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 PENNSYLVANIA PUBLIC UTILITY COMMISSION

The Pennsylvania Public Utility Commission ("PAPUC") submits these comments in response to the Federal Energy Regulatory Commission's ("FERC's" or "Commission's") Notice of Proposed Rulemaking ("NOPR") proposing reforms to electric regional transmission planning and cost allocation requirements, pursuant to FERC's authority under Section 206 of the Federal Power Act ("FPA").[1]

I. COMMUNICATIONS

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II. INTRODUCTION

Located entirely within the PJM Interconnection, LLC ("PJM") footprint, the Commonwealth of Pennsylvania has been a part of PJM's transmission planning and cost allocation policies for decades. As a significant net exporter and consumer of electricity in PJM,

[1] 16 U.S.C. § 824e.

Pennsylvania has also been responsible for paying a large portion of PJM's transmission enhancements and expansions.[2] For 2020 and 2021, Pennsylvania's portion of the PJM Regional Transmission Expansion Plan ("RTEP") projects totaled approximately $752.7 million and $176.9 million, respectively, in transmission investment.[3] Consequently, the PAPUC is highly invested in PJM's transmission planning and cost allocation methodologies and practices. The PAPUC submits these comments in response to the Commission's proposed revisions to some of the rules underlying PJM's planning and cost allocation processes.

III. COMMENTS

A. LONG-TERM REGIONAL TRANSMISSION PLANNING

As the PAPUC stated in its ANOPR comments, the guiding principle for regional transmission planners should be to promote the building of a reliable, secure, and resilient regional grid by using competitive solicitation processes and employing cost containment measures.[4] Because long-term planning has the potential to increase the efficiency of the transmission system, the PAPUC supports FERC's proposal to require RTOs to include a Long-Term Regional Transmission ("LTRT") planning process for transmission planning. LTRT planning should incorporate the core transmission planning principles of Order No. 890,[5]

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[2] Pennsylvania is the third largest net supplier of energy to other states, after Wyoming and Texas. *See* Pennsylvania Report by U.S. Energy Information Administration, available at https://www.eia.gov/state/?sid=PA (October 21, 2021) (last visited July 25, 2022).

[3] PJM's 2020 Pennsylvania State Infrastructure Report (April 2021) at 3, available at https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2020/2020-pennsylvania-state-infrastructure-report.ashx;
PJM's 2021 Pennsylvania State Infrastructure Report (May 2022) at 3, available at https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2021/2021-pennsylvania-state-infrastructure-report.ashx.

[4] PAPUC ANOPR Comments at 5.

[5] *Preventing Undue Discrimination and Preference in Transmission Service*, FERC Stats. & Regs. ¶ 31,241 (2007) (Order No. 890) ((1) strengthening the *pro forma* open-access transmission tariff, or OATT, to ensure that it achieves its original purpose of remedying undue discrimination; (2) providing greater specificity to reduce opportunities for undue discrimination and facilitate FERC's enforcement; and (3) increasing transparency in the rules applicable to planning and use of the transmission system).

as affirmed in Order No. 1000,[6] while allowing for sufficient regional flexibility to accommodate states' implementation of their individual legislative requirements.

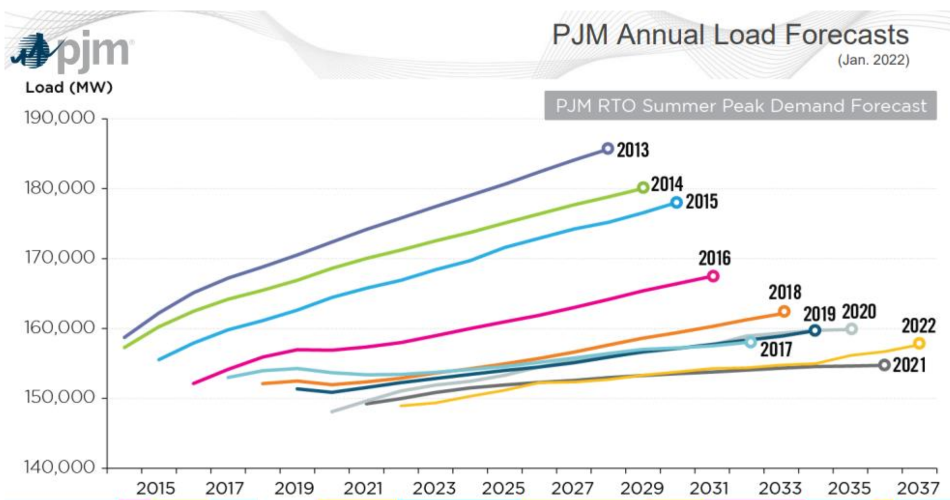
1. 20-Year Horizon For Planning and Benefit Analysis

In the NOPR, the Commission proposes that RTOs use a 20-year transmission planning horizon coupled with three-year reviews for reassessing and revising data, inputs, and factors incorporated in a LTRT plan.[7] Additionally, the Commission proposes to require transmission providers in each planning region to evaluate the benefits of regional transmission facilities over a 20-year horizon, starting from the facility's estimated in-service date.[8] The Commission also states 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."[9] The Commission provides an example where a project that is to become operational in year 10 of a 20-year transmission plan would be evaluated for the next 20 years.[10]

The PAPUC generally supports FERC's proposal for RTOs to engage in long-term planning with regular, reasonably frequent reviews for reassessing and revising scenarios and applicable data. The PAPUC understands and supports the Commission's LTRT planning proposal to function only as a regional planning tool and not as a mandate for construction of selected transmission projects.

