BEFORE THE
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

On July 15, 2021, the Federal Energy Regulatory Commission ("Commission") issued an Advance Notice of Proposed Rulemaking ("ANOPR") proposing to revise existing regional transmission planning, cost allocation and generator interconnection processes.[1] The Pennsylvania Public Utility Commission ("PAPUC") herein files these Comments in response to the ANOPR.

I. COMMUNICATIONS

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

II. INTRODUCTION

The Commission's ANOPR seeks comments on proposed revisions to approved transmission planning processes by regional and local transmission planners, cost allocation methodologies and practices for regional transmission facilities and generator interconnections, and new cost containment and monitoring measures to prevent imprudent transmission spending and incent regional transmission planning. The scope of the ANOPR is significant in terms of the many areas under the Commission's jurisdiction and the long-established precedent it seeks to revise through this rulemaking. The PAPUC is cognizant of the challenges before the Commission to prepare the transmission grid for the evolving generation fleet and the incorporation of federal, state, local, and corporate generation procurement policies. While the PAPUC is supportive of many of the ANOPR proposals, we recommend that the Commission take a more deliberate and measured approach that continues to rely on verifiable and quantifiable benefits for transmission planning and the well-founded cost causation and "beneficiary pays" cost allocation methodologies, while improving cost containment and monitoring practices. The PAPUC respectfully submits these comments in support of our recommendations.

III. COMMENTS

Located entirely within the PJM, Interconnection, LLC ("PJM") footprint, Pennsylvania has been a part of PJM's transmission planning and cost allocation policies for decades. As a significant net exporter of electricity and electricity consumer in PJM, Pennsylvania has also been responsible for paying a large portion of PJM's transmission enhancements and expansions.[2] For 2020 alone, Pennsylvania's portion of the PJM-approved regional transmission expansion plan ("RTEP") projects totaled approximately $752.7 million in transmission investment.[3] Further, Pennsylvania's total RTEP transmission investment from 2016 through 2020 exceeded $4.14 billion.[4] Consequently, our comments will focus on our experience with PJM's transmission planning and cost allocation methodologies and practices in light of the Commission's proposed revisions.

A. Transmission Planning Recommendations

1. *Transmission planning should ensure a reliable, secure, and resilient grid that incorporates economic grid-enhancing technologies and accommodates evolving changes to the generation resource mix, without speculative overbuilding that would burden customers with unnecessary costs.*

The majority of the ANOPR questions related to transmission planning focus on how to revise transmission planning practices in an anticipatory manner to accommodate projected increases of renewable generation on the system. The PAPUC agrees that proactive planning to account for new and reasonably certain interconnecting generation

[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 (September 17, 2020).

[3] *See* 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.

[4] *See* PJM's 2020, 2019, 2018, 2017, and 2016 Pennsylvania State Infrastructure Reports, available at https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2020/2020-pennsylvania-state-infrastructure-report.ashx; https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2019/2019-pennsylvania-state-infrastructure-report.ashx; https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2018/2018-pennsylvania-state-data.ashx; https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2017/2017-pennsylvania-state-infrastructure-report.ashx; https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2016/2016-pennsylvania-state-report.ashx.

should be a planning principle for a regional transmission planner like PJM. At the same time, the PAPUC is mindful of the need to plan the regional transmission system to, first and foremost, be reliable and resilient. As the generation mix within the PJM footprint evolves, there will be many future generation deactivations that may result in significant reliability upgrades due to the retirements of large coal, nuclear, and natural gas generation facilities. In fact, in 2020, PJM received 22 deactivation notifications totaling 4,428 MW.[5] Further, there are an additional 10,161 MW of generation that have requested retirement as of June 30, 2021.[6]

As PJM's transmission costs continue to increase, the Commission should be cautious of mandating additional proactive planning drivers that are not based on secured financial commitments of proposed generator interconnections or building the transmission system to accommodate preferred but uncertain generation development. Instead, transmission planners should continuously study and forecast the evolving generation resource mix in consultation with states, local governments and local authorities, while taking into consideration corporations' generation procurement plans. Incremental transmission planning with regular retooling and updates should provide a nimbler and more cost-disciplined approach to building the grid of the future compared to a plan that envisions an aggressive and speculative generation development without financial commitment measures in place. This type of anticipatory building without financial

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[5] *See* PJM's 2020 Regional Transmission Expansion Plan at 12 (February 28, 2021), available at https://www.pjm.com/-/media/library/reports-notices/2020-rtep/2020-rtep-book-1.ashx.

