulatory outcome that first gained traction during the 1970s when very expensive nuclear power plants that took significant time to build were being constructed during a time of high inflation. As stated in the NOPR, more recently FERC has permitted inclusion of CWIP in rate base as an incentive for transmission deployment.[150]

Inclusion of CWIP in rate base is an exception to the general rule that utility plant must be used and useful before it will be included in rate base. Costs booked as CWIP with respect to a particular project, including financing costs as Allowance for Funds Used During Construction ("AFUDC"), are typically added to rate base only upon completion of that project. Thus, costs booked as CWIP are typically recovered only after a project becomes used and useful. This protects ratepayers from the risk of a project not being completed.

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[148] Task Force Feb. Meeting Transcript at 83:24-85:6 (Comm'r Duffley) & 90:12 (Comm'r Allen).

[149] 18 CFR § 367.1070 Account 107, Construction work in progress.

[150] NOPR at P 329. *See also, Promoting Transmission Inv. through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

NARUC agrees with proposed reform in the NOPR to make Long-Term Transmission Projects ineligible for CWIP in rate base. This approach better aligns risk and reward between shareholders and ratepayers with respect to Long-Term Transmission Projects. CWIP includes financing costs incurred during the development of a project. Ratepayers should not incur costs related to projects that are not completed. Additionally, NARUC requests that FERC review the current abandoned plant policy to ensure that ratepayer benefits from the adoption of the proposed rule with respect to CWIP do not disappear if those costs are still recovered from ratepayers as abandoned plant.

The consequences of including CWIP and associated financing costs in rate base for a transmission project that is not completed can be very significant for ratepayers. For example, in 2007, PJM approved a 275-mile 765 kV line from Amos Substation in West Virginia through Virginia to the new Kemptown Substation in Maryland, known as the Potomac-Appalachian Transmission Highline ("PATH").[151] The Commission granted PATH several transmission rate incentives, resulting in a 14.3% return on equity.[152] PATH (either directly or through its member affiliates) subsequently sought approval from the affected states, was unable to secure approval in any state, and ultimately withdrew those applications. Later PJM studies showed that the

151 *PJM Interconnection, LLC*, 121 FERC ¶ 61,034 at n. 10 (2007).
152 *Potomac-Appalachian Transmission Highline, LLC*, 122 FERC ¶ 61,188 (2008).

project was not needed.[153] After several reconfigurations and analyses, on August 24, 2012, PJM terminated the PATH Project and removed it from the Regional Transmission Expansion Plan.[154]

In requesting approval from the Virginia State Corporation Commission ("SCC") to withdraw, PATH represented that "there's no authority to go to FERC for a construction permit for 2014, or at this point any other year."[155] Nevertheless, PATH continued to collect its annual transmission revenue requirement under its formula rates, until in 2012 it sought approval of more than $120 million in abandonment costs.[156] PATH has continued to collect millions in revenues from customers, and it is unclear when such collection will cease, although it never delivered any electricity anywhere.[157]

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153 *Application of PATH Allegheny Virginia Transmission Corporation, for certificates of public convenience and necessity to construct facilities: 765 kV transmission line through Loudoun, Frederick and Clarke Counties,* Case No. PUE-2009-00043, Order Granting Withdrawal (Jan. 27, 2010)(finding that project not needed to resolve reliability violations in 2014); *Application of PATH Allegheny Virginia Transmission Corporation, for approval and certification of transmission facilities under Va. Code § 56-46.1 and the Utility Facilities Act, Va. Code § 56-265.1 et seq.*, Case No. PUE-2010-00115, Order Granting Withdrawal (May 24, 2011)(finding that the violations the project was expected to resolve had advanced "into the future").

154 *See, PJM Interconnection, LLC and Potomac-Appalachian Transmission Highline, LLC*, 153 FERC ¶ 61,308 (2015).

155 *Application of PATH Allegheny Virginia Transmission Corporation, for certificates of public convenience and necessity to construct facilities: 765 kV transmission line through Loudoun, Frederick and Clarke Counties,* Case No. PUE-2009-00043, Order Granting Withdrawal at n. 6 (quoting counsel for PATH).