[6] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051, P 146 (2011) (Order No. 1000) (requiring transmission providers to participate in a regional transmission planning process that produces a regional transmission plan and that complies with the transmission planning principles of Order No. 890).
[7] NOPR at ¶¶92-100.
[8] NOPR at ¶227.
[9] NOPR at ¶228.
[10] NOPR at ¶227.

The PAPUC supports the approach of utilizing a benefit to cost analysis period as opposed to considering costs and benefits over the entirety of the facility's expected service life. Considering costs and benefits over the full period of a facility's expected life would result in highly speculative benefits and costs. However, the PAPUC is concerned that as the planning and cost/benefit analysis periods lengthen, uncertainty in predictions of load-growth, costs, and benefits will increase, potentially leading to uneconomic transmission projects. A principal factor in determining need for transmission facilities in PJM's existing RTEP process is load-growth projections, including the location of load growth. Load-growth predictions are demonstrably challenging and uncertain, based on experience with PJM's existing 15-year projections in the RTEP process. In PJM, the 2013 summer peak demand forecast for Pennsylvania over a 10-year period was inaccurate and failed to predict load stagnation.[11]



[11] PJM's 2021 Pennsylvania State Infrastructure Report (May 2022), at 30, available at https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2021/2021-pennsylvania-state-infrastructure-report.ashx.

Accuracy in load forecasting is key to determining the benefits of a transmission line. In hindsight, energy efficiency gains drove the load growth declines[12] that the planners failed to predict. Given how demonstrably uncertain long-term forecasts are, the PAPUC requests that the Commission revisit its proposal to set a *minimum* 20-year horizon. The PAPUC supports a long-term horizon of no longer than 20 years for planning and cost/benefit analysis. RTOs should be given flexibility to use a planning horizon that is shorter than 20 years if experience dictates reason to do so.

Additionally, the PAPUC supports the proposed requirement for RTOs to conduct regular and reasonably frequent reassessments of the LTRT plan scenarios. Routine reviews have the potential to update information and data, justify modifications to the plans for building transmission facilities, and ultimately reduce the risk of uneconomic transmission investments. Reassessments should occur at an interval no longer than every three years, but a shorter interval such as every two years may be appropriate if the LTRT planning horizon in PJM is increased from 15 to 20 years. In any event, FERC should give RTOs the flexibility to conduct reassessments at intervals shorter than every three years if circumstances reasonably warrant such review.

2. Factors in Planning

The PAPUC supports FERC's proposal to require information used in the long-term plans to be public and transparent.[13] Regarding the factors to be considered by RTOs in LTRT planning, the PAPUC urges the Commission to allow RTOs the flexibility to determine planning parameters and appropriate categories used for LTRT plan Scenarios in coordination with their

[12] *See e.g.*, https://www.utilitydive.com/news/dealing-with-stagnant-load-growth-iso-new-england-turns-to-gas-efficiency/408985/; https://www.iea.org/commentaries/the-mysterious-case-of-disappearing-electricity-demand.

[13] NOPR at ¶¶123, 227, 330.

stakeholders to ensure that RTOs can avoid conflicts with local and state constitutional, legislative, and regulatory requirements.[14] The factors to be considered in transmission planning should be neither mandatory nor exclusive. Without such built-in flexibility, the PAPUC is concerned that the proposed *required* categories for the LTRT plan Scenarios are overly prescriptive, and depending on the cost allocation method applied, could result in shifting the costs of one state's policy onto other states. Additionally, determinants for LTRT plan Scenarios should not be based on speculative factors. Factors that include federal, state, and local laws and regulations that affect the future resource mix and demand are preferable to factors that include utility, corporate, federal, state, and local goals or policies that have no enforcement mechanisms.[15] The Commission and RTOs should avoid review of other proposed theoretical and ambiguous factors, such as organized geographic zones for generation development[16] and reliance upon withdrawn generation interconnection applications, to determine need for regional transmission facilities.[17] As explained below, while these proposals may be well-intended, they are theoretical concepts requiring rigorous examination to ensure that their use in the LTRT plan does not result in the building of unnecessary or uneconomic regional transmission facilities, resulting in stranded costs.

The intent of the Commission's geographic zones proposal appears to be to build transmission from areas of demand to areas with known wind, solar or other renewable resource potential.[18] However, FERC should recognize that other tangible factors impact actual development of generation, such as state or local land use laws, financing, land costs and

[14] NOPR at ¶¶78, 101-112.
[15] NOPR at ¶104.
[16] NOPR at ¶¶135-153.
[17] NOPR at ¶¶107, 154, 166.
[18] NOPR at ¶¶135-153.

availability, among other factors. Given that the successful development of generation is based upon a developer's ability to address these tangible factors, regions should have the flexibility to define the process for obtaining verifiable and reliable information necessary to identify potential geographic zones to be included in the LTRT plan.

