UNITED STATES OF AMERICA
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
<u>AMERICAN MUNICIPAL POWER, INC.</u>

On July 15, 2021, the Federal Energy Regulation Commission ("Commission" or "FERC") issued an Advanced Notice of Proposed Rulemaking ("ANOPR") to review issues addressed in Order No. 1000[1] as well as other transmission-related regulations to determine whether additional reforms to the regional transmission planning and cost allocation and generator interconnection processes are needed to ensure rates for Commission-jurisdictional service remain just and reasonable, and not unduly discriminatory or preferential. Pursuant to the July 15, 2021 ANOPR inviting comments, American Municipal Power, Inc. ("AMP") offers the following comments for the Commission's consideration.

I. AMP'S INTEREST

AMP is a non-profit Ohio corporation organized in 1971. AMP has 134 members, including 133 member municipal electric systems in the states of Ohio, Pennsylvania, Michigan, Virginia, Kentucky, West Virginia, Indiana, and Maryland, and the Delaware Municipal Electric Corporation, a joint action agency with eight members that is

[1] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) ("Order No. 1000").

headquartered in Smyrna, Delaware. AMP provides wholesale energy supply and related services to its members. AMP's integrated resource strategy is consistent with its corporate sustainability commitment and, in addition to including fossil fuel and a variety of renewable generation projects (wind, run-of-the-river hydroelectric, landfill gas, and solar), AMP's portfolio includes energy efficiency initiatives and carbon management activities.[2] In addition, AMP's actions are guided by a set of Environmental Stewardship Principles approved by the AMP Board of Trustees. Accordingly, AMP is keenly aware of the shift to renewable and carbon free resources to meet the needs of customer demand. AMP acknowledges that this shift could require substantial new transmission facilities and that the use of the electric transmission grid will evolve with the change in resource mix. AMP agrees that now is the time to examine transmission-related regulations and determine whether additional reforms to the regional transmission planning and cost allocation and generator interconnection processes or revisions to existing regulations are needed to ensure that rates for Commission-jurisdictional service remain just and reasonable, and not unduly discriminatory or preferential. AMP commends the Commission for undertaking this timely effort.

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[2] Specifically, AMP operates, or owns and operates, approximately 390 MW of run-of-the-river hydroelectric power generation at existing dams on the Ohio River. In addition, AMP is party to a power purchase agreement for 52 MW of wind generation, purchases 58.3 MW of power and energy from solar generation facilities pursuant to a power purchase agreement between AMP and an affiliate of NextEra and has developed a 3.5 MW solar facility in the City of Napoleon, Ohio. AMP is also currently pursuing an effort to acquire up to 150 MW of additional solar energy resources. AMP has taken action to report and reduce carbon dioxide and other greenhouse gas emissions by funding various carbon offset projects, primarily focused on forestry and landfill gas projects that capture or reduce carbon and methane, throughout its footprint. On May 21, 2020, the AMP Board of Trustees adopted a Policy Position on Carbon Reductions to guide the organization on carbon policy and management.

Particularly because AMP and its members rely on transmission facilities owned and controlled by others, AMP recognizes the importance of a robust transmission grid, and has long been outspoken on the need for open, inclusive, and transparent planning processes, and fair cost allocation in achieving needed transmission expansion. As load serving entities ("LSEs"), AMP's members and AMP are primarily concerned about the ability to provide reliable service to their customer-owners at affordable rates. AMP is also concerned about fundamental changes to components of electricity transmission planning, cost allocation and the generation interconnection queue made without a comprehensive view of the energy and ancillary markets and the capacity constructs that together determine the pricing of wholesale electricity under the Commission's jurisdiction.

AMP is a member of the Transmission Access Policy Study Group ("TAPS"), the American Public Power Association ("APPA") and the Large Public Power Council ("LPPC"), each of which is providing comments as well. Given the extensive range of questions the ANOPR poses - including whether the Commission should make reforms in connection with planning and cost allocation for anticipated future generation, the determination of beneficiaries and cost allocation of transmission costs more generally, transmission planning, generator interconnection reform, and transmission oversight - AMP does not here address all of the issues raised in the ANOPR. AMP generally supports the TAPS, APPA and LPPC comments and offers for the Commission's consideration below its own additional views concerning certain specific matters on which the ANOPR seeks input.

Communications regarding this document should be directed to the following persons, who should be placed on the Commission's official service list in this proceeding:

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II. BACKGROUND

The ANOPR correctly recites the fundamental Federal Power Act ("FPA") principles that guide the Commission's exploration of potential reforms to the regional transmission planning and cost allocation and generator interconnection processes.[3] In a nutshell, the key requirements include the following: First, to satisfy the statutory requirement that they be just, reasonable and not unduly discriminatory or preferential, rates must satisfy the "cost causation" principle—*i.e.*, that rates should have the effect of recovering costs from the entities that cause those costs to be incurred.[4] That bedrock requirement—which is rooted in basic principles of equity[5]—has expanded to include the allocation of costs not only to entities that "caused" a set of costs but also to entities that

[3] *See, e.g.,* ANOPR, P 74.

[4] "[The] cost-causation principle 'add[s] flesh to [the] bare statutory bones' of the just-and-reasonable-rate requirement. *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1255-1256 (2018) ("*Old Dominion*") (quoting *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).

[5] *BNP Paribas Energy Trading GP v. FERC*, 743 F.3d 264, 268-269 (D.C. Cir. 2014) ("[T]he cost causation principle itself manifests a kind of equity. This is most obvious when we frame the principle (as we and the Commission often do) as a matter of making sure that burden is matched with benefit." (citations omitted)).

may be said to "benefit" from the incurrence of costs. Second, to satisfy the statutory standards, there must be a degree of correspondence between the costs assigned to a party (or group of parties) and the benefits that party (or parties) will receive from the incurrence of the costs. Precision in matching the charges and benefits is not mandated; rather, it is enough that the costs allocated be "at least roughly commensurate" with the benefits expected to be received.[6] Third, the benefits considered in evaluating compliance with the cost causation requirement cannot be speculative or unsupported. To validate the allocation of costs, there must be some degree of concreteness to the "roughly commensurate" benefits even if those benefits cannot be quantified in monetary terms (or at all).

Applying the foregoing principles has led the Commission to adopt certain simplifying assumptions that facilitate its consideration of specific cost allocation processes and outcomes. The Commission has specifically found, for example, that at least in PJM "high-voltage transmission facilities have significant regional benefits that accrue to all members of the PJM transmission system."[7] In *Old Dominion,* the U.S. Court of Appeals for the District of Columbia Circuit took note of the fact that no party to the proceeding disputed the proposition that "high-voltage power lines produce significant regional benefits within the PJM network."[8] On that basis, the ANOPR raises the question

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[6] *Illinois Commerce Com'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009).

[7] *PJM Interconnection, LLC*, 142 FERC ¶ 61,214, P 413 (2013). The Commission further found that region-wide cost sharing for a portion of the cost of high-voltage facilities complied with cost-causation requirements because it "capture[d] the full spectrum of benefits associated with high-voltage facilities, including difficult to quantify regional benefits, such as improved reliability, reduced congestion, reduced power losses, greater carrying capacity, reduced operating reserve requirements, and improved access to generation." *Id.* P 414.

[8] *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1260 (2018).

(among many others) whether it may be appropriate to require that transmission providers be responsible for upfront funding "where an interconnection-related network upgrade's voltage exceeds a defined threshold and is likely to produce system-wide benefits."[9]

Nevertheless, the Commission also has approved cost allocation approaches that assign the cost of interconnection-related network upgrades to interconnection customers without reimbursement through transmission service credits. The Commission has done so where the direct assignment of upgrade costs results from a "well-designed and independently administered participant funding policy."[10] Thus, in PJM, generation developers bear the costs of interconnection-related network upgrades without reimbursement through transmission service credits; instead, a developer is entitled to receive long-term, tradable rights (Firm Transmission Rights and Capacity Interconnection Rights) for any additional transmission and interconnection capacity created by the interconnection-related upgrades it funds. These rights are not intended as reimbursement for upgrade costs a developer must fund because, as noted in the ANOPR, there is no requirement that the capacity rights awarded have equal value to the cost of the interconnection-related network upgrades.[11] Variations on participant funding have been approved for use in other RTOs/ISOs, as well, under the Commission's policy on independent entity variations on the *pro forma* open access transmission tariff.[12]

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[9] ANOPR at P 140.