[6] Monitoring Analytics LLC's State of the Market Report for PJM, January through June (August 12, 2021) at 607, available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021q2-som-pjm.pdf.

commitments has the additional flaw that it offers no incentives to anticipate changes in technology, constructability issues, and local concerns.

Transmission costs in PJM have already exceeded those of capacity costs, as reported by PJM's Independent Market Monitor.[7] The PAPUC maintains that 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.

2. *PJM's State Agreement Approach ("SAA") represents an acceptable way of incorporating state public policies in regional transmission planning through an agreement that has garnered significant support by the PJM states.*

PJM's SAA[8] is based on the principle that authorized state governmental entities in one or more states, individually or jointly, may agree voluntarily to be responsible for the allocation of all costs of a proposed transmission expansion or enhancement that addresses state public policy requirements identified or accepted by the participating state(s). The costs of such transmission enhancements or expansion shall be recovered only from the customers of the participating state(s). The SAA transmission planning and cost sharing mechanisms were supported by the Organization of PJM States, Inc. ("OPSI") and the majority of the PJM States.[9] Most recently, New Jersey has requested that PJM initiate project solicitations under the SAA.

[7] *Id*. at 1. ("Starting in the third quarter of 2019, for the first time since the start of the RPM capacity market design in 2007, the cost of transmission per MWh of wholesale power is higher than the cost of capacity.")
[8] PJM Operating Agreement, Schedule 6, Sec. 1.5.9.
[9] Motion to Intervene and Comments of the Organization of PJM States, Inc., Docket No. ER13-198 (December 10, 2012).

In addition, PJM's Operating Agreement allows for incremental cost sharing of different transmission drivers, such as economic, reliability, and public policy, through its multi driver approach.[10] Where state support overwhelmingly endorses a particular transmission planning methodology and cost allocation mechanism, as in the case of the SAA, the Commission should continue to allow for regional flexibility in meeting state public policy goals.

Related to this issue is the planning for generation additions driven by public policy goals. While generation additions are primarily market driven, transmission planning has many drivers including load growth and federal, state, and local public policy desires that are not always aligned. To the extent that these drivers are fully aligned, they can be used to identify areas where additional generation is likely to be needed or developed, such that it may be prudent to synchronize the generation interconnection process for these potential resources with the transmission planning process. However, any additional financial risks associated with this type of public policy driven generation planning should be borne by the sponsoring states and the generators benefitting from the increased efficiencies.

3. The Commission should encourage the incorporation of grid-enhancing technologies in regional and local transmission plans.

Where appropriate and economic, regional, and local transmission planners[11] should incorporate in their transmission planning processes grid-enhancing technologies that

[10] PJM Operating Agreement, Schedule 6, Sec. 1.5.10.

[11] For purposes of these comments, regional transmission planners refers to regional transmission organizations (RTOs) and independent system operators (ISOs) like PJM, while local transmission planners refers to transmission owners that plan their system independently but in coordination with regional planners, similar to the way PJM's incumbent transmission owners plan supplemental projects.

maximize the useful life of assets and deliver savings to customers through increased capacity and efficiency. Such tools should be incorporated in regional and local planning practices on a case-by-case basis, giving the transmission planners the opportunity to study the effect of such technologies on reliability and perform benefit/cost analysis for their utilization on a larger scale.

4. Regional transmission planning should be based on verifiable and quantifiable inputs and assumptions that are available for stakeholder review through an open and transparent transmission planning process. Such processes should take into consideration and incorporate constructability issues and relevant state siting laws.