For any region adopting the geographic zone as part of its LTRT planning scenarios, FERC should require that transmission providers establish a process for organizing geographic zones that is non-discriminatory (by rule and by impact) as to different types of generation resources not intended for the zone. Indeed, using transmission planning to organize geographic zones for potential generation development is a new concept that needs to be examined and understood in terms of its impact on: (1) market entry by generation developers (*i.e*., developers' abilities to secure land rights and power purchase agreements within an organized zone), and (2) wholesale market competition and prices (e.g. if an organized zone supports the development of a specific type of generation resource, how will that impact the ability of developers of different types of generation resources to enter the market inside or outside a zone). Transmission planning also should be examined and understood in terms of its encroachment on the powers expressly reserved in the states under the FPA to determine what generation is developed as well as their transmission siting authority.[19] For example, a state may have public policy reasons to establish economic development zones within a state such as to encourage developers to site

[19] The FPA expressly reserves for exclusive state jurisdiction the regulation and oversight of (1) retail sales of electricity, and (2) the "facilities used for the generation of electric energy" (meaning, the regulation of the power plants themselves, even though FERC regulates these plants' sales of electricity at the wholesale level). 16 U.S.C. §§ 824(a), 824(b)(1); *see e.g. Hughes v. Talen Energy Marketing, LLC*, 578 U.S. 150 (2016) (quoting § 824(b)(1)) ("Indeed, the States' reserved authority includes control over in-state 'facilities used for the generation of electric energy.'"); *Pacific Gas & Elec. Co. v. State Energy Resources Conservation and Development Comm'n,* 461 U.S. 190, 205 (1983) ("Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States."). Likewise, the siting of transmission facilities is largely left to the states. 16 U.S.C. § 824p.

generation in a specific area of a state. In such circumstances, the regional geographic zones used for LTRT planning scenarios could frustrate that state's legitimate policy choices by favoring another state's policy choices. In those circumstances, geographic zones planned through LTRT planning that place greater emphasis on encouraging certain types of renewable resources could frustrate a state's legitimate exercise of its power by discriminating against that state's chosen generation development policies.

The Commission proposes that transmission providers consider, as part of LTRT planning, regional transmission facilities that address interconnection-related needs identified in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection requests.[20] The PAPUC, however, posits that simply because a generation interconnection has been identified multiple times in the generator interconnection process, alone, does not prove need for building transmission facilities as part of the LTRT plan. There must be rigorous examination of "why" the generation interconnection application failed. Considering unsuccessful generator applications without rigorous examination of why the applications failed is speculative and could lead to unnecessary and uneconomic transmission expansion. There are numerous reasons, unrelated to the need for upgraded regional transmission facilities, for an interconnection request, even at the same location, to not succeed, such as: (1) the generator lacked readiness due to any reason, such as not securing site control, financing, or placeholder application; (2) the generator determined the project was uneconomic; or (3) the RTO's engineering studies during interconnection study processes proved that interconnection transmission facilities were unnecessary or were satisfied by another transmission project.

[20] NOPR at ¶¶107, 154, 166.

While the PAPUC recognizes that the FERC requires consideration of facilities that address certain interconnection-related needs when such a need is demonstrated in two or more queue cycles and to upgrades that have a voltage of at least 200 kV and/or an estimated cost of at least $30 million, the PAPUC is concerned that these limitations may encourage gaming by developers. If, for example, an interconnection customer, through its interconnection request learns that the upgrade needed involves an upgrade to a facility with a voltage of 200 kV and that it would cost more than $30 million dollars, that customer could withdraw its interconnection request and simply reapply for the same or similar location and again withdraw to trigger the upgrade in the LTRT plan. Adding more commitments on the part of the interconnection customer or requiring a more thorough analysis of the reasons for withdrawal should prevent this gaming and uneconomic cost shifting issue.

3. Evaluation of Benefits of Regional Transmission Facilities

The PAPUC supports the Commission's proposals for transmission providers to consider an expanded set of benefits and to allow for regional flexibility in defining benefits in the transmission planning process.[21] The PAPUC also supports the Commission's proposal to make the list of benefits identified in the NOPR and set out in Table 1 neither mandatory nor exclusive, but rather to only require transmission providers to be transparent in identifying what benefits they will use in LTRT planning and explain how they will be calculated.[22] RTOs should be given flexibility, in consultation with their constituent states, to apply the identified benefits as appropriate to the resource mix, state and local legislative and regulatory requirements, transmission topography, geography and the economics of their respective planning areas.

[21] NOPR at ¶¶183-185.
[22] NOPR at ¶186.

Regarding the Commission's proposal to allow a portfolio approach to evaluating benefits versus the traditional facility-by-facility approach, the PAPUC is concerned that the portfolio approach may mask unnecessary projects (for example, an individual project may not meet the 1.25 to 1 ratio established in Order No. 1000[23]), and depending on the cost allocation method applied, could result in shifting the costs of one state's policy onto other states.[24] The proposal also causes siting concerns relating to the potential presentation of a portfolio of projects for siting approval whereby a single project may be found by the state siting authority to not be consistent with the public interest and state siting regulations, thus exposing a flaw in the analysis of the benefits of the portfolio.