[10] *Id.* P 105 (citing Order No. 2003 at P 695).

[11] *Id.* P 109.

[12] *See id.* P 110 (discussing the participant funding programs approved for use by MISO and CAISO).

In Order No. 2003, the Commission discussed the conceptual underpinning for participant funding of generation interconnection-related network upgrade costs.[13] There, in expressing its willingness to consider participant funding proposals, the Commission was responding to concerns that spreading the costs of generation interconnection-related network upgrades to other users of the grid (as occurs through the crediting policy) has two deleterious effects. First, spreading the costs to other grid users dilutes the price signals that generation developers receive concerning the costs of building a project in one location or another. By diluting the price signal, developers could be led to locating projects in areas where other costs to the developer (*e.g.*, cost of land, access to water, etc.) are low but the costs of necessary interconnection-related upgrades—costs ultimately borne by others—are high. Second (and related to the first), by spreading upgrade costs to other users of the network, these parties are involuntarily compelled to subsidize a portion of the cost of a generation project without regard to whether they even benefit from the output of the project. Such an outcome obviously violates the equity principle underlying the cost-causation requirement. These are still valid issues today, especially given deficiencies identified in the ANOPR regarding local, regional, and interregional planning.

Absent major improvements in planning and transparency, participant funding of generator interconnection-related network upgrade costs addresses these problems directly and effectively. Further, as discussed in more detail below,[14] participant funding

[13] *See id.* P 106.

[14] *See infra* section V.

of generator interconnection-related network upgrade costs also satisfies the requirement that costs be borne in whole or part by the parties that benefit from the incurrence of those costs. In the case of generator interconnection-related network upgrades, a principal benefit is that construction of such upgrades provides a generation developer the ability to participate in competitive markets without compromising the operation of the grid. The "competitive market access" benefit received by generation developers is not speculative; it is concrete and real, and it merits consideration in evaluating alternative cost allocation approaches for compliance with baseline statutory requirements.

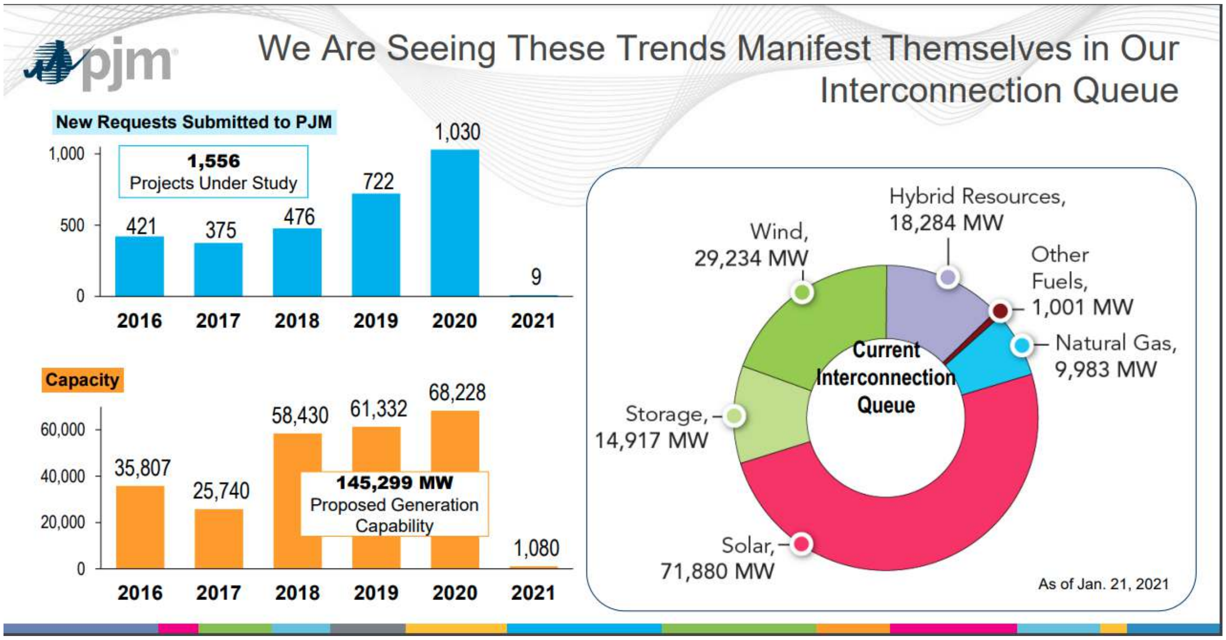
As it considers potential reforms to the regional transmission planning and cost allocation and generator interconnection processes, it is important for the Commission to bear in mind that the processes now in place evolved in the context of the open access transmission/competitive generation paradigm toward which the Commission has moved the electricity industry over the past three decades. Participant funding programs for generator interconnection-related network upgrade costs in particular proceed from the premise that, for markets to yield economically efficient outcomes, competitive generation must not be subsidized by captive transmission customers. Such subsidization is avoided—and more meaningful price signals are communicated—when generation developers are required to bear the costs of network upgrades necessitated by developers' interconnection decisions. Doing so also provides greater confidence that transmission-owning companies cannot gain improper competitive advantages for their affiliated generation interests by inequitably shifting interconnection-related costs to captive load-serving entities. Revisions to existing planning and interconnection processes that fail to give weight to the competitive market environment in which these processes evolved could easily produce unintended consequences adverse to the interests of consumers.

In sum, AMP believes the ANOPR highlights a number of areas in which existing planning and generation interconnection processes might be improved in ways that would better accommodate future renewable generation, and we look forward to participating in the discussion of these opportunities. That said, AMP also urges the Commission to recognize that, if revisions to existing processes fail to accommodate the broader competitive market paradigm in which the existing processes evolved, the potential exists for unintended impacts that contravene the Federal Power Act's mandate that rates be just, reasonable and not unduly discriminatory or preferential.

III. THE POTENTIAL NEED FOR REFORM

There can be little argument that the electricity sector is transforming as the generation fleet shifts from resources located close to population centers toward resources, including renewables, that may often be located far from load centers. The evidence of this shift is reflected in the generation interconnection queues in RTOs. In fact, PJM's generation interconnection queue already consists primarily of intermittent, low/zero energy-cost resources. Specifically, over 92% of the resources in PJM's queue are already renewable or intermittent resources.[15]

[15] *See* PJM, Capacity Market, Capacity Workshop – Session 1, at 26 (February 12, 2021), *available at* https://www.pjm.com/-/media/committees-groups/committees/mic/2021/20210212-workshop-1/20210212-capacity-markets-workshop-session-1-presentation.ashx.



The Commission indicates that it is time to review issues addressed by Order No. 1000 given the passage of time and the changes in the industry that have occurred since its issuance more than a decade ago. AMP agrees that now is a good time to examine the orders under present and anticipated conditions and determine whether and where changes might be needed. However, the Commission makes a number of assumptions in the ANOPR that should be tested before we undertake any efforts to change the rules in reliance on the underlying premises of the assumptions.

