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 Rural Electric Cooperative Association

The National Rural Electric Cooperative Association (NRECA) respectfully submits the following comments in response to the Advanced Notice of Proposed Rulemaking (ANOPR).[1] NRECA submits these comments to provide the broad perspective of its member electric cooperatives. Individual cooperatives may file comments reflecting their specific views and experiences.

I. NRECA Members' Interest in This Proceeding

NRECA appreciates the opportunity to comment on the ANOPR's questions concerning the Commission's current transmission planning and cost allocation and generator interconnection policies, as the Commission both evaluates the effectiveness of its current policies and assesses the need for potential policy reforms to improve these processes in light of future transmission needs, including those associated with changing generation facilities, electricity markets, and public policies.

NRECA is the national trade association representing nearly 900 local electric cooperatives and other rural electric utilities. America's electric cooperatives are built by and owned by the people that they serve and comprise a unique sector of the electric industry. Electric cooperatives operate at cost and without a profit incentive. From growing regions to remote farming communities, electric cooperatives power 1 in 8

[1] 176 FERC ¶ 61,024 (2021).

Americans and serve as engines of economic development for 42 million Americans across 56 percent of the nation's landmass.

NRECA's member cooperatives include 834 distribution cooperatives and 63 generation and transmission (G&T) cooperatives.[2] The distribution cooperatives provide electric service to their end-of-line consumer-members. The G&T cooperatives generate and transmit power to their distribution-cooperative member-owners. Collectively, G&T cooperatives generate and transmit power to nearly 80 percent of the distribution cooperatives in the nation. The remaining distribution cooperatives receive power directly from other generation sources within the electric utility sector. Distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable, and affordable electric service.

Both G&T and distribution cooperatives are "load-serving entities" under section 217 of the Federal Power Act (FPA).[3] Some G&T cooperatives are Commission-jurisdictional public utilities under FPA section 201(e),[4] but pursuant to FPA section 201(f),[5] the vast majority of cooperatives are statutorily outside the Commission's regulatory authority under most provisions of Part II of the FPA.[6] In addition, NRECA member cooperatives include numerous registered entities subject to the mandatory

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[2] See https://www.electric.coop/wp-content/uploads/2021/04/Co-op-Facts-and-Figures.pdf (visited June 21, 2021).

[3] 16 U.S.C. § 824*q* (2018).

[4] 16 U.S.C. § 824(e) (2018).

[5] 16 U.S.C. § 824(f) (2018).

[6] 16 U.S.C. §§ 824–824*w* (2018).

reliability standards developed by the North American Electric Reliability Corporation (NERC) and approved by the Commission under section 215 of the FPA.[7]

The ANOPR seeks comments on issues that affect the interests of NRECA member cooperatives in multiple ways—as load-serving entities; transmission owners and operators; transmission customers; generation owners and operators; wholesale electricity market participants; and owners, operators, and users of the bulk power system. NRECA has participated in all of the Commission's landmark rulemaking proceedings on transmission planning and cost allocation and on generation interconnection.

Cooperatives own and maintain 2.6 million miles, or 42 percent of the nation's electric transmission and distribution lines, including over 44,000 miles of transmission lines. Cooperatives serve an average of eight customers per mile of line and collect annual revenue of approximately $19,000 per mile; other utility sectors average 32 customers and $79,000 in annual revenue per mile.

Electric cooperatives generate about five percent and deliver about 12 percent of the nation's electricity. Cooperatives rely on a broad portfolio of fuels, including clean and renewable resources, as well as energy-efficiency measures, to maintain safe, reliable, and affordable power for their communities. For 2019 (the latest complete year for which figures are available) cooperatives' aggregate retail sales of electricity were derived from a fuel mix consisting of 32 percent coal, 32 percent natural gas, 19 percent renewables, 15 percent nuclear, and two percent oil and other. Cooperatives are reducing carbon emissions through a combination of emission-reduction measures at power plants

[7] 16 U.S.C. § 824*o* (2018).

and by switching to natural gas and renewables. More than 95 percent of electric cooperatives provide electricity generated from renewable resources. From 2010 to 2019, cooperative renewable energy capacity increased 151 percent, to ten gigawatts (GW). Cooperatives have plans to add six GW of renewable capacity from 2020 to 2023, including more than four GW of solar. More than 475 cooperatives in 33 states use wind energy to serve two million homes, the majority of which is contracted through power purchase agreements.

Many consumers in rural communities are less affluent than those in other parts of the nation. In 2019, the median household income for electric cooperative consumer-members was 11 percent below the national average, and electric cooperatives serve consumer-members in 92 percent of the nation's 395 persistent-poverty counties. In addition, many consumers in rural communities, including those who are economically disadvantaged, depend on cooperative-delivered electricity for winter heating. Rural households often lack access to natural gas, and most other heating alternatives, like propane and heating oil, are comparatively expensive. Especially because many rural households lack viable heating alternatives, it is vitally important to these households that electric system reliability be maintained and that electric rates remain affordable with the simultaneous electrification of energy consumption and the decarbonization of the electric sector and the larger economy.