Transmission benefits must be verifiable and quantifiable to justify an allocation of associated costs to ratepayers. Proposed benefits and measurement metrics must also be non-duplicative, reasonably certain, and forward-looking.[25]

4. Selection of Regional Transmission Facilities

Consistent with the Commission's approach in Order No. 1000, the Commission proposes to give regions flexibility to determine the criteria to be used to determine whether to select in the regional transmission plan, for purposes of regional cost allocation, a transmission facility that addresses transmission needs. The PAPUC supports the Commission's proposal to require transmission providers to consult with and seek support and agreement from constituent states within their footprint to develop the selection criteria. This will provide states the opportunity to influence regional planning and cost allocation, thus promoting the public interest and potentially reducing conflicts and disputes over transmission planning and cost allocation.

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[23] Order No. 1000 at ¶646.
[24] NOPR at ¶¶233-235.
[25] NOPR at ¶¶185, 325-327.

5. Consideration of Grid-Enhancing Technologies

The PAPUC supports the proposed requirement for transmission providers to consider dynamic line ratings and advanced power flow control devices. These technologies may help with cost containment, provided the costs of the devices and their operation does not exceed the benefits provided by the ratings and devices.[26]

B. REGIONAL COST ALLOCATION

1. Proposed Cost Allocation Methods by State Negotiation

The PAPUC supports the Commission's proposal to allow constituent states to participate in the regional cost allocation determination as well as the proposal for a default LTRT Cost Allocation Method.[27] The regional cost allocation process can be fraught with conflict and disputes. After a regional transmission facility is selected based on a determination that its projected benefits exceed its costs to a sufficient degree, the transmission planner must allocate the costs among the beneficiaries in the region.[28] Thus, the need for objective, well-defined, and measurable benefits applies not only to planning but to cost allocation as well. It is important that customers who pay the costs allocated with them agree that they are paying for real and appreciable benefits.

While certain benefits may be widely agreed upon, some states may be willing to recognize additional benefits of projects and bear the costs associated with those benefits.[29] Accordingly, state participation in cost allocation determinations is critical to allow states to achieve the benefits they seek from transmission buildout without forcing other states to bear the costs of the projects associated with those benefits. For this reason, the PAPUC has long

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[26] NOPR at ¶272.
[27] NOPR at ¶¶304-310.
[28] PAPUC ANOPR Comments at 8-9.
[29] NOPR at ¶252, fn. 399.

supported the State Agreement Approach ("SAA") used by PJM.[30] The PJM SAA[31] embodies the principle that costs driven by public policy requirements of one state should not be placed on customers in non-participating states. It further provides a platform for multi-state planning by states with complementary or mutual requirements and corresponding cost allocation among them.

The PAPUC is also supportive of further opportunities for states to agree to cost allocations which may advance their goals, so long as those states bear the costs of those decisions. For this reason, the PAPUC supports FERC's proposed State Agreement Process. The State Agreement Process may, like PJM's SAA, allow states to pursue their own policies without interference from regional processes. The PAPUC understands that under the proposed State Agreement Process, one or more state may agree to a cost allocation method for a project selected in the regional transmission plan. Meaning, states in the planning region may agree to a cost allocation method that will apply only to the states that are parties to such agreement. FERC should clarify that a state that is not a party to a cost allocation agreement cannot be required to pay for a selected project.

Governance within the RTOs will be a key component of success for the State Agreement Process in a way that is not required of PJM's SAA. The SAA occurs before project selection.[32] In the first application of the PJM SAA, New Jersey is working with PJM to select the projects which best fit its needs.[33] By contrast, in FERC's State Agreement Process, the state negotiation occurs after project selection.[34] This will put LTRT planning in the driver's seat, and state

[30] PAPUC ANOPR Comments at 5-6.
[31] PJM Operating Agreement, Schedule 6, Sec. 1.5.9.
[32] PJM Operating Agreement, Schedule 6, Sec. 1.5.9.
[33] PJM Interconnection, LLC, Docket No. ER22-902 (Filed January 27, 2022).
[34] NOPR at ¶302, fn. 509.

negotiation will be centered around a project already selected. Thus, the State Agreement Process necessitates carefully tailored governance provisions to ensure that project planning and selection run smoothly while not frustrating the fulfillment of a state's need during the state negotiation process.

To that end, the PAPUC also supports FERC's proposal that the State Agreement Process must comply with Order No. 1000's six regional cost allocation principles.[35] Even though Order No. 1000's principles should be the framework, FERC should be deferential to unanimous agreement by affected states to a cost allocation method adopted as a result of the State Agreement Process. If affected states want to unanimously agree to a cost allocation method for selected transmission facilities, FERC should treat that negotiated result with deference.[36] On the other hand, if states choose not to use a state-negotiated cost allocation process and forgo a role in determining the cost allocation approach for all or a subset of LTRT Facilities, the PAPUC supports the requirement for the transmission providers to propose a LTRT Cost Allocation Method consistent with Order No. 1000's six regional cost allocation principles.[37] FERC, however, should avoid adopting any rule that would prompt a reopening of the existing PJM SAA.