First, the Commission assumes that the new generation resources will be located far from load centers. While there are resources (particularly wind) that may sometimes be located a great distance from load centers, this assumption ignores the growth of distributed energy resources ("DERs"), which are small-scale power generation or storage technologies that are located on an electric utility's distribution system, a subsystem of the utility's distribution system or behind a customer's retail meter. DERs include electric storage, intermittent generation, distributed generation, microgrids, demand response, energy efficiency, thermal storage or electric vehicles and their charging equipment. The Commission has touted its Order No. 2222[16] as helping to enable the electric grid of the future and promote competition in electric markets by removing the barriers preventing DERs from competing on a level playing field in the organized capacity, energy and ancillary services markets run by RTOs/ISOs. Order No. 2222 permits multiple DERs to aggregate in order to satisfy minimum size and performance requirements that each may not be able to meet individually in order to compete more effectively against traditional resources in the hopes that making organized wholesale markets more accessible to DERs will help provide a variety of benefits including: "lower costs for consumers through enhanced competition, more grid flexibility and resilience, and more innovation within the electric power industry."[17]

It is not clear to AMP how the ANOPR's premise of the inevitability of remote renewables coming to market comports with Order No. 2222's vision of a plethora of smaller, local, and distributed renewables forming the grid of the future. If it is likely that investments in one resource type (DERs) will significantly outweigh the other (resources located far from load centers), it would be imprudent to reform transmission planning and cost allocation to accommodate only a small number of such resources. The Commission should gather additional information on whether and to what degree resources will actually be remote from load centers and base any changes on facts and record evidence.

[16] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197 (2021), *order on reh'g*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

[17] FERC Order No. 2222: Fact Sheet, *available at* https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet.

Additionally, it must be recognized that as the generation fleet shifts to more renewable resources, there will be impacts on and perhaps changes required to energy and ancillary service markets since renewable resources have low or no variable costs and the current-day markets in most RTOs/ISOs operate on the basis of single-clearing priced auctions that rely on assets with marginal prices to send price signals. In other words, the shifting resource mix is incongruous with the premises underlying existing market structures. The Commission should be cognizant of the impacts of the shifting resource mix on both transmission planning and cost allocation, as well as the energy and ancillary markets, and make sure any changes to transmission policy do not have unintended consequences on the energy and other markets.

Finally, AMP notes that to better inform the review and reform process, the Commission should use more accurate terminology that is less subject to confusion and manipulation. Specifically, the Commission continues to use the term "transmission provider" when referring to a "public utility that owns, controls, or operates transmission facilities" and includes individual transmission owners when they are separate from the transmission provider, as is the case in regional transmission organizations ("RTOs") and independent system operators ("ISOs"). The use of "transmission provider" is a holdover that has led to significant confusion about whether transmission owners in RTOs/ISOs have authority to do things versus the RTO/ISO. The discussion would greatly benefit from additional clarity and precision in terms. Accordingly, FERC should simply use "Transmission Owner" or "TO" when referring to individual transmission owners and "RTO/ISO" going forward.

IV. IDENTIFYING RELEVANT BENEFITS AND BENEFICIARIES

As frequently noted in the ANOPR, satisfying the Commission's cost-causation principle requires that costs be allocated to beneficiaries in a manner that is at least roughly commensurate with estimated benefits. This requirement—as well as the magnitude of the costs generally at issue with any significant high-voltage transmission project—results in a high priority being placed on the identification of benefits and beneficiaries associated with any network upgrade. The Commission correctly acknowledges that "identifying which types of benefits are relevant for cost allocation purposes, which beneficiaries are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial."[18] It therefore is no surprise that the ANOPR poses a significant number of questions directed to the process of identifying benefits and beneficiaries, including whether current approaches fail to consider relevant benefits of new transmission infrastructure and, in so doing, fail to identify all the parties that should bear costs in order for the cost allocation process to satisfy cost causation standards.[19]

Over time, the Commission has provided a handful of general standards to guide the benefits/beneficiaries identification process, including that (i) costs must not be allocated to parties that receive no benefit from transmission facilities, either at present or in likely future scenarios, (ii) methods used to determine benefits and identifying beneficiaries must be transparent, and (iii) there may be different methods for identifying

[18] ANOPR at P 77 (quoting Order No. 1000 at P 501).

[19] *See, e.g.,* ANOPR at PP 70, 71. Phrasing that inquiry in the converse, the Commission also asks whether there are benefits that are *not* appropriate as considerations in the cost allocation process, and whether the allocation of costs based on such benefits would violate the Commission's statutory mandate. *See id.* P 75.

benefits and beneficiaries depending on the type of transmission facilities at issue, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.[20] Regarding the last recited standard, a recent example vividly demonstrates the need for flexibility in methods of identifying benefits and beneficiaries depending on the purposes of particular upgrades.

In *Public Service Electric & Gas Co. v. FERC*,[21] the U.S. Court of Appeals for the District of Columbia Circuit affirmed FERC orders that approved PJM's use of a new cost allocation method for a proposed upgrade that was intended to resolve potential reliability problems arising from generator instability. Parties seeking review argued that FERC had failed to support its decision not to require use of the method PJM deploys to allocate the costs of upgrades built to resolve flow-based reliability issues (the "Solution-based DFAX" method). Use of the Solution-based DFAX method would have allocated most of the cost to transmission load on the Delmarva Peninsula, while the method FERC approved instead assigned most of the cost to New Jersey. In affirming FERC's orders, the Court of Appeals approvingly cited FERC's reasoning for distinguishing between generator stability issues and thermal overload issues in selecting the appropriate cost allocation method:

> [R]eliability issues caused by thermal overload are solved by increasing the amount of power flowing to the constrained region. In these circumstances, "the beneficiaries of that solution are readily identified based upon those power flows" because "change[s] in power flows are consistent with the intended solution." By contrast, stability issues arise from the inability of a particular generating unit to maintain synchronism with the grid, which in

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[20] *Id.* P 77 (citing Order No. 1000 at PP 637, 668, and 685).

[21] *Pub. Serv. Elec. and Gas,* 989 F.3d 10 (D.C. Cir. 2021).

> turn can result in constrained generation as well as facility outages. And whereas flow–based issues are solved by bringing power to a constrained area, stability–related issues are solved by providing additional transmission pathways from the generator to the grid. Thus, because "the flows on a transmission project to resolve a stability–related reliability issue do not necessarily resolve a constraint by bringing power to load," the Commission found that the beneficiaries of such a project "are not necessarily captured" by following the electrons to their end–point.[22]

Importantly, the Court affirmed FERC's rejection of the claim that Delmarva entities should bear the bulk of the upgrade's costs because the Solution-based DFAX method identified them as the primary "users" of the upgrade given the power flows that would result from the upgrade's operation. In essence, the Commission found (and the Court agreed) that, for some categories of upgrades, "use"—as measured by power flow—does not equate to "benefit." This finding highlights the need for considerable flexibility in selecting the criteria to be applied for the purpose of identifying the benefits and beneficiaries of differing types of upgrades.

Consistent with the foregoing, AMP urges the Commission to recognize and give weight to one of the principal benefits of generator interconnection-related network upgrades: the access to competitive markets those upgrades provide to generation project developers. Just as the power flows on upgrades that would resolve generator instability issues were found not to be a proper measure of "benefits," the power flows on network upgrades built to accommodate a generator interconnection may not fully reflect the benefits conferred by the upgrade. Potentially missing from a purely flow-based benefits analysis is that the upgrade makes it possible for a generation developer to participate in the competitive market for generation services without jeopardizing the

[22] *Id.* at 18 (citations omitted).

reliability of the grid. The market access made possible by a generator interconnection-related network upgrade is what affords a developer the opportunity to earn the profits it anticipated in deciding to build its generation project. This "competitive market access" benefit is substantial, even if quantifying the benefit may present challenges. As the U.S. Court of Appeals for the Seventh Circuit made clear in *Illinois Commerce Commission*, precision in the quantification of benefits is not necessary to support a cost allocation as consistent with the cost-causation requirement.[23] That said, the benefits relied upon to support a particular allocation of costs cannot be wholly theoretical or speculative in nature. There must be a measure of definition and concreteness to a claimed set of benefits, and the measure of benefits must be estimable, to validate the allocation of the very real costs of a network upgrade.[24] In other words, the definition and estimation of benefits must be "meaningful."[25] The competitive market access benefit conferred by a generator interconnection-related network upgrade meets these requirements.