II. Summary of Comments

NRECA regards the ANOPR as an appropriate first step by the Commission in a systematic evaluation of its current transmission planning and cost allocation and generator interconnection policies. NRECA approaches the ANOPR with a view toward the transformation of the electric power sector that is occurring and is expected to continue in coming years, including the electrification of energy consumption; a changing generation mix that includes distributed energy resources; the need for resiliency as it relates to extreme weather events; and related technological, economic, and public policy changes.[8]

If the Biden Administration's goal of achieving carbon-free electricity by 2035 and a "net-zero" carbon economy by 2050 is implemented, whether through legislation or regulation, it will drive significant changes regarding how electricity is generated, transmitted, distributed, and used. If this or any successor policy does move forward, NRECA believes such a transition must be accomplished through a just and reasonable approach over a reasonable and realistic period of time, account for regional differences in energy resource availability and support funding for a range of energy technologies that will be needed to achieve these goals. Any transition must ensure the availability of affordable, reliable electricity to every community—including the rural communities and the 92 percent of persistent-poverty counties that electric cooperatives serve. The costs of this transition, including the investment in additional transmission facilities, should not be placed on the backs of communities, including marginalized rural communities, that will not enjoy commensurate benefits.

NRECA members have several overarching reactions to the ANOPR. First, NRECA member cooperatives have already seen significant transmission cost increases in recent years and share a concern that their member-consumers should not be burdened

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[8] *See* Comments of National Rural Electric Cooperative Association, *Electrification and the Grid of the Future*, Docket No. AD21-12-000 (filed Jul. 1, 2021); Comments of National Rural Electric Cooperative Association, *Climate Change, Extreme Weather, and Electric System Reliability*, Docket No. AD21-13-000 (filed Apr. 15, 2021).

with unjust, unreasonable, or unduly discriminatory transmission cost increases in the years ahead.[9] Because cooperatives are not-for-profit, consumer-owned utilities, all transmission costs borne by cooperatives ultimately are borne by consumers. Transmission is essential to electric cooperatives' ability to deliver reliable, affordable power to their member-consumers. Cooperatives thus support transmission investment that will be used and useful and will benefit consumers by lowering their power bills. Unnecessary transmission expenditures, however, can divert resources that cooperatives could invest in their own systems. NRECA appreciates the Commission's requests for comments on the burden on the customers of load-serving entities resulting from potential policy changes.[10]

Second, NRECA member cooperatives operate in different types of transmission regions, including regions with Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs) and regions without such transmission organizations. Moreover, these regions themselves have significant differences in transmission planning and cost allocation and generation interconnection policies and issues. In Order No. 1000, the Commission understood the need for regional flexibility in transmission planning and cost allocation.[11] The Commission should retain this important

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[9] *See* ANOPR, P 159 ("The potential for a significant investment in the transmission system in the coming years underscores the importance of ensuring that ratepayers are not saddled with costs for transmission facilities that are unneeded or imprudent.").

[10] *See* ANOPR, PP 5, 41, 46, 60, 72, 75, 84, 89, 119, 122.

[11] *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 at P 604 (2011) ("we do not want to prescribe a uniform method of cost allocation for new regional and interregional transmission facilities for every transmission planning region" because "regional differences may warrant distinctions in cost allocation methods among transmission planning regions" and thus "we retain regional flexibility" and allow transmission providers "to develop transmission cost allocation methods that best suit the

principle in any changes to Order No. 1000 that it eventually may propose and adopt in this proceeding. The need for the RTOs/ISOs to retain the ability to have different cost allocation and generation interconnection policies is predicated on the differences in their regional geography and generation and transmission topologies. For example, PJM staff recently noted that 85% of the proposed generation resources in PJM's interconnection queue—1,560 out of 1,826—were within 100 miles of a load center.[12]

Third, in Order No. 1000, the Commission required that each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation, and this method must satisfy six regional cost allocation principles.[13] NRECA believes that the Commission should retain these cost allocation principles going forward, because they have proven to be a workable framework and will provide reasonable guardrails for identifying the benefits and beneficiaries associated with new transmission facilities.[14] In particular, NRECA

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needs of each transmission planning region or pair of transmission planning regions, so long as those approaches comply with the regional and interregional cost allocation principles of the Final Rule"), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 at P 331 ("It may well be the case that evaluating different power supply scenarios will be an effective way of identify[ing] more efficient or cost-effective transmission solutions; however, we will not prescribe any such requirements here, consistent with our preference for regional flexibility in designing regional transmission planning processes."), *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[12] PJM, Data Analysis, Interconnection Policy Workshop (Aug. 27, 2021), available at https://pjm.com/-/media/committees-groups/committees/pc/2021/20210827-workshop-4/20210827-item-04-data-analysis-presentation.ashx.

[13] *See* ANOPR at P 77; Order No. 1000, 136 FERC ¶ 61,051 at PP 603–705. Six analogous principles apply to interregional cost allocation. *Id.* at PP 622, 637, 646, 657, 668 & 685.

[14] *See infra* pp. 25–26.

members strongly support regional cost allocation principle number 1, which requires that "[t]he cost 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."[15] The Commission should retain the judicially sanctioned, bedrock "beneficiary pays" and "roughly commensurate" standards.[16]

Fourth, NRECA member cooperatives recognize that generation interconnection processes in some regions are subject to delay and uncertainty, and that improvements in these processes' design or implementation may be warranted. NRECA members support generation-interconnection reforms that address these issues directly rather than simply shift most of the costs and risks to the customers of load-serving entities and thereby dampening if not eliminating appropriate economic incentives and price signals to interconnecting generators.[17]

Fifth, NRECA stresses that any transmission planning reforms must ensure that load-serving entities will have the transmission facilities needed to provide reliable service to the public and to make long-term power supply arrangements. Notwithstanding the ANOPR's omission of the requirement, FPA section 217(b)(4) requires the Commission to exercise its FPA authority "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving

[15] Order No. 1000, 136 FERC ¶ 61,051 at P 622.