156 *See, Potomac-Appalachian Transmission Highline, LLC,* Docket No. ER09-1256-002, Opinion No. 554, 158 FERC ¶ 61,050 (2017).

157 In a May 1, 2020 compliance filing, PATH identified a number of proceedings at the Commission and in the courts that would first need to be resolved before it could consider dissolution and cancellation of the formula rate. It also indicated that no such dissolution could occur until after "the PATH Companies [evaluated] their financial needs." PATH submitted its 2021 formula rate update on June 1, 2022, which included an actual annual transmission revenue requirement of $622,684 for Rate Year 2021 (more than 10 years after it indicated to the Virginia SCC that the Commission "could not" issue a construction permit).

D. ENHANCED TRANSPARENCY OF LOCAL TRANSMISSION PLANNING INPUTS IN THE REGIONAL TRANSMISSION PLANNING PROCESS

The NOPR emphasizes enhanced transparency of local transmission planning inputs in the regional transmission planning process and identification of potential opportunities to right-size replacement transmission facilities.[158] NARUC generally supports the reforms for local transmission planning and transmission operators evaluating opportunities for "right-sizing" transmission replacements, with certain modifications explained below. NARUC has concerns that some of the reforms may be overly prescriptive and supports reforms that provide states and regions with flexibility to implement these reforms. NARUC also recommends further reforms to improve upon the Commission's proposals. NARUC's support and concerns, as well as the need for additional reforms, are discussed below.

1. Enhanced Transparency and Coordination

In response to the ANOPR, NARUC supported reforms that would improve coordination and transparency between local and regional transmission planning processes.[159] NARUC also supported the consideration of both alternative transmission and non-transmission solutions wherever possible.[160] NARUC's position remains unchanged. Moreover, NARUC generally supports the further processes to improve coordination and transparency identified in the NOPR.

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158 NOPR at PP 398-414.

159 NARUC ANOPR Comments at 14-15. In the ANOPR, the Commission sought "comment on whether and how greater oversight may improve coordination between individual transmission provider's planning processes and regional transmission planning processes." ANOPR at P 171.

160 NARUC ANOPR Comments at 9. In the ANOPR, the Commission noted that Order No. 1000 requires the evaluation of "alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers." ANOPR at P 171.

NARUC agrees that in some planning regions the current regional and local transmission planning processes may not provide "sufficient transparency for stakeholders to understand how best to obtain information and fully participate in the various processes."[161] NARUC also agrees that "by evaluating replacement transmission facilities through the regional transmission planning process, a potentially broader transmission solution may be identified thus obviating the need for a smaller-scope replacement transmission facility."[162] This remains especially important when replacing aging transmission assets to avoid missed opportunities to "upsize" transmission facilities to address multiple system needs and future energy goals, while reducing costs and inefficiencies.[163] NARUC agrees that within RTO/ISO regions, the process for local planning needs improvement, that the replacement of aging facilities lacks transparency and is a growing concern, and that transmission owner compliance with FERC Order No. 890 planning requirements for local planning has been uneven.[164]

NARUC supports enhancing transparency and visibility of local transmission planning processes and coordinating with Long-Term Regional Transmission Planning and other processes that will benefit from this coordination (*e.g.*, reforms to the interconnection queue process). Further, NARUC supports reforms to right-size the replacement of transmission assets that reduce ratepayer cost and address multiple system needs. Any coordination of local and regional transmission planning and right-sizing should include the consideration of grid-enhancing technologies and Non-Transmission Alternatives (demand-side solutions and

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161 NOPR at P 391.
162 NOPR at P 391.
163 NOPR at P 391.
164 NOPR at PP 398-399.

energy efficiency). In addition, as we address further below, reforms should not be overly prescriptive and should provide state and regional flexibility when implementing reforms.