In order to avoid upsetting the PJM SAA, in any final rule, FERC should clarify how the processes proposed in paragraph 302 of the NOPR might blend with the existing PJM SAA. As discussed above, FERC's "ex post" State Agreement Process is designed to occur after project selection has taken place. The PJM SAA cost allocation occurs in practice before project

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[35] NOPR at ¶¶302, 312.
[36] *See United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956). *See also* ISO New England Inc., Docket No. ER22-1528 (May 27, 2022) (Christie concurring, ¶4) (FERC should exercise deference when states agree to policy affecting only those states.)
[37] *See* NOPR at ¶307.

selection. This would qualify as an "ex ante" LTRT Cost Allocation Method rather than FERC's State Agreement Process. Neither the State Agreement Process nor the rules for an "ex ante" LTRT Cost Allocation Method should upset the PJM SAA as it currently exists.

Further, FERC should recognize that while state participation in LTRT planning and Cost Allocation process may work to smooth later state regulatory proceedings, a state's agreement to any State Agreement Process cannot serve to waive or diminish in any manner the state's siting authority over transmission facilities. FERC correctly explains in its NOPR that "states retain siting authority over transmission facilities and will review whether [LTRT] Facilities are consistent with the public interest and state siting regulations."[38]

2. Proposed Definitions

The Commission should use more descriptive definitions of "[LTRT] Cost Allocation Method" and "State Agreement Process" than those currently proposed. In footnote 508, the Commission proposes to define a "[LTRT] Cost Allocation Method" as "an ex ante regional cost allocation method that would be included in each public utility transmission provider's OATT as part of [LTRT] Planning."[39] In footnote 509, the Commission proposes its definition of the "State Agreement Process" as "an ex post cost allocation process that would be included in each public utility transmission provider's OATT as part of [LTRT] planning, which may apply to an individual [LTRT] Facility or a portfolio of such Facilities grouped together for purposes of cost allocation."[40]

The terms "ex ante" and "ex post" as used in these definitions are vague and should be defined or avoided all together. Based on the remainder of footnote 509, the PAPUC

[38] NOPR at ¶314.
[39] NOPR at ¶302, fn. 508.
[40] NOPR at ¶302, fn. 509.

understands the terms “ex ante” and “ex post” to refer to a cost allocation method applied or agreed to either before a facility is selected or after a facility is selected in the regional transmission plan, respectively. Instead of using “ex ante” and “ex post” the Commission should include in the definitions that they are determined either before or after a facility is selected. Moreover, the definition of “State Agreement Process” fails to mention state negotiation. By the terms of the definition, any process that is an “ex post” cost allocation process would qualify as a State Agreement Process, even without state involvement.

These flawed definitions also cause confusion with the separate process described in paragraphs 319 to 324 of the NOPR. In understanding the Commission’s proposal, if an RTO used an “ex ante” default cost allocation process after product selection, the states would have 90 days to propose a different cost allocation for the facility or portfolio of facilities. Based on the structure of the NOPR, the PAPUC understands this process to be a feature of the *ex ante* process. However, because this negotiation occurs after facility selection, it is by definition an ex post “State Agreement Process” as defined in the NOPR. This could cause confusion if the Commission makes rules about the State Agreement Process without clarifying that different rules apply to the 90-day “renegotiation” process in paragraphs 319 to 324.

FERC’s proposed definition of “relevant state entity” is likewise imperfect and may result in multiple entities within a single state being a “relevant state entity” given that FERC refers to utility regulation or siting authority in the definition, but a state’s legislature could have delegated this different authority among different administrative agencies. Specifically, FERC proposes to define a relevant state entity as “any state entity responsible for utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state."[41] While FERC states that it intends to have a single entity designated for each state, FERC's definition does not accomplish that result. Moreover, FERC should not be in the business of defining how a state is able to participate as part of regional state agreement. The single designation requirement intrudes on a state's sovereignty to structure their governing institutions.

3. The 90-Day "Renegotiation" Process

As discussed above, FERC proposes a 90-day renegotiation process so that states may propose an alternate to the default LTRT Cost Allocation Method.[42] The PAPUC does not view the 90-day period as a principal negotiation method for cost allocation. More appropriate processes for principal negotiations are the State Agreement Process proposed by FERC or PJM's existing SAA. The 90-day period is only an add-on to the *ex ante* LTRT Cost Allocation Method. The PAPUC supports flexibility in determining the appropriate period. This is a new process and, given little knowledge and experience of how it will function in practice, flexibility is paramount. To that end, the time period should be set forth in transmission provider tariffs rather than a regulation so that it may more easily be modified should experience prove that 90 days is not an appropriate period for negotiation.

Finally, FERC should clarify its proposal regarding whether transmission providers could file the original cost allocation method if states unanimously agree to an alternative cost allocation method under the renegotiation process described in Paragraph 319. Paragraph 319 provides that if states agree to an alternate cost allocation method, "the public utility transmission provider *may* elect to file it with FERC for consideration under FPA section 205."[43]

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[41] NOPR at ¶304.
[42] NOPR at ¶¶319-324.
[43] NOPR at ¶319.

The PAPUC sees no reason why a transmission provider should be able to override the unanimous agreement of affected states to a cost allocation method.