[16] *See Ill. Commerce Comm'n v. FERC*, 576 F.3d 470 (7th Cir. 2009).

[17] *See infra* pp. 15–16, 25, 28–29.

entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs."[18] All transmission planning and cost allocation reforms the Commission considers in this proceeding must be informed by and comply with this legislative directive,[19] as NRECA notes later in these comments.[20]

Sixth, cooperatives are concerned that federal law and policy provide a "level playing field" for electric cooperatives and public power utilities to plan and invest in building needed transmission infrastructure in the coming years. This includes not only matters such as direct-pay tax incentives for tax-exempt cooperatives that are otherwise unable to use energy tax incentives, which is outside the Commission's purview, but also potential reforms to the Commission's transmission planning policies to facilitate and encourage joint transmission ownership by non-public utility electric cooperatives and public power utilities. Many of the regional transmission facilities discussed in the ANOPR are likely to be large-scale, high-voltage projects. Electric cooperatives should be afforded opportunities to participate financially in these projects. Because cooperatives are consumer-owned, cooperative investment in transmission can be used to

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[18] 16 U.S.C. § 824q (b)(4) (2018). This is the only FPA provision expressly addressing transmission planning.

[19] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 90 (D.C. Cir. 2014) ("Section 217(b)(4) creates a requirement for the Commission, not for utilities. … It would only be violated if the Commission exercised its authority in a manner that was at odds with the needs of load-serving entities." … The ability of load-serving entities to meet their service obligations depends on their ability to deliver power when needed. A failure to meet those obligations occurs when the utility must engage in practices such as rolling blackouts because of insufficient transmission capacity. Thus, Section 217(b)(4) requires the Commission to facilitate the planning of a reliable grid ….").

[20] *See infra* pp. 10, 13, 17 & 19.

benefit consumers by offsetting their transmission costs. The ANOPR does not address non-public utility ownership or joint ownership of transmission, but this remains an important mechanism to build new transmission facilities benefiting the nation's electric consumers in the years ahead.[21]

The remainder of NRECA's comments will address the ANOPR's two main sections, the "The Potential Need for Reform" (Part III below) and "Consideration of Potential Reforms and Request for Comment" (Part IV below).

III. The Potential Need for Reform

A. Considering Anticipated Future Generation

The Commission seeks comment on whether existing regional planning processes adequately "model future scenarios" and incorporate long-term transmission needs, including "the needs of anticipated future generation."[22]

Electric cooperatives recognize the need for, and themselves engage in, long-term resource planning. Most cooperatives have long-term power supply resources (purchased or owned) in their resource portfolios, including more new renewable (wind and solar) resources. As noted above, FPA section 217(b)(4) obligates the Commission to use its FPA authority to facilitate transmission planning and expansion to meet the reasonable needs of load-serving entities to satisfy their service obligations and to enable them to secure long-term firm transmission service for their long-term power supply arrangements.

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[21] *See infra* pp. 22–23.

[22] ANOPR, P 31.

Regarding the overall effectiveness of the existing regional transmission planning processes, NRECA member cooperatives do not report that existing processes in their respective regions are deficient because they are unable to consider anticipated future generation, and cooperatives generally believe that existing processes are flexible enough to accommodate the necessary long-term scenario modelling going forward. Moreover, NRECA members note that improvements in long-term transmission planning processes are already underway in some regions, including MISO's Long Range Transmission Planning (LRTP) initiative and PJM's use of the State Agreement Approach.[23] At this point, NRECA member cooperatives do not agree with the premise that "building transmission facilities to accommodate anticipated future generation," not yet in the generation interconnection queue, "is required to render transmission rates just and reasonable."[24] Load-serving entities' integrated resource plans should be the main guide for the building of transmission facilities to accommodate anticipated future generation.

B. Over-Reliance on the Generation Interconnection Process

The ANOPR asserts that "the generation interconnection process appears to be the principal means by which infrastructure is built to accommodate new generators" and that "because transmission planning processes generally do not plan for the needs of anticipated future generation, transmission infrastructure that is being developed in order to facilitate new generation is constructed largely through the generation interconnection

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[23] *See* https://www.misoenergy.org/planning/transmission-planning/long-range-transmission-planning/; *PJM Interconnection, L.L.C.*, 147 FERC ¶ 61,090 (2021) (approving study agreement between New Jersey Board of Public Utilities and PJM); *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at PP 142-143 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,128, at P 92 (2014); PJM, Intra-PJM Tarifs, Operating Agreement, sched. 6, section 1.5.9(a) (State Agreement Approach).

[24] ANOPR, P 48.

process, which is unlikely to result in the economies of scale that could more efficiently or cost-effectively meet the needs of the changing resource mix."[25]

NRECA member cooperatives do not agree with the premise that too much transmission infrastructure is built through the generation interconnection process rather than through the transmission planning processes. NRECA members report that interconnection-related network upgrades on the transmission system are commensurate with the level of service requested and the impact the requesting generator has on the host or third-party transmission systems. The generation interconnection process appropriately links incremental network upgrade costs to the causer or beneficiary.

Moreover, transmission facilities constructed through RTO regional transmission planning processes result in the development of a regional transmission grid that will reduce the cost to generators of interconnecting to the grid. MISO's LRTP initiative, for example, will improve the efficiency of the generator interconnection process and reduce the need for interconnection-related network upgrades. The Commission's existing transmission planning requirements allow regional flexibility and thus allow such negotiated regional planning approaches to plan transmission facilities to enable load-serving entities to access generation from likely "resource-rich" areas.