2. Local Transmission Planning Inputs

NARUC supports reforms that require public utility transmission providers in each transmission planning region to revise the regional transmission planning process in their OATTs with provisions to enhance transparency. NARUC supports the specific reforms identified in the NOPR that require revisions to: (1) the criteria, models, and assumptions that planners use in their local transmission planning process; (2) the local transmission needs identified through that process; and (3) the potential local or regional transmission facilities that will be evaluated in addressing those local transmission needs.[165] NARUC also supports the reforms that require public utility transmission providers to establish an iterative process that would ensure that stakeholders have meaningful opportunities to participate in and provide feedback on local transmission planning throughout the regional transmission planning process.[166] While NARUC supports the general reforms to the transmission planning process to enhance transparency, the reforms will be overly prescriptive with respect to the timelines and the detailed requirements for meetings under the proposed Stakeholder Review Process.[167] NARUC requests that regions be provided flexibility to determine an appropriate stakeholder process that works best for the region.

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165 NOPR at P 400.
166 NOPR at P 400.
167 NOPR at PP 400-401.

3. Utility Self-Approved Projects and Stakeholder Input

In the NOPR, the Commission proposes a stakeholder transparency process, the "Stakeholder Review Process," that would improve upon existing opportunities for stakeholder review of local transmission projects in some regions of the country.[168] While the Commission's proposal is an important step in the right direction, NARUC recommends that the Commission consider two additional optional reforms. First, the Commission should allow for the option that the proposed Stakeholder Review Process equally apply to repair and/or replacement projects that do not expand the capacity of the transmission system, or do so only incidentally, referred to here as "utility self-approved projects,"[169] in particular those that are forecast to cost $3 million or more. This would not be a requirement, rather an option that state commissions could opt to do by notifying its transmission planner that such review is necessary. Further, to ensure that ratepayer funding is appropriately used to develop the most efficient and cost-effective solutions to identified transmission needs, the Commission should allow the option that local and utility self-approved projects to be reviewed *and approved* as part of regional transmission planning

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168 NOPR at PP 400-402, 404. The Commission's proposed Stakeholder Review Process appears to be based on PJM's existing Attachment M-3 process. *See* Attachment M-3, Additional Procedures for Planning Supplemental Projects and Asset Management Projects, *available at* https://pjm.com/directory/merged-tariffs/oatt.pdf. Thus, the Commission's proposal does not appear to improve upon the existing process for stakeholder review of local projects in PJM.

169 *See* NARUC ANOPR Comments at 48 n.87 (defining utility self-approved projects and emphasizing that "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.'"). The Commission has previously held that repair and replacement projects that do not expand the capacity of the grid are not subject to Order No. 890's transmission planning requirements. *California Pub. Utils. Comm'n v. Pac. Gas and Elec. Co.*, 164 FERC ¶ 61,161 (2018), *order on reh'g*, 168 FERC ¶ 61,171 (2019); *S. California Edison Co.*, 164 FERC ¶ 61,161 (2018), *order on reh'g*, 168 FERC ¶ 61,170 (2019).

processes.[170] Again this requirement would be optional for regional or state planning processes and the decision as to whether this requirement would apply in a given region would be determined by the applicable state commissions.

Allowing the Stakeholder Review Process to apply to both transmission planning and utility self-approved projects may help ensure that ratepayer funds are spent on the most efficient and cost-effective transmission solutions. As NARUC has previously emphasized, unreviewed or under-reviewed utility self-approved projects currently comprise approximately half of investor owned utilities' transmission spending in FERC-jurisdictional RTOs/ISOs.[171] In the absence of this option, the proposed Stakeholder Review Process may only apply to "local transmission planning,"[172] which would exclude review of utility self-approved projects in certain regions.[173] For example, in the California Independent System Operator Corporation ("CAISO") region, repair and/or replacement projects that do not expand the capacity of the grid,

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170 NARUC ANOPR Comments at 48 (recommending that utility self-approved projects "should be evaluated in regional transmission planning processes to ensure they are needed and are the most cost-effective alternative.").

171 NARUC ANOPR Comments at 48 (*citing* 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 6 (explaining 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).

172 *See e.g.*, NOPR at P 400 (emphasis added) ("Under this proposed reform, public utility transmission providers would be required to establish an iterative process that would ensure that stakeholders have meaningful opportunities to participate and provide feedback on *local transmission planning* throughout the regional transmission planning process.").