More generally, whether considered in the setting of generator interconnection, regional transmission planning or a more de-siloed integration of the two, the benefits taken into account for cost allocation should be measured based on actual or reasonably anticipated scenarios that flexibly consider a range of parameters, such as power flows on an upgrade, reductions in congestion or other verifiable economic benefits resulting

[23] *Ill. Commerce Comm'n v. FERC*, 756 F.3d 556, 562 (7th Cir. 2014).

[24] *Id.* at 561, 564–65 (FERC must at least make "an attempt at empirical justification").

[25] *See, e.g.,* Order No. 1000-A at P 679 ("[T]here is no way to identify 'more efficient or cost effective' transmission solutions, or to assess whether costs are being allocated at least roughly commensurate with benefits, without a meaningful estimation of benefits.… [W]hile Order No. 1000 does not define benefits and beneficiaries, it does require the public utility transmission providers in each region to be definite about benefits and beneficiaries for purposes of their cost allocation methods.").

from the upgrade, resolution of reliability issues (including generator stability issues), and the access to competitive markets enabled by an upgrade. And while Order No. 1000 continues to provide sensible categories of benefits (reliability, economics, public policy), RTOs/ISOs are not limited to considering only the benefits specified in that order. Consideration of additional types of benefits that are concrete, verifiable and measurable is appropriate—indeed, in particular circumstances may be *necessary*—to ensure costs are allocated to true beneficiaries as required by the cost causation principle.

The last point necessarily raises for consideration the question of how and by which entity (or entities) are relevant benefits to be identified? In this regard, AMP urges the Commission to recognize that Public Power has an appropriate role in identifying "public policy" benefits, analogous to the role state commissions play in doing so. Public power entities are publicly accountable and the processes they adopt to identify public policy benefits are open and transparent. The policies that public power entities adopt reflect the consensus of the communities that own and support them. Reliance on public power entities to identify public policy benefits important to their stakeholders therefore is consistent with the central goals expressed in the ANOPR. "[E]fforts to plan the transmission system to meet the needs of the changing resource mix will succeed only if the associated cost allocation methods are transparent, equitable, and practicable."[26]

In any event, whichever entity is tasked to identify and measure relevant benefits, it is essential that the process for doing so is open and fully transparent. There is legitimate concern that, without full transparency, a more "holistic" mechanism that integrates the regional transmission planning and generator interconnection processes

[26] ANOPR at P 71 (footnote omitted).

could ultimately become a "black box" to stakeholders; this could result from having so many variables interacting in so many ways that stakeholders are prevented from understanding how particular cost allocation decisions were reached. Put differently, in de-siloing and integrating processes that may currently proceed on separate if parallel paths, care must be taken to ensure that the resulting process is not so complex as to be impenetrable. The antidote to this is openness, genuine opportunities for stakeholder participation, and full transparency at every step of the process—including the identification of relevant benefits and their measurement, the evaluation of alternatives and selection of a preferred or optimal project, the identification of the project's beneficiaries, and the decision about how the project's costs will be shared among those beneficiaries. Each of these steps must be open and transparent to all stakeholders potentially affected by the outcome.

Finally, AMP urges the Commission to recognize that the Federal Power Act's mandate that rates be just, reasonable and not unduly discriminatory or preferential is not the only statutory requirement that should guide its consideration of revisions to the regional transmission planning and generator interconnection processes. At least as important is the mandate set forth in section 217 of the FPA, which expressly requires the Commission to exercise its statutory 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" on a long-term basis.[27] AMP therefore endorses the view that, consistent with FPA section 217(b)(4), any modified approaches the Commission may consider through the ANOPR process

[27] FPA § 217(b)(4), 16 U.S.C. § 824q(b)(4).

should be grounded first and foremost in the resources designated or planned to meet LSEs' load service obligations. Paramount is the need to ensure that transmission planning specifically accounts for and meets the needs of LSEs because it is their customers who ultimately will bear the cost of any potential transmission process reforms.

V. COST ALLOCATION

As discussed in the preceding section, the Commission is bound by the "roughly commensurate test" for assessing costs in proportion to benefits in order to ensure just and reasonable rates.[28] The ANOPR itself recognizes this.[29] The determination of benefits must be measured with reference to actual or reasonably anticipated use, economic benefits, and verifiable reliability benefits.

The ANOPR's tentative proposal to socialize the cost of transmission facilities built to the site of future generation risks violating cost causation principles fundamental to the determination of just and reasonable rates. Potential benefits associated with as-yet to be constructed or even planned generation, would be wholly speculative. Legitimate transmission planning by FERC-jurisdictional public utilities, including RTOs/ISOs, does not encompass building network upgrades to accommodate speculative future generator interconnections.

AMP supports participant funding for network upgrades required by new generator interconnections because this approach requires generators to have a financial stake in the cost of upgrades associated with their interconnection. As a result, participant funding

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[28] *Ill. Commerce* Comm'n *v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009); *S.C. Pub. Serv. Auth.*, 762 F.3d 41, 87 (D.C. Cir. 2014).

[29] ANOPR at P 74.

sends appropriate price signals that ensure efficient siting.[30] No evidence has been presented that the participant funding approach has become unjust or unreasonable for network upgrades required to accommodate generator interconnection requests in RTOs/ISOs.[31]

Participant funding necessarily results in interconnection-related network upgrade costs being allocated entirely to interconnection customers. There is no evidence that network upgrades associated with generator interconnections actually provide benefits to existing or future *transmission customers* (*i.e.,* LSEs and their retail customers).[32] Thus, there is no inappropriate accounting for benefits associated with generator interconnections when allocations of network upgrade costs are made under the participant funding approach and no basis for abandoning such participant funding arrangements.

Whether generators interconnecting later-in-time should bear a share of costs that may typically be assigned to the earlier-in-time generator is an entirely separate matter that the Commission has provided RTOs/ISOs the ability to address in a flexible manner intended to provide an equitable allocation of these costs between generators interconnecting at different times.[33] In the event developers perceive an unfair allocation results from application of existing RTO/ISO rules, they are free to propose changes to

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[30] *See, e.g.,* ANOPR at P 103 ("by placing the interconnection customer initially at risk for the full cost of the interconnection-related network upgrades, the upfront payment provides the interconnection customer with a strong incentive to make efficient siting decisions and, in general, to make good faith requests for interconnection service." (citing Order No. 2003-A at P 613)).

[31] *See id.* P 71.

[32] *See id.* PP 71, 119.

[33] *See id.* P 150.

those mechanisms and may bring such matters to the Commission for appropriate resolution. However, the existence of conflicts regarding an appropriate allocation of network upgrade costs between particular generators offers no support for a reallocation of those costs to LSEs and their retail customers, or for LSEs and their customers to bear the risk of stranded investment associated with network upgrades constructed to facilitate speculative future generator interconnections.

Regional transmission planning and cost allocation must be integrated and addressed holistically.[34] The processes included in existing RTO/ISO tariffs under current Commission rules contain elements of integration and ostensibly address these issues holistically. However, RTO/ISO and incumbent transmission owner implementation of the regional planning process has frustrated efforts to achieve the benefits available from truly effective regional planning. PJM is a prime example. As discussed *infra* section VI, PJM transmission owners routinely drive the development of transmission projects into the "Supplemental" category, where cost allocation is local and projects are designed to provide correspondingly local benefits, without consideration of whether regionally planned projects could resolve multiple transmission issues and provide better value for customers.

The regional transmission planning process in PJM is broken. But this is the result of concerted efforts by transmission owners to avoid the process and PJM's abdication of its regional planning responsibility. It is not justification for upending a reasonable set of cost allocation principles that attempt to allocate the costs of projects that resolve reliability issues, economic considerations, and public policy requirements to their

[34] *See id.* P 86.

respective beneficiaries.[35] To the extent evidence exists showing that particular projects may be able to resolve needs falling in multiple categories, parties have the ability to propose mechanisms to appropriately allocate those costs between multiple sets of beneficiaries.