The Federal Power Act (FPA), 16 U.S.C. § 824 *et seq*., reserves to the states the authority to site transmission facilities and make appropriate need, environmental, and safety determinations for transmission facilities regardless of whether they are included in regional or local transmission plans.[12] The Commission has stated expressly that "the designation of a transmission project as a 'transmission facility in a regional transmission plan' . . . *only* establishes how the developer may allocate the costs of such a facility in Commission-approved rates *if it is built*."[13] The transmission plan does not require that any such facility be built because there is "nothing" in FERC's authority that "explicitly or implicitly *requires that any transmission facilities be . . . constructed*."[14] The decision to build a transmission facility is expressly reserved to the states under 16 U.S.C. § 824(a)

[12] *See Piedmont Envtl. Council v. FERC*, 558 F.3d 304, 310 (4th Cir. 2009) ("states have traditionally assumed all jurisdiction to approve or deny permits for the siting and construction of electric transmission facilities").
[13] FERC Order No. 1000-A, 77 Fed. Reg. at 32,216 (emphasis added).
[14] *Id*. at 32,215 (emphasis added).

and "decisions made in the regional transmission planning process" by the regional transmission planner should not "interfere with these state-jurisdictional processes."[15]

Therefore, to the extent that regional transmission plans conflict with or fail to take into consideration state siting laws, the actual development of such plans may not occur due to states not providing the necessary approvals. To increase transparency and provide needed confidence in the regional transmission plans, the PAPUC urges the Commission to direct that all inputs, assumptions, and data used by the regional transmission planner be verifiable and available for review by stakeholders and state agencies. Regional transmission planners should be familiar with state siting, eminent domain, land use, and environmental laws, as well as other local concerns that may raise constructability issues when developing their regional transmission plans.

B. Cost Allocation Recommendations

1. The Commission should uphold the foundational beneficiary pays principle of Order 1000 for needed transmission facilities identified in the regional transmission planning process.

For needed transmission investment identified in the regional transmission planning process, Order 1000[16] adopted six cost allocation principles grounded in the beneficiary pays methodology. The PAPUC recommends that FERC retain this foundational beneficiary pays principle articulated in Order 1000 – that the costs of needed transmission facilities should be allocated commensurate with the estimated benefits of those facilities.[17]

[15] *Id*.
[16] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (2011), (Order 1000).
[17] *Id.* at PP 622, 639.

This principle, which has withstood judicial scrutiny,[18] has been applied by the regional transmission planners through diverse approaches that address the various regional, operational, and policy considerations of their members and stakeholders.

Cost allocation methods for regional transmission expansion projects should continue to be based on the beneficiary pays principles. Benefits should be quantifiable, verifiable, and sufficiently certain to ensure that costs are appropriately allocated. Inputs, assumptions, and data quantifying the benefits should be readily available for review by stakeholders and provided in a transparent manner by the transmission planner. Claimed benefits, assumptions, and other inputs to such calculations should be updated regularly and shared with stakeholders. Increased transparency in any cost-benefit analysis, as well as opportunities to test and challenge the inputs to the analysis early in the process will likely reduce legal challenges to these critical determinations.

2. The Commission should maintain regional diversity and flexibility in the implementation of Order 1000.

It is not surprising that regional transmission planners have adopted slightly different approaches to their implementation of Order 1000. Such differences reflect the existing variations among the regions with respect to system topology, generation mix, state policies, and importantly, how stakeholders value different drivers for transmission investment. Diversity among the regions is not on its face a cause for concern. Rather, the

[18] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 87-89 (D.C. Cir. 2014) (Order issued by FERC that required electricity transmission providers to devise methods for allocating the costs of certain new transmission facilities to those entities that benefit from them did not violate basic "cost causation" principle, under which costs were to be allocated to those who caused costs to be incurred and reaped resulting benefits; although some beneficiaries might escape cost responsibility, FERC was not required to ensure full or perfect cost causation).

diverse approaches reflect the regional transmission planners' implementation of the Order 1000 planning principles in a way that appropriately reflects crucial stakeholder negotiation and reasoned agreement.