The ANOPR cites no data to support a finding that "too much" network transmission infrastructure (e.g., in dollars or transfer capacity or number of projects) is built through the existing generation interconnection process—much less any data on the lost efficiency in transmission investment that this might entail or the efficiency gains and losses to be expected by potential replacement processes. In this regard, the growth

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[25] ANOPR, PP 32, 34

or anticipated growth in interconnection-related network upgrade costs is not itself evidence of need for reform of generation interconnection process, because these costs appear to have remained quite small relative to total transmission investment. For example, in data filed with the Commission in Docket No. ER21-2282, PJM transmission owners claimed that over the period 2004 to 2020, gross plant for transmission assets increased more than five-fold, from $14.96 billion to $77.7 billion, while over the same period, gross plant for participant funded network upgrades increased from $35 million to $1.31 billion—in other words, rising from 0.2% to 1.7% of total gross plant.[26] Since 2014, and including draft projects in the 2021 MISO Transmission Expansion Plan (MTEP), generator interconnection projects have totaled only 8% of MTEP costs.[27]

Moreover, the ANOPR does not cite evidence that load-serving entities have been unable to build or purchase new low-emission generation due to the lack of transmission infrastructure. In other words, the ANOPR points to nothing indicating that existing generation interconnection processes, despite their delays and uncertainties, are inherently flawed and failing load-serving entities and their customers—i.e., the consuming public, the beneficiaries of Commission regulation pursuant to FPA section 206,[28] as confirmed in the context of transmission planning by the specific directive in FPA section 217(b)(4) quoted above.

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[26] *See* Letter of William M. Keyser to Kimberly D. Bose at 13, *PPL Elec. Utils. Corp.*, Docket No. ER21-2282 (Sept. 20, 2021). The increase in gross plant for participant-funded network upgrades in 2020 over 2019 was 2.1% of the increase in total gross plant over that same year. *Id.* NRECA is not a party to that proceeding and takes no position on the proposed revisions to the PJM transmission tariff in that proceeding.

[27] NRECA member cooperatives' compilation of MTEP data.

[28] 16 U.S.C. § 824e (2018). *See FPC v. Sierra Pac. Power Co.*, 350 U.S. 348, 355 (1956) ("That the purpose of the power given the Commission by § 206 (a) is the protection of the public interest, as distinguished from the private interests of the utilities, is evidenced

C. Cost Responsibility for Transmission Facilities and Interconnection-Related Network Upgrades

The Commission asks whether the current regional transmission planning process, which considers transmission needs driven by reliability, economic, or Public Policy Requirements, "may fail to take into account the benefits of multi-faceted projects for the purposes of cost allocation."[29] NRECA member cooperatives generally believe that the answer is no, because the Order No. 1000 framework is flexible enough to allow regions to agree upon procedures to address such multi-faceted projects. The MISO Multi-Value Project (MVP) process, although it predated Order No. 1000 and was not without its critics with respect to its allocation of costs, is generally regarded as a good example of a regionally negotiated, Commission-approved process to address transmission projects with potentially multiple benefits.[30] The Commission's existing transmission planning framework is flexible enough to accommodate such regional solutions to this potential problem.

The Commission also asks whether interconnection generators are being assigned too much of the cost responsibility for transmission expansion.[31] Again, NRECA member cooperatives generally believe that the answer is no. As the PJM data cited above suggests, load pays for the vast majority of transmission investment through transmission

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by the recital in § 201 of the Act [16 U.S.C. § 824] that the scheme of regulation imposed 'is necessary in the public interest.'").

[29] ANOPR, P 39.

[30] *See Ill. Commerce Comm'n v. FERC*, 721 F.3d 764 (7th Cir. 2013).

[31] ANOPR at PP 40-43. *See also id.* at P 33 ("It appears that … interconnection customers are assigned the costs to construct large, high-voltage transmission facilities.").

rates for which generators receive full deliverability to the PJM system.[32] In other regions, load directly pays for generator-funded interconnection-related network upgrades for which generators receive credits against their transmission bills. Interconnecting generators are responsible for a small fraction of network upgrades. And in most cases, these generators pass through these upgrade costs to project off-takers in power purchase agreements and in other wholesale generation-related charges. To be sure, it can be argued that a particular interconnection-related network upgrade may benefit more than the interconnecting generator. But the prevalence of this potential problem is unclear, and the ANOPR has no data that the current approach to allocating interconnection-related network upgrades regularly fails to allocate upgrade costs in a manner that is roughly commensurate with the benefits drawn from these facilities.

Moreover, assigning costs of network upgrades necessary to interconnect a generator provides an appropriate economic signal to generation developers that one location may be more favorable over another location when transmission costs are considered. Failure to include this economic signal will blunt that price signal and incentivize generation developers to put projects in locations that may lower the project's other costs (e.g., lease payments for land) but may not be the least-cost option when

[32] *See* PJM, An Overview of Participant Funding (Aug. 27, 2021) ("The current crediting policies would not be applicable to PJM's existing interconnection process. All ICs interconnecting to the PJM transmission system are granted full deliverability throughout the PJM Region. There are no separate charges for transmission service in PJM."), available at https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20210827-workshop-4/20210827-item-02b-participant-funding.ashx.

interconnection-related upgrade costs are considered. This is not an economic efficient outcome and will cause consumers to pay more for electricity than otherwise necessary.[33]

From the perspective of a transmission-owning electric cooperative, interconnecting generators are either built by or for the cooperative, in which case the cooperative's members pay for the interconnection-related upgrades, or by an independent, for-profit generation developer, in which case the generation developer pays for the interconnection-related upgrades and passes through the costs to its wholesale customers. If the cooperative were to pay for all generator upgrades without the ability to allocate these costs to the generator or the generator's other customers, then the cooperative's members would be effectively subsidizing the generator's sales to the generator's other wholesale customers.