The mere hypothetical existence of such projects should not lead the Commission down a path toward an amorphous regional planning process with ambiguous cost allocation rules where each project entails a contentious debate over beneficiaries and cost allocation. A cumbersome process like that could drive the number of regionally planned projects in PJM from very low to zero. A much better approach would be for the Commission to enforce its existing rules and require RTOs/ISOs and incumbent transmission owners to actually comply with the regional planning requirements and corresponding cost allocation rules contained in existing tariffs.

VI. TRANSMISSION PLANNING

The Commission asks whether the current planning processes may be resulting increasingly in transmission facilities addressing a narrow set of transmission needs, often located in a single transmission owner's footprint.[36] The Commission notes that if the requirements of the regional transmission planning process result in Transmission Owners expanding mostly local transmission facilities, the regional process "may fail to identify more efficient or cost-effective transmission facilities needed to accommodate anticipated future generation."[37] The Commission indicates that it seeks to better

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[35] *See id.* PP 92, 94.

[36] *Id. P 37.*

[37] *Id.*

understand how the reforms of the federal right of first refusal in Order No. 1000 have shaped the type and characteristics of transmission facilities developed through regional and local transmission planning processes, such as a relative increase in investment in local transmission facilities or the diversity of projects resulting from competitive bidding processes."[38]

The Commission explains that, although local transmission plans - which include only local transmission facilities located solely within a TO's footprint and not selected for regional cost allocation - are subject to the requirements of Order No. 890, neither the local transmission facilities nor the local transmission plans are subject to approval at the regional or interregional level.[39] Accordingly, the Commission accurately notes that local transmission facilities that Transmission Owners provide in individual local plans are rolled into regional plans after only a limited review to ensure the local transmission facilities will "do no harm."[40] The local plans are not subject to the same level of review and vetting that the regional plans get in RTOs.[41] Also, "local transmission facilities planned through a local transmission planning process are not eligible to use the Order No. 1000 regional cost allocation method and instead their costs are allocated to the TO zone where the local transmission facility is located."[42] The Commission has explained that incumbent Transmission Owners are permitted to plan and construct local

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[38] *Id.*

[39] *Id.* PP 17, 25, 50-53.

[40] *Id.* P 17.

[41] *Id.*

[42] *Id.* P 53.

transmission facilities without going through the Order No. 1000 processes in order to meet their reliability and service obligations in their own footprints.[43]

This dichotomy of regional versus local transmission planning has created opportunities for Transmission Owners to opportunistically plan and build more transmission outside of the Commission's open planning process than is subject to regional planning conducted by the regional transmission planners. Moreover, the Commission has endorsed Transmission Owner proposals to expand local planning processes, increase incumbent Transmission Owner authority and further balkanize transmission over the objections of customers, generators, competitive transmission providers, and other RTO stakeholders. AMP supports the Commission's investigation into whether local planning processes are currently operating in a manner that promotes the goals of providing non-discriminatory transmission service and protecting consumers from excessive charges.

As the Commission is aware, through electric restructuring many vertically integrated, regulated monopolies of generation, transmission and distribution were functionally unbundled, resulting in competitive wholesale generation markets but retaining regulated electricity delivery (transmission and distribution) and varying levels of state retail choice. The transmission grid we are using today was not built for free flowing competitive markets and we are using the grid in a way that its original designers never contemplated. Rather, the current grid was designed under a vertically integrated regulatory paradigm where least cost integrated resource planning regularly traded off generation and transmission construction options against one another. The transmission

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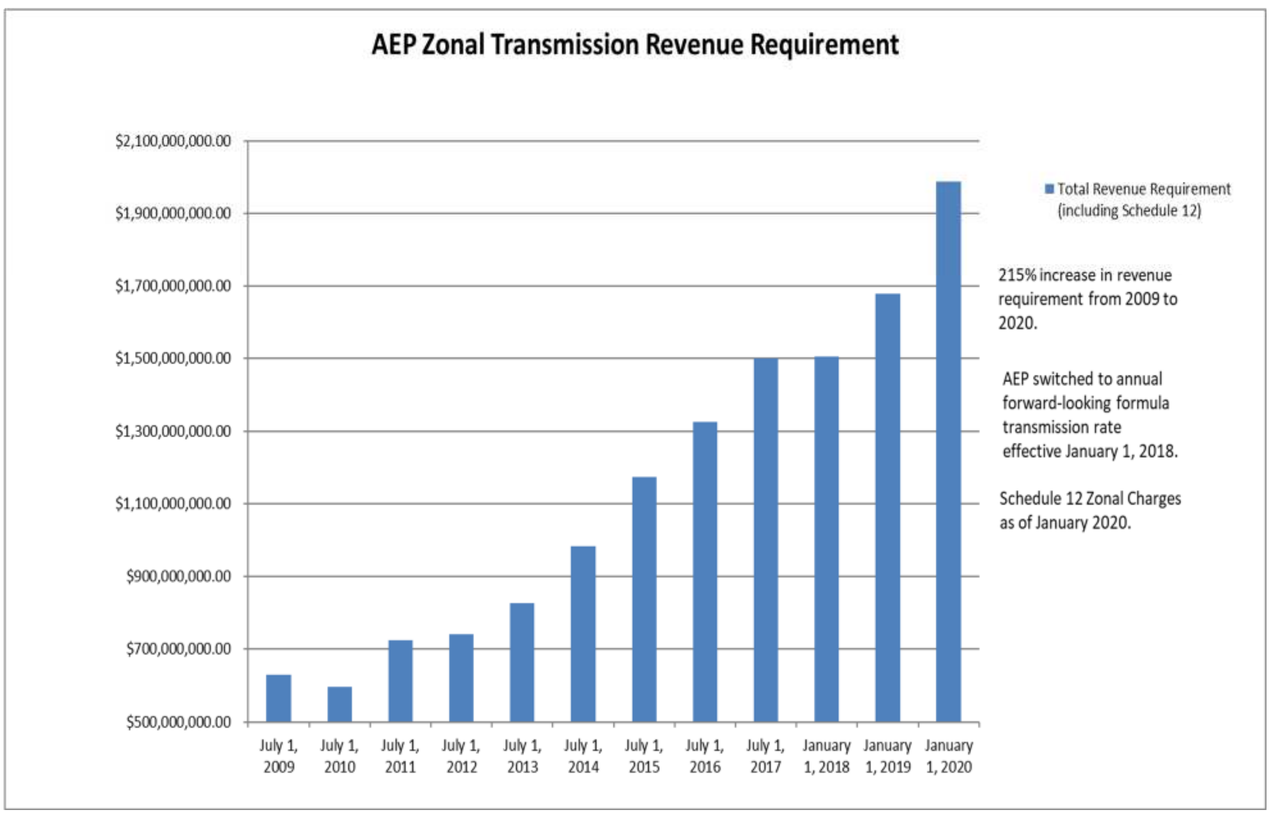
[43] *Id.*