C. CONSTRUCTION WORK-IN-PROGRESS

Given FERC's proposal for transmission planners to use a 20-year planning horizon in LTRT planning, the PAPUC supports FERC's proposal to disallow transmission owners' recovery of construction work-in-progress ("CWIP") costs in rate base[44] for regional transmission facilities selected through the LTRT plan. The PAPUC shares in FERC's concern that the proposed 20-year planning horizon under LTRT planning is too long with too many variables, making it unreasonable to allow CWIP costs to be borne by customers prior to a facility's in-service date.[45]

Specifically, the PAPUC is concerned that over the course of any planning horizon, especially as lengthy as 20 years, there is an increased likelihood of significant changes in demand, resource mix, federal and state energy policy, and other factors that may result in planned regional transmission projects being substantially scaled back, or simply never constructed and put into service. Under a 20-year planning horizon, allowing a 100% CWIP incentive could encourage transmission owners to be less diligent in their research and planning process. More importantly, allowing a 100% CWIP could substantially increase the risk of customers ultimately paying for transmission facilities that are never built and from which they derive no benefit, thereby leading to rates that are unjust and unreasonable.

Like FERC, the PAPUC notes that, public utility transmission providers may still book costs incurred during the pre-construction or construction phase as Allowance for Funds Used

[44] "Allowing transmission developers to include construction costs in rate base prior to commercial operation provides utilities with additional cash flow in the form of an immediate earned return, rather than delaying recovery of those costs until the plant is placed into service." NOPR at ¶329.
[45] NOPR at ¶¶330-334.

During Construction ("AFUDC") and only recover those costs after the project is in service to customers, in accordance with generally accepted utility accounting principles for AFUDC.[46] The PAPUC views AFUDC as a reasonable recovery mechanism for pre-construction and construction costs as it places the onus on transmission providers to prudently plan, construct, and place into service proposed regional transmission projects, and avoids the problem of leaving customers stranded with costs from projects that are never completed. For these reasons, should FERC adopt a planning horizon for LTRT planning of 20 years, the PAPUC supports the Commission's proposal to disallow transmission developers to receive a 100% CWIP incentive.

D. FEDERAL RIGHT OF FIRST REFUSAL

The PAPUC opposes FERC's proposal to amend Order No. 1000's reforms in order to permit the exercise of a federal right of first refusal ("ROFR") for transmission facilities selected in LTRT planning for purposes of cost allocation, even where the transmission provider with the ROFR for such regional transmission facilities establishes joint ownership of the transmission facilities.[47] The PAPUC maintains its opposition to implementing a ROFR or any other limits on competition in the regional transmission planning process, consistent with its stance during the Order No. 1000 proceeding.[48] FERC has correctly acknowledged the risks that a ROFR poses to both the development of regional transmission projects and to consumers who ultimately pay for

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[46] NOPR at ¶333; *see also* Concurring statement of Commissioner Christie, at ¶ 15 (Issued April 21, 2022).

[47] "A [ROFR] is defined […]as the right of an incumbent transmission owner to construct, own, and propose cost recovery for any new transmission project that is: (1) located within its service territory; and (2) approved for inclusion in a transmission plan developed through the Order No. 890 planning process." *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, FERC Docket No. RM10-23-000, Notice of Proposed Rulemaking, at ¶20, n. 21 (Issued June 17, 2010).

[48] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, FERC Docket No. RM10-23-000, Comments of the Pennsylvania Public Utility Commission, at 16 (Filed September 29, 2010) (expressing opposition to a ROFR for reasons which FERC acknowledged in its June 17, 2010 Notice of Proposed Rulemaking).

them.[49] Because competition serves to discipline costs, allowing the incumbent transmission utility to exercise a ROFR, even if done in partnership with another entity, could expose load to higher costs. Given FERC's articulated desire to increase the number of regional transmission projects to meet future needs, it is counterproductive to increase or reinstate barriers that would thereby disadvantage competitive transmission developers who may propose more cost-effective solutions.

To the extent that FERC determines that the elimination of the ROFR by Order No. 1000 resulted in transmission providers focusing on local projects rather than regional projects, the solution is not to appease incumbent transmission owners' reluctance to engage in competition from nonincumbent transmission developers, by restoring the ROFR. To take advantage of the ROFR in FERC's joint-ownership proposal, incumbent transmission providers would be permitted to establish joint-ownership with another incumbent transmission provider – an arrangement which could effectively extend the exclusion of competitive transmission developers to include both local and regional transmission projects.[50] Such a mechanism clearly grants preferential treatment to the incumbent transmission providers and discriminates against

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[49] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, FERC Docket No. RM10-23-000, Notice of Proposed Rulemaking, at ¶¶87-88 (Issued June 17, 2010) ("Where an incumbent transmission provider has a [ROFR], a nonincumbent transmission developer risks losing its investment in developing a proposal for submittal to the regional transmission planning process, even if that proposal is selected for inclusion in the regional transmission plan. We are concerned that it may be unduly discriminatory or preferential to deny a nonincumbent transmission developer that sponsors a project that is included in a regional transmission plan the rights of an incumbent transmission provider that are created by a transmission provider's OATT or agreements subject to the Commission jurisdiction. […] In addition, under these circumstances, nonincumbent transmission developers may be less likely to participate in the regional transmission planning process. If the regional transmission planning process does not consider and evaluate projects proposed by nonincumbents, it cannot meet the principle of being "open." Moreover, such a planning process may not result in a cost-effective solution to regional transmission needs and projects that are included in a transmission plan therefore may be developed at a higher cost than necessary. The result may be that regional transmission services may be provided at rates, terms and conditions that are not just and reasonable.")
[50] NOPR at ¶358.