Historically, the Commission has wisely allowed regional differences in defining the benefits and beneficiaries of transmission system build outs while simultaneously enforcing the regions' adherence to Order 1000's core beneficiary pays principle. In the ANOPR, the Commission has not presented clear evidence that the existing variations in regional implementation of the six cost allocation principles in Order 1000 have failed to achieve just and reasonable transmission rates. Transmission needs of the bulk power system undoubtedly will continue to evolve as the generation types and customer demands evolve – as driven by the markets, environmental law, and state public policy requirements. As noted, FERC's allowance for regional flexibility to date has meant that regional transmission planners have been able to address transmission needs in their regions while also considering various and unique factors, operational considerations, and state public policy requirements within their region.

Regional flexibility should not be replaced by a centralized approach with a standardized definition of and method for quantifying benefits and beneficiaries. The regional stakeholder process allows for innovation and the development of new, creative approaches among its members and stakeholders to meet the evolving demands and needs of the bulk power system.

3. *The Commission should continue to uphold the just and reasonable State Agreement Approach in PJM.*

As noted earlier, the SAA reflects the reasoned agreement of the PJM states on how to address the allocation of transmission costs driven by the varying incentives or mandates found in a state's law. Like other regional approaches, PJM's SAA enjoys the benefit of having general support by PJM's members and the majority of PJM states. More specifically, the SAA prohibits the allocation of transmission costs resulting from a state's law or public policy requirements to customers of load serving entities in other states that are not taking part in the public policy requirements of the other state. Accordingly, the SAA protects customers of load serving entities in non-participating states from bearing the burden of paying the costs for transmission facilities driven by a single state's, or a group of states', public policy requirements.

At the same time, PJM's multi-driver approach allows for incremental cost sharing of different transmission drivers, such as economic, reliability, and public policy. While PJM's multi-driver approach may not have been utilized extensively to date, the potential for its use exists. Rather than declaring PJM's existing cost allocation provisions unjust and unreasonable, the Commission should explore the reasons why the cost sharing provisions of the SAA and the multi-driver approach remain mostly untapped. Additionally, the Commission should allow PJM and New Jersey to continue their exploration of the SAA as a viable option to meet New Jersey's offshore wind goals. Likewise, FERC should encourage PJM and PJM states with aligned public policy requirements to utilize and gain experience under the SAA's provisions before modifying or replacing this widely supported regional agreement.

4. *The Commission should protect customers from paying for transmission costs based on generalized or speculative estimates of transmission benefits.*

The ANOPR observes a common thread among the regions today in that the transmission planning baseline reliability models consider only highly certain generation projects for the build out of transmission infrastructure. The Commission criticizes this common principle and expresses its favor for models that incent the building of transmission infrastructure for anticipated future generation. However, this common thread among the regions reflects a basic ratemaking principle that one must establish a need for something before building it. That basic principle protects customers by assigning transmission costs based on quantifiable and verifiable benefits.

Cost allocation methods that encourage the building of transmission infrastructure for uncertain, anticipated future generation projects would likely not achieve just and reasonable transmission rates because defining the benefits and beneficiaries of such projects would be attenuated. Judicial precedent cautions against broad definitions of benefits and, instead, demands quantifiable and verifiable benefits.[19]

[19] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009) (citing *Transcontinental Gas Pipe Line Corp*., 112 F.E.R.C. P 61,170, 61,924-61,925 (2005)) ("a claim of generalized system benefits is not enough to justify requiring the existing shippers to reduce the fuel costs borne by the existing shippers. However, they point to no evidence in the record that seeks to quantify this benefit, or even shows that such a benefit has occurred.... The Commission concludes that all these alleged benefits are simply too speculative and unsupported to be taken into account.") *See also Ill. Commerce Comm'n v. FERC*, 756 F.3d 556, 565 (7th Cir. 2009) ("To summarize, the lines at issue in this case are part of a regional grid that includes the western utilities. But the lines at issue are all located in PJM's eastern region, primarily benefit that region, and should not be allowed to shift a grossly disproportionate share of their costs to western utilities on which the eastern projects will confer only future, speculative, and limited benefits").