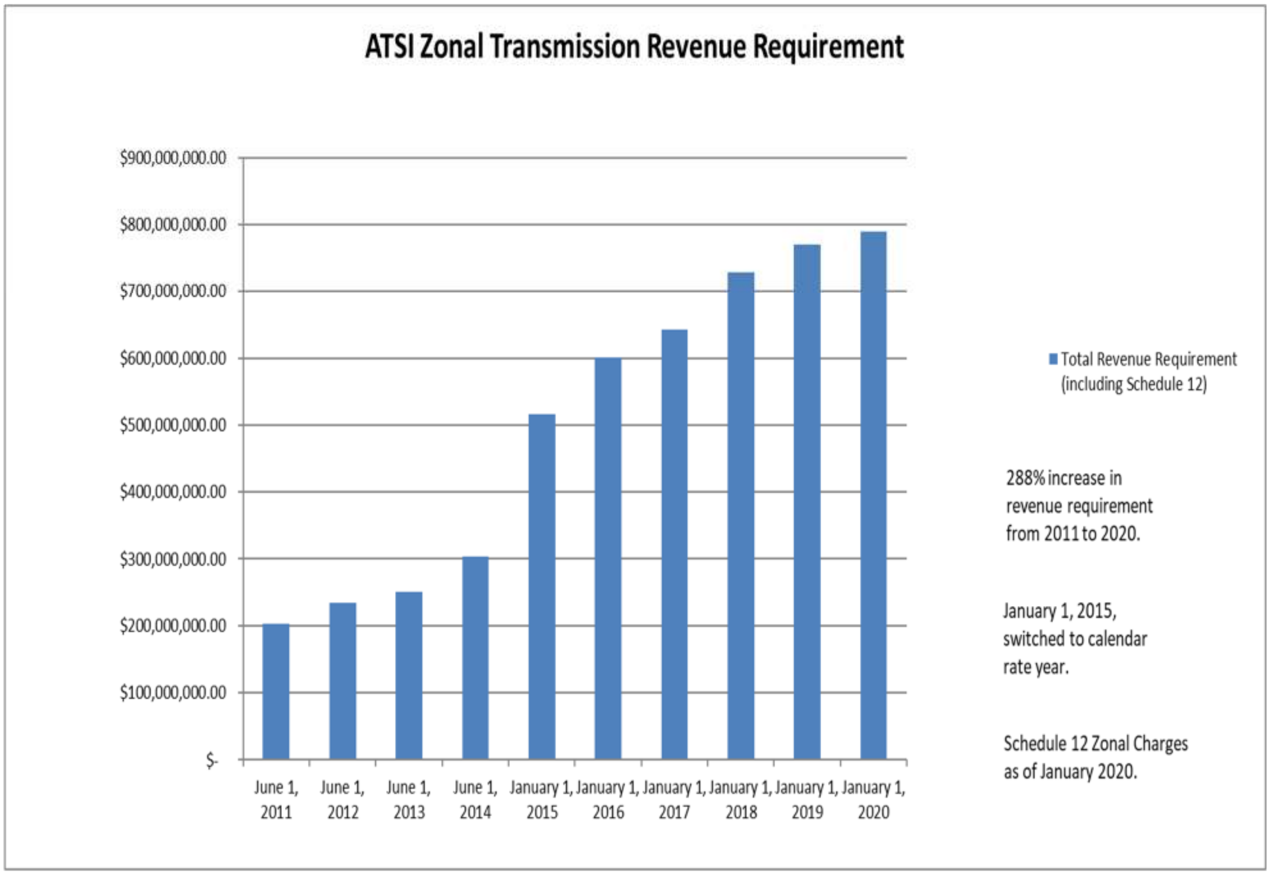
system was designed to reliably transport energy from the central generating stations to load. Occasionally, small generators were installed to provide transmission support services such as voltage support. Nonetheless, transmission is the regulated path to facilitate competitive markets and it is important to remember that transmission owners continue to earn a guaranteed return of and on all of their investments. Without reliable, cost-effective and open transmission, the competitive wholesale market cannot exist. But, a transmission system built for cost-based integrated operation cannot support a bid-based competitive generation market that seeks to be able to supply load from virtually any generating unit in any location.

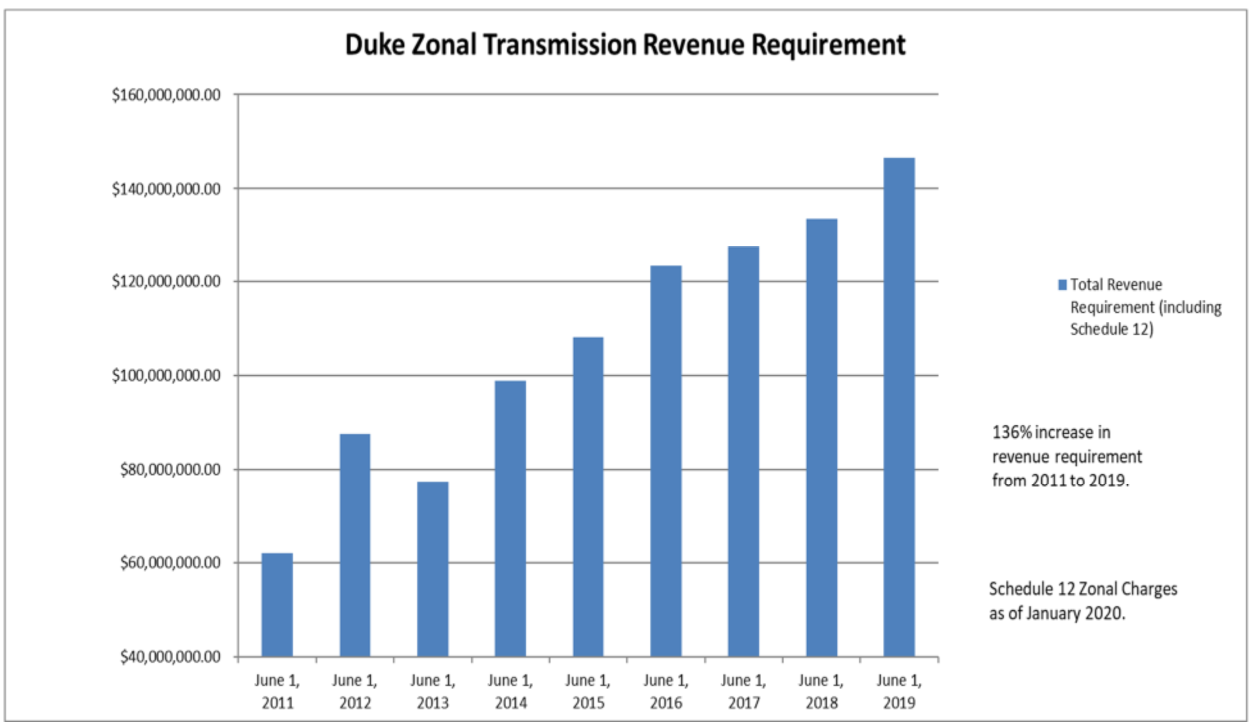
The way we plan the transmission system going forward must take into account more than remote renewable generation. Transmission planning must evolve to reflect: the revised industry structure with mature competitive wholesale markets; public demand for uninterrupted electricity; the need for greater regional/inter-regional coordination; the abundance of aging transmission infrastructure as a result of a dearth of investment between 1970-2010; and ensure affordability, among other things.

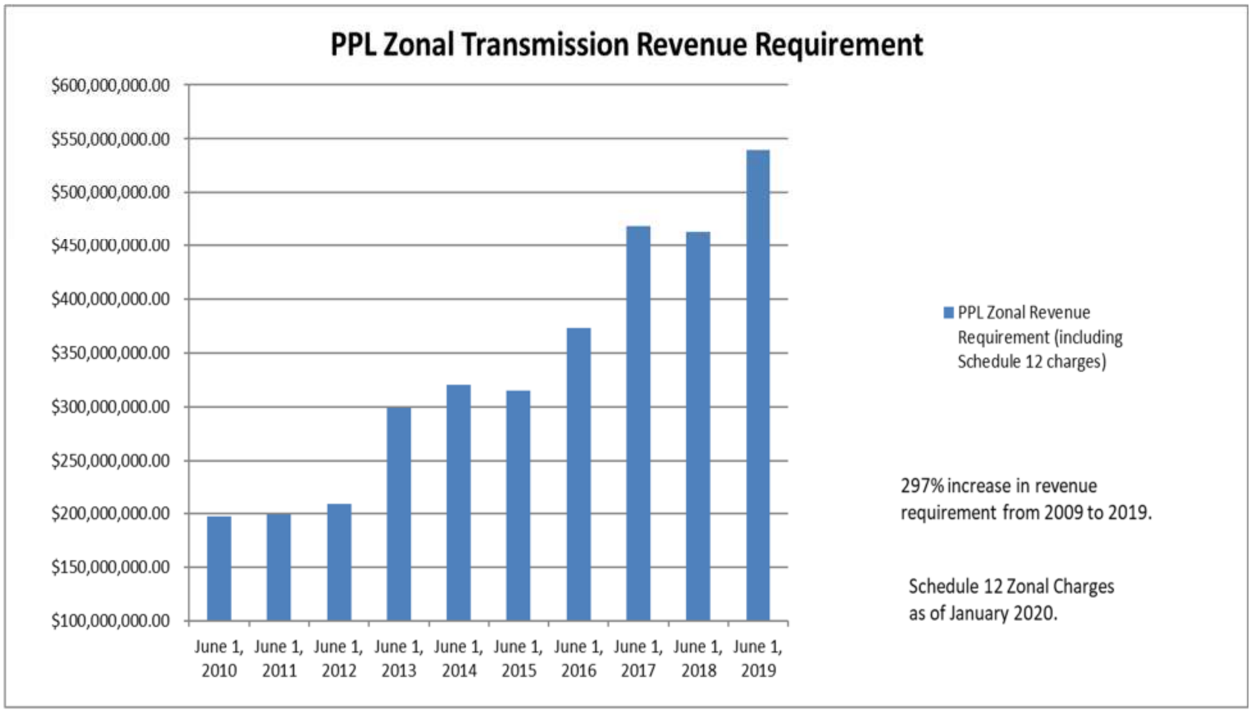
AMP members have made transmission one of AMP's top priorities as a result of the cost increases AMP members are seeing in the transmission component of their bills. In fact, transmission as a percentage of the total bill has increased from 15% in 2015 to 29% in 2020, nearly doubling over a five-year period. The graphs below depict this unprecedented increase in transmission costs in the PJM region as a whole and in certain specific PJM transmission zones where AMP members serve.