173 *See* NARUC Comments at 49 ("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. 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.").

or do so only incidentally, are not considered within the "local transmission planning" process and are not approved as part of the transmission planning process.[174]

The NOPR's proposed Stakeholder Review Process would increase stakeholders' ability to provide input on local transmission planning in certain regions,[175] such as in the CAISO.[176] However, it may fail to ensure that the most efficient and cost-effective transmission solutions will be developed because it appears to vest transmission owners with the discretion to unilaterally reject any and all stakeholder input. Although the NOPR emphasizes that the Stakeholder Review Process will provide "needed additional transparency into local transmission planning processes,"[177] it does not require transmission owners to consider stakeholder input in any specific way or, most importantly, to reach agreement with stakeholders on the "local transmission planning information" that the transmission owner ultimately submits to the grid operator.[178]

To ensure that ratepayer funds are spent on the most efficient and cost-effective transmission solutions, the Commission should allow the option that all transmission projects—regional, local, and utility self-approved projects—be reviewed *and approved* in regional transmission planning processes. The states in each region would be provided flexibility to enact

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174 *See* note 159 *supra*.

175 *See* NOPR at P 401 (requiring at least three stakeholder meetings with at least 25 calendar days between the meetings prior to incorporation of "local transmission planning information" into regional transmission planning processes).

176 *See* Reply Comments of the California Public Utilities Commission, Docket No. RM21-17-000 (November 30, 2021) at 21-22 (where the CPUC similarly called for the Commission to require transmission owners to submit local projects for evaluation with sufficient lead time to allow stakeholders to properly evaluate alternatives and specifically to provide transmission planners and stakeholders with a list of all transmission projects looking forward several years). Notably, the CAISO already reviews local projects—so long as they expand the capacity of the grid—as part of the transmission planning process.

177 NOPR at P 402.

178 NOPR at P 401.

this reform. This optional reform would help to eliminate the existing, perverse incentive for incumbent investor-owned utilities in some instances to concentrate transmission spending on utility self-approved projects and thereby avoid external scrutiny.[179] It would also help ensure that proposed local transmission projects are truly needed and are evaluated in relation to other potentially more efficient and cost-effective alternatives—such as regional projects, grid-enhancing technologies, and/or non-wires solutions—thereby reducing the incentive to concentrate transmission spending on smaller, piecemeal projects.[180]

4. Opportunities to Right-Size Replacement Transmission

NARUC supports reforms that require public utility transmission providers to assess the right-sizing of replacement transmission assets to determine whether the right-sized transmission replacement might more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Planning.[181] Replacing end-of-life facilities with larger facilities, if proven to be beneficial, might in some instances serve regional needs better than a mere replacement facility. Transmission facilities have a long life. When local projects were originally planned, transmission needs were likely different from the needs that will exist at the time the transmission facilities would need replacement. It is thus prudent to reevaluate a facility to determine if a transmission alternative could efficiently serve a regional

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[179] *See* PJM, *2021 Regional Transmission Expansion Plan* (March 7, 2021) at 61, available at https://www.pjm.com/-/media/library/reports-notices/2021-rtep/2021-rtep-report.ashx **(In 2021, there were $3.3 billion in supplemental projects included in the plan)**; at 4 (In 2021, there were $920 million in regionally planned projects, and an additional $48 million in network regional transmission projects added).

[180] *See* NOPR at P 350 (where the Commission acknowledges that under the status quo incumbent transmission owners "may be presented with perverse investment incentives that do not adequately encourage [them] to develop and advocate for transmission facilities that benefit more than just their own local retail distribution service territory or footprint.").

[181] NOPR at PP 403-405.

need. Therefore, allowing a process for transmission owners to assess this possibility independently should be encouraged.

However, NARUC remains concerned that the reforms identified for right-sizing may be overly prescriptive and supports regional flexibility in implementing these reforms. First, FERC has proposed limiting local projects eligible for right-sizing to those operating at or above 230 kV.[182] NARUC is concerned that this threshold could exclude a significant portion of utility self-approved projects and other grid-critical projects. For example, in PG&E's service territory, 52% ($5.6 billion) of the utility's forecast capital expenditures for 2021 to 2026 ($10.9 billion) are self-approved repair and replacement projects that are under 200 kV and are therefore not currently subject to CAISO review and would not be subject to review under FERC's proposal. Providing another example, ISO-NE has many 115 kV lines, and the proposed 230 kV threshold would impede the ability to consider right-sizing many transmission projects in ISO-NE. States should have discretion and flexibility to agree to require right-sizing asset replacement at voltages below 230 kV to help ensure that the majority of project opportunities are addressed.