In setting up a framework that requires regional transmission planners to consider the transmission needs of anticipated (and more uncertain) future generation, the Commission should nonetheless ensure that protections are put in place to shield ratepayers from being assigned stranded costs of transmission projects built for generation resources that do not ever interconnect to the grid despite anticipation of such. Where generation projects do not get built or do not interconnect but result in stranded investments in transmission facilities, the recovery of any such stranded costs from ratepayers in transmission rates would not be just and reasonable.

5. The Commission should uphold the foundational cost causation principle for network upgrades necessary to allow generation to interconnect to the grid.

PJM's cost allocation methods for generator interconnections should continue to be based on cost causation principles for generation projects that have a high likelihood of being interconnected to the transmission system in the near future. From a broad commercial view, generator interconnecting customers seek to access the competitive wholesale electricity market and earn profits as sellers of wholesale power. Moreover, the types and locations of generation interconnection may be driven by various state public policy incentives and requirements. Transmission customers should not be required to subsidize the costs of network system upgrades caused by the market participant.

The participant funding model is just and reasonable because it requires generator interconnecting customers, as the cost-causers of network upgrades, to pay the costs related to such network upgrades.[20] The participant funding model creates incentives that enable efficient siting of generation projects and the building of economical generation. Indeed, the generator interconnecting customer is the cost-causer who should pay for transmission system upgrades because the network upgrades would not be required "but for" its interconnection to the power grid. The participant funding "but for" model means that interconnection costs are appropriately included in the generator's cost of doing business. This way costs are assigned to the market participant that is best positioned to control such costs and benefit from them.

6. The Commission should allow for incremental improvements to the participant funding model rather than eliminate it.

While the PAPUC supports the participant funding model, it is cognizant that the implementation of that principle in PJM has resulted in a significant backlog of renewable generation attempting to interconnect to the grid. Similarly, in the ANOPR, FERC expressed concerns over the first mover bearing the significant costs of network upgrades and the inefficiencies produced by a single developer "testing the waters" by submitting multiple interconnection requests at different sites. Instead of directing the removal of the

[20] *See* Order No. 2003 ¶ 695 ("a well-designed and independently administered participant funding policy for Network Upgrades offers the potential to provide more efficient price signals and more equitable allocation of costs than the crediting approach."); *see also* Order No. 2003 ¶ 702 ("But for" pricing "is consistent with this Commission's policy of promoting competitive wholesale markets because it causes the Interconnection Customer to face the same marginal cost price signal that [] it would face in an efficient, competitive market."); *see also Order Accepting Compliance Filing Subject to the Filing of Certain Revised Tariff Sheets*, 108 FERC ¶ 61,025, at 19 (July 8, 2004) (approving PJM's Order No. 2003 compliance filing, holding that "the 'but for' method [PJM] uses to determine what payments must be made by an Interconnection Customer provides incentives to locate new generation in an efficient fashion."); *see also* 108 FERC ¶ 61,025, at 20 (reaffirming that participant funding for network upgrades is "part of a project's construction cost and business risk, and the Interconnection Customer must consider those cost[s] in determining whether the project is economically worthwhile.").

participant funding model due to these concerns, the Commission should consider further incremental improvements to it. Notably, PJM is actively engaged in making improvements to its model that will alleviate the queue backlog and limit exploratory interconnection requests that slow down the process.

While the participant funding model is well aligned with the cost allocation principle of cost causation, the PAPUC recognizes that potential economies of scale could result from increased coordination among participants within "interconnection cluster zones" identified by the regional transmission planner within a region. Cost sharing among generator interconnecting customers within a close geographical proximity of each other and position in the queue – *i.e.*, clusters – would be just and reasonable because the costs would be shared and allocated among the interconnecting generators and not socialized in the transmission rates. Furthermore, cluster zones identified by the regional transmission planners may reduce the occurrence of a single developer "testing the waters" by submitting multiple interconnection requests at different sites, resulting in more efficient operations. The Commission should allow PJM's contemplated improvements to be developed through the extensive use of its stakeholder process and be implemented to gain sufficient experience from them prior to directing revisions.