PJM Wholesale Transmission Cost Since 2011
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$-
140%
120%
100%
80%
60%
40%
20%
0%
$4.34
$4.71
$5.00
$5.75
$6.93
$7.63
$8.58
$8.84
$9.52
60%
76%
98%
104%
119%
7.0%
9.9%
9.4%
8.2%
12.4%
16.1%
17.3%
14.7%
19.4%
2011
2012
2013
2014
2015
2016
2017
2018
2019
Transmission Cost ($/MWh)
Cumulative Increase Since 2011 (%)
Percentage of Total Cost


AEP Zonal Transmission Revenue Requirement
$2,100,000,000.00
$1,900,000,000.00
$1,700,000,000.00
$1,500,000,000.00
$1,300,000,000.00
$1,100,000,000.00
$900,000,000.00
$700,000,000.00
$500,000,000.00
July 1, 2009
July 1, 2010
July 1, 2011
July 1, 2012
July 1, 2013
July 1, 2014
July 1, 2015
July 1, 2016
July 1, 2017
January 1, 2018
January 1, 2019
January 1, 2020
Total Revenue Requirement (including Schedule 12)
215% increase in revenue requirement from 2009 to 2020.
AEP switched to annual forward-looking formula transmission rate effective January 1, 2018.
Schedule 12 Zonal Charges as of January 2020.


ATSI Zonal Transmission Revenue Requirement
$900,000,000.00
$800,000,000.00
$700,000,000.00
$600,000,000.00
$500,000,000.00
$400,000,000.00
$300,000,000.00
$200,000,000.00
$100,000,000.00
$-
June 1, 2011
June 1, 2012
June 1, 2013
June 1, 2014
January 1, 2015
January 1, 2016
January 1, 2017
January 1, 2018
January 1, 2019
January 1, 2020
Total Revenue Requirement (including Schedule 12)
288% increase in revenue requirement from 2011 to 2020.
January 1, 2015, switched to calendar rate year.
Schedule 12 Zonal Charges as of January 2020.


Duke Zonal Transmission Revenue Requirement
$160,000,000.00
$140,000,000.00
$120,000,000.00
$100,000,000.00
$80,000,000.00
$60,000,000.00
$40,000,000.00
June 1, 2011
June 1, 2012
June 1, 2013
June 1, 2014
June 1, 2015
June 1, 2016
June 1, 2017
June 1, 2018
June 1, 2019
Total Revenue Requirement (including Schedule 12)
136% increase in revenue requirement from 2011 to 2019.
Schedule 12 Zonal Charges as of January 2020.



The majority of transmission projects are moving forward with little to no regulatory oversight. While investment in transmission infrastructure is needed, a lack of transparency and regulatory scrutiny means customers are unable to know if the amount of transmission spend is really needed or provides the most effective solution for the future.

In PJM, the lack of transmission planning oversight is a direct result of the current planning rules and the categorization of transmission projects as either "baseline" or "supplemental." For Baseline Projects, which are those needed for reliability and planned by PJM, there are well documented rules and data available for stakeholders to fully understand how the proposed baseline project best meets clearly identified needs going forward. The planning process for Supplemental Projects — those that are not required to satisfy reliability, operational performance or economic criteria — is left up to the Transmission Owners, receives minimal oversight by PJM, and is not approved by PJM or the Commission and, in most cases also does not undergo any siting process.[44] In compliance with a recent Commission directive,[45] the PJM Transmission Owners have implemented a process to provide stakeholders a minimal amount of information about proposed Supplemental Projects. However, there is not sufficient information to enable stakeholders to replicate or verify the analysis supporting the Transmission Owners' planning. Like baseline project costs, the costs of Supplemental Projects are passed along to consumers, but without a determination that they are necessary or prudent before they go into service. And, importantly, Supplemental Projects are not subject to "open window" competition.

Based on AMP-compiled PJM data from 2005-2019, the total proposed spend on Supplemental Projects has exceeded that of baseline spend ($31.2 billion versus $30.4 billion, respectively). This indicates that more transmission projects are planned and constructed by individual Transmission Owners without a demonstration of need or cost effectiveness than those transmission projects needed for reliability and planned and approved by PJM, the Regional Transmission Organization. In fact, over 90% of all transmission projects, whether they are Supplemental Projects or Baseline Projects, were based on individual Transmission Owner planning criteria in 2018 and 2019.

In the Order No. 1000 process, the MISO Transmission Owners argued that "eliminating the federal rights of first refusal will discourage robust participation in regional

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[44] For example, in Ohio, the Ohio Power Siting Board has jurisdiction over major utility facilities including electric transmission lines and associated facilities of 100 kilovolts (kV) or more. Ohio Revised Code, Section 4906. The vast majority of transmission projects being planned and built in Ohio fall below the 100 kV threshold.

[45] *Monongahela Power Co.,* 162 FERC ¶ 61,129, at PP 101-116 (2018)*, order on reh'g and compliance,* 164 FERC ¶ 61,217 (2018).

transmission planning" because it would incentivize incumbent Transmission Owners with state-imposed retail service obligations to rely on their local process rather than the regional process to expand their transmission systems.[46] The MISO Transmission Owners argued that the result would be (i) the type of divided, inefficient, and potentially duplicative transmission expansion process that Order No. 1000 purported to discourage, and (ii) creation of an unreasonable incentive for utilities with local planning processes to favor local projects when a regional solution is warranted. The Commission was unconvinced and concluded that Order No. 1000 reforms would lead to more competition among developers, which in turn would lead to the identification of more efficient and cost effective transmission facilities. Accordingly, Order No. 1000 eliminated the federal right of first refusal but retained the right of first refusal for transmission facilities "that are located solely within its retail distribution service territory or footprint and that are not submitted for regional cost allocation."[47] Events have demonstrated that the MISO Transmission Owners' prediction was correct.

In PJM, the Operating Agreement identifies the regional transmission planning protocol. It includes exceptions from regional planning and competition for Supplemental Projects, most Baseline Projects below a 200 kV threshold and immediate need projects.[48] Additionally, the Commission has recently authorized the PJM Transmission Owners to exclude from the regional planning process (i) replacement of aging infrastructure even if it expands the capacity of the transmission facilities, and (ii)

[46] Order No. 1000-A at P 167.

[47] Order No. 1000 at P 262.