competitive transmission developers, in violation of the principle of an 'open' transmission planning process, as articulated in Order No. 890.[51]

As the PAPUC noted in its comments to the ANOPR, local transmission projects represented approximately 85 percent of the $752.7 million of RTEP investments in 2020 in Pennsylvania.[52] Given the competitive nature of regional transmission projects, the disparity in investment between local and regional transmission is not accidental. Incumbent transmission providers should not be given another incentive to select non-competitive local projects. Accordingly, the PAPUC opposes any effort to fully restore the ROFR for entirely new transmission facilities selected in a regional transmission plan for purposes of cost allocation.[53]

E. LOCAL TRANSMISSION PLANNING

1. Local Transmission Planning Transparency

Enhancing transparency in local planning is a laudable goal advanced by FERC.[54] However, because FERC proposes adopting the attachment M-3 process wholesale, these new transparency processes will not further enhance PJM's process. Moreover, as the PAPUC discussed in its ANOPR comments,[55] since PJM's Order No. 1000 compliance filings were approved, local transmission planning has significantly increased in the PJM region. Attachment M-3 was added to the PJM Tariff in September 2018,[56] but this process has seemed to have little

[51] NOPR at ¶341, n. 541.
[52] PJM's 2020 Pennsylvania State Infrastructure Report (April 2021) at 3, available at https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2020/2020-pennsylvania-state-infrastructure-report.ashx.
[53] FERC also proposes a 'right-sizing' ROFR for local projects. *See* NOPR at ¶¶408-409. Given that local transmission planning and regional transmission planning are two distinct processes, the PAPUC will address the proposed 'right-sizing' ROFR in our comments to Section VIII of the NOPR.
[54] NOPR at ¶¶399-400.
[55] PAPUC ANOPR Comments at 7-8.
[56] *Monongahela Power Co.*, 162 FERC ¶ 61,129 (2018), order on rehearing and compliance, 164 FERC ¶ 61,217 (2018).

effect to rebalance transmission planning back toward larger regionally beneficial facilities subject to competitive processes.

In advancing the principle that regional projects often provide benefits to a region that local projects do not, the PAPUC generally supports the concept of right-sizing end-of-life projects over 230 kV to gain efficiencies in transmission planning. Not all facilities are appropriately right-sized. A facility should not be right-sized if the total cost of a right-sized facility is greater than the cost of the local project plus a competitively procured project to address the regional need. Additionally, transmission planners should consider if a regional project (*i.e.*, a project procured competitively through Order No. 1000 processes) accrues additional benefits beyond what the right-sized local project would provide. At the same time, transmission planners should take care to avoid additional burdens by creating new critical facilities out of smaller non-critical transmission lines.

In addition, FERC appropriately recognizes that "benefits associated with right-sizing potential replacement transmission facilities to address transmission needs identified through LTRT planning should be evaluated the same as any potential transmission facility that could address that transmission need."[57] The PAPUC fully agrees with this statement, and as with all transmission planning, to determine the needs, the benefits and beneficiaries must be identified to a reasonable degree of certainty.

2. ROFR for Right-Sizing Local Projects

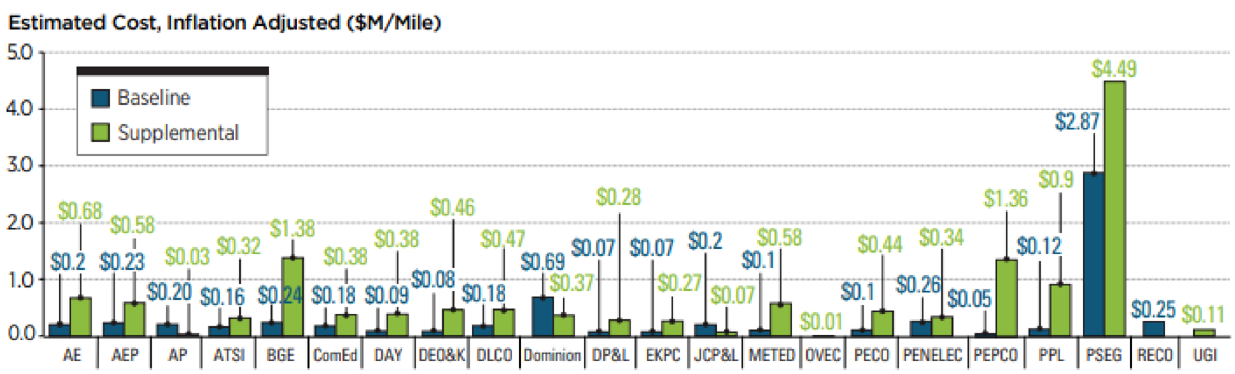
The PAPUC supports competition in transmission development. Order No. 1000 failed to engage the levels of competition to build out the transmission system that its supporters, including the PAPUC, would have hoped, but the solution is not to abandon competition in favor

[57] NOPR at ¶407, fn. 650.