Second, NARUC is concerned that a 10-year horizon for assessing right-sized replacement projects is overly prescriptive and supports regional flexibility in determining the appropriate timeline so regions may choose a shorter or longer time horizon.[183]

5. Assessing Benefits of Right-Sized Transmission

Benefits of projects eligible for regional cost allocation identified through the Long-Term Regional Transmission Planning process should be the same across all categories. Accordingly,

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182 NOPR at P 406.
183 NOPR at PP 403-406.

NARUC supports assessing the benefits of right-sized facilities consistent with the assessment used in the Long-Term Regional Transmission Planning. As the Commission observes, "benefits associated with right-sizing potential replacement transmission facilities to address transmission needs identified through Long-Term Regional Transmission Planning should be evaluated the same as any potential transmission facility that could address that transmission need."[184] As in all transmission planning processes, to determine the needs of a facility, the benefits and beneficiaries must be identified to a reasonable degree of certainty.

6. Cost Allocation and Incremental Costs of Right-Sized Transmission

NARUC supports reforms that if a right-sized replacement transmission facility is selected in the regional transmission plan for purposes of cost allocation, only the incremental costs of right-sizing the transmission facility will be subject to the applicable Long-Term Regional Transmission Cost Allocation Method.[185] In addition, NARUC supports requirements that transmission providers determine incremental costs of right-sizing the transmission facility, consistent with determinations for cost allocation made in Long-Term Regional Transmission Planning.[186]

7. Ensuring Cost Containment in Local Planning

While NARUC supports FERC's proposal on transparency in the local planning process, some states find that FERC's proposal may not fully resolve the trend which has developed since Order No. 1000 of transmission owners avoiding competition by increasing use of local projects.

184 NOPR at P 406.
185 NOPR at P 410.
186 NOPR at P 413.

In its ANOPR comments, NARUC addressed the Commission's request for comment on whether local transmission oversight is needed and whether processes for replacement facilities for aging transmission ensured the evaluation of alternatives to find the most cost-effective methods to serve future needs.[187] FERC took up that mantle and addressed both issues. Namely, as to transparency of local planning, FERC effectively adopted PJM's Attachment M-3 process. Like FERC's proposal on local planning transparency, the PJM Attachment M-3 process establishes an "Assumptions Meeting," a "Needs Meeting," and a "Solutions Meeting" with no fewer than 25 days between each of these meetings.[188] As discussed above, NARUC supports the use of a transparent process defined in the transmission provider's OATT. In its ANOPR comments, NARUC argued that applying Order No. 890 transparency principles was "the most critical reform needed at this time" with respect to utility self-approved projects, including local projects.[189]

Yet, this support does not fully alleviate concern for cost containment of local transmission projects. As pointed out in NARUC's ANOPR comments, local project development has significantly increased.[190] Within PJM, even with using the transparent Attachment M-3 process, local transmission projects and utility self-approved projects have expanded since Order No. 1000.[191] Further reform, whether taken by FERC or on a region-by-region basis, may be needed in order to contain the relatively unchecked costs of local planning processes in states that lack authority to review and approve such projects in RTO/ISO regions.

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187 NARUC ANOPR Comments at 48.

188 NOPR at P 401; PJM Open Access Transmission Tariff, Attachment M-3(c).

189 NARUC ANOPR Comments at 48-49

190 NARUC ANOPR Comments at 55-56

191 NARUC ANOPR Comments at 55, n.100; PAPUC at 16-17; NJ Comments at 4-6.

E. INTERREGIONAL TRANSMISSION COORDINATION AND COST ALLOCATION

NARUC maintains that there may well be reliability, resiliency, economic, and public policy benefits to be gained through more robust interregional connectivity and that there is significant value in enhanced interregional transmission planning to meet evolving transmission system needs. Additional bulk power transfer capabilities across the RTO/ISO and non-RTO regions could become necessary to maintain system reliability during extreme weather events[192] and under a variety of future generation mix scenarios. As such, NARUC supports the Commission's proposal that public utility transmission providers revise their existing interregional transmission coordination procedures to reflect regional long-term scenario-based transmission planning processes.