The same holds true for transmission-dependent electric cooperatives that take service from investor-owned public utilities under an open access transmission tariff, in which case the cost of generator interconnection-related network upgrades would be borne by transmission-dependent electric cooperatives pursuant to their load ratio share of the investor-owned public utility's interconnection-related upgrade costs for interconnecting the new generator.

The Commission notes that in considering reforms to the generator interconnection process, "we remain mindful of the need to ensure that interconnection costs are not unjustly and unreasonably shifted to customers of load-serving entities."[34]

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[33] Furthermore, generation developers are in the best position to manage the costs and risks associated with generation location and siting, which counsels against shifting responsibility for interconnection-related upgrades to transmission owners and thus to load.

[34] ANOPR, P 41.

NRECA member cooperatives endorse that point and urge the Commission to evaluate comments received on this portion of the ANOPR with that perspective firmly in mind.

IV. Consideration of Potential Reforms and Request for Comment

A. Regional Transmission Planning and Cost Allocation Processes

1. *Future Scenarios and Modeling Anticipated Future Generation*

The ANOPR seeks comment "on what factors shaping the generation mix are appropriate to use for transmission planning purposes" and "may be considered for inclusion in scenario modeling," including the source of the Commission's authority to incorporate that factor in the regional transmission planning and cost allocation processes."[35]

At the outset, NRECA is compelled to note that FPA section 217(b)(4) provides the starting point for any future transmission scenario modelling—meeting the future transmission needs of load-serving entities to meet their service obligations to consumers. Transmission planning scenario modelling should begin as a bottom-up process, incorporating the long-term transmission needs of load-serving entities. Load-serving entity long-term resource and transmission planning ordinarily will incorporate the load-serving entity's transmission needs driven by reliability, economics, and public policy requirements.[36]

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[35] ANOPR, P 46.

[36] Because the ANOPR does not discuss the possibility of the Commission having additional authority over transmission siting and approval, NRECA is not addressing the planning reforms that such authority might require.

With respect to the five specific factors listed as examples in the ANOPR,[37] NRECA comments as follows. The first factor, federal, state and local climate and clean energy laws and regulations, clearly should be considered in scenario modelling. The Commission's FPA section 206 authority over practices that directly affect transmission rates includes transmission planning practices and the requirement for transmission planning to consider public policy requirements enacted into law.[38]

Federal, state, and local climate and clean energy goals that have not been enacted into law (factor 2), as well as utility and corporate clean energy goals (factor 3), should be considered to the extent they are incorporated in load-serving entity long-term planning. NRECA does not believe, however, that the Commission has authority to compel transmission planners to incorporate particular precatory or voluntary goals into scenario modelling.

Trends in technology costs, including those associated with electrification of the transportation and building sectors (factor 4), are appropriate for inclusion in scenario modelling. NRECA believes that this factor, while subject to inherent uncertainty, is essential for consideration in projecting future transmission loads. Once again, load-serving entities ordinarily will have incorporated this factor in their long-term planning, making its incorporation in regional transmission planning less controversial. NRECA believes that the Commission has authority to require this factor to be considered in load projections.

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[37] ANOPR, P 46.

[38] *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56-59, 89-90 (upholding Order No. 1000 transmission planning and public policy requirements mandates).

Resource retirements (factor 5) should be considered in transmission scenario modelling so that all load-serving entity needs can be considered in regional transmission plans.

Finally, an additional factor not mentioned in the ANOPR is the changing characteristics of the grid, which should be considered when developing new regional transmission planning models. Increasingly, electricity is not generated at centralized locations and transmitted to local distribution systems for ultimate consumption by load located on the distribution system. Resources such as distributed generation (both utility scale and rooftop), energy storage, and smart devices (such as water heaters and thermostats) are being interconnected to the distribution system. As a result, generation, load, and the ability to control load are all located on the distribution system, reducing the use of the transmission system to serve load. The need for new transmission facilities may be alleviated by non-transmission alternatives—the growing capabilities of the distribution system. Greater communication and coordination between transmission operators and distribution operations will be needed to ensure the capabilities of the distribution system are fully considered in regional transmission planning processes. Without coordination and recognition of distribution system capabilities, regional transmission planning may result in unnecessary infrastructure and costs.

2. *Transmission planning time horizon*

The Commission seeks comment on "whether, and if so, how the regional transmission planning process should be restructured to consider a longer-term outlook."[39] As noted, NRECA member cooperatives support, and engage in, long-term

[39] ANOPR, P 48.

planning. The ANOPR suggests that failing to plan for anticipated future generation far enough in the future may lead to inefficient transmission development,[40] but long-term resource planning must be deliberate and must be based on solid projections to avoid the risk of inefficient transmission decisions and potentially even stranded investment costs that would be borne by customers of load-serving entities. NRECA members report that ten years is generally an appropriate transmission planning horizon and is generally consistent with the definition of Planning Horizon used in the North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Reliability Standards, as well as reporting requirements of state jurisdictions over integrated resource plans.