of rights of first refusal. As explained above, FERC should not give transmission owners' an incentive to choose local projects by granting them new rights of first refusal. The consequence of granting a ROFR for right-sized projects might not just be to displace small local projects, but incumbent transmission owners may use this as a powerful new tool to avoid regional competition. FERC goes so far as recognizing this possibility, noting that proposed right-sizing may displace other regional transmission needs (which may have been competitively procured).[58]

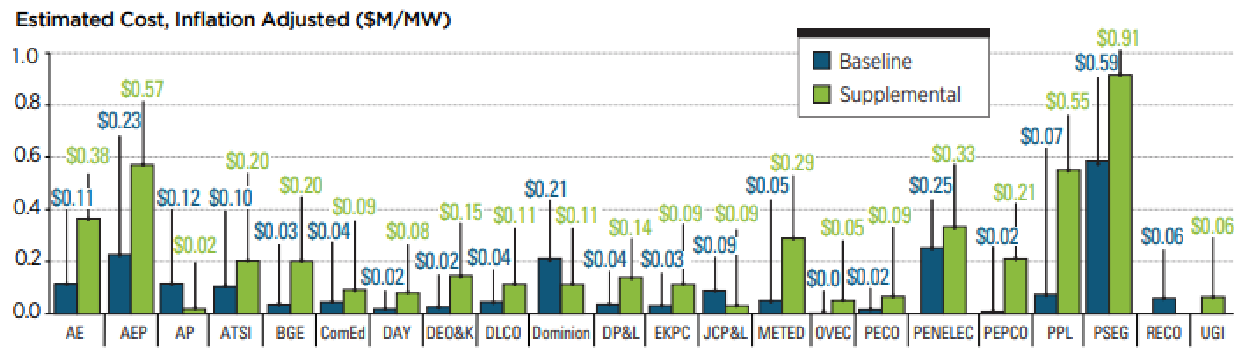
Moreover, projects built by incumbent transmission owners are demonstrably more expensive in almost every case. By mile and by peak load served, over the last decade, PJM baseline projects, which are mostly subject to competition, are less expensive than transmission owner-driven local "supplemental" projects.[59]

Figure 5.10: Baseline and Supplemental Projects Adjusted by Circuit Miles Since 2011



58 NOPR at ¶406.
59 2021 PJM Regional Transmission Expansion Plan, at 294-295, https://www.pjm.com/-/media/library/reports-notices/2021-rtep/2021-rtep-report.ashx

Figure 5.8: Baseline and Supplemental Projects Adjusted by Peak Load Since 2011



While the PAPUC supports the concept of right-sizing to increase efficiencies in planning, the ROFR for right-sized transmission projects proposed by FERC will not result in costs savings or more efficient transmission. The result is more likely to merely allow more avoidance of competitive processes.

F. INTERREGIONAL PLANNING

Given that Pennsylvania is a top net exporter of electric energy in the nation and region, the PAPUC supports increased transparency in interregional transmission coordination.[60] In the current environment of unsettled fuel markets caused by energy supply chain disruptions, it is especially vital for regions to have the tools to effectively and efficiently collaborate with one another to ensure reliable and cost-effective energy supply to the national electric grid.

The PAPUC views the proposed reforms as strengthening interregional planning, as articulated by FERC in Order No. 1000.[61] Specifically, the PAPUC supports FERC's proposal to require transmission providers to revise existing interregional coordination procedures for: (1) the sharing of information regarding the respective transmission needs identified in LTRT

[60] NOPR at ¶¶426-427.

[61] "Clear and transparent procedures that result in the sharing of information regarding common needs and potential solutions across the seams of neighboring transmission planning regions will facilitate the identification of interregional transmission facilities that more efficiently or cost-effectively could meet the needs identified in individual regional transmission plans." Order No. 1000 at ¶368.

planning, as well as potential transmission facilities to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address transmission needs identified through LTRT planning.[62]

The PAPUC also supports FERC's proposal to require 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 to transmission needs identified through LTRT planning.[63] The PAPUC agrees that this proposal, if adopted, would provide the opportunity for public utility transmission providers in neighboring transmission planning regions to consider whether there are interregional transmission facilities that could meet the transmission needs identified through LTRT planning in a more efficient or cost-effective fashion, which, in turn, would facilitate just and reasonable Commission-jurisdictional rates.[64]

However, the PAPUC's support for these proposals is conditioned on the ability of regions to maintain flexibility for defining criteria in considering and selecting such proposed facilities, including criteria that permits the selection of proposed regional transmission facilities over a proposed interregional facility in alignment with meeting applicable local and state requirements. As stated above, regions should have flexibility in determining planning parameters in coordination with the regions' stakeholder communities, including state regulators. This flexibility will further ensure that state regulators and siting authorities can comply with

[62] NOPR at ¶427.
[63] NOPR at ¶428.
[64] NOPR at ¶429.

dynamic applicable local and state requirements and adapt to generation-resource trends and policies.

IV. CONCLUSION

The PAPUC respectfully requests the Commission to consider its comments.

Respectfully submitted,

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Dated: August 16, 2022

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I am on this date serving a copy of the foregoing comments upon each person designated on the official service list compiled by the Federal Energy Regulatory Commission in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure.

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