Specifically, NARUC supports the NOPR's proposed requirements that existing interregional coordination procedures (and regional transmission planning processes as needed) be revised to provide for: (1) the sharing of information regarding the respective transmission needs identified in each regions' Long-Term Regional Transmission Planning process, as well as potential regional transmission facilities identified to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective to address transmission needs identified through Long-Term Regional Transmission Planning.[193]

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[192] *See, e.g.*, SPP's Comprehensive Review of SPP's Response to the February 2021 Winter Storm, which 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." 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.

[193] NOPR at P 427.

In particular, there is significant value in transparency and information sharing at the interregional level. In its ANOPR comments, NARUC posited that "planning process[es] should share system planning information on an interregional level whenever appropriate."[194] The NOPR's proposal to incorporate regional long-term planning processes into existing interregional coordination procedures aligns with NARUC's observations that more specific timeframe and modeling parameters are an area for enhanced interregional planning coordination.

The Commission also proposes to require public utility transmission providers to revise their interregional transmission coordination procedures to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution for transmission needs identified through Long-Term Regional Transmission Planning processes.[195] Consistent with NARUC's position on long-term transmission planning reforms proposed in the NOPR, regions should be afforded flexibility to determine long-term transmission planning and modeling parameters in coordination with their stakeholder communities. Flexibility will help ensure that long-term transmission planning parameters align with diverse local and state siting requirements so that proposed long-term regional transmission projects are more likely to gain state and local approval, and ultimately have a better chance of being placed in service.

NARUC notes that the existing transmission planning framework established by the Commission permits transmission planning regions to conduct the type of long-term planning envisioned by the NOPR; incorporating this type of planning into existing interregional

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194 NARUC ANOPR Comments at 18.
195 NOPR at P 428.

coordination processes is a logical extension. However, the Commission should avoid requiring a heavily prescribed Long-Term Regional Transmission Planning process that would have to be recreated on each interregional seam. Indeed, some of the most successful and promising interregional planning processes to-date have been conducted jointly by RTOs/ISOs outside of the required Order No. 1000 coordination procedures outlined in their Joint Operating Agreements. Specifically, these include the MISO-PJM Targeted Market Efficiency Project study process that addresses historical congestion along the seam, and the SPP-MISO JTIQ study process to identify interregional facilities needed to enable generation along that seam. Maintaining a focus on increasing bulk power transfer capabilities across regions while providing additional opportunities for RTOs/ISOs and non-RTOs to continue to innovate in these ways can help ensure that the Commission's laudable goals with regard to expanded interregional transmission are met in a manner that is practical, recognizes important differences between regions, and as a result is more likely to ensure the durability of interregional transmission planning processes and the benefits these processes may provide.

Finally, the Commission should consider providing clarity in the final rule concerning coordinating regional transmission planning and interregional transmission planning for public utility transmission providers that are not members of, or for planning regions not covered by, an RTO/ISO. Market structures are evolving rapidly in the Western Interconnection. The way the proposed rules may be implemented in this region could impact the pace or direction of that evolution either positively or negatively.

Areas of the Western Interconnection not served by the California ISO are served by two non-RTO planning entities, Northern Grid and West Connect. The proposed rule does not make changes to existing interregional transmission coordination requirements but requires public utility transmission providers to revise their existing interregional transmission coordination procedures.[196] The Commission could consider whether the final rule should encourage more coordination, information sharing, and potentially joint planning between those types of non-RTO/non-ISO planning entities when they are contiguous.

III. CONCLUSION

NARUC respectfully requests that the Commission consider these comments. NARUC thanks the Commission for the opportunity offer its views. Through the NOPR process and engagement in the Task Force, NARUC looks forward to working collaboratively with FERC in exploring these reforms and others.

Respectfully submitted,

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Dated: August 17, 2022

196 NOPR at P 416.

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: August 17, 2022

Respectfully submitted:

/s/ Jennifer M. Murphy