3. *Incorporating State and Local Regulator and Stakeholder Input in Long-Term Transmission Planning*

The Commission notes that "states or other local governing bodies may be uniquely situated in determining how much anticipated future generation is needed, or in providing information related to infrastructure siting or resource mix as influenced by state or local policies," and asks "how their input should be reflected," and whether "additional stakeholder input" should be required in transmission providers' long-term transmission planning and scenario modelling.[41] NRECA member cooperatives believe that state and local governing bodies should be involved and their input reflected according to their jurisdictional responsibilities and authority over load-serving entities' resource planning. Indeed, elected cooperative boards may be the relevant local regulatory authority, as the Commission has recognized in other contexts.[42]

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[40] ANOPR, P 47.

[41] ANOPR, P 52.

[42] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64,100, at P 158 (Oct. 28, 2008) ("The term 'relevant electric retail regulatory

All stakeholders, including load-serving entities and state and local regulators, should be involved as full participants at every step in the planning process, and should have access to all necessary information, subject where necessary to protective agreements. Load-serving entities are essential stakeholders, because their end-use customers will bear the costs of new transmission investment, and FPA section 217(b)(4) requires the Commission to use its authority in a manner that facilitates transmission planning and expansion to meet load-serving entities' needs. Thus, any reforms or revisions to existing planning rules to incorporate a longer-term approach should not "unjustly and unreasonably shift transmission costs to customers of load-serving entities."[43]

4. *Identifying Geographic Zones for Renewable Resource Development*

The Commission asks whether it should require regional transmission planning processes to have "a process to identify geographic zones that have the potential for the development of large amounts of renewable generation and plan transmission to facilitate the integration of renewable resources in those zones."[44] NRECA member cooperatives do not have uniform opinion on whether and, if so, how such zones should be identified and used in regional transmission planning and cost allocation processes in their respective regions. They believe that the relative benefits and costs of this approach will

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authority' means the entity that establishes the retail electric prices and any retail competition policies for customers, such as the city council for a municipal utility, the governing board of a cooperative utility, or the state public utility commission."), *order on reh'g*, Order No. 719-A., 74 Fed. Reg. 37,776 (July 29, 2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[43] ANOPR, P 46.

[44] ANOPR, P 54.

vary from region to region, and from state to state (given their different renewable generation requirements). Accordingly, electric cooperatives believe that this decision should be left to the regional planning processes to resolve, subject to input from state and local governing bodies and to ultimate Commission oversight and approval on a case-by-case basis to ensure that the zone selection and cost-allocation principles accord with Order No. 1000's six cost- allocation principles, reflect the reasonable transmission needs of the region's load-serving entities, and are otherwise just and reasonable.

The Commission also asks "whether there is a need for mechanisms to limit the risk to customers from planning for anticipated future generation" from such generation zones, and notes, as an example on a potential approach, "CAISO's use of an *ex ante* cap on the total cost exposure to transmission customers in addressing generation resource interconnection."[45] NRECA members believe that such mechanisms are essential, because limiting customer risk is a central purpose of the FPA's requirement that transmission rates be "just and reasonable,"[46] and of the principle that transmission costs must be allocated on a basis that is "roughly commensurate" with estimated benefits.[47] Although the Commission's order approving the CAISO *ex ante* cost cap referred to in the ANOPR did not apply the "roughly commensurate" standard, NRECA believes that any regional transmission planning and cost allocation approach that employs such geographic renewable-generation zones must apply this standard. As the ANOPR later

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[45] ANOPR, P 59. The reference is to *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,061 (2007). *See* ANOPR, P 56.

[46] 16 U.S.C. § 824d(a) (2018).

[47] ANOPR, PP 74, 77.

acknowledges, adopting these reforms may require changes to the Commission's abandoned plant policy to better protect customers.[48]

5. *Incentivizing Regional Transmission Facilities*

The Commission requests comment on whether and, if so, how the Commission should "expand or improve any incentives" for the development of "regional transmission facilities that demonstrably may offer a more efficient or cost-effective solution to an identified need than local alternatives."[49]

NRECA filed comments on possible revisions to the Commission's transmission incentives regulations and policies in Docket No. PL19-3-000 in 2019[50] and on the Commission's subsequent notice of proposed rulemaking to revise those regulations and policies in Docket No. RM20-10-000 in 2020.[51] In these comments, NRECA recommended several general policy principles that remain relevant in the present context:

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[48] ANOPR, P 178.

[49] ANOPR, P 61.

[50] Comments of National Rural Electric Cooperative Association, *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, Docket No. PL19-3-000 (filed June 26, 2019). *See Inquiry Regarding the Commission's Electric Transmission Incentives Policy,* 166 FERC ¶ 61,208 (2019) (notice of inquiry).

[51] Comments of National Rural Electric Cooperative Association, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket No. RM20-10-000 (filed July 1, 2020). *See Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 170 FERC ¶ 61,204 (notice of proposed rulemaking), 171 FERC ¶ 61,072 (errata notice) (2020).

- The Commission's transmission incentives policy should implement the statutory purposes laid out in FPA section 219[52] as well as FPA sections 205, 206 and 217(b)(4).
- The Commission should ensure that non-jurisdictional utilities, including cooperatives, have comparable opportunities to obtain incentives and should encourage their participation in transmission projects,
- The Commission's policy should retain the "risks/challenges" approach and the "nexus" test from the Commission's 2012 Incentives Policy Statement[53] for evaluating applications for transmission incentives, where the Commission stated that it expects "incentives applicants to first examine the use of risk-reducing incentives before seeking an incentive ROE based on a project's risks and challenges."[54]
- Incentives should be limited to those necessary to encourage the desired behavior.
- Incentives should not be granted automatically without review.