[48] PJM Operating Agreement, Schedule 6, Sections 1.5.6(n), 1.5.8(c), (n).

prospective transmission additions addressing transmission facilities[49] under PJM operational control that have been identified as Critical Facilities because "if rendered inoperable or damaged, could result in widespread instability, uncontrolled separation, or cascading within an Interconnection."[50] Notwithstanding that the proposed projects address only regionally Critical Facilities, the Commission majority accepted a proposal from PJM Transmission Owners, over the objections of PJM Members, to adopt a new Tariff provision granting those Owners an exclusively local ad hoc planning regime for so-called "M-4 Projects." Thus, in recent years, the Commission has expanded the opportunity for PJM Transmission Owners to avoid regional transmission planning, resulting in more balkanized and less transparent planning that does not enable customers or the regional planners to identify the more efficient and cost-effective transmission solutions.

As Commissioner Clements has noted, "[c]onsideration of reform to local planning processes is appropriate as part of broader transmission planning reform, to ensure that [transmission dependent utilities] are given fair and adequate service, and more broadly to ensure that all transmission system plans – local, regional, and interregional – succeed in identifying cost-effective solutions to established system needs and thereby ensure that any new infrastructure is money well spent by customers."[51] AMP shares the concern

[49] "Transmission Facilities" is a defined term in the PJM Operating Agreement and are facilities that have, among other things "been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region." PJM Operating Agreement, Section 1 (Definitions).

[50] Physical Security Reliability Standard, Order No. 802, 149 FERC ¶ 61,140 (2014)

[51] *GridLiance High Plains LLC*, 174 FERC ¶ 61,078, Commissioner Clements Concurrence at P2 (2021).

that local transmission planning and expansion "may fail to identify more efficient or cost-effective transmission facilities needed to accommodate anticipated future generation."[52] A good first step toward a solution would be for the Commission to stop enabling Transmission Owners to expand local planning processes and require the transmission planners to conduct more centralized and regional transmission planning. The local planning processes should be modified to recognize and minimize their impact in dampening justification for higher voltage regional transmission.

Additionally, the Commission should consider proposals to enhance the regional planning process to include evaluation of uncertain futures and selection of transmission projects common amongst these futures. More specifically, open, transparent and holistic regional planning for future scenarios could provide the necessary basis to identify potential benefits and meet multiple needs *via* a single transmission facility (*i.e.,* "least-regrets" planning). This way, the existing regional transmission planning process could account for anticipated future generation. Regional scenario analysis amongst uncertain futures could identify transmission facilities required in each. This would provide important data and information to developers and policymakers for the basis of future decision-making as well as renewable developers to facilitate more renewable generation.

A recent report prepared by the Brattle Group and Grid Strategies, LLC examines existing examples of holistic transmission planning and identifies five core principles for efficient transmission planning:

1. Proactively plan for future generation and load by incorporating realistic projections of the anticipated generation mix, public policy

[52] ANOPR at P 37.

mandates, load levels, and load profiles over the lifespan of the transmission investment.

2. Account for the full range of transmission projects' benefits and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.
3. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.
4. Use comprehensive transmission network portfolios to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.
5. Jointly plan across neighboring interregional systems to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.[53]

The report cites several examples of transmission planning approaches that utilized the principles and resulted in more cost-effective transmission projects and increased reliability and efficiency. Based on the existing examples, the report argues that transmission planners already have readily available tools to plan using these principles. The report contrasts the successful examples with the currently predominant use of reactive, single-driver approaches to transmission planning and concludes that the current approach is "systematically failing to identify and implement transmission options that offer the lowest system-wide costs and highest benefits for customers."[54] Consistent with AMP's observations of PJM's RTEP protocols, the report notes that "market and regulatory failures create perverse incentives that lead to under-investment in the type of

[53] Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs at 27-28 (October 2021) available at: https://earthjustice.org/sites/default/files/files/transmission-planning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs.pdf.

[54] *Id.* at 71.

regional and interregional transmission that would increase reliability and system-wide efficiency."[55] The Commission should consider reforms to the current transmission planning processes to include open, transparent and holistic regional planning for multiple future scenarios to avoid "unreasonably high system-wide costs that result from the current planning approaches, thereby enabling customers to pay just and reasonable rates by implementing these principles."[56]

VII. INTERCONNECTION QUEUE REFORM

Operating the transmission planning and generator interconnection processes in a more coordinated fashion could have merit. Efforts to reduce uncertainty faced by generators entering the queue later in time may be warranted. However, interconnection procedures must send appropriate price signals to generators to encourage efficient location of facilities and to reduce speculative applications.

Removing the participant funding requirement would create more speculative interconnection requests, not fewer.[57] Removing responsibility for network upgrade costs would allow generators a free option to explore additional projects that may or may not be economic based on other factors, such as permitting and land acquisition feasibility and costs. Further, the possibility that making interconnections "free" to generators would preclude developers from engaging in price discovery regarding network upgrades is no justification for shifting the costs and risks of interconnection-related network upgrades to LSEs and their customers. Instead, assessing higher fees earlier in the process would

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[55] *Id.*

[56] *Id.* at iv.

[57] *See* ANOPR at PP 118, 126.

tend to provide more certainty by discouraging submittal of speculative applications and encouraging earlier withdrawal from the queue of uneconomic projects.

Least-regrets planning for generator interconnections would analyze scenarios that account for the predicted withdrawal of earlier-queued projects. This would tend to produce a set of transmission solutions that more likely accommodate the interconnection customers that remain once others have dropped out of the queue, and improve the "ability of transmission providers to efficiently process interconnection requests from other interconnection customers"[58] by reducing the need for "numerous restudies and reallocation of interconnection-related network upgrade costs."[59] As a result, all interconnection customers would have more certainty over their ultimate share of costs of interconnection-related network upgrades.

Utilizing least-regrets planning for generator interconnections is also a prerequisite for effectively coordinating planning for generator interconnections and regional transmission planning. Optimal integration of these processes is impaired when the solutions to generator interconnection needs are continually in flux. Least-regrets planning would yield more stable solutions by considering multiple future interconnection scenarios.

The ANOPR inappropriately implies that "removing the possibly prohibitive cost assignment that participant funding can place on some interconnection customers" could justify burdening transmission customers, including LSEs and their customers, with those

[58] *See id.* P 114.

[59] *Id.* P 118.

costs.[60] To the extent that participant funding of network upgrades associated with a generator interconnection renders a project uneconomic, that generator should not be built. Eliminating the price signal associated with siting choices by socializing interconnection costs will lead to higher transmission rates, entail lost opportunities to site generation efficiently, and therefore yield higher overall electricity costs for consumers. Correlating interconnection costs with development of supply resources ultimately decreases the cost of electricity supply for customers by ensuring that generators are sited efficiently.[61]

The Commission should mandate a financial commitment sufficient to cover the interconnecting generator's allocated share of any regionally planned project that is designed as a solution to resolve multiple transmission issues (*e.g.*, reliability plus generator interconnection-related network upgrades). This commitment should be required on a timeline and in an amount that will ensure transmission customers are made whole in the event the generator withdraws from the project at any point. Generators that are not participating in regionally planned projects would not be similarly situated to participating generators because withdrawal of participating generators has the potential to shift costs to LSEs and their customers. This distinction supports imposing nonrefundable financial burdens on participating generators and, in return, effectively establishes a separate queue for these interconnections that in some cases could advance the participating generator's interconnection ahead of a non-participating earlier-

[60] *Id.* P 125.

[61] *See id.* P 114.

queued generator. Such advancement would be incidental to participation in the regional project, not unduly preferential.[62]

VIII. CONCLUSION

AMP appreciates the opportunity to provide feedback to the Commission on these important issues and respectfully requests that the Commission take AMP's views into consideration in fashioning any proposed changes to transmission planning, cost allocation and generator interconnection rules and procedures.

Respectfully submitted,

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[62] *See id.* P 156.

CERTIFICATE OF SERVICE

I hereby certify that I have on this date caused a copy of the foregoing document to be served on each person included on the official service list maintained for this proceeding by the Commission's Secretary, by electronic mail or such other means as a party may have requested, in accordance with Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010.

Dated this the 12th day of October, 2021.

/s/ Lisa G. McAlister
Lisa G. McAlister

4810-6613-4526, v. 9