C. Cost Containment Recommendations

1. Cost containment measures

As transmission costs continue to rise, the Commission should explore cost containment measures to be implemented by regional and local transmission planners. For example, where feasible, regional transmission planners should employ competitive solicitations with minimal exemptions. Regional planners can proactively plan the system to minimize immediate need exemptions that relieve a project from competitive solicitations, and, in instances where such exemptions are unavoidable, utilize cost caps and other appropriate cost containment measures. Generally, transmission projects with cost containment provisions that minimize the risk of cost overruns should be preferred over solutions without such measures.

2. Transmission owner-driven projects and RTO participation adder

The vast majority of RTEP projects in PJM today are supplemental projects, projects designed and selected by local transmission planners and not subject to competition. In 2020, PJM evaluated $4.7 billion of local supplemental projects, compared to $413 million of baseline projects approved by the PJM Board for the same period.[21] PJM's baseline projects also contain transmission owner criteria that is largely set at the discretion of the transmission owner. PJM's baseline projects were primarily driven by such transmission owner criteria violations that represented 64 percent, or $264 million, of the total $413

[21] PJM's 2020 Regional Transmission Expansion Plan at 4, 58 (February 28, 2021), available at https://www.pjm.com/-/media/library/reports-notices/2020-rtep/2020-rtep-book-1.ashx.

million of baseline spending for 2020.[22] Taken together, transmission owner criteria-driven baseline and supplemental spending accounted for about 97 percent of all transmission spending in PJM in 2020, with the remaining three percent left for regionally planned projects by PJM. The numbers in Pennsylvania are similar where supplemental projects represented approximately 85 percent of the $752.7 million of RTEP investments in 2020.[23]

Given that the overwhelming majority of transmission spending in PJM and Pennsylvania is done by local transmission planners, such entities should incorporate principles of cost containment, seek efficient transmission solutions, and evaluate alternative routes and solutions in their local plans. Additionally, the Commission should carefully consider whether supplemental projects should be eligible to receive an RTO participation adder where the planning for these projects is done independent of the regional transmission planner. In the separate docket involving electric transmission incentives, the PAPUC supported OPSI's comments which argued that applying the RTO adder to supplemental projects "over-incentivizes transmission owners to rebuild only the grid of the past – without RTO oversight – as opposed to vying for or creating regionally planned projects that provide system-wide benefits that are imperative for the grid of the future." [24] As a result, OPSI urged the Commission to revise its incentive policy so that

[22] *Id*. at 4.
[23] 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.
[24] Comments of the Organization of PJM States, Inc., Docket at 5-6, No. RM20-10 (June 23, 2021).

transmission owners would no longer be eligible to receive an RTO participation incentive for projects that do not require RTO participation.[25]

3. Independent Transmission Monitor

Additionally, the Commission should examine the concept of an Independent Transmission Monitor that can evaluate the projects' fundamentals, cost overruns, and underlying assumptions, as well as provide stakeholders needed industry benchmarks and recommendations on best practices for cost containment. Such monitoring could provide an independent look at the overall needs of a larger region than the regional transmission planners, which are partially dependent on their members, including transmission owners, that may have conflicting interests in advancing their projects over a more efficient solution. For larger interstate transmission projects, an Independent Transmission Monitor could provide potential alternative solutions using regional data and resources to which states and interested stakeholders may not have access. The role of the Independent Transmission Monitor should be advisory to regional transmission planners and provide state siting regulators with data and analysis in a way that properly respects the authority reserved to the states by the FPA.

[25] *Id.*

IV. CONCLUSION

For these reasons, the PAPUC respectfully requests that its Comments be considered by FERC in this proceeding. We urge the Commission to make the appropriate determinations, adopt our recommendations, and direct PJM to implement them.

Respectfully submitted,

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Dated: October 12, 2021

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I am on this date serving a copy of the foregoing document 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.

Dated at Harrisburg, PA this 12th day of October 2021.

Respectfully submitted,

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