NRECA will not comment on the Commission's specific query in the ANOPR whether the Commission should limit equity-return adders for RTO/ISO participation to

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[52] 16 U.S.C. § 824*s* (2018). *See id.* § 824*s*(a) (requiring "incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.").

[53] *Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129 (2012). *See also* Comments of National Rural Electric Cooperative Association, Docket No. RM11-26-000 (Sept. 12, 2011).

[54] 2012 Incentives Policy Statement, 141 FERC ¶ 61,129 at P 11.

regional (not local) transmission facilities.[55] The Commission should refer to any comments of NRECA member cooperatives on this issue.

However, NRECA member cooperatives generally believe that to the extent the Commission provides incentives for the development of regional transmission facilities, the Commission should create a "level playing field" by ensuring that electric cooperatives and public power utilities are able to obtain incentives for developing or participating in jointly developing regional transmission facilities on an equivalent basis with investor-owned utilities and transmission developers.[56] For return-on-equity adder incentives, this may also require the approval of a hypothetical capital structure incentive, because cooperatives generally have lower equity/debt ratios than investor-owned public utilities.

6. *Coordinating Between the Regional Transmission Planning and Cost Allocation and Generation Interconnection Processes*

The Commission asks whether "reforms are needed to improve the coordination between the regional transmission planning and cost allocation and generator interconnection processes," such as operating "on concurrent, coordinated timeframes," or "with the same or similar assumptions and methods."[57] NRECA member cooperatives recognize that generation interconnection processes in some regions are subject to delay and uncertainty, and that improvements in these processes' design or implementation may be warranted (e.g., ensuring that consistent planning assumptions are used in regional transmission planning and generation interconnection processes where possible).

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[55] ANOPR, P 61.

[56] *See supra* pp. 9–10.

[57] ANOPR, P 65.

But NRECA urges caution in this regard. While process improvements should be explored, any reforms should not result in unjustly and unreasonably shifting risks and costs from interconnecting generators to the customers of load-serving entities who may simply happen to reside in the transmission zone of a interconnecting generator, but are not the off-takers or beneficiaries to that generation project. Moreover, NRECA members believe that improvements to this process coordination should be the result of an open, regional decision-making procedure involving all relevant stakeholders.

B. Identification of Cost and Responsibility for Regional Transmission Facilities and Interconnection-Related Network Upgrades

1. *Regional transmission facility benefits identification*

The Commission requests comment on "whether the current approach to cost allocation in regional transmission planning processes fails to consider the full suite of benefits—and the associated beneficiaries—produced by transmission facilities developed to meet the transmission needs of the changing resource mix."[58] NRECA member cooperatives do not believe that existing regional cost allocation approaches fail to identify relevant benefits or beneficiaries of regional transmission projects. The six cost-allocation principles in Order No. 1000 continue to provide a reasonable framework for evaluating whether benefits and beneficiaries are appropriately identified. Moreover, as the Commission itself notes, changes in cost allocation criteria "hold the potential to unjustly shift costs to customers of load-serving entities."[59]

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[58] ANOPR, P 70. *See id.*, PP 85-89.

[59] ANOPR, P 72.

2. *Regional transmission facilities cost allocation*

The Commission invites comment on "whether customers of load serving entities should be required to pay the costs of regional transmission facilities that provide them only with unquantifiable or purported benefits, or be required to pay for costs driven by the public policies of state and local governments in states other than their own."[60] NRECA member cooperatives believe that the answer to the first part of the Commission's query is no: The requirement that costs be allocated "roughly commensurate" with estimated benefits to customers of load-serving entities (or to anyone else) cannot be met by reference to "unquantifiable or purported benefits." Such benefits also cannot form the basis for determining that a transmission project's estimated benefits exceed the applicable benefit/cost thresholds for selecting projects for regional cost allocation.

Moreover, in NRECA's view, the Commission does not have the authority or expertise to require regional transmission planning processes to quantify the benefits of clean-air attributes of newly interconnected generation and identify the beneficiaries for purposes of regional transmission cost allocation.

As for the second part of the Commission's question, NRECA members believe that the costs of transmission facilities required to meet state and local public policy requirements should not be allocated to customers of load-serving entities in other states absent a deliberate process for identifying a regional transmission facility's beneficiaries

[60] ANOPR, P 84.

and agreement by the states involved.[61] The Commission's recent policy statement on State Voluntary Agreements to Plan and Pay for Transmission Facilities[62] recognizes that voluntary agreements between and among states and transmission providers to plan and pay for transmission facilities to effectuate state and local public policy goals is a reasonable solution and allowed under both the FPA and Order No. 1000.

The Commission notes that "there are likely zones or subzones within a region that are rich in renewable resources and therefore have generation significantly in excess of the local load," and asks whether current transmission cost allocation methods over-allocate costs to such zones or generators in such zones.[63] NRECA member cooperatives agree that this situation can occur in RTOs/ISOs and believe that it already has occurred in the Southwest Power Pool.[64] Moreover, MISO faced this issue in the late 2000s but avoided this outcome by adopting a participant funding paradigm.[65] Reforms to the cost allocation process may need to include safeguards to protect loads (including cooperative loads) in such renewable-rich areas, such as requiring periodic reviews by RTOs/ISOs and the adoption of remedial measures.

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[61] *See, e.g., N. Va. Elec. Coop. v. FERC*, 945 F.3d 1201, 1207–08 (2019) (upholding Commission orders allocating the costs of undergrounding three transmission project to customers in state requiring the undergrounding).

[62] *State Voluntary Agreements to Plan and Pay for Transmission Facilities*, 175 FERC ¶ 61,225 (2021) (notice of policy statement).

[63] ANOPR, P 88.

[64] *See Southwest Power Pool, Inc.*, 175 FERC ¶ 61,198, at PP 5–7 (2021).

[65] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,060 (2009).

3. *Interconnection-related network upgrades cost allocation*

The Commission also requests comment on whether the participant funding approach for generation interconnection-related network upgrades in RTOs/ISOs remains just and reasonable.[66] NRECA member cooperatives generally believe the Commission should retain the current "but for" cost allocation principle for generators paying for interconnection-related upgrade costs. This ensures that transmission costs and generation costs are properly allocated and are properly reflected in wholesale market prices. As the Commission itself notes, eliminating or reducing participant funding for interconnection-related network upgrades in RTOs/ISOs risks unjustly or unreasonably shifting costs to customers of load-serving entities.[67] Participant funding ensures that the costs to interconnect in one location versus another are weighed as part of the overall project costs, ensuring an efficient economic outcome in siting generation.[68]

The ANOPR states that in Order No. 2003, the Commission's consideration of an interconnecting generator's incentive to make an efficient generator siting decision involved minimizing transmission costs from interconnection-related network upgrades.[69] The ANOPR asks whether that is still the appropriate rubric for siting renewable generation today, or whether the costs of interconnection-related network upgrades for renewable generation could be "allocated more broadly among those that benefit" and thus reduce the price signal incentivizing the interconnecting generator to minimize

[66] ANOPR, P 71. *See id.*, PP 105, 111-119.

[67] ANOPR, P 119.

[68] *See supra* pp. 15–16.

[69] ANOPR, PP 116–17.

transmission costs.[70] NRECA member cooperatives would oppose such a broad change to the Commission's existing generation interconnection policy and believe that existing Commission policy, including allowing participant funding, provides the appropriate price signal in nearly all cases. Moreover, the ANOPR does not explain the source of the Commission's authority to adopt special cost allocation rules for interconnecting renewable generation that do not apply to other interconnecting generation resources or why such special cost allocation rules would not be considered unjust, unreasonable, and unduly discriminatory or preferential. Indeed, the effect of such a proposal would be to unjustly and unreasonably shift interconnection-related network upgrade costs to the customers of load-serving entities.[71]

C. Enhanced Transmission Oversight

1. *Independent transmission monitor*

The Commission notes that consumers may face significant transmission costs in coming years and, in light of that fact, seeks comment on whether "additional measures may be necessary to ensure that the planning processes for the development of new transmission facilities, and the costs of the facilities, do not impose excessive costs on consumers."[72] As noted above, NRECA member cooperatives support the Commission's attention to the question of whether consumers will bear excessive costs from new transmission facilities.

[70] ANOPR, P 117.

[71] ANOPR, P 119.

[72] ANOPR, P 160.

But NRECA member cooperatives do not support the ANOPR's primary oversight proposal: to require each transmission planning region, RTO/ISO and non-RTO/ISO alike, to have an "independent transmission monitor."[73] This additional layer of oversight largely would duplicate that already provided by RTOs/ISOs, the North American Electric Reliability Corporation as the Electric Reliability Organization, and NERC regional entities, state commissions, and the Commission itself. An independent monitor would be an inadequate substitute for Commission oversight. Moreover, an independent transmission monitor would increase the costs of transmission planning processes that are borne, directly or indirectly, by the customers of load-serving entities and would unnecessarily delay the transmission planning processes, adding another level of review and potential challenges.

2. *State commission oversight*

The ANOPR asks whether the Commission should "add oversight" to transmission planning and cost allocation processes by involving state commissions in those processes.[74] NRECA supports the Commission's collaboration with state regulators in developing reforms to transmission planning and cost allocation rules, as is already occurring through the Joint Federal-State Task Force on Electric Transmission.[75] State commissions already participate as stakeholders in RTO/ISO transmission planning and cost allocation processes, as the ANOPR notes.[76] State commissions also exercise

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[73] ANOPR, PP 163–75.

[74] ANOPR, P 176.

[75] *See Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (2021) (Order Establishing Task Force and Soliciting Nominations).

[76] ANOPR, P 176.

authority under state law as retail regulatory authorities, over state-level generation interconnection (including distributed generation), and, in some states, as wholesale regulators of non-public utilities.[77] NRECA believes that state commissions should retain their role as stakeholders in Order No. 1000 regional transmission planning and cost allocation processes and not as overseers. Any expansion of that role, such as the SPP Regional State Committee authority noted in the ANOPR,[78] should be the result of regional decision-making and not Commission mandate.

V. Conclusion

NRECA appreciates the opportunity to provide comment on the important issues discussed in the ANOPR and respectfully requests that the Commission consider these comments as it evaluates its current transmission planning and cost allocation and generator interconnection policies and considers potential reforms. NRECA reiterates its view that the transformation of the electric power sector that is occurring and is expected to continue in coming years must be accomplished through a just and reasonable approach over a reasonable and realistic period of time and must ensure the availability of affordable, reliable electricity to every community, including rural communities.

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[77] *See, e.g., Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375 (1983).

[78] ANOPR, P 176.

Respectfully submitted,

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October 12, 2021